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THE STATE OF SOUTH CAROLINA
In the Supreme Court

S.C. SUPREME COURT

APPEAL FROM THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA

Public Service Commission Docket Nos. 2018-319-E & 2018-318-E

Duke Energy Carolinas, LLC Appellant-Respondent,

v.

The South Carolina Office of Regulatory Staff, Hasala Dharmawardena, CMC Recycling, Cypress Creek Renewables, LLC, SC Department of Consumer Affairs, Sierra Club, South Carolina Coastal Conservation League, South Carolina Energy Users Committee, South Carolina Solar Business Alliance, Inc., the South Carolina State Conference of the National Association for the Advancement of Colored People, Upstate Forever, Vote Solar, and Walmart, Inc. Respondents,

of whom,

South Carolina Energy Users Committee is Respondent-Appellant.

Duke Energy Progress, LLC Appellant,

v.

The South Carolina Office of Regulatory Staff, Nucor Steel-South Carolina, Cypress Creek Renewables, LLC, SC Department of Consumer Affairs, Sierra Club, South Carolina Coastal Conservation League, South Carolina Energy Users Committee, South Carolina Solar Business Alliance, Incorporated, The South Carolina State Conference of the National Association for the Advancement of Colored People, Upstate Forever, Vote Solar, and Walmart, Inc., .. Respondents.

RECORD ON APPEAL

VOLUME II OF XIII

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1 imposed on you by the North Carolina DEQ for
2 allowing seeps from your coal ash ponds into
3 adjacent water bodies in some of your sites in
4 North Carolina; isn't that correct?

5 A (GHARTEY-TAGOE) That's correct.

6 Q Now, when -- when you estimate that excavating the
7 coal ash residuals from the wet ponds that --
8 pursuant to this DEQ order, is estimated to impose
9 an additional five to six billion dollars in costs,
10 those are costs that, at some later date, you would
11 seek recovery from South Carolina ratepayers?

12 A (GHARTEY-TAGOE) I think what you read said four to
13 five. Didn't it -- what you read earlier, I
14 thought, said four to five. But, in any event,
15 yes. We -- we --

16 Q I -- you're -- you're absolutely correct. I -- I
17 apologize. It's four to five billion dollars.
18 You're right.

19 A (GHARTEY-TAGOE) Yeah. But -- but I -- in any
20 event, we believe that compliance with
21 environmental regulations, whether propounded or
22 whether established by North Carolina or South
23 Carolina, is all cost of service because those
24 power plants were run to generate electricity that
25 was used to serve customers in North Carolina, as

1 well as South Carolina --

2 Q Yes. So --

3 A (GHARTEY-TAGOE) -- and --

4 Q I'm sorry. Go ahead.

5 A (GHARTEY-TAGOE) No, I was just going to say, and

6 the -- the natural byproduct of burning coal is

7 coal ash residuals, and so environmental

8 regulations associated with how you deal with that

9 is part of the cost of service.

10 Q Yes. But, in short -- stand corrected -- the four

11 to five billion dollar additional cost estimate

12 that Duke has published for excavating the coal ash

13 residuals from these ponds, those are costs that

14 you would seek to recover from your ratepayers,

15 correct?

16 A (GHARTEY-TAGOE) That's correct.

17 Q Okay. Now, can we agree that, if the coal ash

18 didn't get disposed of in these unlined ponds in

19 the first place, that the cost of managing the ash

20 from coal production might be significantly less

21 than it will be if you have to excavate these

22 ponds?

23 A (GHARTEY-TAGOE) I don't agree with that.

24 Q Well, put it this way: Don't you -- well, you do

25 agree, don't you, in your appeal -- in your

1 announcement of your appeal, you state explicitly
2 that simply capping these ponds is your preferred
3 alternative, and that that would be far less
4 expensive than excavating the waste and taking it
5 to a lined landfill elsewhere?

6 A (GHARTEY-TAGOE) Correct. And -- and -- yes. In
7 the case --

8 Q So --

9 A (GHARTEY-TAGOE) -- of these sites, yes.

10 Q Yes. So it follows, doesn't it, that if you didn't
11 put the wet ash in the pond in the first place, but
12 instead sent it to a lined landfill before it went
13 into the unlined pond, the cost of management would
14 be less, wouldn't it?

15 A (GHARTEY-TAGOE) No. I mean, you're talking about
16 ash that's been accumulated over decades and
17 second-guessing what we should've done so many
18 years ago. I don't know what the cost would've
19 been then or what the impact on customers would've
20 been.

21 Q But you can't -- you can't accept that it would've
22 been less expensive to have managed it properly in
23 the first place?

24 A (GHARTEY-TAGOE) I do not accept that it was
25 managed improperly.

1 Q Uh-huh.

2 A (GHARTEY-TAGOE) I think it was managed properly.

3 Q I see. Well, in fact, you say, indeed, that you've

4 managed your waste consistent with regulations

5 which have evolved since that time. That's --

6 that's your testimony, isn't it?

7 A (GHARTEY-TAGOE) That's correct.

8 Q All right. But indeed, Duke has not managed its

9 coal ash ponds consistent with the regulatory

10 requirements at all times, have they?

11 A (GHARTEY-TAGOE) There have been violations and --

12 and -- and that you've already noted them, with the

13 seeps and so forth. Yes.

14 Q In fact, you know, not just the penalties in North

15 Carolina for the seeps, but Duke Energy pled guilty

16 to criminally negligent violations of the federal

17 Clean Water Act for its coal ash management

18 practices at a number of its coal ponds in its

19 system, didn't it?

20 A (GHARTEY-TAGOE) Yeah. We pled guilty, yes. To --

21 yes -- a violation of the Clean Water Act.

22 Q Criminally negligent violation of the Clean Water

23 Act?

24 A (GHARTEY-TAGOE) Yes. Which is a strict liability

25 statute.

1 Q Yes. Indeed. And that reflects instances where
2 you certainly didn't act consistent with regulatory
3 requirements, and you acknowledge that?

4 A (GHARTEY-TAGOE) Yes.

5 Q Now, you volunteered again, as you did in your
6 testimony, that you're not seeking recovery from
7 the South Carolina Commission for any fines or
8 penalties incurred for your coal ash management
9 violations in this proceeding, correct?

10 A (GHARTEY-TAGOE) Correct.

11 Q All right. But, despite the fact that you're
12 not -- didn't seek fines or penalties in the North
13 Carolina companion cases, the North Carolina
14 Utilities Commission imposed a mismanagement
15 fine, a fine for mismanaging your coal ash, of some
16 \$30 million?

17 A (GHARTEY-TAGOE) Correct.

18 Q Now --

19 A (GHARTEY-TAGOE) But again, I would say, that was
20 the Commission's determination. They cited, I
21 believe, three instances, and I don't think that
22 reflects mismanagement of an entire fleet of coal
23 combustion basins.

24 Q I would say that -- strike that.

25 All right. Now, I take it that it's your

1 general contention that costs incurred for coal ash
2 management, that is costs included to -- costs for
3 excavating coal ash from your coal ash ponds or
4 otherwise closing those ponds -- capping them, say,
5 for example -- those costs as incurred to date have
6 been prudently incurred by Duke Energy?

7 A (GHARTEY-TAGOE) Correct. And that's why we're
8 requesting a recovery --

9 Q And --

10 A (GHARTEY-TAGOE) -- of those.

11 Q I'm sorry. You finished?

12 A (GHARTEY-TAGOE) And that's why we're requesting
13 recovery of those --

14 Q Indeed.

15 A (GHARTEY-TAGOE) -- costs.

16 Q And that's why, if they -- you're required to
17 excavate the additional ponds, as the North
18 Carolina DEQ has -- has ordered, you would assert
19 that it would be prudent to have those costs
20 charged to South Carolina ratepayers in a future
21 proceeding?

22 A (GHARTEY-TAGOE) Yes.

23 Q Now, when I say "prudent" -- we've had some
24 experience with this Commission and talking about
25 the -- the concept of prudence. You alluded to it

1 in your summary. When you're talking about nine or
2 ten billion dollars, you start ringing some bells
3 in South Carolina. And -- and I ask you whether or
4 not it's your contention that your coal ash
5 management practices are prudent in this sense.
6 Did Duke take all reasonable, prudent steps to
7 avoid, minimize, or mitigate the cost of managing
8 your coal ash?

9 A (GHARTEY-TAGOE) I believe so, and I think this
10 appeal we announced today is part of those steps.

11 MR. GUILD: All right. That's all I have.
12 Thank you.

13 CHAIRMAN RANDALL: Thank you. South Carolina
14 Energy Users?

15 MR. ELLIOTT: No questions. Thank you, sir.

16 CHAIRMAN RANDALL: Thank you. Nucor?

17 MR. SMITH: No questions, Mr. Chairman.

18 CHAIRMAN RANDALL: Thank you, sir. Office of
19 Regulatory Staff?

20 MR. BATEMAN: I have just a few questions, Mr.
21 Chairman.

22 CROSS-EXAMINATION

23 BY MR. BATEMAN:

24 Q Mr. Gharthey-Tagoe --

25 A (GHARTEY-TAGOE) Mr. Bateman.

1 Q -- how are you?

2 A (GHARTEY-TAGOE) Very well, thank you.

3 Q Could the ROE awarded by the Commission in this
4 proceeding potentially affect your total
5 compensation?

6 A (GHARTEY-TAGOE) In a very, very indirect way, but
7 -- actually, I take that back. No. You know,
8 because my compensation -- part of my compensation
9 is incentive based, and I think that's where you're
10 getting to it. Part of that incentive is achieving
11 a certain level of earnings per share. The
12 earnings per share is a calculation of how much
13 profit the Company actually makes. It's not based
14 on the allowed ROE. It's how much money the
15 Company actually makes divided by the number of
16 shares we have outstanding. I will add, the
17 earnings we make is also a component of both
18 revenue and costs, and, so, to the extent that I
19 work hard to reduce costs, I actually turn out well
20 because the earnings will be better. And that's
21 why it's -- it's -- baffles me that the ORS would
22 think earnings per share is a shareholder-focused
23 metric, when, in fact, reducing costs, keeping
24 costs low is directly related to the cost that our
25 customers bear.

1 Q Okay. Switching gears a bit from that, I'd like to
2 ask you a few questions about the Company's
3 stipulation with Nucor. Could you briefly explain
4 to me what the Company agreed to with Nucor?

5 A (GHARTEY-TAGOE) Very briefly, the settlement with
6 Nucor was that we would each -- essentially, one --
7 one of the proposals in this case is to take some
8 portion of the deferred -- excess deferred income
9 taxes reserve that was to go in -- go back to
10 customers -- we had proposed to essentially use it
11 to offset deferred costs associated with a
12 distributed energy program. And the agreement in
13 the settlement essentially allows for less than we
14 had originally proposed. Only about half would go
15 to defer those costs, and the other half would go
16 through other means to customers. That's one
17 element of the settlement.

18 I think the other one has to do with cost
19 allocation and, you know, meetings or corporation
20 associated with future cases. But I think all
21 customers actually do benefit from the settlement.

22 Q Is there anything that the Company agreed to with
23 Nucor not written in the stipulation?

24 A (GHARTEY-TAGOE) Well, yeah. There is a memorandum
25 of understanding that lays out meetings -- having

1 meetings and other engagement -- customer
2 engagement before we file the next case.
3 Q And meetings or customer engagement, anything that
4 would potentially or -- or that does impact
5 customers?
6 A (GHARTEY-TAGOE) There's no commitment, as I
7 understand it. And -- and Witness Bateman might be
8 able to help me here. There is no commitment in
9 the agreement that directly impacts customers, that
10 I'm aware of.
11 Q Mr. Gharthey-Tagoe, we've talked a little bit about
12 the Phase 1 and Phase 2 rates earlier from the
13 2016-227-E case. Regarding DEP's phase-in of
14 rates, isn't it correct that Phase 1 occurred -- I
15 think it was January 1, 2017?
16 A (GHARTEY-TAGOE) I'm going to ask --
17 A (BATEMAN) Are you asking me or . . .
18 A (GHARTEY-TAGOE) What -- what are you suggesting?
19 I talked about that?
20 Q I -- I may've been mistaken. I -- I did think that
21 we talked about it -- not -- not you and I, but --
22 A (GHARTEY-TAGOE) It may've been in your opening
23 statement, but I don't think it was part of my
24 testimony.
25 Q The question may be better directed to Ms. Bateman.

1 A (GHARTEY-TAGOE) Okay.

2 Q Ms. Bateman, was it January 1, 2017 for the initial
3 phase-in of rates?

4 A (BATEMAN) Yeah. So the rate increase started
5 January 1, 2017, and then there was an additional
6 step-up 1/1 of 2018.

7 Q That's right.

8 MR. BATEMAN: And, Mr. Chairman, I believe
9 that's outlined in Commission Order 2016-871.
10 I would just ask that the Commission take
11 judicial notice of that order.

12 CHAIRMAN RANDALL: We'll take judicial notice.

13 MR. BATEMAN: Thank you.

14 Q And, Mr. -- not Mr. Bateman -- Ms. Bateman. Excuse
15 me.

16 A (BATEMAN) Yes, Mr. Bateman.

17 Q Isn't it true that --

18 CHAIRMAN RANDALL: Now this is getting
19 confusing for me.

20 MR. BATEMAN: For me as well, Chairman.

21 Q Isn't it true that DEP does not have a storm damage
22 reserve fund?

23 A (BATEMAN) That is correct.

24 MR. BATEMAN: I think that that is everything
25 that I have. Thank you so much.

1 CHAIRMAN RANDALL: Thank you, Mr. Bateman.

2 Commissioners? Commissioner Ervin.

3 COMMISSIONER ERVIN: Thank you, Mr. Chairman.

4 EXAMINATION

5 BY COMMISSIONER ERVIN:

6 Q I was interested in -- during your earlier
7 testimony about the projected cost of -- that was
8 ordered by the North Carolina Commission to
9 completely remove all the coal ash. And what --
10 what was your estimate of cost, as you understand
11 it?

12 A (GHARTEY-TAGOE) An additional four to five billion
13 dollars.

14 Q Because the -- today's "Charlotte Observer" says
15 that, according to Duke Energy, it could go up to
16 as much as \$10.6 billion. Are you aware of that --
17 that statement?

18 A (GHARTEY-TAGOE) I'm not aware -- I haven't read
19 the "Observer," but I -- I wouldn't be surprised if
20 that was in reference to the total cost when you
21 add that four to six to existing costs that we've
22 calculated.

23 Q Yes, sir.

24 A (GHARTEY-TAGOE) But, again, this is all costs,
25 too, that could change because the work hasn't

1 started yet.

2 Q Correct. And isn't it also true that there's

3 pending, in the North Carolina General Assembly,

4 legislation that would allow for a securitization

5 of certain costs that have been incurred by Duke

6 Carolina?

7 A (GHARTEY-TAGOE) I believe it's legislation related

8 to storm costs, yes.

9 Q Storm damage --

10 A (GHARTEY-TAGOE) And, frankly --

11 Q -- costs?

12 A (GHARTEY-TAGOE) -- we'd love to pursue that here,

13 as well.

14 Q Yes, sir. I was going to ask -- that was going to

15 be my next question.

16 A (GHARTEY-TAGOE) There is actually a securitization

17 bill that's been introduced in the Senate, and

18 we're working, you know, with a sponsor to see if

19 it could be expanded to include storm costs.

20 Q Because that would have the effect -- could have

21 and most likely would have the effect of reducing

22 customer rates for those reimbursements?

23 A (GHARTEY-TAGOE) Absolutely. And -- and that's

24 why, in this case, we actually pulled out all storm

25 costs. You know, we've been deferring storm costs

1 for years. We have 2014 storm costs on our books,
2 and we pulled it out of this case and not asking
3 customers to pay for it now because we think going
4 in that direction could potentially save customers
5 money.

6 Q Millions of dollars, maybe billions.

7 A (GHARTEY-TAGOE) I don't know. Potentially.

8 Q Potentially?

9 A (GHARTEY-TAGOE) Could be. It all depends on what
10 -- the size --

11 Q Right.

12 A (GHARTEY-TAGOE) -- of what you're securitizing --

13 Q Sure.

14 A (GHARTEY-TAGOE) -- and how long you're spreading
15 it out over.

16 Q Well, has Duke Energy given any thought to using
17 securitization as a tool to -- to address the coal
18 ash cost in the future?

19 A (GHARTEY-TAGOE) I do know about a year ago when I
20 was in legal, it was something I thought about,
21 but, no, we haven't pursued that.

22 Q Theoretically, there's no legal impediment? I
23 mean, you could do that? You could use it for
24 that?

25 A (GHARTEY-TAGOE) In theory, you could, yes.

1 Q And I suspect that on -- on -- it could be used for
2 other costs like grid improvements. Is that part
3 of the legislation in North Carolina?
4 A (GHARTEY-TAGOE) No. It's not part -- I think the
5 North Carolina legislation is limited to storms.
6 Q Well, I'm pleased to hear that you're at least
7 considering it for South Carolina because, as we
8 heard in earlier cases -- not this one -- but we've
9 heard that -- that there is substantial cost
10 savings using that tool, and we currently don't
11 have securitization as a part of our law in South
12 Carolina, as you know. So --
13 A (GHARTEY-TAGOE) Yeah. We don't. Just to be
14 clear: I said I -- I have thought about it before.
15 Q Yes, sir.
16 A (GHARTEY-TAGOE) But it's not part of the
17 conversation.
18 Q I -- I understand.
19 A (GHARTEY-TAGOE) Yeah.
20 Q I understand. But it could become a part of the
21 conversation, assuming we got it passed in South
22 Carolina?
23 A (GHARTEY-TAGOE) Yes.
24 Q On Page 31 of your testimony --
25 A (GHARTEY-TAGOE) My direct or rebuttal?

1 Q I believe it's your direct testimony --

2 A (GHARTEY-TAGOE) It would be -- yes. It would be

3 direct.

4 Q -- notes here.

5 A (GHARTEY-TAGOE) Yes.

6 Q You tout the Company's top quartile performance in

7 the JD Power Electric Utility Residential Study.

8 And you've mentioned that earlier today in --

9 A (GHARTEY-TAGOE) Yes, sir.

10 Q -- answering your attorney's questions, and you're

11 to be congratulated on that. It's a very good

12 record. But my question is: On Page 22 of your

13 testimony, you -- you also promote the AMI

14 technology that would reconnect customers faster

15 during power outages and perhaps improve

16 information related to outages. I guess my

17 question is: Since you already have demonstrated

18 such a great service record based on the JD Power

19 Residential Study, do you really need further

20 investments to improve this type of customer

21 service? I mean, you're already doing very well.

22 You're at the top of the nation. How do you

23 justify more costs at this time?

24 A (GHARTEY-TAGOE) I would say absolutely because

25 customer expectations continue to change. We have

1 customers who are used to shopping on Amazon using
2 an app, and until recently, there was no Duke
3 Energy app, for example. So, you know, we -- we --
4 customers start getting used to being able to have
5 everything at their fingertips. The opportunity to
6 pick their own due date, that was something we
7 couldn't offer customers without an AMI
8 infrastructure. Today, you can call the Company
9 and say, "I get paid on the 6th of the month, and I
10 want my bill due on the 6th," and we can make that
11 happen. These are all changing expectations, and
12 my challenge is keeping up with those expectations.
13 And, for the most part, keeping up with those
14 expectations requires to continue to invest to
15 provide reliable, safe, affordable service for our
16 customers.

17 Q Has Duke conducted any kind of cost-benefit
18 analysis to determine whether this would result in
19 the customers saving any money if -- with -- with
20 this increased investment in IT?

21 A (GHARTEY-TAGOE) I would defer that to Jay Oliver
22 or Dan Schneider. I would say Dan Schneider. But
23 I do know -- we know that it will save some money
24 on O&M, for example, because now we do not have to
25 dispatch trucks to do certain things that the AMI

1 can now tell us through computers. So there is
2 some savings in the long run, I believe.
3 Q You also state in your testimony that you're using
4 the "IH-tron" (phonetic) -- am I pronouncing that
5 correctly? -- metering.
6 A (GHARTEY-TAGOE) "EYE-tron" (phonetic) --
7 Q -- Itron --
8 A (GHARTEY-TAGOE) Yes.
9 Q -- Incorporated AMI meter --
10 A (GHARTEY-TAGOE) Yes.
11 Q -- meter provider?
12 A (GHARTEY-TAGOE) Yes.
13 Q It looks like their online catalog lists several
14 meter models that provide multiple applications
15 like you talked about --
16 A (GHARTEY-TAGOE) Yes..
17 Q -- to meet the customers' needs.
18 Did you or someone with Duke look at all the
19 various models and do a comparison to determine
20 whether you're, you know, getting the right one, so
21 to speak?
22 A (GHARTEY-TAGOE) I would defer that to
23 Mr. Schneider, but I think we're getting the best.
24 But, again, with technology, things do change, and
25 as things change, demands change. We may, you know

1 -- when it comes to technology, you're always
2 trying to catch up, usually.
3 Q Is -- is this the same model of meter that you're
4 rolling out for Duke Energy Progress customers?
5 A (GHARTEY-TAGOE) I believe so.
6 Q Is it systemwide pretty much the same --
7 A (GHARTEY-TAGOE) Yes.
8 Q -- meter?
9 A (GHARTEY-TAGOE) It is. It is.
10 Q All right. Did you get some kind of discount on
11 the economy of scale that way?
12 A (GHARTEY-TAGOE) I would hope so. Hopefully --
13 Q I would hope so, as well.
14 A (GHARTEY-TAGOE) -- Mr. -- Mr. Schneider can tell
15 us.
16 Q That's a lot of meters.
17 A (GHARTEY-TAGOE) Yes. It is.
18 Q I want to thank you for your follow-up that you've
19 done. You testified about -- earlier today about
20 following up with individual customers' complaints
21 that we heard at the hearings.
22 A (GHARTEY-TAGOE) Yes, sir.
23 Q And I think that's important, and I appreciate you
24 -- you and your staff doing that. I think it's a
25 very commendable and responsible action to take.

1 I'm particularly interested in hearing a little bit
2 more information about the farmers we heard in
3 Florence and in Sumter, but particularly in
4 Florence from those farmers who felt like they may
5 be misclassified.

6 A (GHARTEY-TAGOE) Yes.

7 Q And you addressed that earlier.

8 A (GHARTEY-TAGOE) Yes.

9 Q You said you identified a certain number of farmers
10 that could -- may benefit from a reduced-rate
11 structure. Do you recall about how many there
12 were, or is that available information?

13 A (GHARTEY-TAGOE) It is, and Mr. Wheeler can give
14 you the specifics, but my recollection is there
15 were about 71 or so who are on MGS and I believe
16 about 59 could actually switch and save money.

17 Q Great.

18 A (GHARTEY-TAGOE) And we've been calling each one of
19 them.

20 Q So you're reaching out to them?

21 A (GHARTEY-TAGOE) Absolutely.

22 Q Great.

23 A (GHARTEY-TAGOE) And I actually called the
24 Commissioner of Agriculture myself, as well as
25 Mr. Ott. Unfortunately, I did not reach them, but

1 I wanted to give them a heads-up that we were doing
2 that.

3 Q I -- I think that's great because, as you -- you
4 know, we heard a lot of testimony about their
5 financial struggles with the storms and --

6 A (GHARTEY-TAGOE) Yes.

7 Q -- and the tariffs and the other cost drivers; it's
8 really putting tremendous economic pressure on --
9 on the farmers in South Carolina in your area.
10 And, of course, any -- any relief would be welcomed
11 relief, so I particularly appreciate that.

12 A (GHARTEY-TAGOE) I agree with that. Thank you.

13 COMMISSIONER ERVIN: Those are the questions I
14 had.

15 CHAIRMAN RANDALL: Thank you. Commissioner
16 Williams?

17 VICE CHAIRMAN WILLIAMS: Thank you,
18 Mr. Chairman.

19 EXAMINATION

20 BY VICE CHAIRMAN WILLIAMS:

21 Q Ms. Bateman, Mr. Gharthey-Tagoe, a few questions for
22 you two.

23 I wanted to echo Commissioner Ervin's
24 commentary regarding following up with your
25 customers. I also appreciate the -- the

1 transparent nature of your presentations today, and
2 I hope you appreciate the Commission's
3 responsibility to ensure that the Company meets its
4 burden and that we provide just and reasonable
5 rates. It's all a part of the process, as you
6 know.

7 I -- I had a question, Mr. Gharthey-Tagoe. I
8 hope you can educate me on something. Earlier this
9 morning -- I can't remember if it was during your
10 summary or during cross-examination -- I think you
11 mentioned that the Company is currently earning
12 about a 4.1 or maybe 4.5 return on equity.

13 A (GHARTEY-TAGOE) No. A 4.1 overall return on rate
14 base.

15 Q Return on rate base. What -- what's the
16 difference?

17 A (GHARTEY-TAGOE) So the -- and when a commission
18 sets rates, it sets a return on rate base, because
19 it's a rate of return, cost-of-service
20 jurisdiction. And that return on rate base is the
21 return we're allowed to earn on the capital we've
22 invested to provide service, and it's a combination
23 of debt costs as well as equity costs because if --
24 this is the way most utilities operate -- investor-
25 owned anyway.

1 Every dollar we spent is either borrowed from
2 lenders, like banks, or from equity shareholders or
3 people who buy our shares. And so the cap
4 structure is a reflection of how much of that cost
5 we've invested was borrowed from banks and lenders
6 or from shares that we sold to shareholders. And
7 each one of these suppliers of capital require to
8 be paid in terms of a return, whether it is a
9 stated interest rate, which is the debt cost, or
10 their return on equity, which is not a stated cost
11 but this Commission sets that level of cost by
12 hearing testimony from witnesses in a case like
13 this.

14 It's the -- essentially, the combination of
15 the two that results in your rate of return on rate
16 base that is set as a basis for setting rates in
17 the case. So the return on equity is just one
18 component of the return on rate base that the
19 Commission allows. I think I said that right.

20 A (BATEMAN) Yes.

21 Q So -- so when -- when you're earning a -- a 4.1, is
22 -- is that -- what is that indicative of? What --
23 what could I tell about the Company based on that
24 metric --

25 A (GHARTEY-TAGOE) So --

1 Q -- or that number?

2 A (GHARTEY-TAGOE) Exactly. And -- and I should have
3 said that, in context, in the last rate case the
4 Commission allowed us to earn 7.1, which is a
5 reflection of the return on equity of 10.1 percent,
6 as well as the cost of debt, which I do not
7 remember at this time. So when the Utility is
8 earning less than its return -- allowed return on
9 rate base, it means it has a certain amount of
10 costs that it is not recovering through its current
11 rates. And that's when you are prompted to come in
12 to adjust those rates. Sometimes we're able to get
13 by without coming in immediately because of the
14 benefit of deferrals and the ability to earn
15 returns on deferrals. Okay.

16 So if you enter a world where you're not
17 allowed to defer any costs or you defer a cost at
18 the detriment to the people who lend you the money,
19 then you get into a world where we will be more
20 likely to be coming in more frequently to recover
21 costs that have been invested to benefit customers.

22 Q Thank you. I appreciate you sharing that with me.

23 Anything you'd like to add, Ms. Bateman? I
24 don't want to leave you out.

25 A (BATEMAN) Maybe just refer you to my Bateman

1 Exhibit 1. Page 2, I think, kind of lays those
2 numbers out and shows the return on equity at the
3 present rates and then, of course, at the proposed.
4 And that all goes into the calculation of the rate
5 increase in this case that we're requesting.

6 Q Okay. Thank you for pointing that out.

7 A (GHARTEY-TAGOE) Thank you.

8 Q Mr. Gharthey-Tagoe, on Page 35 of your prefiled
9 direct testimony, you mentioned investing
10 approximately \$500,000 over the past three years in
11 workforce training programs.

12 A (GHARTEY-TAGOE) Yes.

13 Q I was curious to know whether or not that training
14 is exclusively for Duke talent, or is there
15 investments in community organizations or -- or any
16 entity outside of Duke?

17 A (GHARTEY-TAGOE) No. It's not just for Duke
18 talent. It's for all talent. And I will say last
19 year we also invested another million dollars to
20 the South Carolina technical college system to be
21 awarded as grants to technical colleges all over
22 the state to train linemen, which is one area where
23 we have difficulty hiring enough given the amount
24 of work we've got going on. But they're not --
25 those students, once they graduate, don't have to

1 come to work for Duke. They can work -- and these
2 are not -- I would say -- not customer dollars;
3 these are shareholder dollars that are given as
4 donations.

5 Q So since you've seen -- the Company has a -- a
6 problem recruiting and retaining linemen or just
7 recruiting linemen?

8 A (GHARTEY-TAGOE) Well, I think there's a retention
9 -- there could a retention issue, too. You know,
10 I've heard. And -- and this -- that's not where I
11 spend my time every day. But there are linemen who
12 are contractors. You know, we use a lot of
13 contractors, particularly when it gets to linemen,
14 too, on the distribution system. There are some
15 who -- who move wherever the work is. So they'll
16 work here a little bit, move to Virginia, move to
17 Ohio, if the money is better there.

18 But beyond that, I think most of why we need
19 more is -- so we need more with new or additional
20 skills because, as we deploy things like we
21 proposed in our grid improvement plan, like self-
22 healing networks and so forth and so on, you need
23 the kind of linemen that can manage those and deal
24 with those types of new technologies as well.

25 Q Do you know whether or not the majority of your

1 linemen are South Carolina residents?

2 A (GHARTEY-TAGOE) I do not know that. I do know
3 that, at least for those employed by Duke, we have
4 just a little over 4,000 total employees in the
5 state, but I would say most of them work at our
6 nuclear plants. We have five nuclear units in the
7 state, and most of the -- our employees work there.
8 The remainder will probably be in the distribution
9 and transmission business.

10 Q Thank you. Ms. Bateman, one question for you --

11 A (BATEMAN) Yes.

12 Q -- or a couple of questions.

13 On Page 21 of your direct testimony, you state
14 that the Company subtracted \$1.5 million from the
15 coal ash deferral balance to -- to exclude South
16 Carolina retail portion of the amount that the
17 North Carolina Utility Commission disallowed?

18 A (BATEMAN) Yes.

19 Q Does this amount include South Carolina's portion
20 of a \$30 million mismanagement penalty imposed by
21 the North Carolina Commission?

22 A (BATEMAN) No. It does not. That is just the
23 South Carolina portion of the -- a particular
24 prudence disallowance.

25 Q Okay. And -- and any reason why it doesn't -- why

1 you don't include that?

2 A (BATEMAN) We didn't agree with the management

3 penalty.

4 Q Okay. Does the Company agree that the deferral

5 balance noted by the Office of Regulatory Staff

6 witness Payne, on Page 4 of his surrebuttal

7 testimony, including coal ash contained both

8 operating- and capital-related costs?

9 A (BATEMAN) One second. On his surrebuttal

10 testimony?

11 Q Yes, ma'am.

12 A (BATEMAN) And what page was that?

13 Q Page 4.

14 A (BATEMAN) So does the coal ash balance include

15 both operating and capital?

16 Q Yes, ma'am.

17 A (BATEMAN) So, yes, there is a small piece that the

18 ORS has designated as operating related, and that

19 relates to our capital investments at our operating

20 plants. There is a small portion of depreciation

21 expense -- deferred depreciation expense that

22 results from those capital investments at operating

23 plants --

24 Q Okay.

25 A -- that -- that the ORS has put in that category.

1 Q Okay. Thank you.

2 VICE CHAIRMAN WILLIAMS: That's all my
3 questions, Mr. Chairman.

4 CHAIRMAN RANDALL: Thank you. Commissioner
5 Whitfield.

6 COMMISSIONER WHITFIELD: Thank you,
7 Mr. Chairman.

8 EXAMINATION

9 BY COMMISSIONER WHITFIELD:

10 Q Good afternoon, Ms. Bateman and Mr. Gharthey-Tagoe.

11 A (GHARTEY-TAGOE) Good afternoon.

12 A (BATEMAN) Good afternoon.

13 Q Want to -- got a couple of questions for you, and
14 want to just start off briefly by also reiterating
15 what my colleagues have said: I want to -- want to
16 thank you for following up with those customers at
17 the night hearing and Ms. Smith interjected that
18 here today on the stand, regardless of where you
19 put it here at -- in this part of the case or if
20 you do it in the proposed orders, I certainly
21 applaud you for it for the customers who are
22 struggling -- the residential customers who are
23 struggling and certainly the farmers.

24 And, Mr. Gharthey-Tagoe, I hope that the
25 remaining eleven or twelve farmers who are not

1 eligible for the other rate tariff, that you-all
2 will follow up with them and -- and try to work
3 with them to -- to help them find a solution, as we
4 know how important agriculture is to this state and
5 we also realize the seasonal use and nature of
6 their business. So hopefully, maybe, perhaps in a
7 proposed order you could -- or toward the end, you
8 could update us as you move forward on that.

9 A (GHARTEY-TAGOE) Let me say, those 11 -- and
10 Mr. Wheeler can provide detail on this, but those
11 11, we believe, are best served on the MGS
12 schedule. In other words, their usage is so
13 high --

14 Q Uh-huh.

15 A (GHARTEY-TAGOE) -- that moving them to a
16 different --

17 Q Okay.

18 A (GHARTEY-TAGOE) One -- one, the -- the -- the
19 nature of their operation is such that that's the
20 best rate for them, and then their usage is also so
21 high that the increase in the basic facilities
22 charge really does not impact them the way it does
23 the others.

24 Q Well, I certainly appreciate your reaching out to
25 the 59, and -- and, hopefully, you or your -- your

1 customer service department or some of the folks at
2 -- at the Company can -- can work with them to
3 continue to find solutions.

4 A (GHARTEY-TAGOE) Absolutely. I mean, the -- the --
5 you know, we will certainly -- I think one of the
6 concerns they expressed was that they -- they don't
7 have any designated folks to call when they have a
8 need and so forth. So that's something I'm working
9 through right now.

10 We do have large account managers for folks
11 whose accounts are fairly complex, like industrial
12 operations and all of that. We don't have it for
13 the agricultural community. But we do have it for
14 small/medium business. You know, so I will be
15 working through my internal organization to figure
16 out how best to provide them additional service.

17 Q Well, I hope so. Sounds like you do have ten or
18 eleven/twelve, that -- that don't fit, quite, the
19 industrial rep person's duties or anyone else. So
20 let's -- let's just -- hopefully, they won't fall
21 through the cracks, so to speak.

22 A (GHARTEY-TAGOE) Yes, sir.

23 Q And -- well, thank you for that. And I've got a
24 couple of questions for you.

25 Mr. Gharthey-Tagoe, on Pages 22 through 24 in

1 your prefiled direct testimony, you discuss the
2 Company's proposal for a -- a fee-free credit card
3 program, and we -- we had -- this came up in the
4 DEC case as well. But with respect to this case
5 and with respect to your proposal for residential
6 customers not to pay a convenience fee for account
7 payments via some -- some payment channels, you
8 discuss eliminating the fees for residential
9 customers. And aren't you still going to collect
10 those fees, but just from a different pot of
11 customers?

12 A (GHARTEY-TAGOE) Well, I think the short answer to
13 the question is: We don't collect the fees. We
14 use a third party call "Speedpay" to handle
15 payments. That third party requires the fee. So
16 that's Point Number 1. So it doesn't go into Duke
17 Energy's pocket.

18 Q Correct.

19 A (GHARTEY-TAGOE) It goes into the third party for a
20 -- they actually provide a service. I will also
21 say that today, the other means of payment that do
22 not include a fee, like mailing in a check, like
23 paying by cash or going to a free pay station, all
24 involve some level of costs, and those costs are
25 included in our total cost of service. What we're

1 proposing is to allow those who choose to pay by
2 credit card and debit card to also do so, much like
3 those who mail in checks, except that the
4 associated costs with that also be included in
5 costs of service, much like we do for those who pay
6 by check, cash, or -- or the other payment centers.
7 Q Well, to keep from using the "socializing" word --
8 socializing the costs, folks that are -- that are
9 paying by check or -- or -- or paying directly like
10 that, aren't you -- and I realize the Company
11 doesn't get any of those fees, and I know we're
12 talking about a small amount. I think with some
13 residents that we heard from the night hearings, I
14 think it's the principle of the thing that -- that
15 they have to bear anything to -- in other words,
16 that they have to pay anything to, in effect, pay
17 Duke. You follow what I'm saying?
18 A (GHARTEY-TAGOE) Yes. And -- and that's why we're
19 proposing this. It -- it does come through -- not
20 only through the night hearings, but even in
21 surveys that we conduct, one of the most vexing
22 things for customers is to pay a fee to pay their
23 bill.
24 Q Right.
25 A (GHARTEY-TAGOE) But again, it is a convenience

1 feature. We could -- we could say, "We're not
2 going to let customers pay by credit card or debit
3 card anymore." And I can assure you there would be
4 more customers who are upset about that. All
5 right.

6 We try to make things easier and more
7 convenient for today's economy, and that includes
8 providing the means to pay by credit card or debit
9 card. And because there's a fee associated with
10 it, a fee that we do not benefit from, we think it
11 is appropriate to -- to satisfy those customer
12 conveniences -- to treat it like the other costs
13 associated with the other payment channels.

14 Q And I realize you say the Company doesn't get any
15 of that, and -- and you've been very clear on that.
16 But by your projections, how much will this fee
17 impact each Progress Energy customer's -- Progress
18 residential customer's bill for them?

19 A (GHARTEY-TAGOE) I don't know that off the top of
20 my head, but Witness Quick --

21 Q Quick. Okay.

22 A (GHARTEY-TAGOE) -- will have that.

23 Q Well, I've got another one that you may punt to
24 Witness Quick, also. What -- what percentage do
25 you think the credit card adoption will increase by

1 or what numbers do you think that you project it to
2 increase for the -- for the Progress? I think I
3 asked you this same question --
4 A (GHARTEY-TAGOE) Yeah.
5 Q -- for the DEC --
6 A (GHARTEY-TAGOE) Yeah.
7 Q -- territory.
8 A (GHARTEY-TAGOE) Yeah. I think --
9 Q But for the Progress territory?
10 A (GHARTEY-TAGOE) Yeah. I think it's 10 percent,
11 but again Witness Quick will correct me, I'm sure.
12 Q Okay. I'll make a note to ask her those.
13 A couple of more for you right quick. On Page
14 25 of your testimony, Mr. Gharthey-Tagoe -- I'll
15 give you just a minute to get there.
16 A (GHARTEY-TAGOE) I'm there.
17 Q Okay. Near the top, you say -- you make a
18 statement, I think, along about Line 6. You talk
19 about the cost of electricity in the Southeast
20 dropped 2.6 percent from September 2017 to
21 September 2018. Where did you get that data from,
22 and where do you -- could you -- what are you
23 basing that on? Could you expound on that just a
24 little bit?
25 A (GHARTEY-TAGOE) Yes. That's based on -- in real

1 terms, so if you factor in inflation, you look at
2 what the rates were in 2017 to what the rates are
3 in September 2018, and you calculate it in real
4 terms. That's the result of that.

5 Q Okay. So you're factoring in inflation and
6 other --

7 A (GHARTEY-TAGOE) Yes.

8 Q Okay. All right. Thank you.

9 And one more question for you, Mr. Gharthey-
10 Tagoe. On Page 18 of your direct testimony, you
11 talk about Duke recycling 78 percent of coal
12 combustion byproducts in 2017. That's a pretty
13 high number or higher than I thought. I know in
14 the past utilities weren't able to recycle as much
15 because there were certain other pollutants in the
16 -- in the byproduct that disallowed your -- or made
17 you unable to recycle large portions like this.
18 Could you talk about that just a second?

19 A (GHARTEY-TAGOE) I'll defer that to Mr. Kerin to
20 give you more specifics on that. But, again, this
21 is about recycling in -- in terms of -- I mean,
22 we're talking about beneficial use as well, and
23 it's --

24 Q Right.

25 A (GHARTEY-TAGOE) -- used in road construction. I

1 know some of it has been used at the -- our tarmac
2 at the Asheville airport, for example. But Witness
3 Kerin can give you --

4 Q Okay.

5 A (GHARTEY-TAGOE) -- more detail around that.

6 Q Well, I'll make a note of that to ask him that, as
7 well.

8 A (GHARTEY-TAGOE) Thank you.

9 Q Last question for you -- and -- and if you need to
10 let Ms. Bateman jump in on this one, feel free,
11 since I've kind of left her out. But you have a
12 breakdown on page -- well, you -- you cite a lot of
13 Commission orders on Page 14 of your direct
14 testimony that -- that are things that are
15 included, and I'm familiar with a lot of the -- the
16 orders there -- there in recent years going back to
17 2013.

18 But you've got one that goes way back before
19 my time here to 2001, and it dealt with costs
20 associated with filing notices of application and
21 withdrawal, along with other utilities in the
22 state, to form an RTO. Of course, we're -- we
23 don't have an RTO here.

24 A (GHARTEY-TAGOE) Yes.

25 Q And there's all kind of chatter about all kinds of

1 things going on, but if you could, tell us -- I
2 think Ms. Bateman may have a -- that in her chart,
3 but tell us what that -- how much of that, in
4 dollars, is attributable to that order and -- and
5 where -- what that might entail. And if you want
6 to pull Ms. Bateman in, certainly --

7 A (GHARTEY-TAGOE) Yeah. I don't want her to feel
8 left out.

9 Q Right.

10 A (BATEMAN) Yeah. So the RTO is often called
11 "GridSouth." That might ring a bell. So Duke
12 Energy Carolinas, Duke Energy Progress, and SCE&G
13 all had deferred costs related to this project to
14 explore developing a regional RTO in the area. And
15 then, as it says here, we submitted an application
16 and then a withdrawal. And so all three companies
17 had deferred costs that needed to be recovered from
18 customers. Duke Energy Progress, because we went
19 so long without a rate case and then deferred these
20 costs in the last rate case -- I believe we're the
21 only one that still has these costs left on our
22 books. And I do have the amount.

23 Q Yeah. If you could --

24 A (BATEMAN) Yeah.

25 Q I think it's in --

1 A (BATEMAN) So the GridSouth deferred balance is
2 3,676,000.

3 Q Thank you, Ms. Bateman. Thank you, Mr. Gharthey-
4 Tagoe.

5 COMMISSIONER WHITFIELD: That's all I have,
6 Mr. Chairman.

7 CHAIRMAN RANDALL: Thank you. Commissioner
8 Belser.

9 COMMISSIONER BELSER: Thank you, Mr. Chairman.

10 EXAMINATION

11 BY COMMISSIONER BELSER:

12 Q Good afternoon, Mr. Ghartego.

13 A (GHARTEY-TAGOE) Good afternoon.

14 Q Gharthey-Tagoe. I'm sorry.

15 In your prefiled testimony and also in your
16 summary, you made several references that the
17 Company is complying with state and federal
18 regulations requiring the Company to address coal
19 ash. Can you tell me what those state and federal
20 regulations are?

21 A (GHARTEY-TAGOE) I'm referring --

22 Q You can use their common names if you need to.

23 A (GHARTEY-TAGOE) Yes. The federal CCR rules --

24 Q Okay.

25 A (GHARTEY-TAGOE) -- or coal combustion residual

1 rules.

2 Q Right.

3 A (GHARTEY-TAGOE) That's EPA rules. And then the
4 North Carolina Coal Ash Management Act. The -- in
5 South Carolina, there is no promulgated rule except
6 for general Clean Water Act type rules, but we do
7 have a consent agreement with the Department of
8 Health and Environmental Control to -- that
9 dictates how we can address our coal combustion
10 residuals.

11 Q How did that consent order come about?

12 A (GHARTEY-TAGOE) I -- I don't know. That was
13 before -- I think it was before my tenure, but as I
14 understand it, a similar agreement was entered into
15 with other utilities in the state.

16 Q Who -- I reckon I'm wanting to know: Who initiated
17 the discussion on the consent agreement?

18 A (GHARTEY-TAGOE) You know, we -- we may have been
19 the ones who approached DEQ -- sorry -- DHEC about
20 how they intended or wanted us to deal with the
21 issue. Yeah. I wouldn't be surprised if we
22 initiated -- we were proactive and called them.

23 Q Let's see. In your -- your -- your summary, you
24 mentioned automated phone calls to customers. What
25 -- what were those about?

1 A (GHARTEY-TAGOE) So particularly -- that was, I
2 think, specifically for the notice to the night
3 hearings. We -- we were required to provide
4 notice, and we thought putting it in a newspaper,
5 given the timing, would not have allowed enough
6 customers to be aware of it, and so we initiated
7 "robocalls," as some call it. We don't think ours
8 was as annoying as some of the other ones people
9 get, but that was one way to reach out to customers
10 to invite them to --

11 Q Did they go -- did they go to all customers?

12 A (GHARTEY-TAGOE) That was the goal, yes.

13 Q Sure about that?

14 A (GHARTEY-TAGOE) Well, if we had their number. How
15 about that? If we had their phone number.

16 Q Okay. I just don't think I got one or two. Didn't
17 get any, and I think y'all have got both of my
18 numbers.

19 Let's see. Addressed Mr. Ervin. Vegetation
20 management practices. There were some discussions
21 -- numerous -- well, several discussions during the
22 night hearing, and I reckon I'm a little concerned
23 where there is an easement, and there were a couple
24 of people that talked about danger trees outside of
25 the easement that -- that Progress is now requiring

1 to be cut. And one gentleman said that they were
2 topped off and he couldn't salvage, and another one
3 talked about trees in his yard. What's the
4 authority for removing those trees outside the
5 easement?

6 A (GHARTEY-TAGOE) It's actually spelled out in the
7 easement that, in addition to having that right-of-
8 way, we would have a right to also cut trees that
9 are deemed to be danger trees, which are trees that
10 may be outside the right-of-way but have a
11 potential to fall on a line or in the right-of-way
12 blocking access, and so --

13 Q Blocking access?

14 A (GHARTEY-TAGOE) Well, you know, I'll let
15 Mr. Oliver address that. But I -- I think, if it
16 falls into -- if it has the potential to (hits
17 microphone) fall into the right-of-way --

18 Q I do that all the time.

19 A (GHARTEY-TAGOE) Yeah. Yeah. So it's not just a
20 question of falling on the line, but if there's a
21 problem and you need to access the right-of-way,
22 you know, a tree blocking your way could make a
23 difference between how quickly you restore power.
24 But this is all spelled out in the easement itself.

25 Q Even in those easements that were engaged or

1 executed back '30s and '40s? I think there was
2 some testimony about some pretty old easements.
3 A (GHARTEY-TAGOE) I -- I believe that.
4 Q Okay. There was one gentleman that talked about --
5 about the call with FERC, and I think he had
6 invited some people from Progress to join him on
7 that call with FERC. Do you recall that?
8 A (GHARTEY-TAGOE) I recall that, yes.
9 Q Do you know if those gentlemen did join in on that
10 call?
11 A (GHARTEY-TAGOE) I'm not aware that we were invited
12 to join in on any call.
13 Q Oh, I'm sorry. I thought that -- I forgot his last
14 name now. Mr. Chewning in Sumter.
15 A (GHARTEY-TAGOE) Yes. Yes.
16 Q Okay. Mr. Timmons from Timmonsville, I had a note,
17 said he can't even read his meter and that DEP told
18 him it was up to the subcontractor who put the
19 meter in. Did y'all happen to follow up on that?
20 A (GHARTEY-TAGOE) We did. And -- and we gave him
21 some education on how to read the meter. I think
22 we need to actually improve the information we have
23 on our website, but that's actually available on
24 the website, as well. But I'm -- I was surprised
25 by that response. I don't know why we would refer

1 him to a subcontractor to help him read his
2 meter --
3 Q Well, I was --
4 A (GHARTEY-TAGOE) -- because it is our meter and
5 so --
6 Q I was looking -- I was wondering that, too, because
7 I went back and looked at the reg, and the reg says
8 -- actually, it says "upon request." But I didn't
9 remember that part of it. "Inform its customers as
10 to the method of reading meters," so --
11 A (GHARTEY-TAGOE) Exactly. And -- and when we get
12 new customers, we give them a -- sort of a "welcome
13 to the neighborhood" kit that includes the Customer
14 Bill of Rights, and in there is also some
15 information about meter reading, getting your meter
16 checked upon request once a year or so. So I was
17 very surprised to hear him say that's the response
18 he got.
19 Q There were one or two folks that said that they --
20 somebody had sent a letter to Ms. Good asking for
21 the number of irrigation --
22 A (GHARTEY-TAGOE) Yes.
23 Q -- meters out there. Did y'all ever come up with a
24 number on how many irrigation meters are DEP --
25 A (GHARTEY-TAGOE) Yeah. So that's the letter I

1 refer to in my -- the supplemental --

2 Q Okay.

3 A (GHARTEY-TAGOE) -- Q-and-A that I did with
4 counsel. The number is 513. He thought it should
5 be higher. But, again, when customers sign up, I
6 don't think there's a category that says, "I'm an
7 agriculture customer."

8 Q Right.

9 A (GHARTEY-TAGOE) You know, so we did the research
10 based on SIC codes, which is an industrial coding
11 system for businesses. And that's how we
12 determined that number. And Mr. Wheeler, who is --
13 who did the analysis or was part of that, can tell
14 you more about how we went about identifying who
15 were our agricultural customers.

16 Q For those irrigation pivot meters that some folks
17 have wanted off of the medium general service,
18 what's the new schedule that they were being told
19 about? Do you know?

20 A (GHARTEY-TAGOE) I believe some of them -- and,
21 again, Mr. Wheeler can be -- you know, can help you
22 with that. But some -- for some, we do have a
23 seasonal and -- and intermittent service schedule
24 -- an SI schedule that was beneficial to them, and
25 that was the schedule that I believe we recommended

1 to them.

2 Q Probably one of the -- one or the other, either

3 medium general service or seasonal or --

4 A (GHARTEY-TAGOE) Yes.

5 Q -- maybe some on small general?

6 A (GHARTEY-TAGOE) Yes. Yes. I mean, I think --

7 again, we -- we were just addressing the medium

8 general services -- the MGS class, so they would be

9 moving from there to SGS, yes, or SI, the seasonal

10 intermittent.

11 Q All right. With regard to the -- you mentioned

12 some disagreement with, I believe ORS's adjustment

13 to remove some dues of -- of Chamber of Commerce or

14 -- or other kind of community dues. Would you

15 agree that a corporation such as Duke, that it's

16 very important to be seen as a good corporate

17 citizen?

18 A (GHARTEY-TAGOE) I hear that all the time.

19 Q Is it only going to be a good corporate citizen if

20 the ratepayers pay all the bills?

21 A (GHARTEY-TAGOE) No. The shareholders pay --

22 Q And I'm not trying to be argumentative.

23 A (GHARTEY-TAGOE) No, no. No, no.

24 Q This is kind of figuring out who's responsible for

25 what in this situation.

.1 A (GHARTEY-TAGOE) Yeah. Yeah. Certainly. I mean,
2 our shareholders do pay a lot. As I mentioned, you
3 know, we just gave a \$1 million grant to the
4 technical colleges to train workers, not all of
5 whom would ever -- may ever work at Duke. That's
6 part of our contribution to making this the great
7 state that it is. You know, we do -- I'll tell
8 you, there are lots of industries in this state
9 that we have been on the front lines of getting
10 them into the state. We spend a lot on economic
11 development work to attract these businesses to the
12 state. That's all part of being a good corporate
13 citizen.

14 There are businesses in various cities that
15 call me all the time, "We want you to contribute to
16 this or that." Much of which, we do, and
17 ratepayers don't pay for that.

18 Q But doesn't that benefit Duke in the long run, too,
19 especially if they're in your area, that they're
20 going to be a new customer?

21 A (GHARTEY-TAGOE) It benefits customers, as well,
22 because there are more customers to spread our
23 costs over.

24 Q Thank you very much.

25 A Thank you.

1 Q Ms. Bateman, you're off the hook this afternoon.
2 Thank you for being here.
3 A (BATEMAN) I -- I did want to -- do you still have
4 a question about which of my exhibits kind of
5 represents the current position?
6 Q I'm going to dig back through it.
7 A (BATEMAN) Okay.
8 Q I was just kind of going through all those and
9 getting lost in some of it. But thank you very
10 much.
11 A (BATEMAN) Okay. Because I could help clarify
12 that.
13 Q I really was trying to find the most updated
14 Schedule 2 that -- that -- that broke out all the
15 classes.
16 A (BATEMAN) That's a great question because we have
17 not updated --
18 Q Okay.
19 A (BATEMAN) -- Schedule 2, and so --
20 Q Oh, okay. Well, maybe that's why I couldn't find
21 it.
22 A (BATEMAN) My -- so my response is that the Company
23 would propose to allocate to the customer classes
24 whatever increase is ultimately granted,
25 proportionally to my original Exhibit 2.

1 Q Okay.

2 A (BATEMAN) And I believe I looked at Michael
3 Seaman-Huynh's exhibit. I believe he took a
4 similar approach. I mean, obviously, we disagree
5 on the total amount, but I -- I think -- I think
6 we're on the same page in terms of how to spread it
7 to the customer classes.

8 Q Thank you very much.

9 COMMISSIONER BELSER: Thank you, Mr. Chairman.

10 CHAIRMAN RANDALL: Thank you. My watch just
11 told me it was time to stand up for ten
12 minutes, so -- it's that or faceplant. So
13 we're going to take about ten minutes, and
14 we'll be back.

15 (Off the record from 3:03 p.m.
16 until 3:16 p.m.)

17 CHAIRMAN RANDALL: Please be seated. All
18 right. I'm going to call us back to order,
19 and we will continue with Commissioner
20 questions. Commissioner Hamilton.

21 COMMISSIONER HAMILTON: Thank you, Mr.
22 Chairman.

23 EXAMINATION

24 BY COMMISSIONER HAMILTON:

25 Q Mr. Ghartey-Tagoe, I -- I'm the man from the Pee

1 Dee, and so I got to go back to the Pee Dee Friday
2 afternoon and -- and I'm --

3 CHAIRMAN RANDALL: Get a little closer to a
4 microphone --

5 COMMISSIONER HAMILTON: Okay. I'll do it
6 again.

7 CHAIRMAN RANDALL: -- Commissioner.

8 Q I'll do all I can to -- to let my people know that
9 you have been transparent in calling and trying to
10 collect and hook up with each one of them on -- but
11 I know some discussion we had that came up about a
12 -- this farm -- special farm rate -- agricultural
13 rate, and I believe you said you probably did have
14 a cotton gin rate and things like that.

15 A (GHARTEY-TAGOE) Yes, sir.

16 Q The rates that you've talked about the day that you
17 called the farmers that had the number of meters --
18 was -- does that combine the meters where they just
19 get one bill for the farm or what -- tell us a
20 little bit about it.

21 A (GHARTEY-TAGOE) Okay. I don't believe so. I
22 think Mr. Steve Wheeler can address that question.
23 I -- I -- I don't believe we reduce it to one
24 meter, no.

25 Q Okay. But it -- so how does it help them, then?

1 Or do I need to talk to Mr. Wheeler about that?

2 A (GHARTEY-TAGOE) Mr. Wheeler will be the right --

3 Q I'll do that. Thank you. Thank you very much,
4 sir.

5 Ms. Bateman?

6 A (BATEMAN) Yes?

7 Q Let me ask you a question I've got written down
8 here if I -- if I can find it. Do you agree or
9 disagree with ORS that Customer Connect and AMI
10 meters are not extraordinary expenses as defined by
11 FERC electric chart of accounts?

12 A (BATEMAN) Okay. So, thank you. First, I want to
13 say that that cite to the FERC chart of electric
14 accounts has nothing to do with deferrals. It has
15 to do with criteria to book items to certain FERC
16 accounts that are extraordinary income or
17 extraordinary deductions, so I don't think it's
18 relevant. But I would say that I think Customer
19 Connect and AMI are extraordinary projects that the
20 Company has undertaken. I mean, the -- the -- and
21 Witness Hunsicker can speak more to this, but the
22 Customer Connect is the first new billing system in
23 -- in decades, so I think that's an extraordinary
24 project that the Company is undertaking. And I
25 think the deployment of AMI meters is also

1 extraordinary -- deploying new, automated metering
2 infrastructure to all of our customers. And the
3 possibilities that that will open up is an
4 extraordinary effort, and I think Witness Schneider
5 can speak more to that.

6 Q Okay. I think we'll probably talk to him much more
7 about that, because in the previous year that we
8 had, we had an awful lot of people that were
9 disturbed with the new meters. Thank you very
10 much.

11 A (BATEMAN) Yep.

12 COMMISSIONER HAMILTON: Thank you, Mr.
13 Chairman.

14 CHAIRMAN RANDALL: Thank you. Commissioner
15 Howard.

16 COMMISSIONER HOWARD: Thank you, Mr. Chairman.

17 EXAMINATION

18 BY COMMISSIONER HOWARD:

19 Q Mr. Gharthey-Tagoe, you were pretty vocal there
20 about how you've done and what you've done and what
21 your company has done, I guess I should say, too --
22 you know, to sort of lessen the impact of a rate
23 increase. Is there anything else you want to add
24 to that that you might --

25 A (GHARTEY-TAGOE) I think -- and I'm thinking back

1 through my testimony, both my direct and certainly
2 in testifying today, I've identified some things
3 that we do, some things that we're doing
4 particularly in response to the complaints we've
5 heard at the public hearings, the efforts we've
6 made to make sure that we're not asking for any
7 more than we need. But, ongoing every day, we
8 encourage our employees to keep their costs low,
9 and we will continue to do that. We are continuing
10 to drive costs out of our business because that's
11 what our customers expect, and we will continue to
12 do that.

13 Q Give me your thought process. During the night
14 hearing, I was sort of taken back by the fact that
15 there were farmers that had like 30/40 meters and
16 each one of them billed separately, and I think
17 Commissioner Howard touched on that. Then it
18 occurred to me that in a cost-of-service study, it
19 seemed like there would be some good economic --
20 economics of scale -- scales of economics that
21 would lessen the impact so the same meters -- there
22 would be less a price for each meter than just
23 multiplying out. That further took me to the
24 possibility off declining block rates for multi-
25 meter customers. Do you follow me?

1 A (GHARTEY-TAGOE) Generally, yes.

2 Q I don't know that I do. But --- no -- but it seemed
3 like if a customer had 30 meters, they don't -- it
4 shouldn't be the same cost. Doing a cost-of-
5 service study, it shouldn't be the same for each
6 meter. It should be some -- some economies of
7 scale. And that's a Mr. Wheeler question?

8 A (GHARTEY-TAGOE) Yes. Or Janice Hager. But I --
9 and I don't think that's the way economies of scale
10 work. I mean, if the customer needs less than 10
11 meters, I think they should sign up for less than
12 10 meters. But, if they choose to sign up for 10
13 meters, I think the -- then, you try to put them on
14 the best schedule to minimize their -- their bills,
15 and that's what we're trying to do. But Mr.
16 Wheeler will explain the -- the -- and Ms. Hager
17 can also explain the cost-of-service study and the
18 cost of --

19 Q Yeah. I was just wondering if y'all had given any
20 thought to declining block rates? Have you given
21 it any thought for any particular reason? And you
22 probably answered the question that they should use
23 less meters?

24 A (GHARTEY-TAGOE) Well, I think what I'm saying is
25 they -- they have the meters they have because

1 that's what they need.

2 Q Okay. Ms. Bateman?

3 A (BATEMAN) Yes?

4 Q Let's talk about unprotected EDITs.

5 A (BATEMAN) Yeah.

6 Q They -- you're proposing a 20-year flowback for the

7 property, plant and equipment, and then you're --

8 you're imposing a 5-year flowback for the non --

9 you know, PPEs.

10 A (BATEMAN) Yes.

11 Q What prevents y'all from expediting those years of

12 flowback times?

13 A (BATEMAN) So I think -- and I think Witness

14 Sullivan can speak to this as well, but it has to

15 do with the cash flow impacts on the Company. And

16 so, when the federal tax law was first passed,

17 shortly after that, one of the credit rating

18 agencies came out with a report talking about how

19 the tax reform would have negative impacts on

20 regulated utilities, and Duke Energy was actually

21 put on a -- a -- I think it was a -- like a

22 "negative watch." And I believe this is in John

23 Panizza's -- or John Sullivan's testimony --

24 Panizza's testimony that outlines that. And -- and

25 so I think the credit rating agencies were watching

1 very closely, because the tax reform had the
2 potential, if the benefits were flowed back too
3 quickly to customers, to have negative impacts on
4 the utilities from a cash flow and credit metrics
5 rating perspective. And I think -- and then, they
6 later reversed that and put Duke Energy back to
7 stable outlook, and a lot of that was based on some
8 of the decisions -- Commission decisions that had
9 come out that were considered constructive. So
10 this Commission came out with a decision to require
11 the utilities to defer those impacts and address
12 them in the next rate case. The North Carolina
13 Commission came out with a similar order requiring
14 utilities to address the excess deferred income
15 taxes in the next rate case or within three years,
16 and some of the other Duke Energy jurisdictions
17 came out with other similar constructive orders.
18 And so I think the -- the 20 years and the 5 years
19 is what we thought was reasonable and appropriate
20 to balance the interest of customers along with the
21 impacts to the Company's credit ratings and cash
22 flow.

23 Q Thank you very much.

24 COMMISSIONER HOWARD: Thank you, Mr. Chairman.

25 CHAIRMAN RANDALL: Thank you. Commissioners,

1 anything else?

2 EXAMINATION

3 BY CHAIRMAN RANDALL:

4 Q Let me ask just a couple of questions. Ms. -- Ms.
5 Bateman first. On -- on Page 17, we talked -- of
6 your prefiled testimony -- we talked in the DEC
7 case about the reserve fund for the end-of-life
8 nuclear costs. I have a couple of/three questions
9 on this. That's different than a couple of/six.
10 The Company -- determining now that certain
11 materials and supplies have no salvage value, why
12 -- why do you do that now?

13 A (BATEMAN) So I think that these generally -- we
14 expect that there will be end-of-life costs for the
15 nuclear plants. And, if you look at -- and I
16 believe Witness Henderson can speak more --

17 Q Okay.

18 A (BATEMAN) -- specifically to this -- but the --
19 the nature of the materials and supplies at a
20 nuclear plant in general is such that they have
21 little or no salvage value, and then the same is
22 true for the last core of nuclear fuel. You -- you
23 can't just burn the fuel down to nothing, so we
24 know that there's going to be some costs at the end
25 of the nuclear plant's life, and so what we're

1 proposing is to start establishing a reserve for
2 that now. But I will note -- and I think I -- I
3 put this in my testimony -- that the reserve is a
4 reduction to rate base, and there's a pro forma
5 that I put that reduces rate base by the first
6 year's amortization that we're proposing. It is in
7 a separate GL account, and I can give you a little
8 bit based on our experience, because this is
9 approved in North Carolina. So it was approved in
10 the 2012 North Carolina rate case for DEP. We
11 started accruing for the reserve, and then in the
12 most recent rate case, we update it. So, again, we
13 looked at what's been accrued to date, what are the
14 latest projections, what's the time period left to
15 the end of life that we currently think, and, you
16 know, we updated the accrual to whatever the
17 appropriate amount was based on that rate case.
18 And it's -- it's held in a separate GL account and
19 is a reduction to cost-of-service, can be updated
20 in -- in each rate case.
21 Q Well, let me ask you: How -- how does -- how do
22 you -- you've got certain -- well, how do you
23 decide or tell the difference in -- and I think
24 we've talked about this before -- but certainly
25 end-of-life costs, you're going to have

1 decommissioning, and then you've got the end-of-
2 life reserve. How do you decide which goes where?
3 And is -- is it -- do you do a study or does a
4 third party do a study, or how does that work?

5 A (BATEMAN) So my understanding -- and Witness Doss
6 couple probably explain this in more detail -- is
7 that there are specific requirements to what is
8 included in the official nuclear decommissioning
9 costs that have to be held in a separate trust and
10 that these costs that we're talking about here
11 don't meet that specific definition to be included
12 in nuclear decommissioning.

13 Q Got you. Thank you. Ms. -- and y'all -- y'all can
14 answer this maybe or maybe you will -- someone
15 else. All right. We talked about credit cards a
16 little while ago, and when -- when you've got --
17 how -- how does the cost savings -- is there a cost
18 savings to -- to the Company by using credit cards
19 by preventing bad debt -- bad debt or bounced
20 checks costs by having credit card payments? Does
21 -- do some of those costs offset at all?

22 A (BATEMAN) So I don't believe that is the case, but
23 I would address that question to Witness Quick, as
24 well.

25 Q Okay. Okay. All right. One question I had that I

1 hope we hadn't talked about -- that -- I don't
2 think: In -- in your original application, the
3 Company requested for residential customers a -- a
4 BFC, basic facilities charge, of \$29 and a
5 kilowatt-hour charge is of 11.367 per kilowatt-
6 hour, first 800 kWh, and 10.867 cents per kilowatt-
7 hour for each additional. Under the revised basic
8 facilities charge of 11.96, what -- what are the
9 kilowatt-hour charges? I'm -- I'm -- it's probably
10 in there, and it's probably right in front of me,
11 and you probably said it today, but is -- what are
12 those?

13 A (GHARTEY-TAGOE) I think --

14 Q I know we're talking about money and trying to --

15 A (GHARTEY-TAGOE) Yeah. I -- I don't know that
16 we've accolated that yet --

17 Q Okay.

18 A (GHARTEY-TAGOE) -- but Witness Wheeler will be --

19 Q Wheeler's going to get to that? Okay. Good.
20 We'll ask him.

21 CHAIRMAN RANDALL: All right. Commissioners,
22 any other questions? Any redirect?

23 MS. SMITH: Yes, sir.

24 MR. GUILD: All right. I have a follow-up,
25 too, in whatever order you're planning.

1 CHAIRMAN RANDALL: Okay. Okay. We'll go
2 ahead and how about we do Mr. Guild's follow-
3 up questions and then -- then --

4 MS. GRUNDMANN: Mr. Chairman, I also have some
5 questions. So I don't know in terms of order
6 of presentation? Do you care? Doesn't make a
7 difference to me.

8 CHAIRMAN RANDALL: Okay. Go ahead.

9 MS. GRUNDMANN: It's fine.

10 RECROSS-EXAMINATION

11 BY MR. GUILD:

12 Q Mr. Gharthey-Tagoe, they're betting me how long we
13 would let this exhibit stay up here -- your four to
14 five million dollars. I'm going to take it back
15 right now. Responding to -- to Commissioner Ervin
16 --

17 CHAIRMAN RANDALL: Make sure your microphone's
18 on.

19 Q Mr. Gharthey-Tagoe, responding to Commissioner
20 Ervin's line of questioning, indeed, Duke has
21 supported a Senate bill pending in the South
22 Carolina General Assembly that would enable a
23 securitization under South Carolina law; you're --
24 you're aware of that, aren't you?

25 A (GHARTEY-TAGOE) Senate bill where?

1 Q Senate Bill 110 --
2 A (GHARTEY-TAGOE) In South Carolina --
3 Q -- Senator Massey --
4 A (GHARTEY-TAGOE) Yes.
5 Q -- the Majority Leader's bill?
6 A (GHARTEY-TAGOE) Yes. I --
7 Q Yes. Go ahead.
8 A (GHARTEY-TAGOE) I was just saying, I -- I referred
9 to a bill that we were supporting --
10 Q Yes, sir.
11 A (GHARTEY-TAGOE) -- and hope to expand to include
12 storm costs.
13 Q Yes, sir.
14 A (GHARTEY-TAGOE) That's the one I was referring to.
15 Q Yes, sir. And, indeed, the Sierra Club supports
16 that bill, so we're on the same side on that one,
17 we hope. But you -- your company presented two
18 expert witnesses who testified in support of that
19 legislation before a Senate subcommittee, and
20 you're aware --
21 A (GHARTEY-TAGOE) Yes.
22 Q -- that Duke had representatives there?
23 A (GHARTEY-TAGOE) Yes.
24 Q And -- and one of those representatives, I can't
25 call the gentleman's name, I'm sorry to say, but

1 he, I believe, was the internal Duke man and the
2 other one was an expert outside, and the internal
3 guy said that, as I recall, and I'll get you to
4 tell me if this is right or not, that Duke Energy
5 Progress made use of securitization-enabling
6 legislation in Florida to manage the costs for the
7 early retirement of its Crystal River nuclear
8 plant. Is that -- is that the case?

9 A (GHARTEY-TAGOE) That is correct.

10 Q All right. And -- and so that legislation
11 generally can -- can address typically nonrecurring
12 extraordinary costs that the utility and regulators
13 want to avoid undue impacts to ratepayers despite
14 the fact that they're prudently incurred costs and
15 costs that ultimately are borne by ratepayers, but
16 they are mitigated through the use of a
17 securitization device; is that right?

18 A (GHARTEY-TAGOE) I think I got all that.

19 Q Okay. And -- and -- and storm-related costs are --
20 are one of those -- while storms may be more
21 frequent these days, we fear, just the same,
22 hurricane costs, for example, or extraordinary
23 flooding costs, we don't expect to be recurring
24 year by year. You don't want those to impact
25 ratepayers unduly. Securitization may allow you to

1 soften the blow and still recover?

2 A (GHARTEY-TAGOE) Yes. That's -- that would be the
3 effect of it. Yes.

4 Q And similarly, in the case of the Crystal River
5 facility, extraordinary costs of retiring early a
6 nuclear unit can also be spread with less pain to
7 ratepayers by allowing recovery at a lower debt
8 cost through securitization?

9 A (GHARTEY-TAGOE) Correct.

10 Q All right. Thank you.

11 CHAIRMAN RANDALL: Thank you. Ms. Grundmann?

12 RE CROSS-EXAMINATION

13 BY MS. GRUNDMANN:

14 Q Thank you for your indulgence. I just -- I just
15 want to make sure that the record's clear and that
16 everybody understands and these are questions that
17 I don't care which one of you answers, because I
18 think you both answered some questions before in
19 response to some questions from Commissioner
20 Williams.

21 Mr. Gharthey-Tagoe, you testified earlier to
22 what is known as the "overall rate of return,"
23 correct?

24 A (GHARTEY-TAGOE) Correct.

25 Q Okay. And so I just want to make sure that we're

1 on the same page about what we're talking about.
2 So three primary terms and I want to make sure that
3 we understand them: The "cost of debt" is
4 essentially what you pay -- interest rates or what
5 have you -- on the debt that you take out, the
6 loans that you all secure for the Company; would
7 you agree with that?

8 A (GHARTEY-TAGOE) Yes.

9 Q And then "the return on equity" is akin to the
10 profit that you are able to provide to your
11 shareholders?

12 A (GHARTEY-TAGOE) I don't call it "a profit." I
13 call it "a cost" that I pay to my shareholders.

14 Q Okay. Well, as a non-accountant, as a non-person,
15 it is the money that is left over after all payment
16 of costs that can be returned to shareholders for
17 their investment?

18 A (GHARTEY-TAGOE) Yes.

19 Q Okay. And so the overall rate of return, then, is
20 the delta between the cost of debt and the return
21 on equity; do you agree?

22 A (BATEMAN) Well, it's --

23 A (GHARTEY-TAGOE) I don't think so.

24 Q Correct me. I'm happy to be corrected.

25 A (BATEMAN) Yeah. It's -- it's a --

1 Q I want to make sure that we understand.

2 A (BATEMAN) It's a weighted average, overall rate of
3 return. And so if you look at the percentage of
4 our investments that are funded by debt --

5 Q Yeah.

6 A (BATEMAN) -- and multiply that percentage by the
7 debt rate and then the percentage that is funded by
8 equity investment times the rate of return on
9 equity, you get the overall rate of return.

10 Q But I just want to make sure that everyone -- that
11 we're all thinking the same thing, that when we
12 talk about the overall rate of return, it is not
13 based solely on whatever the ROE is that is awarded
14 to the Company.

15 A (BATEMAN) It also includes the --

16 A (GHARTEY-TAGOE) Oh. I think -- okay.

17 A (BATEMAN) -- capital structure and the cost of
18 debt

19 Q Right.

20 A (GHARTEY-TAGOE) We all agree.

21 Q So then, I -- I don't know whether this can go up
22 on the screen, but Ms. Bateman, I think earlier you
23 -- you directed the Commission if they wanted to
24 look into that particular issue, to -- to take a
25 look at Page 2 of your Exhibit 1 set forth in your

1 original direct testimony. Is that the correct
2 reference that you provided?

3 A (BATEMAN) It could be that one. I would say my --
4 the most updated version of that exhibit is the
5 Bateman Rebuttal Exhibit 1. But we could look at
6 the original if you wanted.

7 Q I'm going to mark it down, because I'm -- I just
8 want to make sure we're looking at the right
9 exhibit here.

10 Q And, Ms. Bateman, for purposes of determining your
11 overall rate of return, would you agree with me
12 that that number has decreased as a result of the
13 changes in the federal income tax?

14 A (BATEMAN) Um . . .

15 Q I'll ask it another way. Would you agree that your
16 overall rate of return is less than it otherwise
17 would have been but for the tax change?

18 A (BATEMAN) I'm not sure I agree with that. Maybe
19 I'm not following your question.

20 Q Well, so, ordinarily, you would have collected from
21 customers, correct, money representing your
22 obligation to pay corporate income taxes at
23 approximately 35 percent?

24 A (BATEMAN) Yes.

25 Q And then you would have subsequently not been

1 collecting income taxes for that amount; is that
2 correct?

3 A (BATEMAN) In this case we're proposing to reduce
4 the customer's rates by the amount of the --

5 Q -- change in the tax rate?

6 A (BATEMAN) -- income tax reduction. Yes.

7 Q And the effect of that change -- I think you were
8 talking about it earlier that the rating agencies
9 made some comments about it with respect to the
10 ADIT, but it also would have affected the income
11 and revenue that you had to operate?

12 A (BATEMAN) So I would disagree with that. And --
13 and let me try to explain. So we have been
14 deferring the impacts of the reduction in tax rate,
15 so we had a reduction in costs with no change in
16 revenue.

17 Q Yeah.

18 A (BATEMAN) So we deferred that reduction in costs.
19 So our revenue stayed neutral and our costs stayed
20 neutral up through new rates effective in this
21 case.

22 What we're proposing to happen when the new
23 rates are effective in this case is for the revenue
24 to decrease to match the decrease in costs. So the
25 income's the same. The revenue decreases and the

1 costs decrease. And so the return, I don't think,
2 is impacted.

3 Q So I have in front of me here and it's up on my
4 computer, so maybe you can explain it to me, but I
5 have a -- I'm looking at Page 1 of your Exhibit 1
6 in your original direct testimony.

7 A (BATEMAN) Yes.

8 Q And I just want to make sure that I understand what
9 I'm looking at -- at -- at the conclusion of this
10 hearing, but if I look at what you've listed as
11 Column 3, "Accounting Adjustments"?

12 A (BATEMAN) Yes.

13 Q You are showing a -- I guess it's a \$329 million
14 adjustment for net -- for net income taxes; is that
15 correct?

16 A (BATEMAN) You're on Page 1 of my rebuttal?

17 Q No. I'm on your direct testimony. That's what I
18 have up in front of me. We can use your
19 rebuttal --

20 A (BATEMAN) Okay.

21 Q -- because Staff has helpfully provided it to me.

22 A (BATEMAN) Okay.

23 Q So we're looking at Column 3, "Accounting
24 Adjustments" C --

25 A (BATEMAN) You're on Page 3? You must be on --

1 Q You have made an adjustment of --
2 A (BATEMAN) Are you on Page 3?
3 Q I'm on Page 1 --
4 A (BATEMAN) Page 1, Column C.
5 Q -- of your rebuttal.
6 Let's start all over.
7 A (BATEMAN) Okay.
8 Q Let's just start all over.
9 A (BATEMAN) I can go to my direct, if that makes it
10 easier.
11 Q I'm on your rebuttal.
12 A (BATEMAN) Okay.
13 Q Page 1 --
14 A (BATEMAN) Yeah.
15 Q -- of Bateman Rebuttal Exhibit 1.
16 A (BATEMAN) Yes.
17 Q I show here that there is an adjustment --
18 A (BATEMAN) Uh-huh.
19 Q -- of 33032.
20 A (BATEMAN) Yes.
21 Q Okay.
22 A (BATEMAN) So 33 million.
23 Q And so that's an actual adjustment?
24 A (BATEMAN) That is a result of all of the pro forma
25 adjustments. So, for example, if we make an

1 adjustment to increase costs to reflect maybe our
2 Customer Connect program, there is a tax impact of
3 that increase in cost and that would be reflected
4 here.

5 Q So this is the totality of all adjustments --

6 A (BATEMAN) Yes. The tax --

7 Q -- but it is overall a \$330 million decrease in
8 revenue or decrease in costs, I guess.

9 A (BATEMAN) You keep saying 333; you mean 33
10 million?

11 Q Well, it's -- it's -- this is in thousands, so it's
12 actually 330 million, isn't it? Am I wrong?

13 A (BATEMAN) I -- I don't see any --

14 Q Well, it's 33,032. That's the number as written.

15 A (BATEMAN) Yeah. So it would be 33 million.

16 Q Okay.

17 A (BATEMAN) Yeah.

18 Q And then --

19 A (BATEMAN) And 32,000. Not 300 million. It's not
20 -- it's not 333 million. It's 33,032,000.

21 Q Okay. Thirty-three million? And then Column 4 is
22 then showing an -- an increase -- and that increase
23 of -- I want to make sure I say the millions right
24 -- it's right here. It's 2336. Let's just say the
25 number as it's listed. And so that results in --

1 that's based upon if you are granted the total rate
2 increase that you seek in these proceedings?
3 A (BATEMAN) Can you give me the column and row?
4 Q Column 4, Line 8. The 2336.
5 A (BATEMAN) So that would be the income taxes before
6 the proposed increase. The level of income tax
7 expense before the proposed increase.
8 Q That's what's left over?
9 A (BATEMAN) No. We're not talking about return.
10 We're talking about income tax expense.
11 Q I'm -- I'm -- I'm just -- right. Where I'm
12 struggling a little bit, where I'm getting a little
13 bit confused --
14 A (BATEMAN) Yeah.
15 Q -- as I go through these numbers is: In Column 2,
16 you show 35368.
17 A (BATEMAN) Yes.
18 Q Then in Column 3, there's a decrease of 33,032.
19 A (BATEMAN) Yes.
20 Q -- which leaves 2336?
21 A (BATEMAN) Yes.
22 Q But then somehow for the increase in Column 5, it's
23 17 million.
24 A (BATEMAN) Yes.
25 Q And I'm trying to understand what that 17 million

1 is associated with.

2 A (BATEMAN) Okay.

3 Q So let me just get to my end question --

4 A (BATEMAN) Okay.

5 Q -- which may have been the easier way to get there.

6 So explain to me what that 17 million is. I -- I

7 assumed that that was the increase in taxes

8 associated with the rate increase proposed in these

9 proceedings.

10 A (BATEMAN) Yes. So what Column 4 shows is that

11 under present rates annualized, the income that the

12 Company is realizing on an adjusted basis is very,

13 very small, and so income tax is very small. But

14 if you were to increase revenue, and therefore,

15 increase income, to a level that allows the Company

16 an opportunity to earn the rate of return that

17 we're proposing in this case, your income taxes

18 increase, because your income increases. And --

19 Q So -- so you're alleging -- so my -- am I

20 understanding you correctly that you're saying

21 based upon current rate base, income taxes are 2.3

22 million?

23 A (BATEMAN) I -- I think it might be more helpful if

24 you flip to Page 3 where it lists the income tax

25 impact by adjustment.

1 MS. SMITH: Mr. Chairman, we've gone so far
2 beyond the original question regarding
3 weighted average cost of capital and, you
4 know, certainly, if there's a precise
5 question, we don't have a problem with it, but
6 we're -- we've gone pretty -- pretty far
7 afield.

8 CHAIRMAN RANDALL: Agreed.

9 MS. GRUNDMANN: I -- I understand you -- the
10 purpose of the question was ultimately just to
11 try to understand -- Witness Bateman suggested
12 that we could look to some of her exhibits to
13 understand the overall rate of return. And I
14 just was having some trouble squaring those
15 numbers, So I was trying to understand if
16 those exhibits, in fact, did what she had
17 indicated they did, which would reflect that
18 -- the overall rate of return. So I just am
19 struggling to understand the numbers and so I
20 was attempting to get clarity on that based
21 upon her earlier testimony.

22 CHAIRMAN RANDALL: Okay. How close are we to
23 that? Because we are getting way off.

24 MS. GRUNDMANN: I -- I appreciate it. I'll --
25 I'll try to wrap up quickly.

1 THE EXAMINATION BY MS. GRUNDMANN CONTINUES.

2 Q Can you direct me again to -- to your Page 3?

3 A (BATEMAN) Page 3 of my Exhibit 1?

4 Q Uh-huh. Yes, ma'am.

5 A (BATEMAN) It lists the income tax impact by

6 adjustment. And so if you wanted to isolate the

7 change in tax rate, that is going to be on Line 34.

8 And, again, I'm not sure if that answers your

9 question or not, but . . .

10 Q I'm not sure that it does. Ms. Bateman, to the

11 extent that I -- I -- as I look through this in --

12 in -- in an attempt to prioritize the time of the

13 Commission, is there anyone else testifying on

14 behalf of the Company that could answer any

15 questions with respect to the taxes other than

16 yourself?

17 A (BATEMAN) Yes. So, I mean, I can answer questions

18 about the impact of the change in the -- the tax

19 rate on the revenue requirement, and then John

20 Panizza -- Witness Panizza is our tax expert --

21 Q Okay.

22 A (BATEMAN) -- that could answer questions about the

23 impacts overall of the -- on the Company's taxes of

24 the federal tax reform, and then John Sullivan can

25 speak to the impacts on the cash flows and credit

1 metrics of the Company.

2 Q I will see if I can't better direct my questions --

3 A (BATEMAN) Okay.

4 Q -- to Mr. Sullivan.

5 A (BATEMAN) Okay.

6 Q Thank you.

7 CHAIRMAN RANDALL: Thank you. Okay, Ms.

8 Smith.

9 REDIRECT EXAMINATION

10 BY MS. SMITH:

11 Q Okay. You ready? Okay. Good. Mr. Gharthey-Tagoe,

12 do you recall when Mr. Guild was referencing a

13 North Carolina order in which the North Carolina

14 Utilities Commission imposed a management penalty?

15 A (GHARTEY-TAGOE) I do.

16 Q Okay. And so he walked through verbally the

17 Commission's decision -- the North Carolina

18 Commission's decision in that regard; is that

19 correct?

20 A (GHARTEY-TAGOE) That's my recollection, yes.

21 Q Okay.

22 MS. SMITH: And so I'd appreciate it if we

23 could take judicial -- if the Commission would

24 judicial notice of North Carolina Utilities

25 Commission -- their order in Docket E-2-1142

1 and that would be dated -- sorry. I lost the
2 date. That would be dated the 23rd day of
3 February 2018.

4 MR. GUILD: Could that just be made -- a copy
5 made available to the parties, Mr. Chairman?

6 I have no objection to the notice.

7 MS. SMITH: Mr. Guild, I was assuming you had
8 a copy since you were asking about it.

9 MR. GUILD: Well, I don't, but I'd appreciate
10 a copy. Thanks.

11 MS. SMITH: You're welcome. You can have this
12 one when I'm done with it.

13 MR. GUILD: Thank you.

14 THE EXAMINATION BY MS. SMITH CONTINUES.

15 Q Mr. Gharthey-Tagoe, I don't know if you have your
16 glasses with you, but can you see what's up on the
17 ELMO?

18 A (GHARTEY-TAGOE) With some effort, yes.

19 CHAIRMAN RANDALL: I want to introduce y'all
20 to some new technology: trifocals.

21 A (GHARTEY-TAGOE) I brought my reading glasses, not
22 my -- sorry.

23 Q And -- and this is Page 204 of that order, and do
24 you mind -- so that we have the full context of --
25 of what we're discussing and what Mr. Guild brought

1 up, can you please read that highlighted language?

2 A (GHARTEY-TAGOE) "The Company has been penalized by

3 the Federal District Court. It cannot seek cost

4 recovery of these monetary penalties of remediation

5 assessments. Further, the mismanagement to which

6 DEP pled guilty was only for a fraction of the time

7 DEP operated the impoundments. No evidence was

8 submitted that DEP's management was imprudent from

9 the initial date of operation."

10 Q Okay. Thank you. And do you recall when Mr. Guild

11 was talking about the DEQ order?

12 A (GHARTEY-TAGOE) Yes.

13 Q And, so, just to be clear, that's the North

14 Carolina Department of Environmental Quality.

15 That's not the Utilities Commission, correct?

16 A (GHARTEY-TAGOE) That's correct.

17 Q And there was an amount that the two of you

18 discussed between four and five -- four to five

19 billion, which could be the monetary impact of that

20 order if it stands?

21 A (GHARTEY-TAGOE) Correct.

22 Q And do you recall Mr. Guild asking you would those

23 amounts be requested of South Carolina customers?

24 A (GHARTEY-TAGOE) Yes.

25 Q Okay. And of that, what would that allocation be?

1 Is that a hundred percent of those costs if they
2 stand to South Carolina or what is the split of
3 that that would -- would North Carolina bear any of
4 those costs?

5 A (GHARTEY-TAGOE) Absolutely. North Carolina, as
6 well our wholesale customers, will bear portions of
7 that cost. The general allocation for costs like
8 that typically is, say, 30 percent of that comes to
9 South Carolina, and even off that, only about ten
10 is DEP.

11 Q Okay. All right. Thank you. And just moving on,
12 do you recall -- let's see here -- do you recall
13 the discussion that you had with Commissioner Ervin
14 on securitization?

15 A (GHARTEY-TAGOE) I do. Yes.

16 Q Okay. And is it your understanding that a
17 securitization statute has to be topic-specific?

18 A (GHARTEY-TAGOE) Yes.

19 Q Okay. And maybe that's what -- was that what you
20 were referring to when you were talking about
21 trying to get storms named --

22 A (GHARTEY-TAGOE) Yes.

23 Q -- in the pending bill?

24 A (GHARTEY-TAGOE) Yes. Yes. I think currently the
25 proposed language of the bill refers to, I believe,

1 nuclear costs as well as costs incurred when the
2 governor has declared a state of emergency. And I
3 understand, based on legal counsel's advice,
4 experts in this field -- I've actually attended an
5 NARUC seminar on this -- that typically for the
6 lenders to actually act on a statute like that,
7 it's got to be very specific as to the type of cost
8 that is being securitized.

9 Q Okay. And is, also, a predicate of that kind of
10 statute whether there's a receivable, whether the
11 costs to be securitized have been deemed as
12 receivable and recoverable by the Utility?

13 A (GHARTEY-TAGOE) Oh, absolutely. I mean, the
14 underlying basis of securitization is -- the
15 Company's issuing bonds that third parties will
16 buy, but, underlying those bonds, are, promised by
17 the State, that the Company would be allowed
18 recovery of the costs that have been securitized.
19 So that's a prerequisite, absolutely.

20 Q Okay. And, in -- in speaking about that predicate
21 receivable, is it also a predicate that there's a
22 return on that receivable to make the
23 securitization work?

24 A (GHARTEY-TAGOE) Absolutely. I mean, the savings
25 to customers is -- one alternative is the

1 Commission allows the Utility to recover it, over
2 some period of time, at its weighted-average cost
3 of capital. The other option is I am able to issue
4 bonds that allow me to only -- let's say my
5 weighted-average cost of capital I was approved in
6 the last case was 7.2 percent, but I'm able to
7 issue bonds that only demand 3 percent interest;
8 the difference of 4.2 percent is what customers are
9 saving. And, if it's a big pot of money, it means
10 big savings, as well.

11 Q Thank you. And do you recall Commissioner Williams
12 asking you about the effort it took for the Company
13 to recruit and retain linemen? Do you recall that?

14 A (GHARTEY-TAGOE) Yes.

15 Q And maybe -- maybe we might want to say "line
16 workers."

17 A (GHARTEY-TAGOE) Yes. I meant "line workers."

18 Q Okay. Great. Had to get that in there. Sorry.

19 And, so, were you aware -- is this a new
20 topic? Has the Company been speaking about this
21 topic before?

22 A (GHARTEY-TAGOE) Oh, absolutely. We -- we had an
23 ex parte presentation, right here, about our -- our
24 grid-improvement program, the need -- the workforce
25 impacts of the needs of the Company and efforts we

1 were making through the technical college system to
2 identify, train, recruit new lineman, yes.

3 Q Okay. And, in terms of --

4 A (GHARTEY-TAGOE) Line workers. I'm sorry.

5 Q Thank you. Thank you. And, in terms of the
6 retention of those line workers, you -- do you
7 recall the conversation about other states
8 attracting those line workers?

9 A (GHARTEY-TAGOE) Yes.

10 Q Okay. And do -- is -- is a similar level of
11 competition for those resources intrastate, between
12 utilities in this state?

13 A (GHARTEY-TAGOE) Absolutely. Absolutely.

14 Q Okay. Thank you. And do you recall when counsel
15 for Walmart was asking you about -- about the
16 taxes? This may be for Ms. Bateman, as well.

17 A (BATEMAN) Yes.

18 Q Do you recall that conversation?

19 A (BATEMAN) Yes.

20 Q And on -- has the Company been deferring the delta
21 between the 35 percent and the 21 percent? Has the
22 Company been deferring those revenues to give them
23 back to customers since January 1st, 2018?

24 A (BATEMAN) Yes. We have been deferring those
25 revenues and accruing a return on those deferred

1 revenues. .

2 Q Okay. And, so, the impact of deferring those
3 revenues was not accreted to the Company's bottom
4 line? You didn't take that benefit to the bottom
5 line?

6 A (BATEMAN) No. And, in fact, they're -- we're --
7 that's why I was confused because we are not having
8 any earnings benefit or earnings impact from the
9 federal tax return. Our intention is to flow all
10 of those benefits back to customers, through
11 revenue reductions. And, so, we've taken steps to
12 make sure that the -- that is the case.

13 Q Okay.

14 MS. SMITH: That's all I have. Thank you.

15 CHAIRMAN RANDALL: Thank you. Any recross?

16 Are we done with it? Okay. Commissioner
17 Ervin's got a question.

18 EXAMINATION

19 BY COMMISSIONER ERVIN:

20 Q And, just to follow up on the securitization issue,
21 there's nothing to prevent the North Carolina or
22 the South Carolina General Assembly from including
23 coal ash costs in a securitization bill, would --
24 would it? I mean, I realize it -- as it currently
25 stands, it's not part of it, but nothing to prevent

1 it from being a part of it?

2 A (GHARTEY-TAGOE) No. Nothing that I'm aware of

3 anyway.

4 Q In fact, if it -- if it does -- it's going to be

5 somewhere between five to ten million dollars if it

6 -- if it has to be done the way the regulators say

7 in North Carolina. Doesn't it make sense to do it

8 by way of securitization?

9 A (GHARTEY-TAGOE) I haven't thought through the full

10 implications of that yet, but, certainly, in

11 theory, yes, customers could save money by

12 securitizing large sums of money versus not.

13 Q In South Carolina, customers could save 30 percent

14 of whatever their cost is going to ultimately be?

15 A (GHARTEY-TAGOE) Yes.

16 Q Thank you.

17 A (GHARTEY-TAGOE) Well --

18 A (BATEMAN) And --

19 A (GHARTEY-TAGOE) -- let me put it this --

20 A (BATEMAN) I would just add, probably, Witness

21 Sullivan could speak --

22 Q Okay.

23 A (BATEMAN) -- a lot to --

24 Q Sure.

25 A (BATEMAN) -- securitization --

1 Q All right.

2 A (BATEMAN) -- as well.

3 Q Okay.

4 A (BATEMAN) And I -- I think one issue with coal ash

5 -- and he could probably speak to this more

6 eloquently -- is that there has to be certainty of

7 recovery, and, so, there has to be an approved,

8 prudent amount, and I'm not sure how appeals impact

9 that. So there has to be like a right --

10 Q Right.

11 A (BATEMAN) -- level of certainty of recovery.

12 Q Assuming that the appeal is denied, then the

13 Company is going to -- or either way, if -- if you

14 win the appeal or it's denied, you're going to, at

15 some point, know what those costs are?

16 A (GHARTEY-TAGOE) I -- I think she was referring to

17 appeals of a Commission order.

18 Q Correct.

19 A (GHARTEY-TAGOE) Because, to secure --

20 Q I see. You've appealed that, as well, in North

21 Carolina?

22 A (GHARTEY-TAGOE) No. We would not.

23 A (BATEMAN) We have not.

24 Q Okay.

25 A (GHARTEY-TAGOE) No. We're talking about future

1 appeals.

2 Q I see.

3 A (GHARTEY-TAGOE) So, for example, if this

4 Commission --

5 Q Yes, sir.

6 A (GHARTEY-TAGOE) -- allowed us to recover for coal

7 ash because you would have to, to support

8 securitization --

9 Q Correct.

10 A (GHARTEY-TAGOE) -- then that decision, if -- as

11 long as there's an appeal pending on it, it would

12 be hard to get anybody to buy the bonds.

13 Q So, in terms of the North Carolina Commission, now

14 that the order is in the record, can I -- can I ask

15 you: Has -- has the North Carolina Commission

16 approved the coal ash cost --

17 A (BATEMAN) They have --

18 Q -- recovery?

19 A (BATEMAN) They have approved cost recovery for the

20 deferred coal ash costs, and I believe there are

21 appeals, though --

22 A (GHARTEY-TAGOE) Yes.

23 A (BATEMAN) -- in that case.

24 A (GHARTEY-TAGOE) Yes. They --

25 Q So those appeals would have to be resolved before

1 you could securitize that debt?

2 A (GHARTEY-TAGOE) Yes.

3 COMMISSIONER ERVIN: Thank you.

4 CHAIRMAN RANDALL: Thank you. Commissioner
5 Whitfield?

6 COMMISSIONER WHITFIELD: Thank you, Mr.
7 Chairman.

8 EXAMINATION

9 BY COMMISSIONER WHITFIELD:

10 Q I've got one -- on follow-up along those lines.
11 Commissioner Ervin just kind of jogged my memory a
12 little bit. And I probably should -- should
13 remember this because I was here, you know, for the
14 Duke Progress merger, but you've testified, talking
15 about the ratepayers benefitting all these years
16 from electricity from coal generation "for decades"
17 is the -- the term you say in your testimony and
18 here on the stand. And none of us had a crystal
19 ball prior to Dan River, but was -- in doing the
20 due diligence during the merger -- and I -- again,
21 I should remember this -- could -- do you recall if
22 -- if there were any discussions about, prior to
23 the merger -- of course, taking on Progress, and,
24 of course, you've got it in both territories, but
25 who would be -- or, you know, they're assuming that

1 liability, Duke Corporate is, obviously. Duke --
2 the -- Duke is assuming that liability taking on
3 Progress, so were there any discussions about
4 something that might be so costly in the future to
5 deal with?

6 A (GHARTEY-TAGOE) Well, to be clear, Duke Energy
7 Progress's coal ash liabilities are Duke Energy
8 Progress's only, and, likewise, DEC's liabilities.
9 So the plants that DEC owns today, like the --
10 Allen was one of those that were mentioned. The
11 costs associated with complying with the loss of
12 that site will only be borne by DEC customers. And
13 costs associated with complying with a loss, as the
14 effect, like HF Lee, or, you know, the Robinson
15 site, would only be borne by DEP customers. In
16 fact, as I recall -- I wasn't a part of the due
17 diligence for the merger, but, as I recall, the
18 merger agreements -- or the stipulation that was
19 ultimately approved in North Carolina -- and I
20 believe we carried it over here -- specifically
21 said that DEP North Carolina or South Carolina
22 customers were not going to be responsible for
23 Crystal River, for example --

24 Q Uh-huh.

25 A (GHARTEY-TAGOE) -- you know, in -- in Florida, or

1 any other obligations we had in Indiana or Ohio.

2 But they are separate corporate entities, so each
3 corporate entity bears their own responsibilities.

4 Q Well, thank you. I -- I just couldn't remember. I
5 -- I do remember that about Crystal River. You're
6 dealing with a different type of generation, of
7 course.

8 A (GHARTEY-TAGOE) Yeah.

9 Q But I just wondered. And, of course, you know,
10 that merger occurred prior to this being pushed to
11 the forefront, too. So thank you for your answer.

12 CHAIRMAN RANDALL: Thank you. Okay. Ms.
13 Bateman, Mr. Gharthey-Tagoe, thank you for your
14 testimony, and you may -- okay. You may step
15 down.

16 (Witnesses stood aside)

17 CHAIRMAN RANDALL: Let's call the next -- next
18 panel.

19 MR. ROBINSON: Mr. Chairman, at this time,
20 we're calling Ms. Lesley Hunsicker --

21 MS. QUICK: Quick.

22 MR. ROBINSON: -- Ms. -- excuse me -- Ms.

23 Retha Hunsicker, Ms. Lesley Quick, and Mr. Don
24 Schneider.

25 (Witnesses affirmed)

1 be entered into the record as though given
2 orally from the stand.

3 Q Mrs. Hager, do you have a summary of your direct
4 and rebuttal testimony you'd like to give the
5 Commission?

6 A (HAGER) I do.

7 Q Would you please do so?

8 A (HAGER) The purpose of my direct testimony is to
9 describe and support the allocation of Duke Energy
10 Progress's electric operating revenues and expenses
11 and original cost rate base assigned to the South
12 Carolina retail jurisdiction and to each customer
13 class according to the cost-of-service studies
14 performed by the Company. Using the principle of
15 cost causation, revenues, expenses, and rate --
16 rate base costs are assigned to the specific
17 jurisdictions and customer classes that caused such
18 costs to be incurred.

19 The cost-of-service study used as the basis
20 for this case begins with the official accounting
21 books and records of DE Progress for the 2017 test
22 year, as discussed by Witness Doss. The costs are
23 grouped according to function, such as generation
24 or transmission; then classified based on whether
25 they are associated with demand, energy, or

1 Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS
2 COMMISSION?

3 A. Yes. I have filed testimony and appeared before this Commission many times
4 including on matters of Fuel Adjustment Clauses, Integrated Resource
5 Planning, Certificates of Public Convenience and Necessity and other issues.
6 I have also appeared before the North Carolina Utilities Commission, the
7 Indiana Utilities Regulatory Commission, and the Federal Energy Regulatory
8 Commission.

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

11 A. My testimony describes and supports the allocation of DE Progress' electric
12 operating revenues and expenses and original cost rate base assigned to the
13 South Carolina retail jurisdiction and to each customer class according to the
14 cost of service studies performed by the Company.

15 II. COST OF SERVICE STUDY OVERVIEW

16 Q. WHAT IS THE PURPOSE OF A COST OF SERVICE STUDY?

17 A. The purpose of a cost of service study is to align the total costs incurred by
18 DE Progress in the test period, with the jurisdictions and customer classes
19 responsible for the costs. The study directly assigns or allocates the
20 Company's revenues, expenses and rate base among the regulatory
21 jurisdictions and customer classes served by the Company based upon the
22 service requirements of those respective jurisdictions and customer classes.

1 These service requirements are based on a number of factors, including
2 differences in usage patterns and size.

3 Cost causation is a key component in determining the appropriate
4 assignment of revenues, expenses and rate base among jurisdictions and
5 customer classes. Under the principle of cost causation, costs are assigned to
6 the specific jurisdictions and customer classes that "caused" such costs to be
7 incurred.

8 Once all costs and revenues are assigned, the study identifies the return
9 on investment the Company has earned for each customer class during the test
10 period. These returns can then be used as a guide in designing rates to provide
11 the Company an opportunity to recover its costs and earn its allowed rate of
12 return.

13 **Q. SHOULD THE COST OF SERVICE STUDY FULLY ALLOCATE**
14 **COSTS AMONG JURISDICTIONS AND CUSTOMER CLASSES?**

15 **A.** Yes. As the cost of service study is used as a guide in designing rates, all costs
16 must be allocated to the appropriate jurisdiction and customer class. If any
17 costs are omitted or remain unallocated, then the utility's rates will not allow
18 for full recovery of the Company's operating expenses, including its approved
19 cost of capital.

1 **III. REVIEW OF DE PROGRESS' COST OF SERVICE STUDY**

2 **Q. HAVE YOU REVIEWED THE COST OF SERVICE STUDIES**
3 **PREPARED BY DE PROGRESS FOR FILING IN THIS CASE?**

4 **A. Yes, as referenced by Witness Bateman in her pre-filed direct testimony, I**
5 have reviewed DE Progress' cost of service studies that were prepared and
6 used in the rate design in this case.

7 **Q. WHAT IS THE SOURCE OF THE COST COMPONENTS THAT ARE**
8 **REFLECTED IN DE PROGRESS' COST OF SERVICE STUDY USED**
9 **TO SUPPORT THE REQUESTED RATE INCREASE?**

10 **A. The cost of service study is based on the official accounting books and records**
11 of DE Progress, supported in this proceeding by Witness Doss. The cost
12 components are comprised of the Company's electric operating expenses and
13 original cost rate base and are based on the historical 12-month period
14 covering January 1, 2017 through December 31, 2017 (the "Test Period").

15 **IV. COST OF SERVICE STUDY PREPARATION**

16 **Q. PLEASE EXPLAIN HOW COSTS WERE ASSIGNED TO THE**
17 **DIFFERENT JURISDICTIONS AND CUSTOMER CLASSES IN THE**
18 **COST OF SERVICE STUDY IN SUPPORT OF THIS RATE CASE.**

19 **A. Generally, there are three key activities that occur when assigning costs in a**
20 cost of service study:

21 **A. Costs are grouped according to their "function." Functions include**
22 production (generation), transmission, distribution, and customer
23 service, billing and sales.

1 B. Functionalized costs are then grouped or classified based on the utility
2 "operation" or service being provided and the related causation of the
3 costs. Typical classifications include demand, energy, and customer-
4 related costs.

5 C. Finally, the costs, which have been functionalized and classified, are
6 allocated or directly assigned to the proper jurisdiction and customer
7 class based on the manner in which the costs are incurred (*i.e.*, based
8 on cost causation principles).

9 *A. Functionalizing Costs*

10 Q. PLEASE EXPLAIN HOW TO FUNCTIONALIZE COSTS.

11 A. The Company accounts for its costs using the Uniform System of Accounts
12 ("USOA") of the Federal Energy Regulatory Commission ("FERC"). The
13 USOA assigns the costs of the Company's plant investment into the primary
14 categories of production (generation), transmission, distribution, and general
15 and intangible plant. Similarly, the USOA categorizes the Company's
16 operating costs into production, transmission, distribution, customer services,
17 and administrative and general functions.

18 *B. Classifying Costs*

19 Q. PLEASE EXPLAIN HOW COSTS ARE CLASSIFIED.

20 A. Functionalized costs are classified according to their cost-causation
21 characteristics. These characteristics are typically defined as demand-related,
22 energy-related, or customer-related.

1 Q. PLEASE DEFINE DEMAND-RELATED COSTS.

2 A. Demand-related costs are costs incurred that vary in direct relationship to the
3 kilowatts ("kW") of demand that customers place on the various segments of
4 the system. Costs that are classified as demand-related include major portions
5 of the Company's investment and related expenses in its production and
6 transmission facilities and a significant portion of the investment and related
7 expenses of its distribution system. These costs tend to remain constant over
8 the short run and do not change based on the amount of energy consumed.
9 These costs are often referred to as fixed costs.

10 Q. PLEASE DEFINE ENERGY-RELATED COSTS.

11 A. Energy-related costs are costs incurred that vary in direct relationship to the
12 amount of energy or kilowatt hours ("kWh") generated and delivered. These
13 costs are often referred to as variable costs.

14 Q. PLEASE DEFINE CUSTOMER-RELATED COSTS.

15 A. Customer-related costs are costs incurred as a result of the number of
16 customers being served. Customer costs do not vary with the customers'
17 volume of usage, but are related to the number of customers.

18 *C. Allocation and Direct Assignment of Costs*

19 Q. PLEASE EXPLAIN HOW COSTS ARE ALLOCATED AND DIRECTLY
20 ASSIGNED.

21 A. Cost components identified as having a direct relationship to a jurisdiction or
22 customer class are directly assigned to that jurisdiction or class before any
23 allocations occur. For example, many distribution-related costs are directly

DIRECT TESTIMONY AND EXHIBITS OF**DAVID C. PARCELL****ON BEHALF OF****THE SOUTH CAROLINA OFFICE OF REGULATORY STAFF****DOCKET NO. 2018-318-E****IN RE: APPLICATION OF DUKE ENERGY PROGRESS, LLC****FOR ADJUSTMENTS IN ELECTRIC RATE SCHEDULES AND TARIFFS****AND REQUEST FOR AN ACCOUNTING ORDER****I. INTRODUCTION****Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.**

A. My name is David C. Parcell. I am a Principal and Senior Economist of Technical Associates, Inc. My business address is Suite 130, 1503 Santa Rosa Rd., Richmond, Virginia 23229.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I hold B.A. (1969) and M.A. (1970) degrees in economics from Virginia Polytechnic Institute and State University (Virginia Tech) and a M.B.A. (1985) from Virginia Commonwealth University. I have been a consulting economist with Technical Associates since 1970. I have provided cost of capital testimony in public utility ratemaking proceedings dating back to 1972. In this regard, I have previously filed testimony and/or testified in over 570 utility proceedings before about 50 regulatory

THE OFFICE OF REGULATORY STAFF
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1 reasonable for rate-setting purposes, and are granted an opportunity to earn a fair rate of
2 return on the assets utilized (*i.e.*, rate base) in providing service to their customers.

3 The rate base is derived from the asset side of the utility's balance sheet as a dollar
4 amount and the rate of return is developed from the liabilities/owners' equity side of the
5 balance sheet as a percentage. Thus, the revenue impact of the cost of capital is derived by
6 multiplying the rate base by the rate of return, including income and other taxes.

7 The rate of return is developed from the cost of capital which is estimated by
8 weighting the capital structure components (*i.e.*, debt, and common equity) by their
9 percentages in the capital structure and multiplying these values by their cost rates. This
10 is also known as the weighted cost of capital.

11 Technically, "fair rate of return" is a regulatory and accounting concept that refers
12 to an *ex post facto* (after the fact) earned return on an asset base while the cost of capital is
13 an economic and financial concept which refers to *ex ante facto* (before the fact) expected,
14 or required, return on a capital base. In regulatory proceedings, however, the two terms
15 are often used interchangeably, and I have equated the two concepts in my testimony.

16 From an economic standpoint, a fair rate of return is normally interpreted to mean
17 that an efficient and economically-managed utility will be able to maintain its financial
18 integrity, attract capital, and establish comparable returns for similar risk investments.
19 These concepts are derived from economic and financial theory and are generally
20 implemented using financial models and economic concepts.

21 With regard to the regulatory standards, my testimony is based on my
22 understanding that two United States Supreme Court decisions provide the controlling
23 standards for a fair rate of return. The first decision is *Bluefield Water Works and*

1 *Improvement Co. v. Public Serv. Comm'n of West Virginia*, 262 U.S. 679 (1923). In this
2 decision, the Court stated:

3 The annual rate that will constitute just compensation depends upon many
4 circumstances and must be determined by the exercise of fair and
5 enlightened judgment, having regard to all relevant facts. A public utility
6 is entitled to such rates as will permit it to earn a return on the value of the
7 property which it employs for the convenience of the public equal to that
8 generally being made at the same time and in the same general part of the
9 country on investments in other business undertakings which are attended
10 by corresponding risks and uncertainties; but it has no constitutional right
11 to profits such as are realized or anticipated in highly profitable enterprises
12 or speculative ventures. The return should be reasonably sufficient to assure
13 confidence in the financial soundness of the utility, and should be adequate,
14 under efficient and economical management, to maintain and support its
15 credit and enable it to raise the money necessary for the proper discharge of
16 its public duties. A rate of return may be reasonable at one time, and
17 become too high or too low by changes affecting opportunities for
18 investment, the money market, and business conditions generally.

19 It is generally understood that the *Bluefield* decision established the following
20 standards for a fair rate of return: comparable earnings, financial integrity, and capital
21 attraction. It also noted that required returns change over time, and there is an underlying
22 assumption that the utility be operated efficiently.

23 The second decision is *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S.
24 591 (1942). In that decision, the Court stated:

25 The rate-making process under the [Natural Gas] Act, *i.e.*, the fixing of 'just
26 and reasonable' rates, involves a balancing of the investor and consumer
27 interests. . . . From the investor or company point of view it is important
28 that there be enough revenue not only for operating expenses but also for
29 the capital costs of the business. These include service on the debt and
30 dividends on the stock. By this standard the return to the equity owner
31 should be commensurate with returns on investments in other enterprises
32 having corresponding risks. That return, moreover, should be sufficient to
33 assure confidence in the financial integrity of the enterprise, so as to
34 maintain its credit and to attract capital.

35 The Commission has looked to the *Hope* and *Bluefield* standards as guidance for
36 setting rates. For example, in both Docket No. 2013-59-E, a Duke Energy Carolinas rate

1 case from 2013, and in Docket No. 2016-227-E, a Duke Energy Progress, LLC rate case
2 from 2016, the Commission stated:

3 In setting rates, the Commission must determine a fair rate of return that the
4 utility should be allowed the opportunity to earn after recovery of the
5 expenses of utility operations. The legal standards applicable to this
6 determination are set forth in Fed. Power Comm'n v. Hope Natural Gas Co.,
7 320 U.S. 591, 602-603 (1944) and Bluefield Water Works and
8 Improvement Co. v. Pub. Serv. Comm'n of W. VA., 262 U.S. 679, 692-93
9 (1923). These standards were adopted by the South Carolina Supreme Court
10 in Southern Bell Tel. & Tel. Co. v. S.C. Pub. Serv. Comm'n, 270 S.C. 590,
11 595-96, 244 S.E.2d 278, 281 (1978). The Court stated:

12 What annual rate will constitute just compensation depends upon many
13 circumstances, and must be determined by the exercise of a fair and
14 enlightened judgment, having regard to all relevant facts. A public utility is
15 entitled to such rates as will permit it to earn a return on the value of the
16 property which it employs for the convenience of the public equal to that
17 generally being made at the same time and in the same general part of the
18 country on investments in other business undertakings which are attended
19 by corresponding risks and uncertainties; but it has no constitutional right
20 to profits such as are realized or anticipated in highly profitable enterprises
21 or speculative ventures. The return should be reasonably sufficient to assure
22 confidence in the financial soundness of the utility and should be adequate,
23 under efficient and economical management, to maintain and support its
24 credit and enable it to raise the money necessary for the proper discharge of
25 its public duties...

26 Southern Bell Tel., 270 S.C. at 595-96, 244 S.E.2d at 281 (quoting
27 Bluefield, 262 U.S. at 692-93). These cases also establish that the process
28 of determining rates of return requires the exercise of informed judgment
29 by the Commission. The South Carolina Supreme Court has held that:

30 [T]he Commission was not bound to the use of any single formula or
31 combination of formulae in determining rates. Its ratemaking function,
32 moreover, involves the making of 'pragmatic adjustments' . . . Under the
33 statutory standard of 'just and reasonable' it is the result reached not the
34 method employed which is controlling. . . . The ratemaking process under
35 the Act, *i.e.*, the fixing of 'just and reasonable' rates, involves the balancing
36 of the investor and the consumer interests. Thus we stated in the Natural
37 Gas Pipeline Co. case that 'regulation does not insure that the business shall
38 produce net revenues.' . . . [B]ut such considerations aside, the investor
39 interest has a legitimate concern with the financial integrity of the company
40 whose rates are being regulated. From the investor or company point of
41 view it is important that there be enough revenue not only for operating
42 expenses but also for the capital costs of the business. These include service

on debt and dividends on the stock. . . . By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.

Southern Bell Tel., 270 S.C. at 596-97, 244 S.E. 2d at 281 (quoting Hope Natural Gas Co., 320 U.S. at 602-03). These principles have been employed by the Commission and the South Carolina Courts consistently.

The three economic and financial parameters in the *Bluefield* and *Hope* decisions – comparable earnings, financial integrity, and capital attraction – reflect the economic criteria encompassed in the “opportunity cost” principle of economics. The opportunity-cost principle provides that a utility and its investors should be afforded an opportunity (not a guarantee) to earn a return commensurate with returns they could expect to achieve on investments of similar risk. The opportunity-cost principle is consistent with the fundamental premise on which regulation rests, namely, that it is intended to act as a surrogate for competition.

Q. HOW CAN THE *BLUEFIELD* AND *HOPE* PARAMETERS BE EMPLOYED TO ESTIMATE THE COST OF CAPITAL FOR A UTILITY?

A. Neither the courts nor economic/financial theory has developed exact and mechanical procedures for precisely determining the cost of capital. This is the case because the cost of capital is an opportunity cost and is prospective-looking, which dictates that it must be estimated. However, there are several useful models that can be employed to assist in estimating the cost of common equity (“return on equity” or “ROE”), which is the capital cost component that is the most difficult to estimate. These include the DCF, CAPM, CE, and risk premium (“RP”) methods. I have not directly employed a RP model in my analyses although, as discussed later, my CAPM analysis is a form of the RP methodology. I describe each of these methodologies in more detail later in my testimony.

1 These criteria are as follows:

- 2 1) Market cap of \$20 billion or greater;
- 3 2) Common equity ratio 40 percent or greater;
- 4 3) Value Line Safety rank of 1 or 2;
- 5 4) S&P and/or Moody's bond ratings of BBB or A;
- 6 5) Currently pays dividends; and,
- 7 6) Not currently involved in a major merger or acquisition.

8 In addition, I have conducted studies of the cost of equity for the electric group that

9 was selected by DEP witness Hevert. I note that I have concerns with Mr. Hevert's

10 inclusion of AVANGRID in his proxy group. This entity is majority owned (over 80

11 percent of outstanding shares) and only began trading (as minority stockholders) in 2015.

12 **Q. PLEASE EXPLAIN WHY YOU ARE USING TWO PROXY GROUPS IN YOUR**

13 **COST OF EQUITY ANALYSES.**

14 **A.** It has long been my practice to develop my own independently determined proxy

15 group and to also conduct cost of equity analyses on the utility witness' proxy group. My

16 conclusions and recommendations, in turn, are based upon my review of the results of both

17 proxy groups.

18 **VIII. DCF ANALYSIS**

19 **Q. WHAT IS THE THEORY AND METHODOLOGICAL BASIS OF THE DCF**

20 **MODEL?**

21 **A.** The DCF model is one of the oldest and most commonly-used models for

22 estimating the ROE for public utilities. The DCF model is based on the "dividend discount

1 model” of financial theory, which maintains that the value (price) of any security or
2 commodity is the discounted present value of all future cash flows.

3 The DCF model is based upon two fundamental principles. First, DCF is based on
4 the postulate that investors value an asset on the basis of the future cash flows (*i.e.*,
5 dividends and ultimate sales in the case of common stocks) they expect to receive from
6 owning the asset. The second DCF principle is that investors value a dollar received in the
7 future less than a dollar received today (*i.e.*, the “time value of money”). Within this
8 context, the current price of a company’s stock is equal to the present value equivalent of
9 the expected dividends and the proceeds from eventually selling the stock. The discount
10 rate that equates the future anticipated dividends and future anticipated selling price with
11 the current market price is the cost of common equity.

12 The DCF model is based upon the concept that the value of a share of stock is the
13 discounted present worth of all the dividends to be received on that share. The DCF
14 equation is:

$$15 \quad P = \frac{C_1}{(1 + K_1)} + \frac{C_2}{(1 + K_2)^2} + \dots + \frac{C_n}{(1 + K_n)^n}$$

16 where: P = current value or price

17 C₁ = cash flow in period 1, etc.

18 K₁ = discount rate in period 1, etc.

19 n = infinity

20 This relationship can be simplified if dividends are assumed to grow at a constant
21 rate of g. As a result, the equation above can be reduced to:

$$22 \quad P = \frac{D}{(K-g)}$$

1 the recovery of expenses (as does ORS witness Payne) and does not address the
2 appropriateness of further adding a return on these expenses. Nor do I propose an
3 "adjustment" to DEP's return on equity, as Mr. Hevert erroneously claims.

4 **Q. DO YOU HAVE ANY RESPONSE TO MR. HEVERT'S CLAIM THAT DEP**
5 **SHOULD BE ENTITLED TO A "RETURN" ON CERTAIN OF ITS DEFERRED**
6 **EXPENSES?**

7 **A.** Yes, I do. It is my understanding that ORS witness Payne is proposing that DEP
8 should receive a "return of" all of its allowable deferred expenses, and only receive a
9 "return on" its deferred capital expenses. Whereas this is an accounting/revenue
10 requirement issue, I concur with ORS witness Payne that there is no requirement that the
11 Company receive a return on its expenditures that are not related to traditional rate base
12 items. It is my understanding, based on more than 40 years of utility rate case experience,
13 that rate base and operating expenses are treated differently, with only rate base items being
14 eligible for a return.

15 **Q. MR. SULLIVAN PROVIDES A TABLE ON PAGE 14 OF HIS SURREBUTTAL**
16 **TESTIMONY THAT PURPORTS TO SHOW AUTHORIZED RETURNS ON**
17 **EQUITY FOR "VERTICALLY INTEGRATED ELECTRIC UTILITIES**
18 **LOCATED IN THE SOUTHEASTERN UNITED STATES." DO YOU HAVE ANY**
19 **RESPONSE TO THIS TABLE?**

20 **A.** Yes, I do. Noticeably absent from this table is Virginia Electric and Power in
21 Virginia⁵ (which is a Southeastern U.S. state). This company, which is perhaps the most
22 closely-related utility to DEP in terms of size and operations, has a currently-authorized

⁵ Mr. Sullivan cites Virginia Electric and Power's ROE in North Carolina (which was a settled ROE) but does not cite the Company's ROE in Virginia (which was a litigated ROE).

1 affirmed, were examined and testified as follows:

2 DIRECT EXAMINATION

3 BY MR. BURNETT:

4 Q Good morning. Mr. Kerin, I'll begin with you.

5 Will you please state your name and business
6 address?

7 A (KERIN) Jon F. Kerin, 411 Fayetteville Street
8 Raleigh, North Carolina.

9 Q By whom are you employed and in what capacity?

10 A (KERIN) I'm employed by Duke Energy Business
11 Services. I'm the vice president of Operations,
12 Maintenance, and Governance for the coal combustion
13 products group.

14 Q Did you cause to be prefiled in this docket, on
15 November 8, 2018, 38 pages of direct testimony in
16 question-and-answer form, and an appendix
17 consisting of 38 pages, and 10 exhibits consisting
18 of 451 pages?

19 A (KERIN) I did.

20 Q Do you have any changes or corrections to that
21 direct testimony or exhibits?

22 A (KERIN) I do not.

23 Q If I were to ask you the same questions that appear
24 in your direct testimony today, would your answers
25 be the same?

1 A (KERIN) They would.

2 Q Did you also cause to be prefiled in this docket on
3 March 18 of this year 25 pages of rebuttal
4 testimony in question-and-answer?

5 A (KERIN) I did.

6 Q Do you have any corrections or changes to that
7 rebuttal testimony?

8 A (KERIN) I do not.

9 Q If I were to ask you the same questions that appear
10 in your rebuttal testimony today, would your
11 answers be the same?

12 A (KERIN) They would.

13 MR. BURNETT: Mr. Chairman, Mr. Kerin also
14 presented supplemental testimony, and upon
15 consultation with ORS, the Company is
16 withdrawing that supplemental testimony.

17 And, Mr. Chairman, at this time, I would
18 move that the prefiled direct and rebuttal
19 testimony of Mr. Kerin be copied into the
20 record as if given orally from the stand, and
21 that Mr. Kerin's exhibits be marked for
22 identification and entered into evidence.

23 CHAIRMAN RANDALL: Okay. Mr. -- Mr. Kerin's
24 prefiled direct and rebuttal testimony will be
25 entered into the record as though given orally

1 from the stand, and his exhibits, Appendix A
2 plus Exhibits 1 through 10, will be entered as
3 Exhibit Number 39.

4 (WHEREUPON, Hearing Exhibit 39 was
5 marked and received in evidence.)

6 Q Now, Dr. Wright, will you please state your name
7 and business address?

8 A (WRIGHT) Julius A. Wright, president of JA Wright
9 & Associates. My address is 18 Edgewater Drive
10 Cartersville, Georgia.

11 Q I believe you just said it, but again, by whom are
12 you employed and in what capacity?

13 A (WRIGHT) President of JA Wright & Associates.

14 Q Did you cause to be prefiled in this docket, on
15 November 8, 2018, 28 pages of direct testimony in
16 question-and-answer form and one exhibit consisting
17 of 16 pages?

18 A (WRIGHT) Yes.

19 Q Did you cause to be filed in this docket on
20 February 11, 2019 an errata to your direct
21 testimony?

22 A (WRIGHT) Yes.

23 Q Do you have any changes or corrections to that
24 direct testimony?

25 A (WRIGHT) No.

1 Q If I were to ask you the same questions that appear
2 in your direct testimony today, would your answers
3 be the same?

4 A (WRIGHT) Yes. They would.

5 Q Did you also cause to be prefiled in this docket on
6 March 18 of this year 41 pages of rebuttal
7 testimony in question-and-answer form?

8 A (WRIGHT) Yes.

9 Q Do you have any changes or corrections to that
10 rebuttal testimony?

11 A (WRIGHT) I do not.

12 Q If I were to ask you the same questions that appear
13 in your rebuttal testimony today, would your
14 answers be the same?

15 A (WRIGHT) Yes. They would.

16 MR. BURNETT: Mr. Chairman, at this time, I
17 would move that the prefiled direct and
18 rebuttal testimony of Dr. Wright be copied
19 into the record as if given orally from the
20 stand, and that his one exhibit be marked for
21 identification and entered into evidence.

22 CHAIRMAN RANDALL: Okay. Dr. Wright's
23 prefiled direct and prefiled rebuttal
24 testimony will entered into the record as
25 though given orally from the stand, and his

1 Exhibit 1 will be entered as Exhibit Number
2 40.

3 (WHEREUPON, Hearing Exhibit 40 was
4 marked and received in evidence.)

5 Q Dr. Wright, do you have a summary of your direct
6 and rebuttal testimony?

7 A (WRIGHT) Yes. I do.

8 Q Would you please present that to the Commission?

9 A (WRIGHT) Yes. My direct testimony supports Duke
10 Energy Progress's (DE Progress's) request for
11 recovery --

12 CHAIRMAN RANDALL: Hang on one second. Do we
13 have a copy of those? Okay. Sorry about
14 that. Go right ahead.

15 WITNESS WRIGHT: That's okay. It makes great
16 reading.

17 A (WRIGHT) My direct testimony supports Duke Energy
18 Progress's (DE Progress') request for recovery of
19 costs related to coal ash disposal expenses that
20 the Company has undertaken in response to new
21 environmental regulations. Environmental
22 compliance costs are similar to other costs a
23 utility spends to produce and deliver power as they
24 are a necessary cost of providing electric service.
25 Specific to coal ash disposal costs, the coal

1 plants associated with these costs have been used
2 and useful in providing low-cost reliable power to
3 South Carolina customers for up to 70-plus years.
4 Consequently, these types of costs and, if any
5 amount is deferred over time, a return, would be
6 appropriately recoverable in the rates and
7 consistent with how the Commission has historically
8 allowed recovery of environmental expenditures.

9 The last decade has seen an evolution in coal
10 ash disposal regulations, beginning with the EPA's
11 publication of proposed new regulations for coal
12 combustion residuals, or CCR, in June 2010. In
13 2015, the EPA finalized those regulations, known as
14 the "CCR rule," which represented the first
15 comprehensive federal regulation of CCR. The
16 proposed and final CCR rule also strongly
17 encouraged the states to adopt federal minimum
18 criteria in their solid waste management plans.
19 Accordingly, states in the region, including South
20 Carolina and North Carolina, have developed their
21 own regulations and policies for ash basin closure
22 that complement the CCR rule.

23 The fact that new standards have been
24 established does not mean that DE Progress's past
25 practices with regard to coal ash disposal were

1 unreasonable. The Company's decisions related to
2 coal ash disposal must be judged in accordance with
3 the regulatory standards and industry practice as
4 it existed at the time. To that end, the Company
5 historically has complied with all coal ash
6 disposal regulations and industry standards for its
7 coal ash handling operations. Today, these rules
8 have simply changed, and the Company must now
9 comply with these new standards.

10 I conclude in my direct testimony that
11 approval of the Company's recovery request is
12 appropriate because these dollars are required
13 expenditures for compliance with new coal ash
14 disposal requirements.

15 My rebuttal testimony addresses several issues
16 related to the recovery of costs associated with
17 coal ash remediation expenses raised in the
18 testimonies of OR Witnesses Dan Wittliff, Michael
19 Seaman-Huyhn, Willie Morgan, SCEUC witness Kevin
20 O'Donnell, and Sierra Club witness Ezra Hausman. I
21 also address general issues on the deferral of a
22 recoverable cost raised by ORS witness Zachary
23 Payne.

24 Taken together, the testimonies of OR
25 Witnesses Wittliff and Seaman-Huyhn recommend

1. disallowance for ash basin closure costs for all
2 activities that they contend were encouraged solely
3 to comply with North Carolina's Coal Ash Management
4 Act, or CAMA.

5 First, this recommendation does not align with
6 the appropriate regulatory standard for denial of
7 cost recovery, including recovery of environmental
8 compliance costs, which requires a finding that
9 specifically identified costs are imprudent or
10 unreasonable. Neither ORS witness identified any
11 specific cost as imprudently or unreasonably
12 incurred.

13 Second, this recommendation would overturn
14 sound regulatory policy that system costs be
15 allocated to the jurisdictions that are served.
16 South Carolina customers have benefited from coal-
17 fired generation of electricity for decades, and
18 ash basin closure is a necessary component of that
19 service. If -- if accepted, ORS's recommendation
20 would have a profound and lasting detrimental
21 impact on the sharing of assets between South
22 Carolina and North Carolina and the customers of
23 both states.

24 ORS witness Morgan recommends a disallowance
25 of litigation expenses associated with alleged

1 violations of environmental laws. It is my
2 understanding that the Company is not seeking costs
3 associated with fines or penalties related to
4 environmental violations, nor any legal expenses
5 associated with them. Of the two categories of
6 litigation costs identified by OR witness Hamm for
7 -- for disallowance, one category does not relate
8 to environmental violations at all, and the other
9 category relates to ongoing litigation that the
10 Company is reasonably defending where there has
11 been no finding of environmental violations. The
12 Company has an obligation to its customers to
13 prosecute and defend those litigation matters and
14 the associated costs should be recoverable.

15 ORS witness Payne recommends that the Company
16 not be allowed to earn a return on its deferred
17 cost during a deferral period. For several
18 deferred expenses, ORS witness Payne proposed lower
19 amortization periods than DE Progress recommended.
20 The Commission should reject the ORS's
21 recommendation because it violates the Regulatory
22 Compact in that it would not allow the Company to
23 earn a fair return on its deferred expenses and
24 recover the full value of prudently incurred costs.

25 SCEUC witness O'Donnell recommends that 75

1 percent of DE Progress's environmental compliance
2 costs should be disallowed based on a faulty
3 comparison of alleged national asset retirement
4 obligations, or ARO amounts, relating to CCRs. The
5 Commission should reject any disallowance,
6 especially one as substantial as the amount Mr.
7 O'Donnell recommends that is not based on facts in
8 evidence that have been proven and verified as
9 substantially significant, and Mr. O'Donnell's
10 flawed proposal fails this test. To do otherwise
11 would constitute poor regulatory policy and would
12 be arbitrary.

13 In addition, Mr. O'Donnell presents an
14 analysis in his testimony that he claims provides
15 evidence that the Company's CCR compliance costs
16 are well above the CCR compliance costs faced by
17 other utilities. However, as I show in my rebuttal
18 testimony, Mr. O'Donnell's estimated CCR compliance
19 costs for other utilities is old or dated
20 information. Because of this, his cost estimates
21 for other utilities' CCR compliance are very much
22 understated as compared to more recent cost
23 estimates, and this error makes this comparison
24 invalid, notwithstanding the numerous errors in his
25 analysis identified by Company witness Kerin.

1 Sierra Club witness Hausman contends that the
2 Commission should condition the Company's recovery
3 of coal ash costs on the future performance of a
4 comprehensive retirement analysis of the Company's
5 coal power plants. Sierra Club's conditional cost
6 recovery proposal should be rejected because it
7 violates accepted ratemaking policy. It is a
8 fundamental tenet of regulatory policy that
9 utilities are allowed to recover their prudently
10 incurred expenses, and Sierra Club has not shown
11 that any of the Company's coal ash costs are
12 imprudent.

13 This concludes my summary of my direct and
14 rebuttal testimonies.

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22 (PURSUANT TO PREVIOUS INSTRUCTION,
23 THE PREFILED DIRECT TESTIMONY,
24 INCLUDING CORRECTION/AMENDMENT,
25 OF JULIUS A. WRIGHT, PH.D. FOLLOWS.)

[Please note: Corrections noted herein reflect the errata
filed 2/11/19.]

BEFORE THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA

DOCKET NO. 2018-318-E

In the Matter of :

Application of Duke Energy Progress, LLC
For Adjustments in Electric Rate Schedules and
Tariffs

) **DIRECT TESTIMONY OF**
) **DR. JULIUS A. WRIGHT**
) **FOR DUKE ENERGY**
) **PROGRESS, LLC**

I. INTRODUCTION AND PURPOSE

1 **Q. PLEASE STATE YOUR NAME, OCCUPATION, TITLE AND**
2 **BUSINESS ADDRESS.**

3 A. Julius A. Wright, Managing Partner, J. A. Wright & Associates, LLC, 18
4 Edgewater Drive, Cartersville GA, 30121. I am a consultant to regulated
5 utilities and regulatory agencies and other public bodies on issues related to
6 economics, economic modeling, regulatory policy, industry restructuring,
7 demand-side investments, and resource planning.

8 **Q. ON WHOSE BEHALF ARE YOU SUBMITTING THIS TESTIMONY?**

9 A. I am submitting this testimony on behalf of Duke Energy Progress, LLC ("DE
10 Progress," or the "Company").

11 **Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL**
12 **EXPERIENCE.**

13 A. I received an undergraduate degree from Valdosta State College (BS
14 Chemistry), an MBA in Finance from Georgia State University, and a
15 Master's and Ph.D. in Economics from North Carolina State University,
16 where I focused on regulatory and environmental economics. Among other
17 past experiences, I served as a Commissioner on the North Carolina Utilities
18 Commission ("NCUC" or the "Commission") from 1985 to 1993. Prior to
19 serving as a member of the Commission, I served three terms as a North
20 Carolina State Senator and worked in process engineering for 12 years at three
21 chemical plants, the last with Corning in Wilmington, NC.

1 Over the past 25 plus years in my consulting practice, I have dealt
2 extensively with electric and natural gas utilities focusing on a number of
3 issues. In this context, I have testified before regulatory commissions and
4 legislative bodies, presented studies and authored reports on issues related to
5 electric and gas regulation, and I have been a guest speaker at the Bonbright
6 Conference, other seminars, and at the Georgia Institute of Technology. I
7 have been a visiting professor teaching both microeconomics and
8 macroeconomics courses at the University of The Virgin Islands. I was also
9 one of three economists engaged by the California State Auditor to examine
10 the problems that led to that state's electric energy crisis in the summer and
11 fall of 2000. I have worked for the last 20 plus years in the field of electric
12 and gas regulation, primarily in the Southeast. A copy of my resume is
13 attached as Wright Exhibit 1.

14 **Q. PLEASE DISCUSS THE PURPOSE OF YOUR TESTIMONY.**

15 A. The purpose of my direct testimony is to support DE Progress' request to
16 recover costs incurred for coal ash disposal in response to new, more stringent
17 environmental regulations.

18 **Q. PLEASE SUMMARIZE YOUR TESTIMONY.**

19 A. In the next section of my testimony, I provide a discussion of the general
20 regulatory principles dealing with the recovery of environmental costs
21 incurred by electric utilities in South Carolina. In Section III, I provide a brief
22 historical review of coal ash disposal regulations, how these regulations have
23 evolved over time, and how these evolving regulations have impacted the

1 Company. I conclude in Section IV by discussing why I believe DE Progress'
2 proposed coal ash related expenses in this filing should be recoverable as
3 recommended in the application and Company witnesses' testimony.

4 **II. BACKGROUND:**
5 **RECOVERY OF ENVIRONMENTAL COSTS**

6 **Q. WHAT ARE RECOVERABLE COSTS AS THEY RELATE TO**
7 **ELECTRIC UTILITY EXPENDITURES IN SOUTH CAROLINA?**

8 A. Recoverable costs include costs that are just and reasonable and used and
9 useful in the provision of adequate, safe, reliable, and reasonable electric
10 service to a utility's customers. Specifically, South Carolina Code of Laws at
11 § 58-27-810 declares the "rates shall be just and reasonable," and this standard
12 is repeated in § 58-27-850. With respect to the "used and useful" standard,
13 like other states South Carolina has defined used and useful utility property as
14 "property which it [the utility] necessarily devotes to rendering the regulated
15 services" and has allowed recovery for such property in rates. *Hamm v. S.C.*
16 *Pub. Serv. Comm'n*, 309 S.C. 282, 286 n. 1, 422 S.E.2d 110, 112 n. 1 (1992)
17 (quoting *Southern Bell Tel. & Tel. Co. v. Pub. Serv. Comm'n of S.C.*, 270 S.C.
18 590, at 600, 244 S.E.2d 278, at 283 (1978)).

19 The "used and useful" definition as it relates to rate base in South
20 Carolina was clarified in a Commission Order that stated "The rate base is
21 comprised of the value of the Company's property used and useful in
22 providing retail electric service to the public..." Order 87-1381, December 30,
23 1987, page 15.

24 With respect to the how retail electric service must be provided to

1 South Carolina ratepayers, the Commission's Code of Regulations Section
 2 103-301(2) states the purpose of the Code of Regulations is to "*to define good*
 3 *practice...intended to insure adequate and reasonable service.*" All of these
 4 policies, along with safety and reliability, are further embodied in the Code of
 5 Regulations in Sections 103-360 which states "[t]he electric plant of an
 6 electrical utility shall be constructed, installed, maintained and operated in
 7 accordance with good engineering practice to assure, as far as reasonably
 8 possible, continuity of service, uniformity in the quality of service, and the
 9 safety of persons and property."

10 As I discuss further herein, because environmental compliance costs
 11 are a necessary used and useful cost of providing safe, reliable and adequate
 12 electric service, then it follows that these types of costs – and a return on those
 13 costs – are recoverable in rates.

14 **Q. ARE ENVIRONMENTAL COMPLIANCE COSTS A NECESSARY**
 15 **EXPENDITURE SIMILAR TO OTHER COSTS A UTILITY MIGHT**
 16 **SPEND IN PRODUCING AND DELIVERING POWER?**

17 A. Yes. In order to comply with environmental regulations the Company incurs
 18 costs and these are similar to other costs necessary for the generation of
 19 electric power. Thus as part of the operating expenses related to coal-fired
 20 generating facilities, coal combustion residuals ("CCR")^{are} ~~is~~ produced in the
 21 coal combustion process, and this ash has been collected in compliance with
 22 environmental regulations at the time. These environmental expenses include
 23 costs like scrubbers or coal ash facilities which can be rate base type expenses

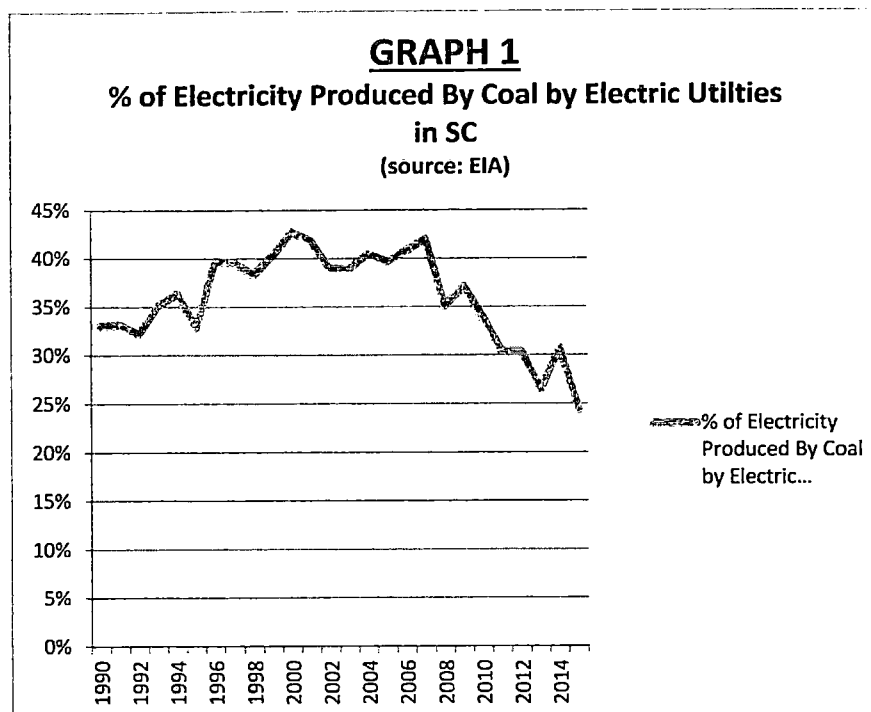
1 whose costs would be recovered over time. In addition, environmental costs
2 related to the treatment of pollutants, like ammonia and lime, or the cost of
3 emission allowance for SO₂, NO_x, mercury, and particulates, are all variable
4 environmental costs and are generally recoverable through the fuel adjustment
5 rider in South Carolina (§ 58-27-865). All of these environmental costs are
6 necessary for producing electricity in compliance with environmental
7 standards and, like nuclear decommissioning costs or coal plant retirement
8 costs, based on my experience and knowledge of fuel adjustment cost
9 recovery mechanisms in many states, these types of costs have long been
10 deemed recoverable from a utilities' ratepayers, including DE Progress in
11 South Carolina.

12 It should also be recognized that the coal plants associated with these
13 costs have been used and useful in providing low-cost, reliable power to South
14 Carolina customers for more than a century, and that is true regardless of
15 whether the generating plant is located in South Carolina or North Carolina –
16 all of the Company's generating units provide service on a systemwide basis
17 to both states. Consequently, these types of costs and, if any amount is
18 deferred over time, a return would be appropriately recoverable in rates to
19 ensure that the Company received the equivalent of the full amount of those
20 costs.

1 **Q. WHY HAVE YOU CONCLUDED THAT THESE COAL-FIRED**
2 **ELECTRIC GENERATING PLANTS HAVE BEEN USED AND**
3 **USEFUL IN THE PROVISION OF LOW-COST ELECTRIC SERVICE**
4 **TO CUSTOMERS IN SOUTH CAROLINA.**

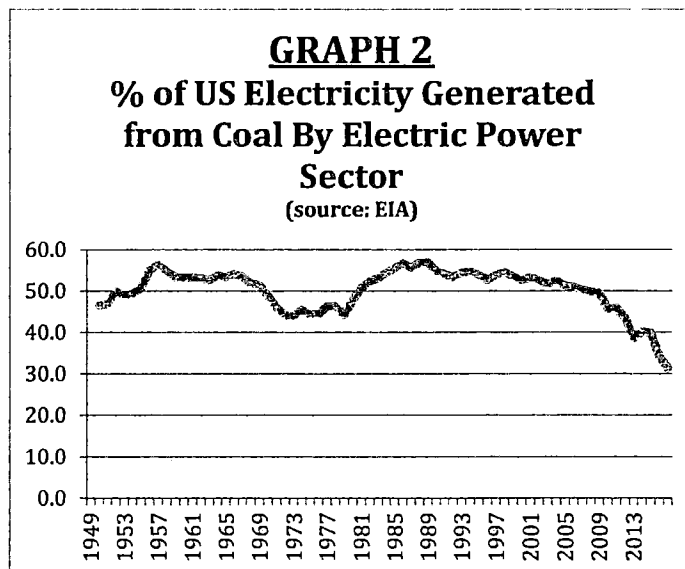
5 A. The Company's electric power generation from burning coal dates back to the
6 1920's. For example, the Cape Fear Plant in Moncure, North Carolina, began
7 commercial operation in 1923 with an ultimate generating capacity of 316
8 MW. Because power generation facilities are generally operated on a lowest
9 cost facility being used first, one can conclude that the Company's coal plants
10 have been used and useful in providing low-cost, reliable power to South
11 Carolina customers for more than a century. This conclusion is illustrated in
12 Graph 1 that illustrates that since 1990 (the earliest data available for the EIA)
13 usually more than 30% of the South Carolina's electric generation was
14 provided by coal-fired generation.¹ While more recently this dependence on
15 coal has diminished because of new environmental standards, coal-fired
16 generation continues to be an important component of DE Progress'
17 generation in South Carolina.

¹ This was the latest statewide data available from the EIA when the first draft of this testimony was developed. See State Historical Tables for 2015 (October 2016 as revised November 2016) (<https://www.eia.gov/electricity/data/state/>).



1 For a more historic perspective on the importance of coal to the
 2 nation's electric industry, Graph 2 indicates that for the past seven decades
 3 coal has provided the fuel to produce about 50% of the nation's electric
 4 energy.² It should be noted that coal was chosen as a fuel source, both in
 5 South Carolina and nationwide, primarily on the basis of economics, meaning
 6 that at the time it was the least costly, reliable option to use as a generation
 7 fuel resource. Because of this economic fact, but for the use of coal-fired
 8 generation, historical electric prices in the State and nationwide would have
 9 been higher.

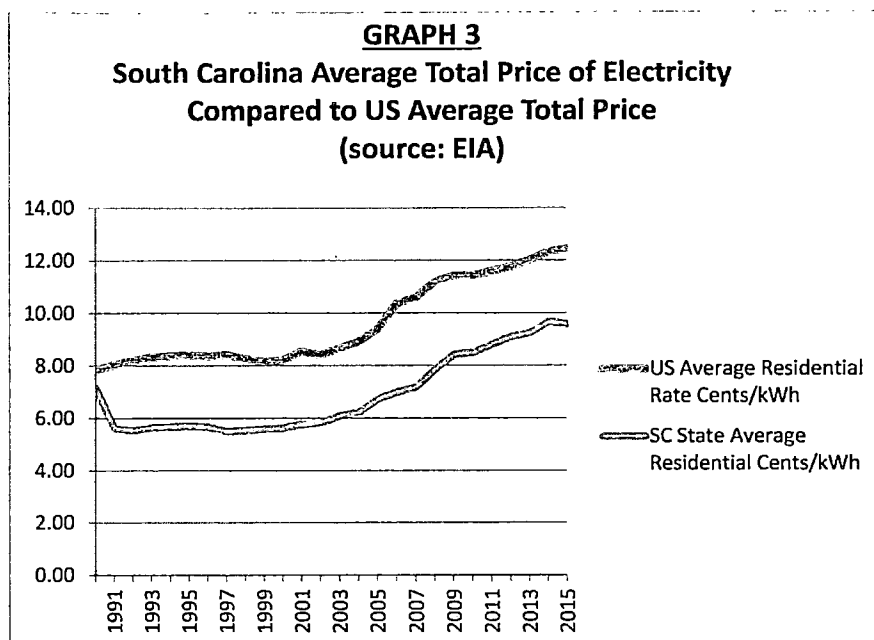
² This was the latest nationwide data available from the EIA. See April 2017 Monthly Energy Review, Table 7.2b Electricity Net Generation: Electric Power Sector (April 25, 2017) (<https://www.eia.gov/totalenergy/data/monthly/archive/00351704.pdf>).



1 In addition, the use of DE Progress' coal-fired generation has directly
 2 benefitted the State's customers by virtue of the fact that South Carolina's
 3 average retail electric rates have historically been below the national average.
 4 This is shown in Graph 3 which provides a historical comparison of the
 5 State's average electric price to the nation's. As this Graph 3 indicates, the
 6 State's average electric prices have been below the national average since at
 7 least 1990, which is the first year this state level data was available at the EIA.
 8 These below national average electric rates have been an economic benefit to
 9 South Carolina and its electric consumers.³ Because electric rates are
 10 determined by the underlying cost to produce the electricity, and recognizing
 11 that coal-fired plants were chosen and are dispatched primarily for economic
 12 reasons, this simply means that the State's "below average" electric rates have

³ This was the latest statewide data available from the EIA. See
<https://www.eia.gov/totalenergy/data/annual/showtext.php?t=ptb0810>.

1 been achieved in large measure because of the State's use of its coal-fired
2 electric generation.



3 **Q. HAS THIS COMMISSION ALLOWED THE RECOVERY OF COSTS**
4 **RELATED TO ENVIRONMENTAL EXPENDITURES?**

5 A. Yes. I have already discussed how some environmental costs in South
6 Carolina, such as ammonia, lime and other reagents, are recovered through the
7 fuel adjustment rider (§ 58-27-865). Importantly, the recovery of other
8 environmental costs, such as scrubbers or ash basins, related to environmental
9 compliance would be consistent with the public policy of the South Carolina
10 which states it is "the public policy of the State to maintain reasonable
11 standards of purity of the air and water resources of the State, consistent with
12 the public health, safety and welfare of its citizens, maximum employment,

1 the industrial development of the State..." (at § 48-1-20).

2 Consequently, in order to comply with both the State's public policy
3 goals and remain compliant with environmental standards, the Company has
4 made numerous investments over time in compliance with historical coal ash
5 and other environmental regulations, as discussed at length in the direct
6 testimony of Company Witness Kerin. It is my experience that these types of
7 costs, including the reasonable costs associated with operating, maintaining
8 and upgrading environmental equipment, plus a return, have been routinely
9 recovered as a cost of service through general rate cases, whether as capital or
10 ongoing operation and maintenance expense or some combination thereof.

11 In summary, when a utility invests in scrubbers to meet new and
12 heightened environmental standards, these costs have routinely been
13 recoverable. Similarly, when a utility invests dollars to meet new
14 environmental coal ash remediation standards, these costs should likewise be
15 recoverable. For example, in South Carolina the deferral balance of costs
16 associated with a Cliffside Unit 5 scrubber were amortized and in the rate base
17 (Settlement Agreement, Nov. 30, 2011, Docket No. 2011-271-E, Attachment
18 A, page 2). In addition, in Docket No. 2009-226-E costs associated with
19 scrubbers at the Allen Steam Station were amortized and in rate base
20 (Settlement Agreement, Nov. 24, 2009, Docket No. 2009-226-E, Attachment
21 A, page 2).

22 Where state specific requirements are indicated, those costs are often
23 shared between the two states consistent with the manner in which electrons

1 flow. In other words, shared costs for facilities that generate or have
2 generated electricity to both North and South Carolina are allocated between
3 the two states.

4 **Q. HAS THIS COMMISSION ADDRESSED THE RECOVERY OF NEW**
5 **COSTS ASSOCIATED WITH COAL ASH DISPOSAL ?**

6 A. Yes. In Docket No. 2016-227-E, DE Progress was allowed to recover coal
7 ash expense amortized over fifteen (15) years plus the Order's approved
8 return, albeit the Order did state that this finding had no precedential effect
9 and will not prejudice the position of any Party in any future proceeding
10 before the Commission.⁴ In this case, the Company is asking to be allowed to
11 recover coal ash expenses amortized over five years.

12 **Q. HOW ARE COSTS RECOVERED WHEN THE COSTS RELATE TO**
13 **FACILITIES IN TWO DIFFERENT STATES, LIKE WITH THE**
14 **ELECTRIC SYSTEM IN NORTH CAROLINA AND SOUTH**
15 **CAROLINA?**

16 A. Under this scenario, cost recovery depends on the type of cost. Some state
17 specific costs, unless directly assigned, are shared, or allocated, between both
18 states. In other words, shared costs for facilities that generate or have
19 generated electricity to both North and South Carolina are usually allocated
20 between the two states. These type of costs include a variety of things such as
21 workers compensation type costs, differences in everyday operating costs like
22 employees expenses, contractor expenses, fuel costs, and even costs like fuel

⁴ Order in Docket No. 2016-227-E, Dec. 21, 2016, page 11, paragraph 15.

1 transportation which can be different depending on the location of a
2 generating station (for example, rail service from coal mines to North Carolina
3 can be different, and usually cheaper because of distance, then rail service to
4 South Carolina). In addition, property taxes in South Carolina are higher than
5 property taxes in North Carolina, however these taxes for system assets like
6 generation plants are allocated to the whole system and not recovered on a
7 state specific basis.

8 **Q. HAVE NORTH CAROLINA AND SOUTH CAROLINA SHARED**
9 **ENVIRONMENTAL EXPENSES PRIOR TO THIS CASE?**

10 A. Yes. For example, the Cliffside and Allen generating stations scrubbers
11 mentioned above have been costs shared between the two states. This cost
12 sharing is common where a utility's operations span multiple states and the
13 utility property used to provide one particular state's electric service may be
14 located in another state. Also, the Company has entered into a Consent
15 Agreement with the South Carolina Department of Health and Environmental
16 Control (and a related Settlement Agreement with several environmental
17 groups) dealing with coal ash at the Robinson Plant, and the costs associated
18 with these South Carolina agreements are shared with North Carolina
19 ratepayers. Additional examples of states sharing environmental costs would
20 be the Southern Company utilities in Georgia, Alabama, Mississippi, and
21 Florida, and Entergy with electric utility services in Mississippi, Arkansas,
22 Louisiana, and Texas. In addition, coal ash disposal costs and beneficial reuse
23 revenues have to date been allocated and shared between both states.

1 **III. A BRIEF REVIEW OF THE HISTORY OF**
2 **COAL ASH DISPOSAL STANDARDS**

3 **Q. PLEASE DISCUSS SOME OF THE INITIAL COAL ASH DISPOSAL**
4 **STANDARDS.**

5 A. The Company's electric power generation from burning coal dates back to the
6 1920's. All of the Company's coal plants produced CCRs as fly ash and
7 bottom ash as direct by-products of the coal combustion process. In the
8 1950's the electric utility industry began to transport bottom ash by water
9 sluicing to constructed surface impoundments, which we commonly refer to
10 as ash basins. Over time, as discussed in more detail in the direct testimony of
11 Company Witness Kerin, the Company has consistently followed industry
12 standard practices in compliance with coal ash regulation.

13 **Q. DID THE COMMISSION ALLOW THE STATE'S ELECTRIC**
14 **UTILITIES TO RECOVER THE COSTS ASSOCIATED WITH THESE**
15 **EARLIER COAL ASH DISPOSAL REGULATIONS?**

16 A. Yes. As I mentioned earlier, these types of expenses have been routinely
17 recovered as a cost of service and included in rate cases including the
18 reasonable costs associated with operating, maintaining and upgrading
19 environmental equipment. The cost recovery for these rate-based
20 environmental costs also usually included a return. Also, as I mentioned
21 earlier, in Docket No. 2016-227-E, the Commission allowed DE Progress to
22 recover coal ash expense amortized over fifteen (15) years plus the Order's

1 approved return.⁵

2 **Q. HOW HAVE THE COAL ASH DISPOSAL STANDARDS CHANGED**
3 **OVER THE PAST DECADE?**

4 A. Coal ash use and disposal has been studied by the Environmental Protection
5 Agency ("EPA") since the mid-1980s. After several studies and some limited
6 regulatory standards, on May 22, 2000, the Environmental Protection Agency
7 ("EPA") determined the need to regulate coal combustion wastes that are
8 disposed in landfills and surface impoundments under Subtitle D (applicable
9 to non-hazardous waste) of the Resource Conservation and Recovery Act.

10 On December 22, 2008, a dike at a surface impoundment at Tennessee
11 Valley Authority's ("TVA") Kingston Fossil Plant in Harriman, Tennessee,
12 failed. In part as a response to this TVA accident, on June 21, 2010, the EPA
13 published in the Federal Register proposed new coal ash disposal regulations
14 for CCRs.⁶ The proposed regulations specifically referenced the TVA
15 incident as a major reason for the proposed rule.⁷ The EPA's proposed coal
16 ash disposal rule also discussed several other coal ash incidents that led to the
17 promulgation of the rule:

18 *"at the time of the May 2000 Regulatory Determination, the*
19 *Agency was aware of 14 cases of proven damages and 36 cases*
20 *of potential damages resulting from the disposal of CCRs. The*
21 *Agency has since learned of an additional 13 cases of proven*
22 *damages and 4 cases of potential damages, including a*
23 *catastrophic release of CCRs from a disposal unit at the*
24 *Tennessee Valley Authority (TVA) Kingston facility in*
25 *Harriman, Tennessee in December 2008. In total, EPA has*
26 *documented 27 cases of proven damages and 40 cases of*

⁵ Order in Docket No. 2016-227-E, Dec. 21, 2016, page 11, paragraph 15.

⁶ Federal Register/Vol. 75, No. 118/Monday, June 21, 2010/Proposed Rules, page 35128.

⁷ IBID, page 35132.

1 *potential damages resulting from the disposal of CCRs. Proven*
 2 *damage cases have been documented in 12 states, and*
 3 *potential damage cases—in 17 states.”⁸*

4 A more thorough discussion of these newer coal ash disposal regulations is
 5 contained in the testimony of Company Witness Kerin.

6 **Q. DID THE ACCIDENTAL COAL ASH SPILL AT THE DUKE ENERGY**
 7 **CAROLINAS’ DAN RIVER FACILITY IMPACT THE FINAL CCR**
 8 **RULE?**

9 A. No. First, it is important to note that the EPA’s proposed rule’s publication
 10 date precedes the February 2, 2014 coal ash release accident at the Dan River
 11 Steam Station (“Dan River”), the Dan River accident was not mentioned in
 12 the EPA’s proposed rule, nor could it have been, as a reason for establishing
 13 the rule. Later, the finalized EPA rule, signed on December 19, 2014 and
 14 published in the *Federal Register* (FR) on April 17, 2015 (the “CCR Rule”),⁹
 15 did reference the Dan River accident, but it did not indicate that the accident
 16 modified the proposed rule. Second, in promulgating the CCR Rule the EPA
 17 cited hundreds of potential risks or incidents with ash ponds similar to Dan
 18 River that led to the adoption of the Rule. Based on the citing of these
 19 numerous incidents along with the timing of the CCR Rule, I would conclude
 20 that the Dan River accident did not change the CCR regulations, although it
 21 probably added support for the EPA’s proposals.

⁸ IBID, pages 35143, 35143.

⁹ See Federal Register/Vol. 80, No. 74/Friday, April 17, 2015/Rules and Regulations, page 21343; 21393-94.

1 Q. HOW DID THE ACCIDENTAL COAL ASH SPILL AT THE
2 COMPANY'S DAN RIVER FACILITY IMPACT NORTH
3 CAROLINA'S CAMA LAW?

4 A. Based on my review, it likely impacted the timing, but I cannot conclude that
5 it impacted the substance of the standards. There is no doubt that the Dan
6 River spill certainly helped prompt the North Carolina General Assembly to
7 examine the State's and national coal ash disposal policies and regulations.
8 Out of that legislative investigation came North Carolina's Coal Ash
9 Management Act ("CAMA"). However, some four years prior to the Dan
10 River accident, the EPA had already proposed and was close to finalizing its
11 new coal ash regulations. I feel confident the EPA's proposed coal ash
12 regulations helped inform the State's legislative leaders regarding the
13 language contained in CAMA for several reasons. First, having served in the
14 North Carolina General Assembly, I am sure that the legislative process
15 leading to CAMA included an investigation of, and used where appropriate,
16 the then current or proposed EPA coal ash standards. Second, there are many
17 similarities between the proposed EPA rule and CAMA. For example, both
18 discuss groundwater monitoring at length, both provide for the same two types
19 of coal ash pond closure methods, the definitions used in both are very similar
20 and sometimes use identical wording, and both contain three levels of
21 hazardous potential classifications associated with coal ash ponds.¹⁰

¹⁰ It should be noted that the risk levels identified in the EPA proposed rule were based on dam or dike structural integrity and the potential for loss of life or the level of economic harm. The levels of risk in CAMA considered structural integrity as one of several factors to consider and the risk was not strictly related to loss of life.

1 Finally, the proposed CCR regulation also strongly encouraged the
2 states to adopt at least the Federal minimum criteria in their solid waste
3 management plans.¹¹ Therefore, even without the Dan River accident in 2014
4 and the enactment of CAMA shortly thereafter, had CAMA not been enacted
5 in 2014, I believe that the State of North Carolina Legislature and/or the
6 State's Department of Environmental Quality may have taken steps to adopt
7 coal ash regulations similar to CAMA shortly after the CCR Rule was
8 finalized in 2015. Regardless, the Company must comply with both the
9 Federal and State coal ash disposal standards.

10 **Q. ARE THERE ANY SOUTH CAROLINA STATE SPECIFIC LAWS OR**
11 **GUIDELINES THAT THE COMPANY MUST FOLLOW IN ITS**
12 **DISPOSAL OF CCRS?**

13 A. Yes. For DE Progress in South Carolina there is one Consent Agreement with
14 DHEC applicable to ash management at the Robinson Plant. The Robinson
15 Consent Agreement, DHEC 15-23-HW, between Duke Energy Progress, Inc
16 (now DE Progress) and DHEC, requires ash excavation of a 1960 lay-of-land
17 ash storage area located south of the ash basin. This Consent Agreement also
18 includes provisions to initiate permitting of an on-site CCR lined landfill to
19 store the excavated ash.

20 Additionally, the South Carolina legislature passed H.B. 4857 in 2016,
21 which requires utilities to dispose of coal combustion residuals resulting from
22 the production of electricity to be placed in Class 3 landfills, except under

¹¹ Federal Register/Vol. 80, No. 74/Friday, April 17, 2015/Rules and Regulations, page 21430.

1 limited circumstances.

2 **Q. WHAT ARE THE SPECIFIC COAL ASH DISPOSAL STANDARDS**
 3 **THAT DE PROGRESS MUST NOW MEET WITH RESPECT TO ITS**
 4 **CURRENT COAL ASH DISPOSAL SITES?**

5 A. Company Witness Kerin discusses these standards in detail. In short, the
 6 Company must comply with the 2015 Federal CCR Rule adopted by the EPA
 7 which established national minimum criteria for active CCR landfills and
 8 basins and inactive basins containing water, it must also comply with any
 9 CAMA obligations (which are similar to the CCR Rule as discussed by
 10 witness Kerin), and it must comply with the Robinson Consent Agreement as
 11 well as two Settlement Agreements¹² between the Company and North
 12 Carolina regulators and any other state agency requirements, such as those
 13 that may be required by DHEC.

14 **IV. THE COMPANY'S PROPOSED COAL ASH COST**
 15 **RECOVERY PROPOSAL IS REASONABLE**

16 **Q. WHAT ARE THE COSTS THE COMPANY IS SEEKING TO**
 17 **RECOVER THAT YOUR TESTIMONY ADDRESSES?**

18 A. DE Progress has reasonably and prudently incurred and expects to incur a
 19 total of \$526.4 million (on a system basis) related to incremental ash pond
 20 closure compliance costs from July 2016 through December 2018.

¹² A Sept. 29, 2015 Settlement Agreement Between DE Progress and the North Carolina Department of Environmental Quality with regard to four generating facilities and an agreement between the Company and the same NC agency regarding the Asheville and H.F. Lee generating facilities.

1 Q. THE COMPANY IS ALSO ASKING THE COMMISSION TO ALLOW
 2 THE COMPANY TO DEFER COAL ASH RELATED EXPENSES
 3 PENDING RECOVERY ADJUDICATION IN A FUTURE RATE
 4 CASE. IS THIS A COMMON PRACTICE UNDER SOUTH
 5 CAROLINA REGULATORY PROCEDURES?

6 A. Yes. A deferred account mechanism is not unusual in ratemaking. In his
 7 book discussing utility regulation Goodman indicates that "The use of
 8 deferred cost accounting in the ratemaking context is so common and so
 9 fundamental a regulatory tool that no agency is likely to consider it necessary
 10 to study whether as a matter of policy costs should be deferred..."¹³ In
 11 Docket No. 2015-96-E (Order No. 2015-308) this Commission allowed ~~the~~
 12 ~~Company~~ DE Carolinas to defer costs associated with coal ash related environmental
 13 remediation costs. DE Carolinas also has a currently effective deferral
 14 approved in the Commission's Order in Docket No. 2016-196-E, dated July
 15 13, 2016. DE Progress has a similar deferral that is ongoing, which was
 16 approved in the Order in Docket No. 2016-227-E, dated December 21, 2016.

17 Q. IS IT REASONABLE TO EXPECT CUSTOMERS TO PAY FOR THE
 18 DISPOSAL OF COAL ASH?

19 A. Yes. Those dollars are required to be spent in compliance with new coal ash
 20 disposal requirements. Such a circumstance is not new in the history of
 21 environmental regulations in the United States, where it is commonplace for
 22 restrictions to be modified and become more restrictive over time. For

¹³ Goodman, Leonard, "The Process of Ratemaking," Public Utility Reports, Vienna, Va, 1998, p. 322.

1 example, in our day-to-day life we have all experienced ever-tightening
2 environmental restrictions on the automobiles we drive, as the emissions
3 standards have grown increasingly stringent and more costly over the past few
4 decades and the related costs have increased the costs of driving.

5 So, too, have electric utility generating plants been the focus of ever-
6 tightening and more costly environmental standards. As an example, consider
7 the evolution of coal gas smokestack emission standards, which are generally
8 related to the federal Clean Air Act ("CAA") and its various updates or
9 amendments.¹⁴ The enactment of the CAA of 1970 resulted in a major shift in
10 the federal government's role in air pollution control by authorizing the
11 development of comprehensive federal and state regulations to limit
12 emissions. The EPA was created on December 2, 1970, in large measure to
13 implement the various requirements of the CAA.¹⁵ Major revisions and
14 stricter clean air standards were adopted as updates to the CAA in 1977 and
15 1990 and these new standards impacted coal-fired generating plants.¹⁶

16 Following the CAA 1990 amendments, the EPA devised a strategy to
17 further reduce NOx emissions from coal-fired power plants by imposing
18 tighter NOx emissions standards. In addition, in 1998, the EPA issued a rule
19 that required 21 states (including North Carolina and South Carolina) to
20 further reduce NOx emissions through the use of newer, cleaner control

¹⁴ While sometimes the standards did not specifically target older coal-fired generating plants, invariably the more stringent standards would either impact a utility's total emissions limits, or a state's, consequently impacting even those older facilities that were not specifically targeted by newer emissions regulations.

¹⁵ See: <https://www.epa.gov/sites/production/files/2015-08/documents/peg.pdf>.

¹⁶ See: <https://www.epa.gov/clean-air-act-overview/clean-air-act-requirements-and-history>.

1 strategies.¹⁷.

2 Consequently, the history of environmental regulation is replete with
3 examples of ever-tightening environmental regulations with the result being,
4 with respect to utilities, the associated costs for meeting these ever-tightening
5 environmental regulations usually becoming the responsibility of customers.
6 Likewise, the issue of ever-tightening environmental regulations with respect
7 to coal ash standards is the genesis of the Company's request as it relates to
8 these new and additional coal ash disposal costs.

9 **Q. ARE CERTAIN COAL ASH COSTS NOT RELATED TO**
10 **COMPLIANCE WITH THE CCR RULE OR CAMA ALSO**
11 **RECOVERABLE FROM CUSTOMERS?**

12 A. Yes. As I mentioned earlier, DE Progress in South Carolina entered into a
13 Consent Agreement with DHEC applicable to ash management at the
14 Robinson Plant which requires ash excavation of a 1960 lay-of-land ash
15 storage area located south of the ash basin. This Consent Agreement also
16 includes provisions to initiate permitting of an on-site CCR lined landfill to
17 store the excavated ash. Additionally, the Company entered into a Settlement
18 Agreement with the South Carolina Office of Regulatory Staff and other
19 parties related to the recovery of certain coal ash remediation costs, and this
20 settlement was approved by this Commission in the aforementioned Order in
21 Docket No. 2016-227-E, dated Dec. 21, 2016, page 11, paragraph 15. All of
22 the costs related to the Robinson Plant Consent Agreement and costs related to

¹⁷ See: <http://instituteeforenergyresearch.org/studies/the-facts-about-air-quality-and-coal-fired-power-plants/>.

1 the aforementioned Settlement Agreement must all be recovered, or in the
2 latter case, continue to be recovered, even if these costs may be above those
3 necessary to comply with the CCR Rule or CAMA.

4 **Q. ARE THERE ANY COSTS RELATED TO CAMA THAT ARE IN**
5 **EXCESS OF THE FEDERAL CCR RULE'S COSTS THAT ARE**
6 **BEING REQUESTED IN THIS FILING?**

7 A. This is discussed in Company Witness Kerin's testimony. As he discusses,
8 there are some CAMA costs that are considered a system cost whose recovery
9 is being requested, but there are other North Carolina resident-specific costs
10 related to CAMA and not required by the CCR that the Company is not
11 seeking to recover from South Carolina customers.

12 **Q. DOES THE FACT THAT NEW STANDARDS WERE ADOPTED**
13 **MEAN THAT DE PROGRESS' PAST PRACTICES WERE**
14 **UNREASONABLE?**

15 A. No. It is well established that the standard for determining the prudence of a
16 utility's actions should be whether management decisions were made in a
17 reasonable manner and at an appropriate time on the basis of what was
18 reasonably known or reasonably should have been known at that time. To that
19 end, a basic public utility regulatory principle is that a decision's prudence
20 "must be based on a contemporaneous view of the action or decision under
21 question. Perfection is not required. Hindsight analysis – the judging of

1 events based on subsequent developments — is not permitted.”¹⁸ In short, the
2 Company’s decisions related to coal ash disposal must be judged in
3 accordance with the regulatory standards and industry practice as it existed at
4 the time the decisions were made based on the fact that this was the
5 information available to the Company at that time.

6 With respect to this prudence evaluation criteria, as discussed in the
7 direct testimony of Company Witness Kerin, the Company historically has
8 complied with all coal ash disposal regulations and used industry standard
9 disposal operations for all its coal ash handling operations. Today, the coal
10 ash disposal standards have simply changed and been updated as has occurred
11 with many environmental standards over time. In the past, the Company was
12 required to meet the coal ash disposal standards at the time, and so too it must
13 now comply with the new coal ash disposal standards.

14 **Q. IN YOUR OPINION ARE THE COAL ASH DISPOSAL COSTS THAT**
15 **DE PROGRESS IS SEEKING TO RECOVER IN THIS CASE “USED**
16 **AND USEFUL” UTILITY COST?**

17 **A.** Yes. DE Progress’s coal ash disposal sites have always been used and useful
18 as part of the coal-fired generation production process. As I discussed earlier
19 the Company’s coal fired generating plants, whether located in South Carolina
20 or North Carolina, have been used and useful and provided electric service
21 that produced economic benefits to customers in South Carolina for decades.
22 In addition, as referenced in the direct testimony of Company Witness Kerin,

¹⁸ Phillips, Charles F., The Regulation of Public Utilities, Public Utilities Reports, Arlington, VA., 1993, p. 340.

1 the Company has historically spent dollars in order to comply with the coal
2 ash disposal regulations in effect at the time, and these dollars were a
3 necessary expenditure related to used and useful utility costs made in the
4 provision of electric service at the time. The Company was, and continues to
5 be, obligated to meet the needs of its customers. This obligation to serve
6 requires the disposal of coal ash subject to the disposal standards at the time,
7 thereby rendering the disposal sites for this coal ash, for which costs DE
8 Progress seeks recovery in this case, “used and useful” in providing electric
9 service. In addition, it should be noted that these same costs were just found
10 to be “used and useful” in three different proceedings in North Carolina
11 including the Company’s proceeding last year where the North Carolina
12 Commission specifically stated that these type of costs were “used and useful
13 in the provision of service to the Company’s customers (Order, Docket E-2,
14 Sub 1131, page 18).

15 **Q. HAS THE COMMISSION ALREADY ADDRESSED THE RECOVERY**
16 **OF THESE SPECIFIC TYPE OF COAL ASH DISPOSAL COSTS**
17 **WITH ANOTHER ELECTRIC UTILITY?**

18 A. Yes. As I mentioned, in Docket No. 2016-227-E, DE Progress was allowed to
19 recover these same coal ash expenses, albeit the Order did state that this
20 finding had no precedential effect and will not prejudice the position of any
21 Party in any future proceeding before the Commission.¹⁹

¹⁹ Order in Docket No. 2016-227-E, Dec. 21, 2016, page 11, paragraph 15.

1 **Q. ARE THERE EXAMPLES OF UTILITY INFRASTRUCTURE**
2 **PROJECTS THAT DEALT WITH AN ENVIRONMENTAL ISSUE**
3 **AND COST RECOVERY THAT IS SIMILAR IN NATURE TO THE**
4 **COAL ASH ISSUE IN THIS FILING?**

5 A. I believe a similar situation that is instructive are the ongoing costs related to
6 gas pipeline safety and integrity. Like coal ash regulations, these pipeline
7 safety and integrity regulations have changed and become more costly over
8 the past few years. For example, in 2011 the DOT and Pipeline and
9 Hazardous Materials Safety Administration ("PHMSA"), promulgated
10 regulations that require inspection, repair, rehabilitation and/or replacement of
11 the highest risk natural gas pipeline infrastructure by pipeline operators. The
12 program included an inventory of pipelines by type, system evaluation to
13 identify risks and an implementation plan to mitigate those risks. South
14 Carolina natural gas systems have had expenditures to comply with these new
15 regulations and South Carolina Electric & Gas Company has been allowed to
16 collect these costs through a deferral mechanism, including a return, and
17 collect these costs over time (Docket. No. 2014-461-G, see filings dated Dec.
18 3, 2014, ORS filing dated Dec. 10, 2014, and Commission Directive dated
19 Dec. 17, 2014).

20 **Q. ARE THERE OTHER EXAMPLES OF ENVIRONMENTAL COST**
21 **RECOVERY SIMILAR TO THE COST RECOVERY OF COAL ASH**
22 **DISPOSAL?**

23 A. Yes. As I mentioned earlier in this testimony, in this Commission's Docket

1 No. 2011-271-E, costs associated with a Cliffside scrubber were amortized
2 and in the rate base. In addition, in Docket No. 2009-226-E costs associated
3 with scrubbers at the Allen Steam Station were amortized and in rate base.

4 **Q. ARE THERE POTENTIAL COST SHARING LIABILITIES RELATED**
5 **TO THESE COAL ASH DISPOSAL COSTS THAT MIGHT**
6 **MATERIALIZE AND THUS DIMINISH THE OVERALL COST**
7 **IMPACTS ON CUSTOMERS?**

8 A. Yes. The Company has filed insurance litigation. When and if those monies
9 materialize, customers should see the benefit of those proceeds, like spent fuel
10 litigation. However, these cases can take many years to finally resolve. It
11 would be appropriate for the Commission to monitor these cases and ensure
12 that any outcome benefits customers. It is my understanding that the
13 Company has no objection to that approach.

14 **Q. ARE THERE WAYS THAT THE COMPANY MIGHT SUGGEST**
15 **THAT THE COMMISSION COULD ADOPT AS A MEANS OF**
16 **MITIGATING THE OVERALL RATE IMPACT FROM THESE NEW**
17 **ADDITIONAL COSTS?**

18 A. Yes. For example, it is not unusual for such costs to be stretched out over a
19 number of years so that the impact on rates is more manageable. If that type
20 of option is adopted, however, then it is appropriate for the utility to receive
21 carrying costs to ensure it is made whole for all costs.

1 Q. BECAUSE ONLY PRUDENTLY INCURRED COSTS ARE
2 RECOVERABLE, HAVE YOU EXAMINED WHETHER THE
3 ACTUAL DOLLARS BEING REQUESTED BY THE COMPANY ARE
4 REASONABLE AND PRUDENT?

5 A. I have examined the filing, many of the Federal and State laws related to coal
6 ash disposal, the testimony of Company Witness Kerin and other Company
7 witnesses, reviewed past Commission Orders regarding environmental cost
8 recovery, discussed with the Company its history related to coal ash disposal,
9 and reviewed the more recent settlement agreements related to coal ash
10 disposal. Based on my review, I believe that the Company is in the best
11 position to address coal ash disposal and the related costs in conformance with
12 State and Federal coal ash disposal requirements and I believe their actions in
13 this regard are prudent.

14 Q. DO YOU BELIEVE THE COMPANY'S COAL ASH COST
15 RECOVERY PROPOSAL IS REASONABLE?

16 A. Yes. I believe that the Company's proposals to recover its costs for
17 complying with updated coal ash disposal regulations are reasonable and
18 consistent with the historical regulatory treatment of similar costs.

19 Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY
20 AT THIS TIME?

21 A. Yes.

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23 (PURSUANT TO PREVIOUS INSTRUCTION,

24 THE PREFILED REBUTTAL TESTIMONY OF

25 JULIUS A. WRIGHT, PH.D. FOLLOWS.)

BEFORE THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA**DOCKET NO. 2018-318-E**

In the Matter of:	)	
Application of Duke Energy Progress, LLC	)	REBUTTAL TESTIMONY OF
For Adjustments in Electric Rate Schedules	)	DR. JULIUS A. WRIGHT
And Tariffs and Request for an Accounting	)	FOR DUKE ENERGY
Order	)	PROGRESS, LLC

I. INTRODUCTION AND PURPOSE

1 **Q. PLEASE STATE YOUR NAME, OCCUPATION, TITLE AND**
2 **BUSINESS ADDRESS.**

3 A. Julius A. Wright, Managing Partner, J. A. Wright & Associates, LLC, 18
4 Edgewater Drive, Cartersville, Georgia, 30121. I am a consultant to regulated
5 utilities and regulatory agencies and other public bodies on issues related to
6 economics, economic modeling, regulatory policy, industry restructuring,
7 demand-side investments, and resource planning.

8 **Q. ON WHOSE BEHALF ARE YOU SUBMITTING THIS TESTIMONY?**

9 A. I am submitting this rebuttal testimony on behalf of Duke Energy Progress, LLC
10 ("DE Progress," or the "Company").

11 **Q. ARE YOU THE SAME JULIUS A. WRIGHT WHO FILED DIRECT**
12 **TESTIMONY IN THIS CASE?**

13 A. Yes.

14 **Q. PLEASE DISCUSS THE PURPOSE OF YOUR REBUTTAL**
15 **TESTIMONY.**

16 A. The purpose of my rebuttal testimony is to address several issues discussed in
17 the direct testimony of intervenors related to the recovery of costs associated
18 with coal combustion residuals ("CCR"), also referred to as coal ash,
19 remediation expenses.

1 **Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.**

2 **A.** First, my rebuttal testimony recommends that the Commission reject the cost
3 recovery disallowances related to coal combustion residuals (“CCR”) proposed
4 by Office of Regulatory Staff (“ORS”) Witness Dan Wittliff.

5 Second, I respond to ORS Witness Michael Seaman-Huynh and his
6 recommendation that the Commission disallow recovery of what he terms
7 additional costs related to North Carolina laws and regulations. In my rebuttal,
8 I discuss why his proposed segregation and disallowance of what he terms
9 North Carolina allocated costs is incorrect and contrary to traditional regulatory
10 policy and would ultimately result in increased costs for the Company’s South
11 Carolina customers.

12 Third, I respond to ORS Witness Willie Morgan’s recommended
13 disallowance for litigation expenditures that he believes are related to the
14 Company’s violation of environmental laws.

15 Fourth, I respond to ORS Witness Zachary Payne’s recommended
16 accounting treatment of the Company’s deferred costs, and I show why his
17 recommendation is contrary to long-standing recovery principles and policy.

18 Fifth, I respond to several issues related to coal ash costs raised by South
19 Carolina Energy Users Committee (“SCEUC”) Witness Kevin O’Donnell. I
20 respond to his claim that the Company’s coal ash related costs are much higher
21 than other electric utilities. I also discuss why his recommended disallowance
22 of 75% of the Company’s proposed coal ash costs is inconsistent with
23 traditional regulatory cost recovery principles.

1 Finally, I respond to Sierra Club Witness Ezra Hausman's contention
2 that the Company's recovery of CCR expenses be conditioned on the
3 Company's completion of a retirement analysis. My rebuttal testimony
4 discusses why this proposal violates longstanding rate-making principles.

5 **II. RESPONSE TO ORS WITNESS WITTLIFF**

6 **Q. WHAT ARE MR. WITTLIFF'S RECOMMENDATIONS RELATED TO**
7 **THE COMPANY'S CCR MANAGEMENT THAT YOU ARE**
8 **RESPONDING TO IN THIS REBUTTAL TESTIMONY?**

9 A. I am responding to several of Mr. Wittliff's arguments. First, I respond to his
10 (and ORS Witness Seaman-Huynh's) overarching contention that South
11 Carolina ratepayers should not be required to pay an allocated portion of costs
12 incurred by the Company to comply with North Carolina environmental
13 regulations. Next, I explain how Mr. Wittliff's argument for cost disallowance
14 fails to meet the appropriate regulatory standard for excluding costs from
15 recovery. Finally, I address Mr. Wittliff's specific recommendations related to
16 the CCR management underway at the Cape Fear, Asheville, H. F. Lee, Sutton
17 and Weatherspoon facilities in North Carolina, where he identifies a percentage
18 of CCR management costs that he claims were due to North Carolina law and
19 should, therefore, not be allocated to South Carolina customers.

1 **A. Recovery of Environmental Compliance Costs For CCR Management**

2 **Q. DOES DEP AGREE WITH MR. WITTLIFF'S CONCLUSION THAT**
3 **THE COSTS HE RECOMMENDS BE EXCLUDED FROM RECOVERY**
4 **IN THIS CASE ARE RELATED ONLY TO CAMA AND ARE NOT**
5 **COSTS REQUIRED BY THE FEDERAL CCR RULE?**

6 **A. No. I understand that the Company disagrees with Mr. Wittliff's apparent**
7 **conclusion that there are substantial differences between costs that may be**
8 **required by CAMA as compared to costs that are required by the Federal CCR**
9 **Rule. This specific issue is addressed in the rebuttal testimony of Mr. Kerin.**

10 **Q. EVEN ASSUMING THERE ARE DIFFERENCES BETWEEN CAMA**
11 **AND CCR RULE COSTS, DOES THAT JUSTIFY MR. WITTLIFF'S**
12 **RECOMMENDATION TO DISALLOW CAMA-RELATED COSTS?**

13 **A. No. As I discuss in this section of my rebuttal testimony, even if there are**
14 **differences in the CAMA-related and Federal CCR Rule-related costs, these**
15 **differences do not disqualify such CAMA-related costs from recovery from**
16 **South Carolina customers.**

17 **Q. IS MR. WITTLIFF'S PROPOSAL FOR DISALLOWANCE OF WHAT**
18 **HE TERMS "CAMA-RELATED COSTS" CONSISTENT WITH**
19 **ESTABLISHED REGULATORY PRACTICES FOR MULTI-STATE**
20 **UTILITIES?**

21 **A. No. Mr. Wittliff states (page 30, lines 18-19) that "it is the position of ORS that**
22 **costs incurred as a result of jurisdictional laws should not lead to increased costs**
23 **to ratepayers outside of that jurisdiction." ORS Witness Seaman-Huynh (page**

1 7, lines 1-5) makes this same argument. This position is extreme and incorrect,
2 and neither witness offers any policy justification for wholesale disregarding
3 costs to comply with another state's laws. It is my experience that costs are
4 allocated and recovered from customers based on which customers are served
5 or benefitted by the actions that led to those costs. In this case, it is undisputed
6 that the coal ash located at all of the Company's coal sites was produced as a
7 result of providing electric energy to the Company's customers in both South
8 Carolina and North Carolina. Therefore, the costs related to the CCR unit
9 closure should likewise be borne by customers in both states. Furthermore,
10 even though some costs to serve electric customers may be incurred due to a
11 jurisdiction-specific law, such as differences in property taxes, this does not
12 mean that the costs of such a law are not recoverable from all customers who
13 benefit from the electric service activity associated with the law. This is how
14 South Carolina and North Carolina have historically treated such costs.

15 Finally, the Company does not have the option to ignore South Carolina
16 or North Carolina state law. If the Company is to continue to supply electric
17 service, it must comply with the environmental laws of both South Carolina and
18 North Carolina. The Company cannot simply pick and choose which
19 environmental laws with which to comply. It would, therefore, be unreasonable
20 to disallow costs the Company has incurred to follow the law.

1 **Q. CAN YOU PROVIDE ANY EXAMPLES OF STATE SPECIFIC COSTS**
2 **THAT ARE SHARED BY NORTH CAROLINA AND SOUTH**
3 **CAROLINA CUSTOMERS?**

4 A. Yes. Some state specific costs that are often shared between the states include
5 property taxes on generation and transmission assets, differences in everyday
6 operating costs like employee expenses, contractor expenses, fuel costs, and
7 even costs like fuel transportation, which can differ depending on the location
8 of a generating station (for example, rail service from coal mines to North
9 Carolina can be different, and usually cheaper because of distance, than rail
10 service to South Carolina). In addition, it is my understanding that, the
11 Company has returned and is proposing to continue to return to South Carolina
12 customers \$30 million of excess deferred income taxes resulting from a
13 decrease in the North Carolina state income tax rate. This decrease in the
14 income tax rate is the result of North Carolina legislation. If it is the ORS's
15 position that South Carolina customers should not pay for any costs due to
16 North Carolina legislation, then they should also propose that South Carolina
17 customers not receive any benefits due solely to North Carolina legislation, and
18 therefore, the company would need to collect from customers the \$29 million
19 of North Carolina state income taxes it has already passed through to customers
20 and remove the remaining \$1 million from the case.

1 **Q. HAVE NORTH CAROLINA AND SOUTH CAROLINA SHARED THE**
2 **COMPANY'S ENVIRONMENTAL COMPLIANCE COSTS PRIOR TO**
3 **THIS CASE?**

4 A. Yes. In fact, it is my experience that most, if not all, of the environmental costs
5 the Company has expended, absent some unusual circumstance, have been
6 shared between the states. For example, coal ash beneficial reuse revenues
7 have, to date, been allocated and shared between both states. Also, as I
8 mentioned in my direct testimony, in this Commission's Docket No. 2011-271-
9 E, costs associated with a Cliffside facility scrubber, located in North Carolina,
10 were allocated to and recovered from South Carolina customers. Similarly, in
11 Docket No. 2009-226-E, costs associated with scrubbers at the Allen Steam
12 Station, also located in North Carolina, were likewise recovered from South
13 Carolina customers.

14 **Q. IS THIS TYPICAL IN OTHER STATES AS WELL?**

15 A. Yes. This type of cost sharing is common where a utility's operations span
16 multiple states and the utility property used to provide one particular state's
17 electric service may be located in another state. Some examples of other states
18 sharing environmental costs include:

19 *Application of Southwestern Electric Power Company for Authority to*
20 *Change Rates, SOAH Docket No. 473-17-64, PUC Docket No. 46449*
21 *(Sept. 21, 2017); Order on Rehearing (Mar. 19, 2018) (Allowed the*
22 *environmental costs associated with retro-fitting a facility located in*
23 *Louisiana in which a Texas utility owned an interest to be included in*

1 the Texas utility's rate base).

2 *In re: Petition for approval of 2016 depreciation and dismantlement studies,*
 3 *approval of proposed depreciation rates and annual dismantlement*
 4 *accruals and Plant Smith Units 1 and 2 regulatory asset amortization,*
 5 *by Gulf Power Company, Order No. PSC-17-0178-S-EI, FL PSC*
 6 *Docket No. 160170-EI (May 16, 2017) (Base rate case where Florida*
 7 *PSC allowed Gulf Power cost recovery of environmental costs*
 8 *associated with a plant in Georgia in which Gulf Power had an*
 9 *ownership interest through Gulf Power's environmental cost recovery*
 10 *clause).*

11 *In Re Environmental Cost Recovery Clause, Docket No. 090007-EI, 2009 WL*
 12 *2028575 (Mar. 31, 2009) (Florida Public Service Commission*
 13 *approves Gulf Power's inclusion of environmental costs (including*
 14 *costs related to closure of an ash pond) relating to a Mississippi coal-*
 15 *fired generating unit in which Gulf Power owned an interest in its*
 16 *environmental compliance program, which program costs Gulf Power*
 17 *recovers through its environmental cost recovery clause).*

18 **Q. HOW IS SOUTH CAROLINA ADDRESSING THE CCR UNITS THAT**
 19 **ARE LOCATED WITHIN THE STATE?**

20 **A.** South Carolina stakeholders have demonstrated a strong preference for
 21 excavation of coal ash ponds through settlements or negotiations with its
 22 electric suppliers, which predates the adoption of the Federal CCR Rule and
 23 CAMA. This excavation preference is more prescriptive than the CAMA

1 policies and reflects the most expensive type of closure option. For example,
2 with respect to the Company's Robinson facility in South Carolina, on July 15,
3 2015, the Company entered into a Consent Agreement with the South Carolina
4 Department of Health and Environmental Control ("SCDHEC"). This
5 agreement called for the excavation of all of this site's CCR units, even those
6 inactive units which were not covered under the CCR Rule.

7 It is important to note that the costs associated with these South Carolina
8 agreements are appropriately allocated and recovered from North Carolina
9 customers as approved by the North Carolina Utilities Commission's Feb. 23,
10 2018 Order in the Company's recent North Carolina general rate case (Docket
11 No. E-2, Sub 1142, page 149, 159, 188, 272).

12 **Q. WHAT DO YOU BELIEVE WOULD BE THE ULTIMATE RESULTS IF**
13 **THIS COMMISSION WERE TO ADOPT MR. WITTLIFF'S**
14 **RECOMMENDATIONS THAT ANY COSTS ASSOCIATED WITH**
15 **NORTH CAROLINA'S CAMA LAW SHOULD BE EXCLUDED FROM**
16 **RECOVERY IN SOUTH CAROLINA?**

17 **A.** I discuss this in more detail in my response to ORS Witness Seaman-Huynh.
18 However, in brief, in the near term, the Company's financial condition would
19 be negatively impacted, likely resulting in an increase in the Company's cost of
20 capital. Over time, this would lead to additional costs for all of the Company's
21 customers. In other words, over time both South Carolina's and North
22 Carolina's customers' electric service costs would increase due to South
23 Carolina customers failing to pay their fair share of these environmental costs.

1 In addition, the failure of South Carolina customers to pay their
2 allocated share of these costs would certainly be an unwelcome result to North
3 Carolina citizens and regulators, as it would mean that North Carolina
4 customers are currently paying their share of costs related to South Carolina's
5 coal ash standards, which require more costly and extensive remediation than
6 what is required by either CAMA or the Federal CCR Rule. Contemplating this
7 result leads to the legitimate question of why is it appropriate for South Carolina
8 and its citizens to require and have costs recovered from North Carolina
9 customers for excavation of South Carolina coal ash ponds, but it is not
10 appropriate for similar and even less costly remediation for North Carolina coal
11 ash ponds to be recovered from South Carolina customers? In the end,
12 accepting Mr. Wittliff's recommendation would likely result in some state
13 regulatory jurisdictional issues that could even cause both states and the
14 Company to rethink whether sharing generation assets still makes sense.

15 This conclusion is not simply supposition. In the Company's recent rate
16 case Order in North Carolina (Feb. 23, 2018, Docket No. E-2, Sub 1142, page
17 219), the North Carolina Utilities Commission stated, with respect to the
18 sharing of costs between the states "After consideration of this issue, the
19 Commission finds and concludes that the adjustment recommended by Public
20 Staff witness Maness to allocate all system-level CCR costs by a comprehensive
21 allocation factor produces a more reasonable and appropriate outcome than the
22 proposal by the Company to allocate a portion of these costs in a manner that
23 does not allocate them to the South Carolina retail jurisdiction. Although the

1 costs in question were required pursuant to North Carolina law, the costs are
2 inherently related to the burning of coal to provide electricity to the entire DEP
3 system, including the South Carolina retail jurisdiction. The fact that these
4 particular costs are associated with plants that are geographically located in
5 North Carolina is no more relevant with regard to the proper allocation of these
6 costs than it is to the proper allocation of other costs, such as fuel expense and
7 other variable O&M expenses, which are allocated to the entire DEP system.”

8 Based on this statement, I would expect that the North Carolina Utility
9 Commission would be both surprised and troubled should this Commission
10 deny the Company recovery of South Carolina’s share of CCR related costs,
11 regardless of whether those costs were incurred to meet the requirements of
12 CAMA or the Federal CCR Rule.

13 **Q. DOES MR. WITTLIFF CONTEND THAT CAMA REQUIREMENTS**
14 **ARE UNREASONABLE OR OUT OF LINE WITH WHAT OTHER**
15 **STATES ARE NOW REQUIRING REGARDING ASH BASIN**
16 **CLOSURES?**

17 **A.** No, he does not, nor could he credibly make such an argument. For example,
18 Virginia has recently adopted state-specific CCR unit closure legislation,
19 similar to CAMA in requiring site specific closure standards and other
20 requirements. Additionally, other states have adopted basin closure rules and
21 regulations through their regulatory agencies that are more prescriptive than the
22 Federal CCR Rule and/or reached settlements with their electric utilities
23 regarding coal ash remediation that require steps beyond those required by the

1 Federal CCR Rule. These new environmental regulations and legal settlements
2 have resulted in South Carolina's surrounding states adopting coal ash
3 remediation policies that achieve similar closure standards as required by
4 CAMA, as illustrated in the following list:

5 *Georgia* - Adopted the Federal CCR Rule, but the Georgia Department
6 of Natural Resources adopted additional guidelines in October 2016 that
7 are more restrictive than the Federal CCR Rule at the time in that these
8 rules also related to inactive facilities not covered by the Federal CCR
9 Rule. Georgia also has pending legislation, HB 94, which does address
10 coal ash landfill restrictions. In addition, Georgia Power has agreed to
11 close all 29 of its coal ash ponds. While Georgia Power initially agreed
12 to cap 12 ponds in place and excavate 17, recently that utility has agreed
13 to excavate two more large sites;

14 *Virginia* - Adopted the Federal CCR Rule, then passed legislation that
15 requires Dominion Energy to excavate all of its coal ash sites in the
16 Chesapeake Bay Watershed and also requires beneficiation at two sites.
17 The legislation also has a 15 year time limit on the excavation, and
18 allows cost recovery (plus a return), employment requirements, and
19 reporting requirements;

20 *Tennessee* - The Department of Environment and Conservation has
21 adopted the Federal CCR Rule, but the Department's rule indicated that
22 it would oversee TVA's coal ash closure and even if TVA was in
23 compliance with the Federal CCR Rule the Department may require

1 additional actions. Recent court action is also requiring extensive
2 excavations of various TVA sites;

3 **Florida** - Adopted the Federal CCR Rule, but most of this state's coal
4 ash is beneficiated. In addition, Tampa Electric Company recently
5 decided to excavate its coal ash site at Big Bend Power Station and
6 submitted its closure plan for the site on October 2018;

7 **Alabama** - According to the Alabama Public Service Commission, the
8 Alabama Department of Environmental Management has not yet
9 adopted the Federal CCR Rule but is considering seeking EPA approval
10 for a state program that must be as stringent as the Federal CCR Rule.
11 In addition, Alabama Power currently is involved in litigation that
12 would require excavation of its CCR units.

13 **Q. CAN YOU PLEASE COMPARE NORTH CAROLINA'S COAL ASH**
14 **REGULATIONS TO THOSE IN SOUTH CAROLINA?**

15 **A.** Through settlements with its electric utilities, South Carolina stakeholders have
16 displayed a strong preference for the excavation of unlined coal ash basins – a
17 result that is more prescriptive, more extensive, and more costly than what
18 would have been allowed under CAMA or the Federal CCR Rule for some sites.
19 Today, every unlined coal ash pond in South Carolina is being or will be
20 excavated. For example, in addition to the example of the Company's Robinson
21 facility I discuss above, in 2013 Santee Cooper agreed to excavate its Grainger
22 site. In 2012, SCE&G settled a lawsuit by agreeing to excavate its Wateree and
23 Canadys sites.

1 **Q. DOES MR. WITTLIFF DISAGREE WITH THE COMPANY'S**
2 **APPROACH TO CCR CLOSURE IN SOUTH CAROLINA?**

3 A. No. Mr. Wittliff does not take issue with the Company's closure strategy for
4 Robinson. I find that position interesting considering his statement that "North
5 Carolina law and court decisions, over which South Carolina ratepayers have
6 no meaningful input, should not place an additional burden on the ratepayers of
7 South Carolina" (page 31, lines 4-6). Therefore, I assume Mr. Wittliff would
8 agree with the proposition that North Carolina could simply adopt South
9 Carolina's coal ash closure preferences and excavate all of the sites in North
10 Carolina with South Carolina paying its full share of the increased costs that
11 would come with such a policy.

12 **Q. IF NORTH CAROLINA SIMPLY FOLLOWED SOUTH CAROLINA'S**
13 **CURRENT COAL ASH REMEDIATION PREFERENCES, WHAT**
14 **WOULD BE THE RESULTING COMPLIANCE STANDARD AND**
15 **COSTS?**

16 A. As I indicated above, South Carolina's coal ash remediation policies require
17 excavating every unlined coal ash site. Where CAMA and the Federal CCR
18 Rule allow some North Carolina sites to be capped-in-place, which is generally
19 a less costly option than excavation, these sites, if located in South Carolina,
20 would likely be excavated. Therefore, if North Carolina adopted this policy the
21 costs would far exceed what is being requested in this filing.

B. The Appropriate Regulatory Standard For Disallowance of Costs

Q. IN YOUR OPINION, IS MR. WITTLIFF'S ARGUMENT FOR COST DISALLOWANCE AN APPROPRIATE BASIS FOR DISALLOWING MORE THAN HALF OF THE COMPANY'S COSTS FOR COMPLYING WITH CAMA AND THE FEDERAL CCR RULE?

A. No. The appropriate regulatory standard for denial of cost recovery is a finding that specifically identified costs were either not prudent,¹ were unjust or unreasonable,² or were incurred for facilities or expenses that are not considered used and useful³ in the provision of electric service. As I will explain, Mr. Wittliff fails to present an argument that meets any of these three regulatory cost disallowance standards.

Moreover, simply relying on a claim that the Company is responding to a North Carolina law and, therefore, these costs only relate to North Carolina,

¹ "Regulators, in turn, agree to allow the utility to recover any costs that are "prudently" incurred in order to earn a "fair" return on its investment." Public Utility Commission Study, EPA Contract No. EP-W-07—064, March 31, 2011, page 5. "Although the burden of proof of the reasonableness of all costs incurred which enter into a rate increase request rests with the utility, the utility's expenses are presumed to be reasonable and incurred in good faith. *Hamm v. S.C. Pub. Serv. Comm'n*, 309 S.C. 282, 286, 422 S.E.2d 110, 112 (1992) (citations omitted). "This presumption does not shift the burden of persuasion but shifts the burden of production on to the Commission or other contesting party to demonstrate a tenable basis for raising the specter of imprudence." *Id.* See also *Utils. Servs. of South Carolina, Inc. v. South Carolina Office of Regulatory Staff*, 392 S.C. 96, 109-10, 708 S.E.2d 755, 762-63 (2011) (confirming that the same standard applied after the formation of the ORS).

² Such a regulatory policy fails to meet the most basic regulatory requirement that rates are based on "known and measurable" dollars. See *Hamm v. S.C. Pub. Serv. Comm'n*, 309 S.C. 282, 291, 422 S.E.2d 110, 115 (1992) ("adjustments for known and measurable changes in expenses...must be known and measurable within a degree of reasonable certainty") and see §58-27-810 states that "Every rate made, demanded or received by any electrical utility or by any two or more electrical utilities jointly shall be just and reasonable."

³ With respect to the "used and useful" standard, South Carolina, like other states, has defined used and useful utility property as "property which [the utility] necessarily devotes to rendering the regulated services" and has allowed recovery for such property in rates. *Hamm v. S.C. Pub. Serv. Comm'n*, 309 S.C. 282, 286 n. 1, 422 S.E.2d 110, 112 n. 1 (1992) (quoting *Southern Bell Tel. & Tel. Co. v. Pub. Serv. Comm'n of S.C.*, 270 S.C. 590, at 600, 244 S.E.2d 278, at 283 (1978)).

1 as Mr. Wittliff suggests, could be seen as arbitrary and capricious when this
2 coal ash and any related costs have clearly been incurred as a result of providing
3 electric service to customers in both South Carolina and North Carolina.

4 **Q. HAS MR. WITTLIFF PRESENTED ANY ARGUMENT OR FINDING**
5 **THAT THE COSTS HE SEEKS TO EXCLUDE FROM RECOVERY**
6 **ARE IMPRUDENT OR UNREASONABLE?**

7 A. No. Mr. Wittliff has not performed a prudence analysis of DE Progress' costs.
8 The disallowances he recommends are entirely tied to whether costs are related
9 to CAMA.

10 **Q. HAS ANY REGULATORY JURISDICTION EVER EXAMINED AND**
11 **RULED ON THE QUESTION OF WHETHER THE COSTS MR.**
12 **WITTLIFF SEEKS TO DISALLOW IN THIS CASE WERE**
13 **PRUDENTLY INCURRED?**

14 A. Yes. The North Carolina Utilities Commission recently ruled on this issue.
15 After filings and extensive testimony from Mr. Wittliff and other witnesses and
16 cross examination, that body concluded that the Company's coal ash basin
17 closure costs were prudent. (Order of Feb. 23, 2018, Docket No. E-2, Sub 1142,
18 page 187, 188).

19 **Q. HAS MR. WITTLIFF PRESENTED ANY ARGUMENT OR FINDING**
20 **THAT THE COSTS HE SEEKS TO EXCLUDE FROM RECOVERY**
21 **ARE NOT USED AND USEFUL?**

22 A. No. The disallowances he recommends are entirely tied to whether costs are
23 related to CAMA. Furthermore, it is undisputed in this case that the coal plants

1 associated with these costs and the related coal disposal facilities have been
2 used and useful in providing low-cost, reliable power to South Carolina
3 customers for more than 70 years. Consequently, these types of costs and, if
4 any amount is deferred over time, a return, would be appropriately recoverable
5 in rates to ensure that the Company recovered the equivalent of the full amount
6 of those costs.

7 **C. Costs Related To Specific Plants**

8 **Q. ARE THE COSTS FOR WHICH MR. WITTLIFF SEEKS TO**
9 **DISALLOW RECOVERY IN THIS CASE RELATED TO SPECIFIC**
10 **SITES?**

11 **A.** Yes. He recommends disallowances for five sites: Asheville, Cape Fear, H. F.
12 Lee, Sutton and Weatherspoon.

13 **Q. WHAT IS MR. WITTLIFF'S RECOMMENDATION WITH RESPECT**
14 **TO THE ASHEVILLE PLANT?**

15 **A.** Mr. Wittliff indicates that North Carolina's Mountain Energy Act required an
16 accelerated closure schedule that led to excavation of coal ash at Asheville
17 whereas he claims the Federal CCR Rule would have allowed a less expensive
18 cap-in-place option. He then attempts to quantify what he claims is the
19 difference in the cost of these two options (his quantification in this regard is
20 rebutted by Company witness Kerin) except that he also recommends what he
21 has calculated to be engineering and planning costs (see Wittliff Direct T. at 40-
22 41). The result is that he would disallow recovery at this time of \$98.2 million
23 in Asheville CCR sites closure costs, for which he says the Company can seek

1 recovery after 2020 (Wittliff Direct T. at 42:5-6).

2 **Q. IS MR. WITTLIFF'S ARGUMENT THAT THE COSTS ASSOCIATED**
3 **WITH THE ASHEVILLE PLANT ARE UNRECOVERABLE AT THIS**
4 **TIME BECAUSE THEY ARE IN RESPONSE TO CAMA AND NOT**
5 **THE FEDERAL CCR RULE REASONABLE?**

6 A. No. This is not a reasonable argument from a regulatory cost recovery
7 perspective in my opinion. Mr. Wittliff did not present evidence that the
8 Company's Asheville closure strategy was unreasonable or imprudent.
9 Assuming the Commission found the Asheville closure strategy to be prudent
10 and reasonable, and there is no evidence to the contrary, then the costs should
11 be recoverable at this time. The Company must comply with the laws of both
12 North Carolina and South Carolina. ORS asks this Commission to conclude
13 that DE Progress incurred costs at Asheville because it complied with the
14 Mountain Energy Act. This effectively places the South Carolina Public
15 Service Commission in the position of having to determine what is a reasonable
16 coal ash compliance regulation for the state of North Carolina. For this case,
17 the Commission would have to conclude that the CCR Rule is the only
18 reasonable way to manage coal ash, and anything more prescriptive is excessive
19 by definition. This ignores that the CCR Rule contemplates that states may
20 develop more stringent regulation and it ignores the actions that South Carolina
21 stakeholders have already taken that are above and beyond the requirements of
22 the CCR Rule.

1 **Q. WHAT IS MR. WITTLIFF'S RECOMMENDATION WITH RESPECT**
2 **TO THE SUTTON PLANT?**

3 A. Mr. Wittliff indicates that the Company actions at Sutton were not required by
4 the CCR Rule but only due to CAMA requirements (Wittliff Direct T. at 37:19-
5 23), and therefore that the Company should do nothing with respect to coal ash
6 at Sutton at this time. He then recommends a disallowance of \$186.4 million,
7 He argues that, except for what he has calculated as planning and engineering
8 costs, the rest of the costs expended at Sutton should be disallowed for recovery
9 from South Carolina ratepayers at this time (Wittliff Direct T. at 40:4-6).

10 **Q. IS MR. WITTLIFF'S ARGUMENT THAT THE COSTS ASSOCIATED**
11 **WITH THE SUTTON PLANT ARE UNRECOVERABLE AT THIS**
12 **TIME BECAUSE THEY ARE IN RESPONSE TO CAMA AND NOT**
13 **THE FEDERAL CCR RULE A REASONABLE REGULATORY-BASED**
14 **ARGUMENT?**

15 A. No. Just as with the costs of the Asheville facility, this is not a reasonable
16 argument from a regulatory cost recovery perspective in my opinion. The
17 Company must comply with the laws of both South Carolina and North
18 Carolina. South Carolina customers have enjoyed the benefits of the electric
19 power produced by this facility for many years. Like South Carolina has done,
20 North Carolina has a legitimate right to adopt coal ash closure procedures
21 appropriate for that state. Moreover, as I have stated the coal ash closure plans
22 in North Carolina are actually less costly then the apparent coal ash closure
23 policies adopted in South Carolina. And finally, Mr. Wittliff did not present

1 evidence that the Company's Sutton closure strategy was unreasonable or
2 imprudent.

3 **Q. WHAT IS MR. WITTLIFF'S RECOMMENDATION WITH RESPECT**
4 **TO THE CAPE FEAR AND H. F. LEE PLANTS?**

5 A. Both the Cape Fear and H. F. Lee sites are beneficiation sites. Mr. Wittliff
6 indicates that the Company should do nothing with respect to coal ash at Cape
7 Fear recommends a disallowance of \$33.6 million or all of the costs the
8 Company is seeking recovery with respect to this facility. With respect to the
9 H. F. Lee site he does allow recovery of some level of costs. His overall
10 reasoning for his cost disallowance at both facilities is that the Federal CCR
11 Rule would not have required any of the beneficiation the Company is
12 undertaking, which is only required by CAMA. (Wittliff Direct T. at 34, Table
13 5.2 and Wittliff Direct T. at 35:15-18).

14 **Q. ARE MR. WITTLIFF'S ARGUMENTS THAT COAL ASH COSTS AT**
15 **CAPE FEAR AND H. F. LEE ARE NOT RECOVERABLE BECAUSE**
16 **CCR SITE CLOSURE AT CAPE FEAR IS NOT REQUIRED UNDER**
17 **THE CCR RULES, OR BENEFICIATION AT EITHER SITE IS NOT**
18 **REQUIRED UNDER THE CCR RULES REASONABLE?**

19 A. No. Mr. Wittliff has presented no argument that DE Progress' closure
20 methodology is unreasonable or imprudent; his only claim is that the costs are
21 not required under the Federal CCR Rule. Moreover, with respect to the Cape
22 Fear site, it is difficult to imagine that the Company should or would be allowed
23 by regulators and courts to simply do nothing at Cape Fear at this time,

1

1 particularly given the current activity in neighboring states and given current
2 coal ash remediation plans in South Carolina resulting in excavation of all
3 unlined sites, including inactive basins. Furthermore, for both facilities the
4 Company must comply with the coal ash laws of both North Carolina and South
5 Carolina.

6 **Q. IS THERE ANY OTHER REASON WHY IT IS AN UNREASONABLE**
7 **ARGUMENT THAT COAL ASH BENEFICIATION COSTS AT CAPE**
8 **FEAR AND H. F. LEE ARE NOT RECOVERABLE BECAUSE**
9 **BENEFICIATION AT EITHER SITE IS NOT REQUIRED UNDER THE**
10 **CCR RULES?**

11 A. Yes. I am informed by Company personnel that DE Progress' beneficiation
12 projects at its Cape Fear and H. F. Lee sites will actually flow back a large cost
13 savings to South Carolina customers. Because these sites are being beneficiated
14 under CAMA, following Mr. Wittliff's recommendation in this case would
15 mean these cost savings would go completely to North Carolina customers and
16 not be realized by the Company's customers in South Carolina.

17 **Q. WHAT IS MR. WITTLIFF'S RECOMMENDATION WITH RESPECT**
18 **TO THE WEATHERSPOON PLANT?**

19 A. Mr. Wittliff essentially makes the argument that beneficiation costs at
20 Weatherspoon were only because of CAMA and unnecessary under the Federal
21 CCR Rule. Thus, he recommends disallowance of what he has identified as the
22 CAMA related - costs of \$6.04M (Wittliff Direct T. at 43: 1-12).

23 **Q. IS MR. WITTLIFF'S ARGUMENT FOR HIS PROPOSED**

1 **WEATHERSPOON DISALLOWANCE CORRECT?**

2 A. No. DE Progress is not beneficiating ash under CAMA at Weatherspoon as
3 Mr. Wittliff suggests (Wittliff Direct T. at 42: 21-23).and instead is selling raw,
4 unprocessed ash to buyers who can use it to offset some of the costs for closing
5 that site.⁴ CAMA required the Company to select three sites for the installation
6 of ash beneficiation equipment to process ash into a refined product. Those
7 sites are H.F. Lee, Cape Fear, and Buck (DE Carolinas). Weatherspoon does
8 not qualify as a beneficiation site under CAMA and the suggestion that the
9 Company's ash disposal efforts at Weatherspoon are required by CAMA is
10 wrong. DE Progress identified Weatherspoon as a site for cost-effective
11 beneficial re-use of ash in the cement industry. This is a win-win for the cement
12 industry and customers Likewise, Mr. Wittliff does not criticize the closure of
13 Weatherspoon by excavation. Mr. Wittliff questions the logic of CAMA's
14 beneficiation requirement that he erroneously believes applies to this site. If the
15 Commission accepts Mr. Wittliff's erroneous assertions that Weatherspoon is a
16 CAMA beneficiation site or that reuse of ash is somehow beyond the scope of
17 the CCR Rule, then the related cost savings should not pass to SC customers.

1 **III. RESPONSE TO ORS WITNESS SEAMAN-HUYNH**

2 **Q. WHAT IS MR. SEAMAN-HUYNH'S RECOMMENDATION**
3 **REGARDING WHAT HE TERMS NORTH CAROLINA**
4 **JURISDICTIONAL COSTS?**

5 **A.** Mr. Seaman-Huynh's direct testimony (p. 7, lines 1-4) indicates that the ORS
6 recommends the Commission disallow recovery of what he terms additional
7 costs related to North Carolina laws and regulations. He refers to Mr. Wittliff
8 for more discussion on this issue and the exact recommendations. By "laws
9 and regulations," he is referring to CAMA.

10 **Q. AS A GENERAL REGULATORY PRINCIPLE, WHY DO YOU**
11 **DISAGREE WITH THIS RECOMMENDATION?**

12 **A.** While I have addressed this issue in my response to Mr. Wittliff, I will provide
13 a more expansive response here. The Company acknowledges, and I agree, that
14 there are times when direct allocation of costs between jurisdictions is
15 appropriate; but, direct allocation of costs between jurisdictions for many, if not
16 most, costs is the exception, and not the rule, when jurisdictions share joint
17 assets and thus enjoy the mutual benefits that come from sharing those assets.
18 The coal ash that is related to these so-called CAMA costs was produced in
19 providing electric service to customers in both South Carolina and North
20 Carolina. There is no dispute that South Carolinians benefitted from the low
21 electric rates and reliable service this Company has provided for decades, in
22 large part due to its coal-fired electric generation. Therefore, just as those
23 customers in South Carolina have benefitted from this coal-fired electric

1 service, they should likewise pay for the costs associated with that service,
2 including these new environmental compliance costs.

3 **Q. CAN YOU CITE SOME SPECIFIC REASONS WHY MR. SEAMAN-**
4 **HUYNH'S PROPOSED JURISDICTIONAL COST ALLOCATION**
5 **RECOMMENDATION IS NOT IN THE CUSTOMERS' BEST**
6 **INTEREST?**

7 A. Yes. First, while Mr. Seaman-Huynh may think his proposal is saving South
8 Carolina customers money; it is not, as further discussed in Mr. Kerin's rebuttal.
9 Further, his proposal, if accepted, could call into question the equities of sharing
10 assets and economies of scale across a multi-state structure. In other words, the
11 "slippery slope" and the unintended consequences that come with ORS's ill-
12 conceived proposal far outweigh any perceived benefit that ORS may believe
13 customers will see due to their suggested disallowances.

14 Additionally, if the Commission followed this recommendation, it
15 would cause investors to reevaluate their views on this Commission's
16 regulatory policies. As numerous return on equity experts have testified, the
17 investment community does evaluate how regulatory commissions respond to
18 utility filings and these evaluations are reflected in a utility's perceived riskiness
19 and, in turn, in its cost of capital. I believe that if this Commission were to
20 accept Mr. Seaman-Huynh's recommendation, it would negatively impact
21 investors' perceptions of this Commission, which would likely increase the
22 Company's cost of capital, resulting in increased rates.

1 Q. CAN YOU CITE ANY OTHER SPECIFIC REASONS WHY MR.
2 SEAMAN-HUYNH'S PROPOSED JURISDICTIONAL COST
3 ALLOCATION RECOMMENDATION IS NOT IN THE CUSTOMERS'
4 BEST INTEREST?

5 A. Yes. A very important fourth reason, as I discussed briefly in response to Mr.
6 Wittliff, is that such a ruling may result in a negative reaction from North
7 Carolina regulators. It is reasonable to assume the North Carolina Utilities
8 Commission would likely take umbrage at such a ruling and see it as South
9 Carolina taking advantage of North Carolina's customers. To wit, most of the
10 Company's generating facilities are located in North Carolina and, yet, for
11 decades these facilities have served citizens in both states. To now disallow
12 legitimate environmental regulations and related costs, regulations that as I
13 have discussed are less stringent and less costly than regulations currently
14 applied in South Carolina, would likely be perceived as North Carolina
15 customers essentially subsidizing South Carolina customers.

16 In the end, I believe accepting this recommendation would likely result
17 in jurisdictional allocation controversies between South Carolina and North
18 Carolina, would result in increased rates over time, and could call into question
19 the equities of sharing assets and economies of scale across a multi-state
20 structure.

1 **IV. RESPONSE TO ORS WITNESS MORGAN**

2 **Q. WHAT ISSUE ARE YOU ADDRESSING RELATED TO ORS WITNESS**
3 **MORGAN'S DIRECT TESTIMONY?**

4 A. I am responding to ORS Witness Morgan's updated Adjustment #36. This is
5 an adjustment to operations and maintenance ("O&M") expenses to remove
6 \$875,000 in certain expenses which include litigation expenses purportedly
7 attributable to legal actions related to coal ash.

8 **Q. WHAT IS HIS BASIS FOR THIS ADJUSTMENT?**

9 A. ORS Witness Morgan references ORS Witness Wittliff's direct testimony and
10 his claim that "the Company violated state and federal laws resulting in
11 damages to the environment." (ORS Witness Morgan Direct Test. 5:12-15).
12 Relying on Mr. Wittliff's testimony, ORS Witness Morgan concludes that:

13 "Customers should not bear the burden of legal costs related to the
14 Company's failure to operate its coal ash basin in accordance with state
15 and federal rules and regulations. Inclusion of the legal costs as an
16 allowable expense forces ratepayers to pay for Duke Energy Carolinas,
17 LLC's ("DEC" or "Company") failure to comply with the law.
18 Furthermore, the legal expenses are not related to providing adequate
19 electrical service and the customers derived no benefit from the
20 expenditures. These legal costs should be the shareholders
21 responsibility which in turn incentivizes the regulated utilities to operate
22 in compliance with federal, state and local laws."

23 (ORS Witness Morgan Direct Test. 5:14-22).

1 Q. CAN YOU PLEASE DESCRIBE WHAT LEGAL FEES ARE
2 ASSOCIATED WITH THIS PROPOSED DISALLOWANCE?

3 A. The proposed disallowance appears to derive from litigation expenditures that
4 are listed in DE Carolinas' Confidential response to ORS Audit request number
5 43. The expenditures listed in that response relate to two matters involving the
6 Company: 1) the ongoing insurance recovery litigation and 2) defense of state
7 enforcement actions.

8 Q. DO YOU AGREE THAT THESE LEGAL FEES SHOULD BE
9 EXCLUDED FROM RECOVERY?

10 A. No. These legal fees should be recoverable from ratepayers.

11 Q. WHY DO YOU BELIEVE THAT THESE LEGAL FEES SHOULD BE
12 RECOVERED FROM RATEPAYERS?

13 A. There are two basic reasons for this conclusion. First, as a general matter, legal
14 fees should be recoverable because they represent a legitimate, reasonable, and
15 prudent business expenditure and, absent a finding that a specific legal expense
16 was imprudent or unreasonable, these expenses should be recoverable. The
17 Company must be afforded the opportunity to defend itself from lawsuits
18 especially from non-government related parties that is the origination of much
19 of the Company's legal expenses, including those in this case. Indeed, the
20 Company might even be considered a "target" so to speak for lawsuits and must
21 be allowed to vigorously defend itself.

22 Second, Mr. Wittliff's testimony does not support ORS Witness
23 Morgan's rationale for the recommended disallowance. I believe that a cost

1 disallowance must be based on the specific facts and circumstances that support
2 such a proposed cost disallowance. With respect to this criterion, ORS Witness
3 Morgan claims “[c]ustomers should not bear the burden of legal costs related
4 to the Company’s failure to operate its coal ash basin in accordance with state
5 and federal rules and regulations. (page 5, lines 14-15).” To support this claim
6 and related proposed cost disallowance, he references Mr. Wittliff’s direct
7 testimony and what he claims are environmental violations. However, the
8 litigation costs associated with the ongoing insurance litigation was initiated by
9 the Company for the benefit of its customers to enforce insurance policies and
10 obtain indemnity from insurers for costs incurred associated with coal ash
11 remediation. The insurance case is focused on legal liability on account of
12 property damage caused by an occurrence, not environmental violations. If the
13 Company prevails in this litigation, the costs it recoups from its insurers will be
14 passed along to benefit its customers.

15 **Q. OTHER THEN THIS INSURANCE RELATED LITIGATION, DOES**
16 **MR. WITTLIFF IDENTIFY OR DISCUSS THE LITIGATED**
17 **MATTERS FOR WHICH ORS WITNESS MORGAN IS**
18 **RECOMMENDING DISALLOWANCES?**

19 A. Only partially. Mr. Wittliff’s direct testimony discusses litigation relating the
20 Company’s alleged environmental violation (page 16, lines 16-18), where he
21 cites his Exhibits 5.0 through 5.4 as legal actions that he believes indicate the
22 Company committed violations of environmental regulations. Only three of

1 those exhibits, Exhibits 5.3.1, 5.3.2, and 5.4 relate to the state enforcement
2 actions for which ORS is recommending its disallowance.

3 Mr. Wittliff's Exhibits 5.3.1 and 5.3.2 are summary judgment orders
4 from state enforcement actions that were filed against the Company in 2013.
5 These state enforcement actions preceded the passage of both the federal CCR
6 Rule and the CAMA. It is my opinion that the Company has a legitimate right
7 and an obligation to defend itself from allegations of wrongdoing when the
8 Company believes it is in compliance with the then current coal ash regulations.
9 Moreover, the Company should defend itself and ratepayers in a legal
10 proceeding when the potential result could be the requirement that the Company
11 undertake coal ash remediation procedures that are beyond the current
12 regulatory requirements, and, which in the end, could prove far more costly to
13 customers than what would be required by either CAMA or the CCR.
14 Importantly, there has been no finding by the Court in these actions that the
15 Company violated any environmental statute or rule.

16 Wittliff Exhibit 5.4 is a North Carolina Settlement Agreement where the
17 Company had no admission of guilt and finding or admission of a violation. I
18 believe it is reasonable to expect the Company to defend itself and ratepayers
19 from the potential for expensive and unnecessary legal rulings and, in
20 appropriate instances, settling lawsuits. Moreover, often these lawsuits are
21 brought by non-government entities and the Company surely has a right and
22 responsibility to defend its customers and stockholders from these type lawsuits
23 over which they have no control as to how many and when such lawsuits might

1 occur. Therefore, it is my opinion that these legal fees are a legitimate and
2 recoverable expense.

3 **V. RESPONSE TO ORS WITNESS PAYNE**

4 **Q. WHAT IS MR. PAYNE'S RECOMMENDATION WITH RESPECT TO**
5 **RECOVERY OF DEFERRED COSTS?**

6 A. Generally speaking, Mr. Payne recommends that any cost deferrals, except
7 those related to deferred income tax, be categorized as either an operating-
8 related or capital-related cost. Based on my discussions with Company
9 accountants, it is my understanding that he has further recommended that what
10 he has identified as operating-related, including deferred O&M, depreciation
11 and property tax expenses, not be included in rate base and be recovered over
12 time with no return on the deferred costs during the time period when these
13 costs are being recovered (amortization period). He has also recommended no
14 return on the deferred balances during the deferral period. Finally, for several
15 of his deferred expense costs, he has proposed amortization periods much
16 longer than what the Company is proposing.

17 **Q. WHAT IS THE ULTIMATE MONETARY IMPACT OF HIS**
18 **RECOMMENDATION?**

19 A. His recommendation does not allow the Company the opportunity to recover its
20 true costs for two reasons. First, by not allowing the recovery of a return on
21 uncollected deferred costs during the deferral period, whatever that deferred
22 cost may be including uncollected depreciation, the Company does not have the
23 opportunity to recover all of its costs associated with these deferred accounts.

1 Second, increasing the amortization period (see Company witness Bateman
2 Rebuttal Testimony) and not allowing a return over the time period the costs
3 are being recovered, prevents the Company from recovering its costs associated
4 with the cost of money.

5 **Q. IS HIS RECOMMENDATION CONSISTENT WITH YOUR**
6 **UNDERSTANDING OF THE USUAL METHODOLOGY EMPLOYED**
7 **TO RECOVER DEFERRED COSTS?**

8 A. No. In my experience, his recommendation to disallow the recovery of a return
9 on a large portion of the Company's deferred costs is inconsistent with the
10 normal cost recovery allowed by regulatory bodies. Specifically, it violates the
11 basic regulatory compact, which can be stated as follows: "*A rate - regulated*
12 *entity incurs costs in order to provide reliable service to customers within its*
13 *approved service territory in a not unduly discriminatory manner with the*
14 *expectation that it will have the right to recover those prudently incurred*
15 *costs, plus earn a fair rate of return on the capital that has been invested in*
16 *the business to support reliable utility service.*" (emphasis added) ⁵

17 **Q. HOW DOES MR. PAYNE'S RECOMMENDATION VIOLATE THE**
18 **BASIC REGULATORY COMPACT?**

19 A. Yes, because it does not allow the Company the opportunity to recover its
20 prudently-incurred costs.

⁵ "Accounting for the Effects of Rate Regulation," Edison Electric Institute, July 2011, page 5 (emphasis added). See also *S. Bell Tel. & Tel. Co. v. Pub. Serv. Comm'n*, 270 S.C. 590, 595, 244 S.E.2d 278, 280-81 (1978) ("the governing principle for determining rates to be charged by a public utility is the right of the public on one hand to be served at a reasonable charge, and the right of the utility on the other to a fair return on the value of its property used in the service") (citing *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n of West Virginia*, 262 U.S. 679 (1923)).

1 Q. MR. PAYNE INDICATES IN SEVERAL PLACES IN HIS TESTIMONY
2 THAT ORS'S RECOMMENDATION "STILL ALLOWS THE
3 COMPANY TO RECOVER ITS ACTUAL DEFERRED COSTS" (page
4 8, lines 12-14, page 12, lines 12-13). IS THIS STATEMENT CORRECT
5 WITH RESPECT TO HIS PROPOSED COAL ASH
6 RECOMENDATION?

7 A. He is not correct when he does not allow the Company to recover in rates a
8 return on portions of the deferred accounts. A basic understanding of
9 accounting, finance, and economics tells us that there is a cost of money. In our
10 daily life, this is the interest rate on our credit cards or the interest rate we pay
11 on our home loans. In the context of utility regulation, we have cost of capital
12 witnesses that explain the costs of a utility's capital. In addition, regulation
13 accounting has various accounts like rate base and working capital accounts for
14 which a cost of capital, represented by a return, is computed. So, too, the dollars
15 the Company has spent and placed in a deferred account, have a cost -- these
16 dollars were not borrowed from investors for free and the Company is paying
17 those costs. Therefore, if a return on these deferred expenses is not allowed,
18 then it means the Company has not been allowed the opportunity to recover its
19 legitimate and prudent costs.

1 **Q. CAN YOU PROVIDE ANOTHER REASON WHY NOT ALLOWING A**
2 **RETURN PREVENTS THE COMPANY FROM RECOVERING ITS**
3 **TRUE COSTS?**

4 **A.** Yes. The most basic reason is it completely ignores the effect of inflation over
5 time; and, this impact is aggravated by Mr. Payne's other recommendation to
6 stretch out the Company's proposed cost recovery amortization periods (page
7 12, lines 2-3, 16-17). Thus, Mr. Payne's recommendations not only ignore the
8 fact that dollars the Company invests cost money, but he even ignores the
9 impact of inflation on the recovery of those costs. In the most basic economic
10 terms, if one ignores the impact of inflation and spreads over many future years
11 the recovery of dollars spent today, this means the Company can never recover
12 its true costs and never be made whole.

13 **Q. DO YOU HAVE ANY OTHER COMMENTS REGARDING MR.**
14 **PAYNE'S TESTIMONY?**

15 **A.** Yes. In several places he comments that the ORS recommendation "still allows
16 the Company to recover its actual deferred costs through amortization of the
17 proposed deferral balance which is a sufficient level of cost recovery." (for
18 example page 8, lines 12-14, page 12, lines 13-14). I am at a loss to understand
19 what he means by the term "a sufficient level of cost recovery." I am also
20 unfamiliar with this term being the standard of cost recovery applied in a
21 regulatory forum because it seems to require a subjective opinion. In my
22 experience, the standard of cost recovery in regulation is the recovery of all

1 prudent and reasonable costs plus a reasonable return on those costs recovered
2 over time.

3 Even accepting Mr. Payne's concept that a sufficient level of cost
4 recovery is an appropriate regulatory standard, I believe this is a vague choice
5 of words and he provides no indication as to how to measure "sufficient."
6 Unless it is totally subjective, I am left to ponder what financial or other metrics
7 were used by ORS in its determination of sufficiency? I believe that adopting
8 sufficiency as a regulatory guideline, along with the adoption of Mr. Payne's
9 recommendations regarding no return on much of the Company's deferred
10 costs, would elicit a negative response from the investment community. This
11 would result in an increase in the Company's cost to borrow money or attract
12 equity investors, resulting in higher future rates for all of its customers.

13 **VI. RESPONSE TO SOUTH CAROLINA ENERGY USERS**
14 **COMMITTEE WITNESS O'DONNELL**

15 **Q. WHAT ISSUES ARE YOU RESPONDING TO WITH RESPECT TO**
16 **MR. O'DONNELL?**

17 **A.** I am responding to the two basic issues that he raises regarding coal ash
18 compliance costs. First, I dispute his conclusion that the Company's coal ash
19 remediation costs "are MUCH greater than the coal ash AROs from other
20 utilities [and this] strongly implies that the North Carolina CAMA legislation
21 is much more stringent than the CCR Rule requirements." (page 41, lines 8-11)
22 Second, I dispute his overall recommendation that 75% of the Company's coal
23 ash remediation costs requested in this case be disallowed.

1 **Q. MR. O'DONNELL INDICATES THAT THE COMPANY'S CCR SITE**
2 **CLOSURE COSTS ARE MUCH GREATER THAN THE CLOSURE**
3 **COSTS OF OTHER COMPANIES AND THIS IS DUE TO CAMA (page**
4 **41, lines 8-11). DO YOU AGREE?**

5 **A.** I do not agree, and I believe that a fatal flaw with his argument is one of timing.
6 To explain, he uses data from SNL Financial and 2017 financial statements to
7 extract his data (page 46, lines 1-5). While this may seem to be current, in the
8 context of coal ash, this is not true since there are ongoing regulatory and legal
9 proceedings and various Company coal ash updates. For example, in the past
10 thirty days Virginia adopted a very costly coal ash bill that will significantly
11 impact Dominion Energy; and, Georgia Power, in October of 2018, updated the
12 sites it is excavating by adding an additional 29 million tons of ash to be
13 excavated. These laws in other states are evolving since the passage of the
14 Federal CCR Rule, as evidenced by the legislation recently adopted in Virginia,
15 the recent introduction of a bill in Georgia, and the numerous ongoing legal
16 proceedings in other jurisdictions. It just so happens that South Carolina and
17 North Carolina began the process earlier, and, in fact, South Carolina essentially
18 leads the Southeast as it began excavation of its sites in 2012.

19 To illustrate the current state of cost estimates, refer to the following
20 table that compares Mr. O'Donnell's cost estimates to some updated cost
21 estimates. Table JAW-1 shows that for three neighboring utilities, Georgia
22 Power, Alabama Power, and Dominion Energy (in Virginia), Mr. O'Donnell's
23 ARO coal ash compliance dollars are significantly less than what these utilities

1 have recently reported. Mr. O'Donnell doesn't even report TVA, whose
2 compliance costs are still in dispute but could range far in excess of the current
3 \$2 billion estimate if the least costly method of closure is not used. Therefore,
4 because neighboring state utilities are just now beginning to get new rules, or
5 settle cases, the coal ash costs Mr. O'Donnell is reporting for these neighboring
6 states are lower than the more current cost estimates. Consequently, Mr.
7 O'Donnell's conclusion that the Company's "coal ash costs are MUCH greater
8 than the coal ash AROs from other utilities" and that this increased cost is
9 caused by CAMA (page 47, lines 4-7) is contradicted when one considers more
10 recent coal ash cost data.

TABLE JAW-1: COMPARISON OF O'DONNELL REPORTED COAL ASH COMPLIANCE COSTS				
COMPANY	O'Donnell Reported Cost, Direct Testimony Table 8, page 46	Estimated Cost to Comply With CCR and State Regulations		Source
		Minimum	Maximum	
Dominion Energy Virginia	\$624M	\$5.6B to 8.2 B+ (note, with the passage of the recent legislation the costs is expected to approach the estimates for excavation, which the legislation requires)		AECOM Report in Response to SB 1398, Tables ES-1, ES- 2, Nov. 2017 and https://www.richmond.com/news/virginia/coal-ash-excavation-could-cost-dominion-ratepayers-an-extra-per/article_7c0269a2-c791-58d8-949c-5710083b1875.html December 17, 2018
GA Power	\$1.424B	\$1.5B	\$2.0B (note, this does not include the recent 29 million tons to be excavated at two additional sites – to put this additional 29 million ton potential cost in perspective, the recent VA legislation calls for Dominion to excavate 28 million tons at a cost estimate of \$5.6 B to over \$ 8.2 B)	http://www.ajc.com/business/georgia-power-close-ash-lagoons-sooner-could-cost-billion/Un9uNUQFtsZZBJXVgKGNak/ , June 13, 2016
AI Power	\$324M	\$1.14B	No estimate provided	Docket No. 18117, AI Power Compliance Plan, Dec. 13, 2016
TVA	Not reported	\$3.5M	\$2.3B	http://www.powermag.com/tva-backs-in-place-coal-ash-impoundment-closure-method-over-remo

1 Q. EVEN IF THE COMMISSION WERE TO ACCEPT MR.
2 O'DONNELL'S ASSERTION THAT THE COMPANY'S COAL ASH
3 COMPLIANCE COSTS ARE IMPROPERLY HIGHER THAN OTHER
4 ULTITIES IN THE NATION, IS HIS PROPOSED 75% COST
5 DISALLOWANCE A PROPER METHOD OF ADDRESSING THIS
6 CONTENTION?

7 A. No. The appropriate mechanism for adopting a cost disallowance is a finding
8 that a specific level of costs is imprudent, unreasonable, or not used and useful.
9 Mr. O'Donnell makes none of these arguments but simply advocates for a
10 blanket 75% cost reduction with no identification of costs that were imprudent,
11 unreasonable, or not used and useful.

12 VII. RESPONSE TO SIERRA CLUB WITNESS HAUSMAN

13 Q. SIERRA CLUB WITNESS DR. EZRA HAUSMAN CONTENDS THAT
14 THE COMMISSION SHOULD REQUIRE THE COMPANY TO
15 CONDUCT A COMPREHENSIVE RETIREMENT ANALYSIS AND
16 THAT THE RECOVERY OF THE CCR COSTS BE CONDITIONED ON
17 THE FILING OF THIS ANALYSIS (page 26, l.11-16, page 27, l.1-8). DO
18 YOU AGREE?

19 A. No. I disagree with his recommendation of conditional recovery for several
20 reasons. First, approving a "conditional cost recovery" is inconsistent with the
21 facts of this proceeding. To wit, the Company is expending resources to meet
22 environmental compliance deadlines. These expenditures are not optional, and
23 they are time sensitive. Therefore, unless these costs have been demonstrated

1 to be imprudent, unreasonable, or not used and useful, which no witness has
2 contended or provided evidence to support, then the recovery of these costs
3 should be allowed at this time.

4 Second, a conditional approval is inconsistent with the cost recovery
5 standards under which this Commission has based its regulatory policies
6 (discussed earlier in this testimony). Those policies are that costs are
7 recoverable if they have been demonstrated to be prudent, reasonable, and used
8 and useful. Again, no witness has contended or provided evidence to dispute
9 these costs meet this standard, thus the recovery of these costs should be
10 allowed at this time.

11 Third, because these expenditures are required at this time in order to
12 meet legal deadlines, as Mr. Kerin has explained in his direct testimony, then
13 the Company has the legal right to seek recovery of these costs in a timely
14 manner and has done so in this case. To accept Dr. Hausman's "conditional
15 recovery" would essentially cast a shadow of delay on potential future refunds
16 with respect to these now conditionally recovered expenses, which would likely
17 elicit a negative reaction from the investment community. The reason is
18 because of a risk that the Company's earnings would apparently be subject to
19 restatements as a result of customer refunds if, in the future, the Commission
20 did not approve of the comprehensive retirement analysis upon which Dr.
21 Hausman conditions his cost recovery approval.

22 Finally, I am at a loss to understand how this "conditional recovery"
23 idea would even work. I believe, at the very least, such a policy would be seen

- 1 as retroactive ratemaking, which is not allowed in most regulatory jurisdictions,
2 including South Carolina.
- 3 **Q. DOES THIS CONCLUDE YOUR PRE-FILED REBUTTAL**
4 **TESTIMONY AT THIS TIME?**
- 5 **A. Yes.**

1 THE EXAMINATION BY MR. BURNETT CONTINUES.

2 Q Mr. Kerin, do you have a summary of your direct and
3 rebuttal testimony?

4 A (KERIN) Yes. I do.

5 Q Would you present it at this time?

6 A (KERIN) I will. My direct testimony presents Duke
7 Energy Progress's (DE Progress's) request for
8 recovery of expenses that the Company has occurred
9 between July 1, 2016 and September 30, 2018 to
10 comply with the environmental requirements for the
11 disposal of coal combustion residuals, or CCRs. DE
12 Progress's request does not include any costs that
13 have been incurred related to fines, penalties, or
14 guilty pleas related to CCRs or any costs
15 associated with events related to those fines,
16 penalties, or guilty pleas.

17 My testimony also presents Duke Energy
18 Progress's supplemental request for recovery of CCR
19 compliance costs occurred from October 1, 2018
20 through December 31st, 2018. CCR disposal
21 regulations and industry practices have evolved
22 significantly over almost a century of providing
23 electric power service from coal-fired plants.
24 During this evolution, DE Progress has consistently
25 complied with the CCR disposal standards that were

1 in place at that time.

2 Based on industry developments that occurred
3 in the 1950s, the enactment of the Clean Air Act in
4 the 1970s and its amendment in the 1990s, and the
5 enactment of the Clean Water Act in 1972, along
6 with the creation of the National Pollution
7 Discharge Elimination System, or NPDES permitting
8 program, wet ash handling and ash basins were the
9 primary lawful, effective way to meet CCR needs and
10 environmental requirements in the years prior to
11 the advent of today's requirements. In many cases,
12 ash basins were actually created or relied upon to
13 effectuate prior regulatory regulations.

14 With each evolution of these environmental
15 regulations, the Company has changed how it's
16 operated its coal-fired stations to comply
17 accordingly, and at each step in the environmental
18 regulatory evolution process, the Company has been
19 in line with industry standards and has reasonably,
20 prudently managed CCRs and its coal ash basins.

21 The latest evolution of these requirements,
22 the Federal Environmental Protection Agency's CCR
23 rule, as well as state-specific regulations and
24 oversight in the Company's service territories, has
25 occurred since the Company's last rate case. DE

1 Progress is now subject to new federal and state
2 regulations that require to take significant
3 actions to modify its operations, and as a result,
4 incur substantial new expenditures associated with
5 those modifications.

6 All the Company's ash basins must be closed
7 under either the CCR rule, state-specific
8 regulations and oversight, or both. All closure
9 plans must be approved by the respective state
10 agencies. The Company has begun the process of
11 closing or submitting plans to close its ash basins
12 in accordance with its regulatory obligations. The
13 actions and decisions that Duke Energy Progress has
14 taken to comply with federal and state regulatory
15 requirements, including the Company's current and
16 future activities and solutions, have been
17 reasonable, prudent, and cost-effective, given the
18 individual characteristics of each CCR plant and
19 basin site.

20 My rebuttal testimony responds to the direct
21 testimony of Office of Regulatory Staff, ORS,
22 witness Dan Wittliff and SECUC witness Kevin
23 O'Donnell. No witness in this case have challenged
24 Duke Energy Progress's closure strategy for its ash
25 basins under federal -- under applicable federal or

1 state regulatory requirements, nor have any
2 witnesses in this case alleged that the Company has
3 taken actions that are not -- that are unreasonable
4 or imprudent. Instead, Wittliff -- Witnesses
5 Wittliff and O'Donnell asked this Commission to
6 simply ignore the coal -- the North Carolina Coal
7 Ash Management Act, or CAMA, because it is too
8 costly.

9 Specifically, I disagree with the
10 recommendations of ORS witness Wittliff that all
11 compliance costs attributed to CAMA should be
12 disallowed for the Company's Asheville, Sutton,
13 Cape Fear, HF Lee, and Weatherspoon sites. Like
14 South Carolina and other states in the country,
15 North Carolina has adopted environmental policies
16 and preferences for coal ash disposal that
17 compliment federal closure requirements under the
18 CCR rule. Duke Energy Progress is obligated to
19 follow state regulations and is doing so in an
20 environmentally responsive and cost-effective
21 manner. The suggestion that South Carolina
22 customers can enjoy all the savings of sharing
23 power generation units with the North Carolina
24 customers, but ignore any compliance costs with
25 valid laws, would present grave harm to South

1 Carolina customers if taken to its logical
2 conclusion.

3 I also explain that, in addition to their
4 misguided proposals to ignore valid CAMA costs, Mr.
5 Wittliff's and Mr. O'Donnell's specific proposed
6 disallowances are based on incorrect facts and
7 unrealistic assumptions.

8 First, I disagree with Mr. Wittliff's
9 contention that Duke Energy Progress could have
10 closed its Asheville basin by capping them in
11 place, as opposed to its chosen method of
12 excavation and off-site disposal, absent CAMA.
13 Throughout his testimony, Mr. Wittliff also appears
14 to conflate the cap-in-place and the excavation
15 closure methodologies, at one point suggesting that
16 an on-site landfill should've been constructed,
17 while at the same time urging cap-in-place. I know
18 that Mr. Wittliff has conducted no engineering
19 analysis to support his conclusions, which render
20 his recommended disallowance unsupportable. Mr.
21 Wittliff's surrebuttal testimony makes no attempt
22 to resolve this lack of engineering analysis and
23 his internal inconsistencies in his testimony. The
24 Company closure approach is the proper closure
25 method based on site-specific and regional

1 conditions.

2 Second, I disagree with ORS Wittliff's --
3 witness Wittliff's erroneous conclusion that,
4 absent CAMA, the Company could have left its ash
5 basins at the Cape Fear plant untouched
6 indefinitely because those basins are not covered
7 by the CCR rule. The position that DE Progress
8 could or would've taken a do-nothing approach for
9 the Cape Fear units, when similar basins at the
10 South Carolina's Robinson and WS Lee stations that
11 are also not covered by the CCR rule were being
12 excavated, is wholly unrealistic.

13 I also explain how Mr. Wittliff has
14 conveniently ignored the fact that the provisions
15 in the federal CCR rule that he relies upon to
16 support his do-nothing approach at Cape Fear site
17 have been found to be arbitrary, capricious, and
18 without factual support by the DC Circuit Court of
19 Appeals and has been remanded to the EPA.

20 Mr. Wittliff's surrebuttal testimony doubles
21 down on that do-nothing approach, again without
22 concluding whether the do-nothing approach would've
23 -- had been reasonable and prudent from an
24 environmental and safety perspective. The lack of
25 any reasonableness and prudence analysis is a flaw

1 that pervades all of Mr. Wittliff's testimony.

2 I also disagree with ORS Wittliff's contention
3 that CAMA ash beneficial reuse ash recycling
4 requirements that are associated -- and associated
5 costs from his DE Progress HF Lee and Cape Fear
6 plants and Duke Energy Carolina's Buck plant are
7 more costly to South Carolina customers than the
8 federal CCR rule. In fact, CAMA's ash
9 beneficiation requirements actually results in a
10 net savings for South Carolina customers, and under
11 ORS's proposal, those net savings would all need to
12 be given to North Carolina customers only.

13 Next, I disagree with Wittliff's contention
14 that Sutton closure schedule, under CAMA, has
15 increased costs for the customers of South
16 Carolina. Mr. Wittliff incorrectly assumes that
17 closure activities would've been required -- would
18 not have been required until 2021 at Sutton under
19 the CCR rule, and this is inaccurate. Mr.
20 Wittliff's entire disallowance figure is dependent
21 on his incorrect interpretation of the CCR rule.
22 He compounds this error by assuming that, over
23 time, resources become cheaper as demand for them
24 grows stronger, and this conclusion is logically
25 unsound and factually incorrect.

1 Mr. Wittliff was forced, in his surrebuttal
2 testimony, to acknowledge that closure under the
3 CCR rule would've had to been completed by 2021,
4 which means that, like Asheville, the closure
5 timing at Sutton was not substantially affected by
6 CAMA. This fundamental error makes his proposed
7 disallowance for Sutton completely inaccurate.

8 Regarding Witness Wittliff's recommended
9 disallowance for the Weatherspoon, I disagree with
10 his contention that his calculation of costs
11 attributable to CAMA's beneficiation requirements
12 should be disallowed. To be clear, Weatherspoon is
13 not being beneficiated pursuant to CAMA. In fact,
14 Weatherspoon does not even qualify as a
15 beneficiation site under CAMA. Mr. Wittliff's
16 uninformed observations while on a half-day visit
17 do not somehow convert Weatherspoon to a CAMA
18 beneficiation site.

19 Furthermore, Mr. Wittliff has failed to
20 recognize that the beneficial reuse of ash at
21 Weatherspoon is saving, not costing, customers more
22 money.

23 Lastly, I would like to note my strong
24 disagreement with Mr. Wittliff's disallowance
25 methodology with the -- which attempts to determine

1 recoverable and disallowable costs for each site by
2 developing weighted average percentage based on
3 costs from different sites operating in different
4 conditions. Disallowance for a given site should
5 only be based on the analysis of actual costs
6 incurred at that site and the determination that
7 those individual costs were not reasonably and
8 prudently incurred. Mr. Wittliff himself has
9 admitted that the weighted average percentage
10 approach that he uses here was too unreliable and
11 unsupportable to use during his testimony in the
12 North Carolina rate case, and in fact -- and that
13 fact has not changed how he is in North -- in South
14 Carolina.

15 With respect to Witness O'Donnell, his
16 analysis recommendation of a 75 percent
17 disallowance of Duke Energy Progress's coal ash
18 cost relies on multiple analytical flaws that are
19 each fatal to his conclusion. Specifically, I do
20 not agree with his conclusion that his national
21 comparisons of CCR asset retirement obligations, or
22 ARO, amounts that showed Duke Energy Progress's ARO
23 is overstated by 75 percent. I enumerate 22
24 factors that Mr. O'Donnell does not appear to have
25 considered, which must be accounted for in order to

1 seriously attempt this type of analysis. I explain
2 that, if Mr. O'Donnell actually considered those
3 factors, he would've discovered that his analysis
4 was invalid. I recommend that the Commission
5 consider the reasonableness of DE Progress's ARO
6 amount on its own merits, based on the facts of
7 this case, without regard to Mr. O'Donnell's
8 speculative proposal.

9 This concludes the summary of my direct and
10 rebuttal testimony in this case.

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22 (PURSUANT TO PREVIOUS INSTRUCTION,
23 THE PREFILED DIRECT TESTIMONY,
24 INCLUDING CORRECTION/AMENDMENT,
25 OF JON F. KERIN FOLLOWS.)

[Please note: Corrections noted herein reflect changes
enumerated in the errata filed 1/19/19; please also see that
document here: [https://dms.psc.sc.gov/Web/Matters/
Detail/281403](https://dms.psc.sc.gov/Web/Matters/Detail/281403)]

**BEFORE
THE PUBLIC SERVICE COMMISSION OF
SOUTH CAROLINA**

DOCKET NO. 2018-318-E

IN THE MATTER OF:

Application of Duke Energy Progress, LLC)	DIRECT TESTIMONY OF
For Adjustments in Electric Rate Schedules)	JON F. KERIN FOR
And Tariffs)	DUKE ENERGY PROGRESS, LLC

I. INTRODUCTION

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

A. My name is Jon F. Kerin. My business address is 411 Fayetteville Street, Raleigh, North Carolina, 27601-1849. I am employed by Duke Energy Business Services, LLC, as Vice President, Coal Combustion Products ("CCP") Operations, Maintenance and Governance. In this docket, I am testifying on behalf of Duke Energy Progress, LLC ("DE Progress" or the "Company"). As more fully discussed below, my responsibilities have included providing governance and operations support leadership to Duke Energy Corporation's regulated operating companies, including DE Progress. Relevant to this testimony, during 2014, I held the position of General Manager in the Ash Basin Strategic Action Team -- referred to as "ABSAT." I was named to my current role in 2015. In July 2018, I assumed additional responsibilities in the CCP organization for the Operations and Maintenance division.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I have a Bachelor of Science degree from the University of Maryland. I have over 30 years of experience in the electric utility industry, where I have been involved in various complex and challenging projects. In addition to my CCP experience, my background includes experience at various nuclear electric generating power plants and in other corporate functions. Prior to the merger of Progress Energy, Inc. and Duke Energy, I was the Director of the Project Management Center of

1 Excellence for Progress Energy, Inc. After the merger, I became General
2 Manager, Performance Improvement in the Project Management and Construction
3 Department before transitioning to the ABSAT team. In these roles, I worked
4 with new project implementation and construction teams to ensure that major
5 compliance projects and major construction projects were planned, executed, and
6 completed in a reasonable, prudent, and cost-effective manner as required by
7 regulatory bodies in Duke Energy's regulated jurisdictions. In these roles, I
8 worked on and provided advice and leadership to over a dozen major projects
9 with combined costs exceeding \$5 billion. I also led efforts to develop and
10 establish enterprise-wide procedures to ensure all regulated projects were
11 completed in a prudent and cost-effective manner.

12 **Q. WHAT WAS THE PURPOSE OF THE ASH BASIN STRATEGIC ACTION**
13 **TEAM?**

14 A. The ABSAT team was the umbrella organization created for Duke Energy
15 companies to address the laws, regulations, and orders concerning the
16 management of coal-combustion residuals ("CCR").¹ These new compliance
17 requirements apply to electric generating sites with new and existing CCR
18 landfills and surface impoundments (collectively "CCR units"), and impose new
19 obligations regarding landfill design, structural integrity design and assessment
20 criteria for CCR basins, groundwater monitoring and protection procedures,
21 closure of impoundments, and operational and reporting procedures for the

¹ CCR refers to fly ash, bottom ash, boiler slag, and flue gas desulfurization materials generated from burning coal for the purpose of generating electricity by electric utilities. 40 C.F.R. § 257.53.

850-4

1 disposal and management of CCRs. This work has now been absorbed into the
2 CCP organization.

3 During my work on the ABSAT team, I spent approximately 3,000 hours
4 working exclusively on CCR issues. During this time, I reviewed and became
5 knowledgeable on relevant state and federal regulations dealing with CCR issues
6 as detailed further in my testimony and as set out in Kerin Exhibit 1. I also
7 studied and became familiar with historical industry practices and standards to
8 comply with these regulations. As part of this process, I interviewed legacy
9 employees in Fossil Hydro Operations, Environmental Health and Safety, and
10 Central Engineering who worked at, and with, coal combustion generating units
11 and CCR handling sites. I reviewed historical company documents dealing with
12 these facilities and sites to gain an understanding of how CCR handling standards
13 inside and outside of the Company have developed over time. I also interviewed
14 legacy employees at other Southeast utilities including Dominion Energy, AEP,
15 TVA and Southern Company.

16 As part of my duties on the ABSAT team, I toured and inspected every
17 CCR basin in Duke Energy's North and South Carolina jurisdictions. I also
18 toured and examined other CCR units at Duke Energy's Midwest sites, and
19 Dominion Energy, AEP, TVA, and Southern Company sites. During my tenure
20 on the ABSAT team, I developed CCR evaluations for each of Duke Energy's
21 CCR sites and, where applicable, worked on developing comprehensive work
22 plans when work was needed on any of those sites. In the course of my duties, I
23 also interfaced with other utilities to discuss and enhance mutual understandings

1 on evolving industry standards relating to CCR issues, and shared and received
2 best practices across the electric industry. I developed an industry peer group to
3 discuss CCR issues, which meets semi-annually and includes companies such as
4 Dominion and Southern Company. In this capacity, I also gained an
5 understanding and knowledge of coal ash management practices at utilities across
6 the country.

7 **Q. WHAT ARE YOUR PRIMARY RESPONSIBILITIES AS THE VICE**
8 **PRESIDENT, OPERATIONS, MAINTENANCE, AND GOVERNANCE?**

9 A. I am responsible for regulatory affairs, operations support, and other centralized
10 CCR functions. My team works to define, establish, and maintain fleet CCP
11 standards, programs, processes, and best practices within functional areas for all
12 fossil plant sites. My team also oversees site operations and maintenance
13 ("O&M") of CCP facilities, including CCR and high-hazard dam operations and
14 maintenance, production landfills, decommissioning and demolition, and
15 byproducts management.

16 In my current role, virtually 100 percent of my time is dedicated to CCR
17 oversight, compliance, operations, maintenance, and project execution activities.
18 I have continued to review and study evolving rules and regulations related to
19 CCR issues. I have also maintained my presence in industry peer groups
20 regarding CCR issues and continue to help monitor, develop, and implement
21 industry best practices and standards for CCR issues.

1 **Q. HAVE YOU EVER TESTIFIED BEFORE A REGULATORY BODY?**

2 A. Yes. I filed direct testimony regarding CCR issues in DE Progress' rate case in
3 South Carolina in Docket 2016-227-E and appeared before the Public Service
4 Commission of South Carolina in October 2016 in connection with that case. I
5 also filed direct and rebuttal testimony regarding CCR issues in DE Progress' and
6 Duke Energy Carolinas, LLC's ("DE Carolinas") recent North Carolina rate cases
7 in Docket Nos. E-2, Sub 1142 and E-7, Sub 1146, respectively, and testified
8 before the North Carolina Utilities Commission in connection with those cases.

9 **Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

10 A. DE Progress is seeking recovery of CCR expenses incurred from July 2016
11 through ~~August~~ ^{September} 2018 and estimated costs to be incurred ~~September~~ ^{October} 2018 through
12 December 2018 related to compliance with applicable regulatory requirements.
13 The purpose of my testimony is to explain those regulatory requirements and to
14 explain how our compliance actions and decisions, including our current plans to
15 meet existing legal requirements, have been reasonable, prudent, and cost-
16 effective approaches to comply with those regulatory requirements.

17 **Q. PLEASE BRIEFLY SUMMARIZE YOUR TESTIMONY.**

18 A. DE Progress has become subject to both federal and state regulatory requirements
19 that mandate closure of its ash basins and other ash storage areas. Since the early
20 1900s, DE Progress has disposed of CCR in compliance with then-current
21 regulatory requirements and industry practices. Until the 1950s, CCR were either
22 emitted through, in the case of fly ash, smokestacks or, in the case of bottom ash,
23 manually removed from boilers and stored in fill areas. Since that time, the

1 industry transitioned to wet sluicing using water to remove ash from boilers, and
2 to clean the electrostatic precipitators ("ESP"), preventing ash from being emitted
3 through the smokestacks. This effluent, as well as flue gas desulfurization
4 ("FGD") blowdown, was then diverted to ash basins, or impoundments. DE
5 Progress has 19 ash basins in the Carolinas.

6 In the mid-1970s, the enactment of the Clean Air Act (42 United States
7 Code §7401 et seq.) and its subsequent amendment in the 1990s required electric
8 utilities to capture more CCRs through the use of ESP or bag houses and FGD
9 blowdown. The Clean Water Act of 1972 (33 United States Code §1251 et seq.),
10 and the subsequent creation of the National Pollutant Discharge Elimination
11 System ("NPDES") permitting system, made wet ash handling and ash basins the
12 primary lawful and effective way to meet CCR needs and environmental
13 requirements from 1974 until 2015.

14 In June 2010, the United States Environmental Protection Agency
15 ("EPA") proposed national minimum criteria to regulate the disposal of CCRs and
16 the operation and closure of active CCR landfills and existing and inactive CCR
17 surface impoundments. Approximately five years later, the EPA published the
18 final CCR Rule in the Federal Register in April 2015.

19 In South Carolina, DE Progress entered into a Consent Agreement with
20 the South Carolina Department of Health and Environmental Control
21 ("SCDHEC") in July 2015. Pursuant to this agreement, DE Progress agreed to
22 excavate its ash basins and ash storage areas at the Robinson Steam Station in
23 Darlington County, South Carolina. It should be noted that other South Carolina

1 utilities are closing their ash basins in a similar fashion and also pursuant to
2 Consent Agreements with and approval from SCDHEC.

3 Also, in 2014, the state of North Carolina enacted the Coal Ash
4 Management Act of 2014 ("CAMA"), which requires that all ash basins in North
5 Carolina be closed, either through excavation or via the cap-in-place method. In
6 many respects, the state law mirrors the federal CCR Rule.

7 All of DE Progress' ash basins must be closed under the CCR Rule, South
8 Carolina regulatory oversight, and closure plan approvals, and/or CAMA. The
9 Company has begun the process of closing, or submitting plans to close, its ash
10 basins in accordance with the program with the most restrictive requirements.
11 There is a great deal of duplication and interaction between the CCR Rule and
12 state regulatory requirements. As I explain below in my testimony, many of the
13 actions Duke Energy will take will serve multiple compliance purposes. In fact,
14 many actions and draft rules applicable to many utilities, not just Duke Energy,
15 were already being developed prior to 2014, and we are now in another wave of
16 evolution in environmental regulation pertaining to ash. *See* Kerin Exhibit 2. In
17 response to these new requirements addressing CCR disposal activities, the
18 Company is adding dry fly ash, bottom ash, and FGD blowdown handling
19 systems to operating coal-fired plants that are not already so equipped. The
20 Company is also modifying all active and decommissioned plants to divert storm
21 water and low-volume wastewater away from the basins.

22 Accordingly, the Company is requesting recovery of the incremental
23 compliance costs related to coal ash pond closures incurred starting July 2016 to

1 ~~September~~ ^{October} 2018, and expected costs from ~~September~~ ^{October} 2018 to December 2018 as
 2 explained in more detail by Witness Bateman. My testimony and exhibits
 3 demonstrate that both of these incurred and expected compliance costs are
 4 reasonable, prudent, and cost-effective given the individual facts and
 5 circumstances at each power plant and ash basin site at issue.²

6 **Q. HOW IS YOUR TESTIMONY ORGANIZED?**

7 A. In this Section I, I have provided information concerning my background and the
 8 purpose of my testimony. In Section II, I provide an overview of the generation
 9 resources, including coal-fired generation, that the Company has used to reliably
 10 and efficiently serve customers for over 100 years of its existence. I explain that
 11 CCR are the natural byproduct of burning coal to generate electricity. I discuss
 12 the Company's past practices for the storage and disposal of CCR, and I explain
 13 that its practices have been in accordance with the electric power industry's
 14 prudent standards and applicable laws, regulations, and permit requirements as
 15 they have existed over time. In Section III, I discuss the new requirements
 16 imposed on the Company under the new CCR compliance requirements. In
 17 Section IV, I discuss the Company's plans to comply with the CCR compliance
 18 requirements, the required regulatory approvals and permits for DEP compliance
 19 plans, including timing and implementation issues, and costs incurred to date and
 20 expected over the next several years. I also explain and demonstrate how each of
 21 the Company's historical and ongoing CCR compliance costs are reasonable,

² This case excludes any fines or penalties incurred by DE Progress related to ash basin closure or management.

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1 prudent, and cost-effective given the individual facts and circumstances at each
2 power plant and ash basin site at issue.

3 **Q. ARE YOU PROVIDING ANY EXHIBITS WITH YOUR TESTIMONY?**

4 **A.** Yes, I have attached 10 total exhibits, described below, as well as an appendix:
5 Kerin Exhibit 1: Statutes and Regulations (listing of relevant coal ash
6 environmental regulations);
7 Kerin Exhibit 2: CCR Rule (text of the Federal CCR Rule);
8 Kerin Exhibit 3: Site Locations NC and SC (map of coal ash facilities);
9 Kerin Exhibit 4: Site Facts (site-specific background information);
10 Kerin Exhibit 5: Ash Basin Information (site-specific information about ash units)
11 Kerin Exhibit 6: Responses to Rule Changes Through the Decades DEP
12 (summary of DE Progress' compliance with evolving environmental regulations);
13 Kerin ^{Revised} Exhibit 7: Beneficiation Year 2015 thru ^{September} ~~August~~ 2018 (summary of
14 beneficiation at DE Progress Sites);
15 Kerin Exhibit 8: Graphics Cap-in-Place and Landfill (graphical depiction of cap-
16 in-place and landfill closure methodologies);
17 Kerin Exhibit 9: Closure Plans (site-specific closure plans and engineering
18 reports); and
19 Kerin ^{Revised} Exhibit 10: Components of 2015-2018 Recovery Request (summary of
20 costs and regulatory drivers relevant to DE Progress' application).

1 **II. DE PROGRESS' GENERATION RESOURCES**

2 **Q. PLEASE PROVIDE AN OVERVIEW OF THE COMPANY'S ELECTRIC**
3 **GENERATION ASSETS.**

4 A. DE Progress has provided reliable electric generation for decades to its retail and
5 wholesale customers in South Carolina and North Carolina from a diverse
6 portfolio of generating assets including those that generate electricity using coal,
7 nuclear fuels, natural gas, hydro flows, and solar photovoltaic energy sources.
8 Until recently, coal has been the historic "go-to" fuel choice for base-load, least-
9 cost reliable service. Accordingly, in South Carolina and North Carolina, the
10 Company has operated eight coal-fired generating facilities with CCR units that
11 contain historically produced CCR directly resulting from the coal combustion
12 process. These eight coal-fired DE Progress generating facilities have 19 CCR
13 basins that date back to the early 1950s and were an integral part of historical
14 coal-fired power generation at these sites.

15 **Q. WHAT IS THE CURRENT STATUS OF THE COMPANY'S COAL-**
16 **FIRED GENERATING FACILITIES?**

17 A. Of the eight coal-fired DE Progress generating facilities with ash basins, coal-
18 powered electric generation has since ceased at five of these stations, including
19 the Cape Fear, H.F. Lee, Robinson, Sutton, and Weatherspoon Plants. Refer to
20 Kerin Exhibit 3 for the geographical location of the eight coal-fired generating
21 facilities with ash basins in the DE Progress service territory.

1 **Q. WHAT ARE COAL COMBUSTION RESIDUALS?**

2 **A.** CCR are byproducts produced from the burning of coal in coal-fired power
3 generation plants and include fly ash, bottom ash, boiler slag, and FGD material.
4 Fly ash and bottom ash are direct byproducts of the coal combustion process. Fly
5 ash is a very fine, powdery material composed mostly of silica produced from the
6 burning of finely ground coal in the boiler. Bottom ash is a coarse, angular ash
7 particle that is too large to be carried up into the smoke stacks, so it forms in the
8 bottom of the coal furnace. Bottom ash makes up approximately 15 percent of the
9 total ash produced. In the early years of operation, bottom ash was manually
10 collected at the bottom of the boiler, and then transported to an ash storage
11 location. Later, the industry utilized a water sluice process to efficiently transport
12 the bottom ash to ash storage basins. In the early years, fly ash went directly out
13 the smoke stack. The industry later employed collection of the fly ash using
14 electrostatic precipitators and bag houses in order to improve air emissions, where
15 the ash was then efficiently water sluiced to an ash basin. As I explain above, DE
16 Progress' coal-fired generation facilities either have been or are being modified to
17 incorporate dry fly ash and/or dry bottom ash handling. Additional CCR flow in
18 the form of wastewater is produced by the operation of FGD systems at specific
19 operating coal-fired sites. All of the types of CCR mentioned above are
20 byproducts of the electricity production process lifecycle at coal-fired generation
21 plants.

1 **Q. PLEASE PROVIDE A HISTORY OF DE PROGRESS' ELECTRIC**
2 **GENERATION RELYING ON COAL AS THE FUEL SOURCE.**

3 A. The Company's electric power generation from burning coal dates back to the
4 1920's. As an example, the Cape Fear Plant in Moncure, North Carolina began
5 commercial operation in 1923 with an ultimate generating capacity of 316
6 megawatts ("MW"). Kerin Exhibit 4 provides details regarding the commercial
7 operation date, generation capacity (MW), and retirement date, if applicable, for
8 the eight DE Progress coal-fired generating stations with ash basins in the
9 Carolinas.

10 All of these coal plants produced CCR, fly ash, and bottom ash, as direct
11 byproducts of the coal combustion process. In the 1950's the electric utility
12 industry began to efficiently transport bottom ash by water sluicing to constructed
13 surface impoundments, which we commonly refer to as ash basins. Some of DE
14 Progress' older ash basins include the 1950 and 1955 ash basins at the H.F. Lee
15 Plant and the 1956 ash basin at the Cape Fear Plant. Kerin Exhibit 5 provides
16 details regarding when DE Progress ash basins were constructed, their estimated
17 content of ash in tons, and when they were taken out of service, if applicable. The
18 CCR contained in these basins represent the byproduct of decades of reliable coal-
19 fired generation at these sites and a process step in the electricity generation life
20 cycle.

1 **Q. HOW HAVE ENVIRONMENTAL COMPLIANCE OBLIGATIONS**
2 **RELATED TO CCR MANAGEMENT EVOLVED OVER TIME?**

3 **A.** Environmental regulations related to CCR management have evolved
4 significantly over time, affecting how the Company has operated its coal-fired
5 stations in compliance with new and evolving environmental obligations. At each
6 step in the environmental regulatory evolution process, DE Progress was in line
7 with industry standards and reasonably and prudently managed CCR and its coal
8 ash basins.

9 Before the Clean Air Act was amended in 1970, the only type of CCR
10 collected at the Company's plants was bottom ash. Bottom ash was sometimes
11 stored in basins and sometimes placed dry on the land surface in "lay of land"
12 areas, which was lawful at the time. After new Clean Air Act requirements were
13 put in place, the utility industry, including DE Progress, added electrostatic
14 precipitators to coal-fired plants in the 1970s to reduce air emissions of fly ash.
15 The collection of fly ash significantly increased the volume of CCR being handled
16 at the plants, giving rise to the need for larger basins and ash handling systems.
17 Additionally, since the 1990 Clean Air Act amendments, a greater emphasis on
18 sulfur emissions control has prompted many coal burning power plants to install
19 FGD units (also known as "scrubbers"). FGD scrubbers generate byproducts,
20 primarily gypsum, which are classified as a type of CCR.

21 In 1972, the Federal Water Pollution Control Act, now known as the Clean
22 Water Act ("CWA"), was amended to provide a new comprehensive program for
23 regulating discharge of pollutants into the waters of the United States and

1 regulating quality standards for surface waters. The CWA resulted in the
2 establishment of a systematic permit system to monitor water quality and to
3 provide specific limits for the flow and content of process water leaving these ash
4 basins. Many of the Company's ash basins (at least one at each power plant) were
5 operating before the passage of the CWA amendments in 1972, which created the
6 NPDES permitting program. These plants subsequently received NPDES permits
7 from South Carolina and North Carolina after the states received authority from
8 EPA to issue permits.

9 In accordance with the CWA, EPA promulgated Effluent Limitations
10 Guidelines ("ELGs") for the Steam Electric Power Generating industry category
11 in 1974. The Development Document for the 1974 rule states that most coal-fired
12 plants across the industry used wet ash handling and ash basins for treatment of
13 ash handling wastewater, although some plants employed other methods for site-
14 specific reasons, such as space constraints. In the 1974 rule, the EPA set limits
15 based on Best Practicable Control Technology Currently Available ("BPT") and
16 Best Available Technology Economically Achievable ("BAT") for fly ash
17 transport water and bottom ash transport water. In both cases, the limits were
18 based on the use of wet ash handling and treatment in ash basins. In 1982, the
19 EPA withdrew the BAT limitations on fly ash transport water and left the limits
20 on bottom ash transport water unchanged.³ The ELGs for the Steam Electric
21 Power Generating category were not amended again until 2015. As a result, from
22 1974 to 2015, ash basins were a lawful and effective way of meeting the

³ The rule did prohibit the discharge of fly ash transport water at new facilities.

1 wastewater treatment requirements under the CWA. In 2015, the EPA finalized
2 new ELGs that adopted a zero discharge requirement for both fly ash and bottom
3 ash transport water at existing facilities. Meeting these limits effectively requires
4 converting to dry ash handling or ceasing plant operations.

5 Before 2015, CCRs were not regulated under the Resource Conservation
6 and Recovery Act ("RCRA"). CCRs are classified under RCRA as a "special
7 waste." Under RCRA § 3001(b)(3)(A) (known as the Bevill Amendment), fossil
8 fuel combustion waste and several other waste categories were initially exempt
9 from regulation as hazardous waste under RCRA Subtitle C. The EPA was
10 required to assess fossil fuel combustion waste and the other types of exempted
11 waste and submit a formal report to Congress on its findings. The EPA was then
12 required to make a final regulatory determination as to whether the special waste
13 should be regulated as a hazardous waste. The EPA published rules in 1993 and
14 2000 concluding that CCR should not be regulated as hazardous waste. On
15 December 22, 2008, a large coal ash spill occurred at the TVA power plant in
16 Kingston, Tennessee. While this event prompted the industry to take note of the
17 causes for the TVA spill from an operational perspective, the event also prompted
18 the EPA to revisit its determination regarding CCR. On June 21, 2010, the EPA
19 proposed regulations under RCRA to address the risks from the disposal of CCR
20 generated from the combustion of coal at electric utilities and independent power
21 producers. This proposal contained three regulatory options. Under the first, the
22 EPA proposed to list CCR as special wastes subject to regulation under Subtitle C
23 (hazardous waste) of RCRA when they are destined for disposal in landfills or

1 surface impoundments. Under the other two options, the EPA proposed to
2 regulate disposal of such materials under Subtitle D (non-hazardous waste) of
3 RCRA by issuing national minimum criteria. Because the proposals were very
4 different, it was difficult for the utility industry, including the Company, to
5 predict the timing and methods that would be required under the new rule for
6 closing ash basins. The rule was not finalized until 2015 when the EPA
7 announced its selection of the Sub-Title D option, regulating CCR as non-
8 hazardous waste. Additional details about the CCR Rule are set out below.

9 Before the CCR Rule, CCR management was regulated under South
10 Carolina state law by statutes and regulations dealing with water quality
11 protection and solid waste management. Ash basins were regulated through dam
12 safety regulations and NPDES permits. Use of ash removed from ash basins was
13 regulated by rules for distribution of residual wastewater solids, which required a
14 permit for the use of removed ash. Construction and operation of landfills were
15 governed by solid waste rules, and beneficial use of dry ash for structural fill was
16 regulated by provisions of the solid waste rules.

17 As noted above, in July 2015, the Company entered into the Robinson
18 Consent Agreement ("Consent Agreement") with SCDHEC, which addressed
19 future ash management at the Robinson plant. The Consent Agreement requires
20 ash excavation of the 1960 lay-of-land ash storage area, located south of the ash
21 basin. The Consent Agreement also includes provisions to initiate permitting of
22 an onsite lined CCR landfill to store the excavated ash from the Robinson Plant's
23 ash basin and lay-of-land area.

1 In 2014, the North Carolina General Assembly passed CAMA, which,
2 among other things, requires the closure of ash basins in North Carolina according
3 to a defined schedule.

4 Compliance with each phase of new environmental regulatory
5 requirements that I have discussed required DE Progress to modify its operations
6 and incur additional expenditures. Kerin Exhibit 6 graphically depicts how these
7 regulations and requirements changed over time and how DE Progress reasonably
8 and prudently responded to each of those changes.

9 **Q. HOW DID THESE EVOLUTIONS IN ENVIRONMENTAL**
10 **OBLIGATIONS IMPACT CCR PRODUCTION AND STORAGE AT THE**
11 **COMPANY'S COAL-FIRED GENERATION FACILITIES?**

12 A. Both the volume and characteristics of CCR managed at the Company's facilities
13 have changed in response to changes in air emissions control requirements,
14 beginning with the use of electrostatic precipitators to capture fly ash. As the
15 coal-fired generating plants addressed evolving air emissions requirements,
16 modifications such as the addition of selective catalytic reduction equipment to
17 control emissions of nitrogen oxides and FGD systems were made to many of DE
18 Progress' coal-fired generating plants. The addition of FGD systems affected the
19 existing ash basins by directing FGD blowdown flow to the CCR basins, which
20 represented a new additional CCR flow. At certain sites, such as at the Asheville
21 Plant, newly-constructed engineered wetlands were built within the footprints of
22 the CCR basins to process the FGD blowdown flow. At other sites, such as the
23 Roxboro Plant, FGD forward flow and settling ponds were built within the

1 footprint of the ash basins to process the new CCR flows. Further, as a result of
2 new FGD systems being added, limestone pile run-off flows and gypsum pile run-
3 off flows were typically also directed to the existing ash basins.

4 Consistent with the rest of the industry, as recognized by the EPA in its
5 ELGs, the Company has relied primarily on ash basins to treat these waste
6 streams, at least as a final step. The ash basins have been effective at treating
7 wastewater to meet NPDES permit limits. In the absence of any regulatory
8 directive to do so, the Company reasonably did not pursue and should not have
9 pursued regulatory closure or retrofitting for any site that was still generating ash
10 and that maintained its NPDES permit. However, the South Carolina Consent
11 Agreements in 2014 and 2015 established a new set of procedures for closure
12 plans for plants in South Carolina. In compliance with the CCR Rule and state
13 regulatory requirements, the Company has now prepared closure plans or site
14 analysis and removal plans, as applicable, for all of its ash basins.

15 Historically, the Company has invested in conversion to dry ash handling
16 at certain plants when it was called for by site-specific conditions. For example,
17 in 1990, DE Progress converted to dry fly ash handling at Roxboro given that site
18 specific conditions warranted the conversion. Following the promulgation of the
19 CCR Rule passage of CAMA, however, the Company is converting to full dry ash
20 handling at all operating plants as required by those requirements and as the only
21 viable alternative to plant closure. This involves both installing new equipment
22 and securing disposal capacity. The ash basins are a part of the coal-fired
23 generation process at the sites and provide dilution, settling and/or retention

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1 functions for other power plant process water flows, such as low volume
 2 wastewater, coal pile run-off, landfill leachate, and FGD wastewater.
 3 Additionally, all plant discharges will be rerouted away from ash basins at retired
 4 and active sites.

5 DE Progress has also historically pursued opportunities to sell ash for
 6 beneficial reuse and will continue to do so as feasible. As the regulatory
 7 requirements for ash reuse tightened, the Company limited its sale of ash to
 8 situations in which compliance could be carefully monitored.

9 In summary, beyond the storage of fly ash and/or bottom ash, the
 10 operation of ash basins has historically evolved to accept new CCR flows
 11 resulting from FGD modifications required to address air emissions and also to
 12 accept other non-CCR process flows, such as coal pile run-off and low volume
 13 wastewater. The construction and use of the ash basins is the final step in the
 14 generation process that has resulted in reliable, efficient, coal-fired electricity in
 15 the Carolinas for many decades.

16 **Q. IS THERE ANY BENEFICIAL REUSE FOR THE CCRS?**

17 A. Yes. As referenced above, Duke Energy has endeavored across its coal-fired
 18 generating fleet to maximize the beneficial use of production ash and to reclaim,
 19 where possible, stored ash for sale for beneficial use. Ash beneficiation began in
 20 DE Progress in 1998 at the Roxboro Station. From January 2016 through ^{September} ~~August~~ 2018, 30 percent of the DE Progress fleet production ash, or approximately
 21 ~~334,000~~ ^{336,000} tons, was sold for beneficial reuse to produce products such as a
 22 replacement for Portland Cement, bricks, and blocks. It should be noted that the
 23

1 beneficial uses of ash for products are limited based on the quality of the ash
2 produced or stored, particularly the carbon content, and the regional market
3 demand. Also, beneficial use opportunities as a structural fill are limited based on
4 specific regional projects that are in need and by statutory and regulatory
5 requirements. Please refer to Kerin Exhibit 7 for details on sales for beneficial
6 use of production ash and stored ash in the Carolinas.

7 **Q. WERE THE COMPANY'S CCR HANDLING PRACTICES IN**
8 **ACCORDANCE WITH INDUSTRY PRACTICE AND REGULATORY**
9 **REQUIREMENTS?**

10 **A.** Yes. In 1988, the EPA submitted its Report to Congress on Wastes from the
11 Combustion of Coal by Electric Utility Power Plants ("1988 Report"). The 1988
12 Report is a comprehensive assessment of the electric utility industry's use of coal
13 and management of CCR up to that point in history. The 1988 Report found that
14 80 percent of CCR in the industry was being treated and stored in surface
15 impoundments or disposed of in landfills. Of those units, only 40 percent were
16 lined, either with a synthetic, clay, or composite liner. Historically, surface
17 impoundments were the single most widely used treatment and storage method
18 for CCR. At the time of the 1988 Report, landfilling of CCR was increasingly
19 common. As of 1988, Duke Energy was employing both surface impoundments
20 and landfills, which the 1988 Report noted were the most commonly used types of
21 treatment, storage, and disposal units used by the industry.

22 In the preamble to the CCR Rule, the EPA provided an updated
23 assessment of the coal-fired electric power industry. The CCR Rule details that in

1 2012 alone, over 470 coal-fired electric generating facilities burned over 800
2 million tons of coal, generating approximately 110 million tons of CCR in 47
3 states and Puerto Rico. In 2012, approximately 40 percent of the CCR generated
4 were beneficially used, with the remaining 60 percent treated and stored in CCR
5 surface impoundments; of that 60 percent, approximately 80 percent was stored in
6 onsite basins and landfills. Across the United States, CCR disposal currently
7 occurs at over 310 active onsite landfills, averaging over 120 acres in size with an
8 average depth of 40 feet and at over 375 active onsite surface impoundments.
9 Stated differently, the Company is re-using (selling) and storing CCR in the same
10 manner and at approximately the same percentages as the coal-fired utility
11 industry's national averages. Duke Energy's practices have been and continue to
12 be consistent with those of the industry.

13 Similar to the industry, DE Progress has onsite CCR landfills that are
14 actively receiving production fly ash and some bottom ash, at specific coal-fired
15 generating sites, including the Mayo and Roxboro Plants in the Carolinas. Also
16 similar to the industry, DE Progress has active ash basins that will receive bottom
17 ash, and some fly ash, at specific coal-fired generating sites through first quarter
18 2019. These sites include the Asheville Plant, the Mayo Plant, and the Roxboro
19 Plant in the Carolinas. The ash handling practices for ash basins and ash landfills
20 in the Carolinas are consistent with the applicable regulatory requirements that
21 were in effect during the history of these CCR units.

1 Q. ARE THE COMPANY'S CCR STORAGE AND HANDLING
2 CONSISTENT WITH THE PRACTICES OF OTHER DUKE ENERGY
3 AFFILIATES?

4 A. Yes. The Company's CCR storage and handling practices are consistent across
5 the Duke Energy fleet, including coal generation located in Florida and in the
6 Midwest. Duke Energy as it exists today has been formed over the years through
7 the mergers of several utilities with independently operated coal-fired generation,
8 including the Cinergy Corporation in 2006 and Progress Energy, Inc. in 2012.
9 Indeed, going farther back in time, Progress Energy, Inc. was created in 2000
10 from the merger of legacy utilities Carolina Power & Light ("CP&L") and Florida
11 Power Corporation ("FPC"). Similarly, Cinergy Corporation was created in 1994
12 by the merger of legacy utilities Public Service Indiana ("PSI") and Cincinnati
13 Gas & Electric Company ("CG&E"). Yet, the historical and current CCR
14 handling and use of CCR units is consistent across all of these legacy companies
15 that make up Duke Energy today, and consistent with the industry.

16 **III. NEW REQUIREMENTS REGARDING CCR AND ASH BASINS**

17 Q. PLEASE DESCRIBE THE CCR COAL ASH REGULATORY
18 REQUIREMENTS.

19 A. The CCR compliance requirements described below represent new regulatory
20 requirements that have significantly changed the operation and life cycle of the
21 onsite ash basins and ash landfills. The Company must comply with the CCR
22 Rule, South Carolina coal ash Consent Agreements and closure plans, CAMA in
23 North Carolina, and other agreements and court orders concerning the

1 management and disposal of CCR, operation and closure of CCR units, and
2 corrective action and post-closure care.

3 **Q. PLEASE SUMMARIZE THE MAJOR REQUIREMENTS UNDER THE**
4 **CCR RULE.**

5 A. The purpose of the CCR Rule is to protect groundwater and water quality near
6 CCR units and ensure stability of those units. The EPA's final CCR Rule
7 established national minimum criteria for CCR landfills and surface
8 impoundments that consist of: (1) location restrictions; (2) design and operating
9 criteria; (3) groundwater monitoring and corrective action; (4) closure
10 requirements and post-closure care; (5) recordkeeping; (6) notification; and (7)
11 Internet posting requirements. These requirements are summarized below, and
12 they result in different impacts at each CCR unit, depending on site-specific
13 factors.

14 The CCR Rule requires that new and existing CCR surface impoundments
15 and new CCR landfills and lateral expansions meet location restrictions for:
16 (1) placement above the uppermost aquifer; (2) wetlands; (3) fault areas;
17 (4) seismic impact zones; and (5) unstable areas. If a CCR basin does not meet
18 the location restrictions, then basin closure is required under the CCR Rule. The
19 specific location restriction assessments that are most likely to affect the
20 Company's CCR basins, because of typical geological characteristics and historic
21 groundwater elevations in the Carolinas, are placement above the uppermost
22 aquifer and wetlands.

1 The placement above the uppermost aquifer location restriction requires
2 that existing CCR basins be constructed with a base that is located no less than
3 1.52 meters (five feet) above the upper limit of the uppermost aquifer or
4 demonstrate that there will not be an intermittent, recurring, or sustained
5 hydraulic connection between any portion of the base of the CCR unit and the
6 uppermost aquifer due to normal fluctuations in groundwater elevations
7 (including the seasonal high water table).

8 The wetlands location restriction considers whether the CCR unit causes
9 or contributes to significant degradation to wetlands, and in the event of such
10 effects, sets out compensatory steps that may be taken to achieve no net loss of
11 wetlands in order to avoid basin closure.

12 The CCR Rule contains design criteria for new CCR landfills and lateral
13 extensions and new CCR surface impoundments, as well as structural integrity
14 criteria for new and existing CCR surface impoundments, including an
15 assessment of dam safety factors.

16 The CCR Rule contains operating criteria for fugitive dust control, run-on
17 and run-off controls for landfills, hydraulic capacity requirements for surface
18 impoundments, and inspection requirements for landfills and surface
19 impoundments. If the ash basin dam does not achieve the minimum factor of
20 safety requirements, then ash basin closure is required. The CCR Rule also
21 contains requirements for the assessment of groundwater impacts from CCR
22 landfills and surface impoundments. It provides requirements for the assessment
23 of corrective measures, selection of remedies, and implementation of corrective

1 action programs for identified groundwater impacts. Results of the groundwater
2 assessment may also require ash basin closure.

3 The CCR Rule contains requirements for how and when CCR basins must
4 be closed. It provides two alternatives for closure, "closure by leaving ash in
5 place" and "closure through removal of the CCR," also referred to as excavation.
6 In the case of closure by leaving ash in place, commonly referred to as "cap-in-
7 place," it provides design criteria for the closure cap system. Post-closure
8 monitoring requirements are also detailed in the CCR Rule. Lastly, the CCR Rule
9 requires specific notifications, such as to state agencies; specific requirements for
10 record keeping, such as the written operating record; and, also, specific
11 requirements for posting information on a publicly accessible Internet site.

12 **Q. HOW ARE CCRS CLASSIFIED UNDER THE CCR RULE?**

13 A. As stated in the CCR Rule, the EPA considers CCR to be a non-hazardous solid
14 waste.

15 **Q. HOW IS THE CCR RULE ENFORCED?**

16 A. The CCR Rule was promulgated as a self-implementing rule that could only be
17 enforced by citizen suit and not by administrative measures. However, the Water
18 Infrastructure Improvements for the Nation Act (WIIN Act), which was signed
19 into law in December 2016, gave the EPA immediate direct enforcement
20 authority, authorized states to establish permit programs for implementing the
21 CCR Rule, and required the EPA to do so, conditioned on federal funding, in
22 those states that do not adopt a CCR permit program.

1 **Q. TO WHICH DE PROGRESS UNITS DOES THE CCR RULE APPLY AND**
2 **WHY?**

3 A. Pursuant to Section 257.50(b) of the CCR Rule, the requirements of the CCR
4 Rule apply to all owners and operators of new and existing landfills and surface
5 impoundments, including any lateral expansions of such units that dispose or
6 otherwise engage in solid waste management of CCR generated from the
7 combustion of coal at electric utilities and independent power producers.
8 Pursuant to Section 257.50(c), the CCR Rule also applies to inactive CCR surface
9 impoundments at active electric utilities or independent power producers,
10 regardless of the fuel currently used at the facility to produce electricity. When
11 the CCR Rule was promulgated, it contained a provision that excluded “legacy”
12 impoundments and CCR landfills at sites where the utility had ceased producing
13 electricity prior to October 19, 2015, the effective date of the CCR Rule. *See*
14 Section 257.50(e). Two legacy impoundments at one DE Progress coal-fired
15 generating site – the Cape Fear Plant – qualified for exemption under Section
16 257.50(e). The issue of whether the CCR Rule must apply to impoundments at
17 power plant sites that have ceased generating electricity was litigated in the D.C.
18 Circuit Court of Appeals in *Util. Solid Waste Activities Group, et al., v. Envtl.*
19 *Prot. Agency*, 901 F. 3d 414 (D.C. Cir. 2018) (“*USWAG v. EPA*”). In that case,
20 environmental petitioners asserted that there was no rational basis for excluding
21 impoundments at inactive plants given that the CCR Rule covers inactive
22 impoundments at active facilities and, therefore, impoundments such as those at
23 the Cape Fear Plant must be regulated pursuant to RCRA. In the recently issued

1 decision, the court agreed with the position of the environmental petitioners and
2 determined that the EPA's decision to exclude legacy impoundments from the
3 CCR Rule was "arbitrary and capricious." The EPA is expected to undertake an
4 expedited rulemaking to bring these legacy impoundments into the CCR Rule.
5 Accordingly, as a result of the D.C. Circuit Court of Appeals' decision, the CCR
6 Rule will apply to all DE Progress Sites.

7 **Q. IN ADDITION TO THE CCR RULE AND CAMA, IS THE COMPANY**
8 **SUBJECT TO SPECIFIC SOUTH CAROLINA COMPLIANCE**
9 **OBLIGATIONS CONCERNING THE MANAGEMENT OR**
10 **REMEDIATION OF CCR?**

11 **A.** Yes. DE Progress has other CCR-related obligations that result from South
12 Carolina environmental regulatory oversight under existing rules and regulations.
13 For DE Progress in South Carolina, there is one Consent Agreement with the
14 SCDHEC applicable to ash management at the Robinson Plant. The Robinson
15 Consent Agreement (15-23-HW) between DE Progress and SCDHEC requires
16 ash excavation of a 1960 lay-of-land ash storage area located south of the ash
17 basin. SCDHEC has also approved DE Progress' plan to excavate ash from the
18 Robinson Plant ash basin. This Consent Agreement includes provisions requiring
19 DE Progress to initiate permitting of an onsite lined CCR landfill to store the
20 excavated ash from the Robinson Plant's ash basin and lay-of-land area. As of
21 September 2018, DE Progress is in the process of preparing for construction of
22 the onsite landfill.

1 **Q. PLEASE BRIEFLY SUMMARIZE THE MAJOR REQUIREMENTS**
2 **UNDER CAMA.**

3 A. CAMA requires closure of all ash basins in North Carolina, with the closure
4 option and closure deadline driven by a prioritization risk ranking classification
5 process. CAMA requires that all CCR ash basins be closed by dates ranging from
6 2019 to 2029. The law requires the cessation of storm water flows to CCR ash
7 basins and conversion to dry ash handling. Groundwater wells are required along
8 with monitoring and post-closure maintenance programs. CAMA also requires
9 that the Company provide permanent water supplies to all homeowners within an
10 established boundary of the ash basins. Lastly, the Company must install and
11 operate three ash beneficiation projects capable of annually processing 900,000
12 tons (300,000 tons from each site) of ash stored within the impoundments at the
13 site to specifications appropriate for cementitious products.

14 **Q. HOW IS CAMA ENFORCED?**

15 A. CAMA implementation in North Carolina is overseen by the North Carolina
16 Department of Environmental Quality ("NCDEQ"), which has enforcement
17 authority over CAMA compliance issues.

18 **Q. TO WHICH DE PROGRESS FACILITIES DOES CAMA APPLY AND**
19 **WHY?**

20 A. CAMA applies to all of DE Progress' CCR surface impoundments in North
21 Carolina located at seven coal-fired generating sites.

1 Q. SINCE CAMA ONLY APPLIES TO THE COMPANY'S NORTH
2 CAROLINA FACILITIES, HOW IS IT RELEVANT TO THIS SOUTH
3 CAROLINA RATE PROCEEDING?

4 A. South Carolina customers receive the benefit from electricity generated at DE
5 Progress' South Carolina and North Carolina plants, therefore, South Carolina
6 customers should also share costs from the generation process of electricity
7 production in both South Carolina and North Carolina. This issue is addressed in
8 greater detail in the direct testimony of Company Witness Wright.

9 Q. DO THE CCR RULE, SOUTH CAROLINA REGULATORY POLICY,
10 AND CAMA REQUIRE CLOSURE OF THE COMPANY'S CCR BASINS?

11 A. Yes. Under one or a combination of the above-listed federal and state regulatory
12 regimes, the Company will be required to close all of its CCR basins.

13 Q. HOW DO THE CCR RULE AND STATE REGULATORY
14 REQUIREMENTS WORK TOGETHER TO ADDRESS MANAGEMENT
15 AND REMEDIATION OF THE COMPANY'S CCR BASINS?

16 A. The CCR Rule requires DE Progress to comply with minimum national criteria,
17 as well as applicable state laws, in the closure of ash basins. Thus, the CCR Rule
18 provides overarching requirements pursuant to which each state may set forth
19 more specific regulations. However, as long as minimum national criteria are
20 satisfied, the CCR Rule does not specify a particular method for closing ash
21 basins. Thus, the CCR Rule leaves to the states to approve the method of ash
22 basin closure, as long as such method meets the timeframes and minimum
23 requirements set forth in the CCR Rule. In North Carolina, the method of closure

1 required under the CCR Rule will be selected through the process set forth in
2 CAMA. In addition, CAMA requires the submittal of detailed Corrective Action
3 Plans ("CAPs") to NCDEQ to address groundwater impacts. CAMA sets forth
4 specific closure methods which are consistent with the CCR Rule's minimum
5 national criteria for sites deemed intermediate risk. The CCR Rule regulates CCR
6 landfills in addition to CCR surface impoundments, whereas CAMA only
7 addresses CCR surface impoundments. Finally, South Carolina has required
8 utilities to excavate ash storage areas, which are exempt from CCR Rule
9 applicability because they ceased receiving CCR prior to the effective date of the
10 rule.

11 **Q. ARE THERE SOME SITES TO WHICH THE CCR RULE APPLIES, BUT**
12 **NOT TO EACH SPECIFIC CCR BASIN AT THAT SITE?**

13 A. Yes. The CCR Rule does not apply at historical inactive ash basins that contain
14 CCR but had no liquids on or after October 19, 2015. For example, at the H.F.
15 Lee Plant site, three basins referred to as Ash Basin 1, Ash Basin 2, and Ash
16 Basin 3 are not subject to the CCR Rule because these inactive ash basins were all
17 dry as of the effective date of the CCR Rule. However, at the same H.F. Lee
18 Plant site, the 1982 Active Ash Basin is subject to the CCR Rule because it
19 contained CCR and liquids on October 19, 2015. Please refer to Kerin Exhibit 5
20 for a detailed breakdown of DE Progress' ash basins in the Carolinas and which
21 ash basins are subject to the CCR Rule.

1 **Q. IN ADDITION TO THE CCR RULE, SOUTH CAROLINA OVERSIGHT,**
2 **AND CAMA, IS THE COMPANY SUBJECT TO ANY OTHER**
3 **REGULATORY COMPLIANCE OBLIGATIONS CONCERNING THE**
4 **FUTURE MANAGEMENT OR REMEDIATION OF CCR?**

5 **A.** Yes. DE Progress is subject to a settlement agreement with DEQ. The Settlement
6 Agreement dated September 29, 2015, between DEQ and DE Progress requires
7 that remedial action as otherwise required to address groundwater impacts from
8 ash basins be accelerated at four North Carolina sites. It specifically requires the
9 installation and operation of extraction wells on the eastern portion of the Sutton
10 Plant property where groundwater exceeds the NCAC Title 15A Subchapter 2L
11 water quality standard.

12 The DEQ Settlement Agreement also requires accelerated remediation at
13 the Asheville Plant and the H.F. Lee Plant. The Settlement Agreement states that,
14 for these two sites, the accelerated remediation can be tailored to each facility's
15 unique characteristics.

16 **Q. PLEASE EXPLAIN HOW THE COMPANY IS COMPLYING WITH ITS**
17 **COAL ASH REGULATORY OBLIGATIONS INCLUDING THE CCR**
18 **RULE, SOUTH CAROLINA OVERSIGHT, AND CAMA.**

19 **A.** DE Progress has reviewed and inventoried the applicable requirements to
20 determine the full scope of required actions to be taken by the Company, and the
21 limitations and/or constraints imposed by some of those requirements. The
22 Company intends to complete the most limiting actions by the earliest applicable
23 due dates across these various compliance regulatory drivers. Required actions

1 and due dates are routinely monitored in various Duke Energy management
2 meetings in the CCP organization.

3 As an example, both CAMA and the CCR Rule require the development
4 of ash basin closure plans. CAMA, however, is more granular in the required
5 level of detail to be included in the narrative of the proposed closure plan as
6 compared to the CCR Rule. Conversely, the CCR Rule has a more limiting due
7 date for development of the ash basin closure plans. Therefore, for sites to which
8 both the CCR Rule and CAMA are applicable, the less granular closure plans
9 were developed to meet the CCR Rule's required due date of October 2016, while
10 more detailed closure plans are separately being developed to meet the exacting
11 requirements of CAMA by the December 2019 deadline.

12 As discussed above, the CCR Rule requires DE Progress to comply with
13 minimum national criteria, as well as any applicable state laws, in the closure of
14 ash basins. Thus, the CCR Rule leaves to the states to approve the method of ash
15 basin closure, as long as such method meets the timeframes and minimum
16 requirements set forth in the CCR Rule. In South Carolina, the method of closure
17 required under the CCR Rule was selected based on coordination with and
18 oversight by SCDHEC. In North Carolina, CAMA risk rankings and any other
19 DEQ applicable requirements may dictate a specific closure approach such as ash
20 basin closure by excavation.

21 In addition to closure requirements, Duke Energy is complying with the
22 other CCR Rule requirements at its facilities in South Carolina, including its

1 groundwater monitoring and corrective action, recordkeeping, notification, and
2 Internet posting requirements.

3 Again, the Company will complete the most limiting action with respect to
4 closure method and timeframe.

5 **IV. DUKE ENERGY'S COMPLIANCE PLANS**

6 **Q. HOW DO THE REQUIREMENTS UNDER THE CCR RULE, SOUTH**
7 **CAROLINA OVERSIGHT, AND CAMA AFFECT THE COMPANY'S**
8 **COAL-FIRED PLANTS?**

9 A. The CCR compliance requirements affect how the coal-fired power plants operate
10 and effectively require the coal ash basins to be retired. With regard to ash basin
11 operation, modifications to the power plants are required to direct storm water
12 flow away from the ash basins and to cease bottom ash and fly ash sluice flow to
13 the basins. As the ash basins are closed, other process streams, such as low-
14 volume wastewater, coal pile run-off, and FGD blowdown flows, must also be
15 directed away from the ash basins to facilitate de-watering and closure. As
16 detailed earlier in this testimony, the CCR Rule, South Carolina oversight, and
17 CAMA require closure of the ash basins; the timing and approach of these
18 closures are dictated by the most limiting regulatory requirement.

19 **Q. PLEASE DESCRIBE THE COMPANY'S ACTIVITIES UNDERTAKEN**
20 **PURSUANT TO CCR REGULATORY OBLIGATIONS?**

21 A. For each site, preliminary engineering and design work was performed to
22 determine the best ash basin closure option for the site as well as permitting
23 needs. Ash basin closure requires the removal of all in flows to the basin such as

1 sluiced ash, process water, and storm water prior to ash basin closure options of
2 excavation, cap in place, and/or beneficiation.

3 DE Progress' approach for closing specific CCR units has evolved over
4 time to meet the changing state and federal regulatory landscape. State-specific
5 regulatory obligations, such as the Robinson Consent Agreement and CAMA,
6 provided additional clarity for developing closure options. Additionally, technical
7 investigations of groundwater, dam stability, and environmental concerns has
8 continued to inform the Company's decision-making.

9 For both state and federal regulatory obligations, a ground water
10 monitoring program has been established. This includes the installation of
11 numerous groundwater wells and well monitoring for at least 30 years following
12 basin closure.

13 To comply with the federal CCR Rule's mandates on stopping flows to the
14 ash basins, many sites required modifications to convert to dry ash handling, new
15 or additional wastewater treatment, and rerouting of storm and process water
16 handling. These activities are largely complete at the DE Progress sites.

17 Once the basin in flows are stopped, the ash basin can then be closed by
18 excavation, cap in place, and/or beneficiation, depending on engineering and
19 scientific analysis and regulatory requirements. For any of the closure methods,
20 the basin water must be treated and removed. Site Closure Plans and Site
21 Analysis and Removal Plans have been developed for each site and are attached
22 to my testimony as Kerin Exhibit 9. Kerin Exhibit 8 provides illustrations of the
23 technical approaches to the excavation and cap-in-place closure methods.

1 **Q. HAS THE REASONABLENESS AND PRUDENCY OF THE CLOSURE**
2 **OPTIONS THAT THE COMPANY HAS SELECTED FOR EACH SITE**
3 **BEEN FULLY EVALUATED AND SCRUTINIZED IN A PRIOR RATE**
4 **PROCEEDING?**

5 A. Yes. As I mentioned earlier, I testified on behalf of DE Progress in its North
6 Carolina rate case that was filed in 2017. Certain intervenors to the case hired
7 engineering consultants to review and critique the Company's decision-making
8 with regard to its selected CCR compliance options. The North Carolina Utilities
9 Commission held that DE Progress' selected closure options were reasonable and
10 prudent, with only limited exceptions. As an appendix to my testimony, I am
11 providing site-by-site summaries of each DE Progress site, which include
12 historical background, an explanation of the Company's selected closure option,
13 and an overview of the issues raised and decided in the North Carolina rate case.
14 *See Appendix.*

15 **Q. CAN YOU PLEASE PROVIDE THE COMPLIANCE COSTS RELATED**
16 **TO ASH POND CLOSURE REQUESTED FOR RECOVERY IN THIS**
17 **CASE?**

18 A. DE Progress reasonably and prudently incurred and expects to incur a total of
19 \$526.4 million (on a system basis) related to incremental ash pond closure
20 compliance costs from July 2016 through December 2018. Company Witness
21 Bateman describes the calculation of and the recovery requested related to this
22 deferred balance. These current and expected compliance activities are

1 reasonable, prudent, and cost-effective solutions given the individual
2 characteristics of each CCR plant and basin site.

3 **Q. HAS THE COMPANY IDENTIFIED ANY COSTS THAT IT WILL NOT**
4 **BE SEEKING FROM SOUTH CAROLINA CUSTOMERS?**

5 A. Yes. The Company will not be seeking from South Carolina customers certain
6 costs that are associated with the provision of drinking water to North Carolina
7 residents. These costs include the provision of bottled water and permanent
8 drinking water supplies, *e.g.*, connection to a public water supply or filtration
9 systems. The Company has decided to absorb the share of these costs that the
10 North Carolina Utilities Commission ordered should be allocated to South
11 Carolina.

12 **Q. HOW, IF AT ALL, DO THE COMPANY'S HISTORICAL CCR**
13 **PRACTICES IMPACT THE COMPLIANCE COSTS THAT DE**
14 **PROGRESS IS SEEKING IN THIS PROCEEDING?**

15 A. They do not affect them at all. I make clear in prior sections of my testimony that
16 DE Progress' historical handling of CCRs was reasonable, prudent, and consistent
17 with industry standards over time. These facts are important to show that nothing
18 that DE Progress has done historically is causing the Company to incur any
19 unjustified costs today to comply with coal ash regulatory requirements.

1 Q. REGARDING THE ASH POND CLOSURE COSTS ALREADY
2 INCURRED OR EXPECTED TO BE INCURRED PRIOR TO DECEMBER
3 2018, WHAT DO THOSE COSTS COMPRISE AND WHY ARE THEY
4 REASONABLE AND PRUDENT COSTS?

5 A. In Kerin/^{Revised}Exhibit 10, I have broken these costs down into their core components
6 and have described the plants to which these costs apply. In detailing these costs,
7 I have also provided narrative summaries as to why these costs were incurred and
8 why the compliance actions that led to those costs were the most reasonable and
9 cost-effective options given the applicable facts and circumstances. This exhibit,
10 coupled with the balance of my testimony and exhibits, demonstrate that these
11 costs are reasonable and prudent.

12 Q. DOES THIS CONCLUDE YOUR TESTIMONY?

13 A. Yes.

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23 (PURSUANT TO PREVIOUS INSTRUCTION,
24 THE PREFILED REBUTTAL TESTIMONY OF
25 JON F. KERIN FOLLOWS.)

**BEFORE
THE PUBLIC SERVICE COMMISSION OF
SOUTH CAROLINA
DOCKET NO. 2018-318-E**

IN THE MATTER OF:

Application of Duke Energy Progress, LLC	)	REBUTTAL TESTIMONY OF
For Adjustments in Electric Rate Schedules	)	JON F. KERIN
and Tariffs and Request for an Accounting	)	FOR DUKE ENERGY
Order	)	PROGRESS, LLC

I. INTRODUCTION

1
2 **Q. PLEASE STATE YOUR NAME, OCCUPATION, TITLE, AND**
3 **BUSINESS ADDRESS.**

4 A. My name is Jon F. Kerin. My business address is 411 Fayetteville
5 Street, Raleigh, North Carolina, 27601-1849. I am employed by Duke
6 Energy Business Services, LLC, as Vice President, Coal Combustion
7 Products ("CCP") Operations, Maintenance and Governance.

8 **Q. ON WHOSE BEHALF ARE YOU SUBMITTING THIS**
9 **REBUTTAL TESTIMONY?**

10 A. I am submitting this rebuttal testimony on behalf of Duke Energy
11 Progress, LLC ("DE Progress," or the "Company").

12 **Q. ARE YOU THE SAME JON KERIN WHO FILED DIRECT**
13 **TESTIMONY IN THIS CASE?**

14 A. Yes.

15 **Q. PLEASE DISCUSS THE PURPOSE OF YOUR REBUTTAL**
16 **TESTIMONY.**

17 A. The purpose of my rebuttal testimony is to address several issues
18 discussed in the direct testimony of intervenors that are related to the
19 Company's request to recover its compliance expenses for managing
20 coal combustion residuals ("CCR"). Specifically, I will address issues
21 raised in the testimonies of Office of Regulatory Staff ("ORS") Witness
22 Dan J. Wittliff and South Carolina Energy Users Committee
23 ("SCEUC") Witness Kevin W. O'Donnell.

1 **Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.**

2 **A.** Mr. Wittliff proposes serious and financially harmful disallowances of
3 costs the Company has prudently incurred in closing ash basins. He
4 proposes disallowing a total of \$333,480,308 for Asheville, Cape Fear,
5 H.F. Lee, Sutton, and Weatherspoon based on the mere fact that there is
6 a state border running through the Company's service territory, failing
7 to appropriately acknowledge the shared costs and benefits of the
8 generation serving DE Progress' customers in South Carolina and North
9 Carolina. In other words, the single basis for Mr. Wittliff's
10 recommended disallowances is that DE Progress is complying with a
11 North Carolina law (the Coal Ash Management Act or "CAMA"). Mr.
12 Wittliff contends that South Carolina customers should not pay for that
13 compliance because, in his view, CAMA is too expensive. This
14 position, that South Carolina customers can enjoy all the savings of
15 sharing power generation units with North Carolina customers but can
16 ignore any legal compliance costs that he deems too expensive, would
17 present grave harm to South Carolina customers if taken to its logical
18 conclusion (which Company Witness Dr. Julius Wright will address in
19 his rebuttal testimony). In addition to being bad policy with dire
20 consequences to the State, Mr. Wittliff's disallowance methodology and
21 recommendations are based on incorrect and unrealistic assumptions,
22 and I will reveal these errors and flaws in my rebuttal testimony.

1 Mr. Wittliff also attempts to use this forum as new ground to
2 rehash arguments before the Public Service Commission's ("PSC" or
3 the "Commission") that were fully litigated in North Carolina and
4 rejected by the North Carolina Utilities Commission ("NCUC") in DE
5 Progress' and Duke Energy Carolinas, LLC's ("DE Carolinas") North
6 Carolina rate cases (NCUC Docket No. E-2, Sub 1142; NCUC Docket
7 No. E-7, Sub 1146). In those cases, Mr. Wittliff's arguments were
8 essentially a smear campaign directed at the Company presumably to
9 punish the Company for the Dan River incident—the costs of which are
10 not being charged to South Carolina customers. In fact, approximately
11 two-thirds of Mr. Wittliff's testimony rehashes the same "Duke Energy
12 is bad" arguments that he submitted on behalf of the Attorney General's
13 Office to the NCUC. Those arguments were fully litigated and, for good
14 reasons, rejected in the North Carolina case. Moreover, such assertions
15 are not relevant to his recommended disallowances in this case and the
16 Commission should not have to spend multiple days of hearing time
17 listening to them as the NCUC had to endure.

18 Similar to Mr. Wittliff, SCEUC Witness O'Donnell's coal ash
19 testimony presents the same incorrect and rejected arguments that he
20 made in the Company's North Carolina case. Like Mr. Wittliff, Mr.
21 O'Donnell also contends that CAMA is more expensive than the federal
22 CCR Rule and that South Carolina should be free to ignore any law that
23 SCEUC deems to be too expensive. Mr. O'Donnell simply suggests that

1 a 75 percent disallowance of all the Company's coal ash compliance
2 costs seems correct to him based on his perusal of what he contends are
3 national coal ash compliance costs in other states. Notwithstanding the
4 obvious invalidity of this position, I will explain the multiple errors that
5 Mr. O'Donnell commits and will demonstrate why his "thumb in the
6 air" method of cost recovery cannot and should not be taken seriously
7 by this Commission.

8 **II. RESPONSE TO ORS WITNESS WITTLIFF**

9 **Q. IN GENERAL, WHAT IS YOUR OVERALL IMPRESSION OF**
10 **MR. WITTLIFF'S TESTIMONY?**

11 A. I do not believe that Mr. Wittliff's testimony is helpful to the
12 Commission's assessment of DE Progress' reasonable and prudent
13 coal ash expenses in this docket, and therefore should be rejected.

14 **Q. WHY DO YOU BELIEVE THAT MR. WITTLIFF'S**
15 **TESTIMONY IS NOT USEFUL?**

16 A. Mr. Wittliff spends approximately four pages of his testimony
17 discussing his engineering experience and his experience with coal ash,
18 yet he offers no substantive engineering opinions. Mr. Wittliff's
19 recommended disallowances are not based on any finding of
20 imprudence regarding the Company's closure strategies or execution
21 thereof. Instead, the disallowances are based entirely on a poor
22 regulatory policy argument that the Company should not be able to
23 recover expenses to comply with a North Carolina law. If the

1 Commission rejects Mr. Wittliff's poor policy argument, which it
2 should, then none of Mr. Wittliff's testimony matters in this proceeding
3 because every conclusion and recommendation that he reaches in his
4 testimony is dependent on the Commission accepting that ill-founded
5 argument.

6 **Q. HOW WOULD YOU CHARACTERIZE THE BULK OF MR.**
7 **WITTLIFF'S TESTIMONY?**

8 A. The first thirty pages of Mr. Wittliff's testimony largely mirror his
9 testimony in the North Carolina case and the rhetoric recycled in those
10 pages has nothing at all to do with the theory that he is attempting to
11 advance here. He discusses the evolution of environmental regulations
12 relating to CCR, historic utility industry practices for managing CCR,
13 the Company's historic management practices, and the genesis of
14 CAMA. None of this testimony, however, is relevant to Mr. Wittliff's
15 substantive recommendations to this Commission. While I vehemently
16 disagree with Mr. Wittliff's mischaracterizations of the industry's and
17 the Company's CCR management practices, they are not relevant to the
18 Company's request to recover its compliance costs in this case.

19 **Q. WHY DO YOU SAY THAT THE BULK OF MR. WITTLIFF'S**
20 **TESTIMONY IS IRRELEVANT?**

21 A. ORS's single recommendation to the Commission is to disallow costs
22 that the Company has incurred to comply with North Carolina law, the
23 CAMA. Mr. Wittliff insinuates that DE Progress caused CAMA, which

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1 was an argument that completely failed in North Carolina and for good
 2 reason. Nonetheless, Mr. Wittliff has apparently seen fit to raise this
 3 argument again here.¹ However, what is missing from Mr. Wittliff's
 4 testimony is most important. He does not allege that CAMA is a
 5 punitive law nor can he, because it is not. He does not allege that CAMA
 6 is an unreasonable or excessive law for North Carolina or if adopted
 7 elsewhere, because it is not. He does not allege that CAMA reflects bad
 8 environmental policy, nor can he, because it does not. Nor does he
 9 allege that CAMA's closure requirements conflict with the closure
 10 options available under the EPA's CCR Rule, nor can he, because they
 11 do not. Further, he does not allege that the Company took any
 12 imprudent or unreasonable action to comply with CAMA and the CCR
 13 Rule, nor can he, because it did not. Therefore, Mr. Wittliff's
 14 discussion of the Company's CCR management history is irrelevant to
 15 his recommended disallowances and is just a distraction from his flawed
 16 and irresponsible theory of disallowance.

17 **Q. ARE YOU ADDRESSING REGULATORY IMPLICATIONS OF**
 18 **THE ORS'S RECOMMENDED DISALLOWANCE POLICY?**

19 **A.** No, not directly. Company Witness Dr. Wright discusses the regulatory
 20 implications and flaws of ORS's recommended disallowance policy for

¹ See *Order Accepting Stipulation, Deciding Contested Issues and Granting Partial Rate Increase*, Docket No. E-2, Sub 1142 at 196-99 (NCUC February 23, 2018); *Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction*, Docket No. E-7, Sub 1146 at 270-72 (NCUC June 22, 2018).

1 CCR expenses in his rebuttal testimony, but I do not need to be a policy
2 expert or a lawyer to know that Mr. Wittliff poor policy proposal lacks
3 fundamental fairness.

4 **Q. DO YOU HAVE ANY GENERAL OBSERVATIONS REGARDING**
5 **MR. WITTLIFF'S DISALLOWANCE TESTIMONY?**

6 A. Yes. At the outset, I will note that Mr. Wittliff's proposed specific
7 disallowances are entirely dependent on speculating what the Company
8 hypothetically would or would not have done in the absence of CAMA.
9 That is not reality, and the reasonableness and prudence of the
10 Company's costs should be judged in light of actual circumstances.

11 It is easy for Mr. Wittliff to provide a simple, conclusory opinion
12 that things would be different if CAMA did not exist. What Mr. Wittliff
13 did not do, and cannot do, is state with any certainty how exactly things
14 would have played out in his alternate reality. Mr. Wittliff's testimony
15 is built on speculation: "the CAMA rules resulted in costs exceeding
16 what *would* have been the costs under the Federal CCR Rules alone."
17 (Wittliff Direct 30:12-13) (emphasis added). He should be held to his
18 own standard. (Wittliff Direct 32:15 ("speculation...should not be
19 considered in this proceeding")). Keeping this in mind, I address the
20 flawed assumptions upon which Mr. Wittliff's recommended
21 disallowances are based and will demonstrate that his suggested
22 disallowances (totaling \$333,480,308 – Asheville (\$98,220,932), Cape

1 Fear (\$33,631,199), H.F. Lee (\$9,207,711), Sutton (\$186,376,226), and
2 Weatherspoon (\$6,044,240)) are unfounded.

3 **Q. PLEASE SUMMARIZE MR. WITTLIFF'S BASIS FOR A**
4 **DISALLOWANCE OF CERTAIN ASHEVILLE CCR COSTS.**

5 A. Mr. Wittliff argues that, while the timing of closure at Asheville was not
6 affected by CAMA, the Company's closure method was influenced by
7 CAMA, thereby increasing costs. He then apparently suggests that the
8 Company could have closed its Asheville basins by capping them in
9 place, as opposed to excavation. He then attempts to quantify the
10 alleged premium imposed by CAMA to serve as his recommended
11 disallowance for the site.

12 **Q. HOW DO YOU RESPOND TO MR. WITTLIFF'S**
13 **RECOMMENDED DISALLOWANCE FOR ASHEVILLE**
14 **COSTS?**

15 A. I would first note that Mr. Wittliff's testimony regarding Asheville is
16 self-contradictory and difficult to follow, which has made it difficult to
17 identify specific arguments for me to rebut. For example, throughout
18 his discussion of Asheville, Mr. Wittliff conflates two distinct closure
19 methodologies: "cap-in-place" and excavation. Mr. Wittliff
20 recommends that the Company be allowed to recover costs for
21 engineering and planning "and for cap-in-place disposal". Yet, at the
22 same time, he argues that there "would have been ample room for on-
23 site disposal of ash impounded at Asheville," a fact that is irrelevant if

1 he contends that the site should have been capped in place. (Wittliff
2 Direct 40:19; 41:1-3). Further compounding the confusion created by
3 his testimony, Mr. Wittliff uses DE Progress' Robinson site, where ash
4 is to be placed in an "on-site landfill rather than capped in place", as a
5 comparison site to Asheville, which again contradicts his argument for
6 the Asheville site. (Wittliff Direct 41:18).

7 **Q. ARE THERE ANY ADDITIONAL FLAWS IN MR. WITTLIFF'S**
8 **TESTIMONY REGARDING ASHEVILLE?**

9 A. Mr. Wittliff's testimony lacks any factual support for his alternative
10 closure proposals and does not demonstrate any analysis of site-specific
11 conditions, including: engineering analysis demonstrating the technical
12 and practical feasibility of cap-in-place or an onsite landfill; the precise
13 location and size of an on-site landfill; cost estimates for cap-in-place
14 or an on-site landfill; permitting requirements for cap-in-place or an on-
15 site landfill; or the likelihood of obtaining requisite federal, state and
16 local permitting approval for cap-in-place or an on-site landfill. Had
17 Mr. Wittliff attempted to investigate any of these factors, he would have
18 found that excavation is the proper closure method for the Asheville site,
19 regardless of CAMA, due to site specific conditions. Seismic
20 conditions in the area would have prevented cap-in-place from being a
21 viable permanent closure solution at Asheville. Additionally, the
22 Company had started excavation at the Asheville site before CAMA was
23 enacted to provide ash for recycled use at construction projects such as

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1 the Asheville airport. Mr. Wittliff's testimony is devoid of any
2 necessary analysis, and his recommended disallowance for Asheville
3 should be rejected.

4 **Q. PLEASE SUMMARIZE MR. WITTLIFF'S BASIS FOR A**
5 **DISALLOWANCE OF ALL CAPE FEAR CCR COSTS.**

6 A. Mr. Wittliff argues that the Company is only closing the ash basins at
7 Cape Fear because it is required to do so under CAMA. If CAMA did
8 not exist, he argues, the Company would only be required to comply
9 with the federal CCR Rule and would have left the ash basins at Cape
10 Fear untouched indefinitely. Accordingly, he recommends a
11 disallowance of all Cape Fear compliance costs incurred to-date.

12 **Q. HOW DO YOU RESPOND TO MR. WITTLIFF'S**
13 **RECOMMENDED DISALLOWANCE FOR CAPE FEAR**
14 **COSTS?**

15 A. Mr. Wittliff's recommended disallowance of Cape Fear expenses should
16 be rejected because his position defies belief when considered in the
17 context of the real world². The suggestion that DE Progress could or
18 would have taken a "do nothing" approach to Cape Fear's ash basins,
19 while at the same time closing all of its other ash basins in South
20 Carolina and North Carolina, defies regulatory reality. Arguing this "do

² I again note that my testimony here factually rebutting Mr. Wittliff's arguments is not an acceptance of his flawed policy suggestion that CAMA requirements can simply be ignored. Rather, my testimony demonstrates that Mr. Wittliff's theories fail no matter how ones considers them.

1 nothing” approach would have been reasonable and accepted by
2 regulators and stakeholders for Cape Fear’s inactive CCR units, when
3 similar inactive ash storage areas at the Company’s Robinson station
4 and DE Carolinas’ W.S. Lee station were being excavated, is an absurd
5 proposition. In fact, under Mr. Wittliff’s faulty logic, it follows that
6 South Carolina customers should refund North Carolina customers all
7 money spent for excavating ash from the inactive basins at the Robinson
8 and W.S. Lee sites in South Carolina because they were otherwise
9 exempt from the CCR Rule.

10 Additionally, Mr. Wittliff acknowledges that after the CCR Rule
11 was promulgated containing the provision that excluded retired ash
12 basins such as those present at the Cape Fear and the W.S. Lee sites, the
13 EPA was sued in 2015. That lawsuit alleged, among other things, that
14 the exclusion of inactive CCR surface impoundments at retired power
15 plants from the CCR Rule was arbitrary and capricious because it failed
16 to meet the Resource Conservation and Recovery Act’s (“RCRA”)
17 standard of “no reasonable probability of adverse effects.” In August
18 2018, the United States Court of Appeals for the District of Columbia
19 Circuit found “the Rule’s legacy ponds exemption is unreasoned,
20 arbitrary, and capricious” and vacated and remanded these provisions of
21 the CCR Rule to EPA. As a result, EPA will have to affirmatively
22 undertake regulatory changes to the CCR Rule to implement the court’s
23 judgment, including adding new provisions to the rule specifically

1 regulating legacy impoundments. Although Mr. Wittliff acknowledges
2 this lawsuit and rulemaking, he tells the Commission to ignore these
3 real-world facts and only focus on his hypothetical view of how the
4 world may have turned out had CAMA never been passed.

5 **Q. PLEASE SUMMARIZE MR. WITTLIFF'S BASIS FOR A**
6 **DISALLOWANCE OF H.F. LEE CCR COSTS.**

7 A. Mr. Wittliff states that the Company is beneficiating ash at the H.F. Lee
8 site only because of CAMA, which is true. He then argues that
9 beneficiation is not a requirement under the federal CCR Rule;
10 therefore, the Company should not be able to recover costs related to
11 beneficiation at Cape Fear.

12 **Q. DO YOU TAKE ISSUE WITH HOW MR. WITTLIFF**
13 **ATTEMPTED TO QUANTIFY CAMA COSTS AT H.F. LEE?**

14 A. Yes. In his testimony (page 36, lines 20-23), Mr. Wittliff states that
15 based on his visit to the H.F. Lee site it "appears" that most of the work
16 he saw looks like beneficiation work and therefore recent costs at the
17 site must be for beneficiation. This, of course, is not a valid method of
18 determining costs.

19 **Q. DOES CAMA'S BENEFICIATION REQUIREMENT RESULT IN**
20 **INCREASED COSTS FOR SOUTH CAROLINA?**

21 A. No. In total, for both DE Progress and DE Carolinas, CAMA's
22 beneficiation requirement actually results in a net savings for South
23 Carolina. Between DE Progress and DE Carolinas, the Company

1 selected three sites for beneficiation projects: H.F. Lee (DE Progress),
2 Cape Fear (DE Progress), and Buck (DE Carolinas). Those sites were
3 selected based on the quality and quantity of ash present at the site;
4 logistical factors; and proximity to relevant markets where the
5 beneficiated ash can be sold. The ash basins at those sites are being
6 closed by excavation, and the ash is being beneficiated as opposed to
7 being disposed in permitted landfills. For the H.F. Lee and Cape Fear
8 sites, beneficiation under CAMA is providing an estimated net savings
9 compared to closure without beneficiation of approximately \$703
10 million on a total system basis. Mr. Wittliff and the ORS appear to have
11 overlooked this fatal flaw to their policy argument that CAMA be
12 ignored as if it never existed. Under their theory, if South Carolina
13 customers will not pay costs associated with CAMA, then they fairly
14 cannot enjoy the superior savings afforded by CAMA beneficiation at
15 the H.F. Lee and Cape Fear sites and would owe North Carolina
16 customers a net refund for those costs savings. This demonstrates how
17 the ORS's ill-advised policy of ignoring laws it does not like creates
18 absurd results in the real world.

19 **Q. IS CAMA'S BENEFICIATION REQUIREMENT**
20 **UNREASONABLE AS SUGGESTED BY MR. WITTLIFF?**

21 **A.** No. DE Progress' and DE Carolinas' beneficiation projects at H.F. Lee,
22 Cape Fear, and Buck utilize technology that was first deployed and
23 approved in South Carolina at SCANA coal ash facilities.

1 **Q. PLEASE SUMMARIZE MR. WITTLIFF'S BASIS FOR A**
2 **DISALLOWANCE OF SUTTON CCR COSTS.**

3 A. Mr. Wittliff argues that, absent CAMA, DE Progress could have started
4 closure of Sutton's CCR units later than when it did. He then
5 recommends that the Commission disallow the Company's site closure
6 costs that were incurred earlier than they allegedly would have been
7 absent CAMA.

8 **Q. HOW DO YOU RESPOND TO MR. WITTLIFF'S**
9 **RECOMMENDED DISALLOWANCE FOR SUTTON COSTS?**

10 A. Mr. Wittliff does not appear to take issue with the closure strategy or the
11 types of closure costs at Sutton, since he suggests that the Company
12 could recover its construction and transportation costs in the future.
13 Instead, Mr. Wittliff disputes the timing of the Company's costs, which
14 is based on his apparent assumption that the price of labor, supplies,
15 materials, and equipment gets cheaper as time passes and demand
16 increases. This assertion, of course, defies common sense.

17 **Q. IS MR. WITTLIFF'S PROPOSED TIMELINE FOR SUTTON**
18 **CLOSURE BASED ON CORRECT ASSUMPTIONS?**

19 A. No. Mr. Wittliff's recommended disallowance should be rejected in its
20 entirety because it is based on two demonstrably false assumptions: 1)
21 that "Sutton closure was directed by CAMA and the North Carolina
22 orders" and 2) "that the CCR rules would not have required closure
23 actions at Sutton to even commence until October 31, 2020."

1 As to Mr. Wittliff's first error, Sutton's ash ponds did not meet
 2 wetlands or aquifer location restrictions under the CCR Rule.³
 3 Therefore, the closure of Sutton under the CCR Rule was triggered
 4 based on those CCR standards and not CAMA as Mr. Wittliff contends.

5 Next, Mr. Wittliff incorrectly concludes that under the CCR
 6 Rule, the Company would not have commenced closure at Sutton until
 7 October 31, 2020. (Wittliff Direct 38:4-7). Closure deadlines under
 8 the CCR Rule were set with the last placement of waste streams in
 9 Sutton's basins, which occurred on July 6, 2016. The July 2016 trigger
 10 date is explicitly referenced in Kerin's Exhibit 10, but was ignored or
 11 missed by Mr. Wittliff in his testimony.

12 Therefore, given the fact that Mr. Wittliff's entire disallowance
 13 for Sutton depends on his assumptions that CAMA dictated the closure
 14 timing at Sutton, which it did not, and that closure would not have
 15 commenced until 2020, which is also incorrect, the Commission should
 16 reject Mr. Wittliff's entire disallowance for Sutton.

17 **Q. WOULD MR. WITTLIFF'S PROPOSED TIMELINE FOR**
 18 **SUTTON CLOSURE UNDER THE CCR RULE HAVE**
 19 **REDUCED CLOSURE COSTS?**

20 **A.** No. Even if one accepts Mr. Wittliff's incorrect allegation that CAMA
 21 accelerated DE Progress' closure timing at Sutton, an extended closure

³ This information was provided to ORS in discovery and is posted online for the general public. See <https://www.duke-energy.com/our-company/environment/compliance-and-reporting/ccr-rule-compliance-data>.

1 schedule, as proposed by Mr. Wittliff, would actually result in higher
2 total project costs for that site. These higher costs would be attributable
3 to increased overhead and changing market conditions, like vendor and
4 resource availability. The Company is ahead of most utilities in the
5 region in terms of its progress in achieving ash basin closure. If the
6 Company delayed its closure and extended the closure schedule as
7 proposed by Mr. Wittliff, it would be competing with other utilities for
8 limited, experienced vendors and specialized resources. In fact, the
9 Company has seen these real-world price increases take place, a fact that
10 Mr. Wittliff ignores in his hypothetical version of reality. For example,
11 over the past three years labor costs for truck drivers and equipment
12 operators have increased eight and nine percent, respectively.

13 **Q. PLEASE SUMMARIZE MR. WITTLIFF'S BASIS FOR A**
14 **DISALLOWANCE OF WEATHERSPOON CCR COSTS.**

15 **A.** Mr. Wittliff agrees with the Company's decision to close
16 Weatherspoon's basins by excavation. He also agrees with the
17 Company's timeline for closing Weatherspoon. In fact, his only
18 disagreement with the Weatherspoon closure is his contention that the
19 Company is beneficiating ash from that site under the North Carolina
20 CAMA provisions." (Wittliff Direct 42:21-23).

1 Q. HOW DO YOU RESPOND TO MR. WITTLIFF'S
2 RECOMMENDED DISALLOWANCE FOR WEATHERSPOON
3 COSTS?

4 A. Mr. Wittliff is wrong again. DE Progress is not beneficiating ash under
5 CAMA at Weatherspoon as Mr. Wittliff suggests and instead is selling
6 raw, unprocessed ash to buyers who can use it to offset some of the costs
7 for closing that site.⁴ CAMA required the Company to select three sites
8 for the installation of ash beneficiation equipment to process ash into a
9 refined product. As discussed above, those sites are H.F. Lee, Cape
10 Fear, and Buck (DE Carolinas). Weatherspoon does not qualify as a
11 beneficiation site under CAMA and the suggestion that the Company's
12 ash disposal efforts at Weatherspoon are required by CAMA is wrong.

13 Q. DOES MR. WITTLIFF SAY WHAT THE COMPANY SHOULD
14 HAVE DONE INSTEAD OF REUSING THE WEATHERSPOON
15 ASH?

16 A. No, nor does he criticize the Company's closure of Weatherspoon by
17 excavation. Instead, Mr. Wittliff questions the logic of CAMA's
18 beneficiation requirement which he erroneously believes applies to this
19 site.

⁴ It is also worth noting that the CCR Rule encourages beneficiation

1 Q. HAS MR. WITTLIFF PROVIDED ANY JUSTIFICATION FOR
2 THE COMPANY ADOPTING AN ALTERNATIVE DISPOSAL
3 OPTION?

4 A. No.

5 Q. HAS THE COMPANY SELECTED THE MOST COST
6 EFFECTIVE, FEASIBLE DISPOSAL STRATEGY FOR
7 WEATHERSPOON?

8 A. Yes. The Company initially selected an offsite landfill option for
9 Weatherspoon whereby ash would be excavated and moved to a landfill
10 disposal offsite. The estimated costs for this disposal strategy were
11 contained in the Company's 2016 ARO and totaled approximately \$232
12 million. Subsequently, DE Progress sought bids for reuse options for
13 the ash at Weatherspoon and was able to secure a contract to provide ash
14 to cement kilns in South Carolina for use in the construction industry.
15 That decision has resulted in approximately \$23 million in estimated
16 costs savings for DE Progress' customers compared to what they would
17 have otherwise paid. By all accounts then, it appears that Mr. Wittliff
18 does not want South Carolina customers to have their fair share of these
19 savings.

20 Q. DO YOU HAVE ANY OTHER CRITICISMS OF MR.
21 WITTLIFF'S TESTIMONY REGARDING WEATHERSPOON?

22 A. Yes. He estimates that three-fourths of the Weatherspoon costs in 2017
23 were attributable to "engineering and planning" without providing any

1 basis or conducting any apparent investigation as to what actual costs
2 are. He then estimates that half of fourth quarter 2017 and half of the
3 first three quarters of 2018 were attributable to the CCR Rule, again
4 without any basis. Compounding his problems, Mr. Wittliff arrives at a
5 disallowance number that is not connected to any specific activities or
6 costs at the site. Thus, his disallowance numbers are a product of fiction
7 and have no basis in the actual facts in this matter.

8 **III. RESPONSE TO SCEUC WITNESS O'DONNELL**

9 **Q. WITNESS O'DONNELL RECOMMENDS A DISALLOWANCE**
10 **OF 75% OF CCR EXPENSES BASED ON WHAT HE CALLS A**
11 **NATIONAL COMPARISON OF CCR ASSET RETIREMENT**
12 **OBLIGATION (ARO) AMOUNTS. DO YOU AGREE WITH HIS**
13 **CONCLUSIONS?**

14 **A.** No, I do not. Mr. O'Donnell has simply repackaged his failed
15 inflammatory theory from DE Progress' North Carolina rate case. Mr.
16 O'Donnell's "analysis" has the same significance of taking a list of
17 home sales prices from around the Southeast and the country without
18 regard to the size, location, features, or age of the houses; listing them
19 out in order of greatest to least cost; and then concluding that houses in
20 certain areas of the country are overpriced because they are not the same
21 as house prices in other places in America. While Mr. O'Donnell claims
22 that he has taken fair measures to make his comparison of national CCR
23 ARO amounts valid (such as applying a random 65 percent capacity

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1 factor to coal plants located at various CCR sites), I do not see where
2 Mr. O'Donnell has accounted for or even considered the following
3 factors in his analysis:

- 4 a. The number of coal plants in the Company's fleet;
- 5 b. The type of coal plants in the Company's fleet;
- 6 c. The age of the plants in the Company's fleet;
- 7 d. The amount of coal at each of the plants in the Company's fleet;
- 8 e. The type of coal used in each of the plants in the Company's
9 fleet;
- 10 f. The actual MW capacity of each coal plant, over their lifetime
11 considering plant upgrades that may have occurred adding
12 generation;
- 13 g. The type of environmental controls, if any, installed on the
14 plants in the Company's fleet (e.g., electrostatic precipitators,
15 flue gas desulfurization);
- 16 h. Whether any plants in the company's fleet utilize dry ash
17 handling;
- 18 i. Whether any CCRs generated from the plants in the Company's
19 fleet are being sold for beneficial reuse;
- 20 j. The type of CCR basins in the Company's fleet;
- 21 k. The location of the CCR basins in the Company's fleet;
- 22 l. Whether other utilities have closed some of their coal ash basins;

- 1 m. Soil and other geologic conditions of the CCR basins in the
2 Company's fleet;
- 3 n. State specific laws applicable to CCR basins in the Company's
4 fleet;
- 5 o. Regulatory rules and regulations for each state applicable to the
6 CCR costs and AROs in Table 8 of his testimony;
- 7 p. Whether any CCR costs have been excluded from the ARO
8 amounts listed in Table 8 of his testimony (*e.g.*, write-offs);
- 9 q. ASPE Cost Estimate Classifications for each ARO amount
10 stated in Table 8 of his testimony;
- 11 r. Macro-level assumptions used by each company in deriving the
12 ARO amounts (*e.g.*, basin closure dates, closure methods, etc.);
- 13 s. The scope of work assumed in each ARO estimate;
- 14 t. Any contracts, RFPs, RFIs, or bidder responses for work to be
15 performed;
- 16 u. Comparisons of actual, to-date costs to projected costs in the
17 AROS when considering recently passed or proposed
18 legislation;
- 19 v. Whether any CCR basins were excluded from the ARO amount
20 (*e.g.* not subject to the federal CCR Rule) and if so, why; and
- 21 w. The amounts and types of CCRs in the basins for each company.
- 22 Without consideration of these elements, I do not see any
23 reasonable basis for taking Mr. O'Donnell's recommendation seriously.

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1 Further, many of the figures that Mr. O'Donnell uses in his comparison
2 appear to be unreasonable on their face. For example, Mr. O'Donnell's
3 SNL data shows Ohio Power Company's ARO to be \$1.66 million.
4 Even if it is assumed that Ohio Power used cap in-place for its ash
5 basins, \$1.66 million is a wildly unreasonable estimate for covering
6 hundreds of acres of ash.

7 In addition to using incorrect figures in his "analysis," Witness
8 O'Donnell did not consider the fact that the other utilities he listed in
9 his testimony are in very different stages within their coal ash
10 management timeline than DE Progress, as discussed in the rebuttal
11 testimony of Dr. Wright. Witness O'Donnell mistakenly takes the ARO
12 data he copied from SNL as gospel, as opposed to characterizing them
13 for what they are, which are rough estimates. If Mr. O'Donnell had gone
14 behind the numbers, he would likely have discovered that there is
15 substantial uncertainty about the level of actual closure costs of many
16 of the utilities listed. For example, his analysis does not consider
17 legislation that was recently passed by the Virginia General Assembly
18 that will significantly increase closure costs for Virginia Electric and
19 Power Company ("VEPCO" d/b/a Dominion Energy). This legislation
20 requires VEPCO to excavate all of its basins located in the Chesapeake
21 Bay Watershed after the company had already submitted closure plans
22 calling for cap-in-place at most of these sites. The total estimated costs
23 for VEPCO to close these basins is \$5.2 billion to \$8.6 billion, which

1 reflects an 897 to 1,314 percent increase from the ARO estimate cited by
2 Mr. O'Donnell for that company.

3 A further consideration that is absent from Mr. O'Donnell's table
4 is that closure costs (such as labor, trucking) will vary greatly based on
5 geographic regions, supply and demand, timing of closure, and many
6 other factors that would have to be normalized to develop an accurate
7 comparison (if it is even possible). DE Progress is much farther along
8 in the closure process than most other utilities in other states. As a
9 result, the comparison Mr. O'Donnell is trying to draw provides no
10 value to this case.

11 I therefore recommend that the Commission determine the
12 reasonableness of DE Progress' ARO amount on its own merits based
13 on the facts in this case.

14 **Q. DO YOU BELIEVE THAT SCEUC WITNESS O'DONNELL HAS**
15 **A CREDIBLE BASIS FOR SAYING THAT DE PROGRESS'**
16 **COAL ASH AROS ARE HIGHER THAN AROS FOR UTILITIES**
17 **IN OTHER STATES BECAUSE OF CAMA?**

18 **A.** No. Witness O'Donnell made no attempt to quantify DE Progress' coal
19 ash AROs resulting from CAMA, as compared to its obligations under
20 the CCR Rule. Nor did he attempt to determine the impetus for coal ash
21 AROs for the other utilities to which he compares DE Progress. Since
22 Mr. O'Donnell cannot attribute any specific ARO coal ash costs to
23 CAMA and cannot attribute ARO coal ash costs for other companies to

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1 any particular regulatory obligation, he cannot credibly testify that DE
2 Progress' ARO coal ash costs are higher because of CAMA, even if that
3 fact were relevant to this proceeding, which it is not.

4 **Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?**

5 **A. Yes.**

1 MR. BURNETT: Mr. Chairman, these witnesses
2 are available for questions.
3 CHAIRMAN RANDALL: Thank you. Walmart?
4 MS. GRUNDMANN: No cross.
5 CHAIRMAN RANDALL: Thank you. Ms. Ferguson?
6 MS. FERGUSON: No cross, Mr. Chairman.
7 CHAIRMAN RANDALL: Mr. Guild?
8 MR. GUILD: Thank you, Mr. Chairman.
9 CHAIRMAN RANDALL: Hang on, Mr. Guild. Let's
10 -- let's -- let's take a quick break --
11 MR. GUILD: All right.
12 CHAIRMAN RANDALL: -- first, and then we'll
13 start with you when this is --
14 MR. GUILD: Yep.
15 CHAIRMAN RANDALL: -- when we finish. We'll
16 take about ten minutes.
17 (Off the record from 11:13 a.m.
18 until 11:26 a.m.)
19
20 CHAIRMAN RANDALL: Please be seated. Okay.
21 Mr. Guild.
22 MR. GUILD: Mr. Chairman, thank you. With
23 some trepidation, Mr. Chairman, I'm going to
24 attempt a "Stinson Ferguson maneuver" here to
25 try to save us all a little time. With the

1 Company's --

2 CHAIRMAN RANDALL: We're going to name this

3 after you. I like it.

4 MR. GUILD: And she deserves it, Mr. Chairman,

5 in my opinion.

6 With the Company's approval --

7 CHAIRMAN RANDALL: Hang on.

8 MR. GUILD: -- let's make a stab at this.

9 CHAIRMAN RANDALL: (To the court reporter)

10 What do you need?

11 THE COURT REPORTER: Do you want me to swear

12 the witnesses in? I didn't --

13 CHAIRMAN RANDALL: They've already -- they're

14 already sworn in. They're -- they're the same

15 ones.

16 THE COURT REPORTER: Oh, I'm so sorry.

17 CHAIRMAN RANDALL: You're good.

18 THE COURT REPORTER: I'm so sorry. Thank you.

19 CHAIRMAN RANDALL: I've been confusing Ms.

20 Tackett all morning long, so she --

21 THE COURT REPORTER: It's Monday. I'll have

22 this down by lunch.

23 CHAIRMAN RANDALL: All right, Mr. Guild.

24 MR. GUILD: All right. Subject to this

25 working out, I have no questions for Dr.

1 Wright and we'll see if we can make this quick
2 with -- with Mr. Kerin.

3 CROSS-EXAMINATION

4 BY MR. GUILD:

5 Q Mr. Kerin, you testified in the Duke Energy
6 Carolinas proceeding before the Commission last
7 month, did you not?

8 A Yes. I did.

9 Q We all have to remember now, yes, it was last
10 month. And you remember my colleague, Ms. Bridget
11 Lee for Sierra Club asking you a series of
12 questions about the Company's coal ash management
13 practices in that case?

14 A Yes. I do.

15 Q Recognizing that Duke Energy Progress is a
16 different utility and that company and site-
17 specific facts may differ, subject to those
18 caveats, Mr. Kerin, if I asked you the same
19 questions today that Ms. Lee asked you in that
20 other proceeding, would your answers be the same?

21 A Yes. They would.

22 Q All right. Thank you, Mr. Kerin.

23 MR. GUILD: And -- and with that response, Mr.
24 Chairman, I would request that the Commission
25 take judicial notice of that portion of Mr.

1 Kerin's testimony that responded to the
2 questions of Ms. Bridget Lee on behalf of the
3 Sierra Club in the Duke Energy Carolinas
4 proceeding Docket 2018-319-E, and the
5 transcript reference I have is Volume 6, Pages
6 1249 to 1263.

7 CHAIRMAN RANDALL: We will take judicial
8 notice. Thank you.

9 MR. GUILD: And that's all the questions I
10 have. Thank you, gentlemen.

11 CHAIRMAN RANDALL: Thank you. And the
12 Ferguson Rule is intact.

13 Okay. Let's see. Mr. Elliott.

14 MR. ELLIOTT: Mr. Chairman.

15 CHAIRMAN RANDALL: Sorry. You were standing
16 there and I was just looking at who was next
17 on the list.

18 MR. ELLIOTT: Well, I didn't know whether to
19 interrupt your chain of thought. I'm sorry.
20 Thank you, Mr. Chairman.

21 CROSS-EXAMINATION

22 BY MR. ELLIOTT:

23 Q I going to need the ELMO. Thank you. Mr. Kerin.

24 A (KERIN) Yes, sir.

25 Q How are you this morning?

1 A (KERIN) Fine. Thank you.

2 Q Good, thanks. All right. As I understand it, from
3 your testimony, that during 2014 you held the
4 position of general manager in the Ash Basin
5 Strategic Action Team referred to as "ABSAT"; am I
6 correct?

7 A (KERIN) That is correct.

8 Q Can you tell me a little bit about what your duties
9 were in that capacity?

10 A (KERIN) My role in the ABSAT team was to --
11 responsibilities for the overall governance and
12 programatic items that we were working on as part
13 of the establishment of the ABSAT team.

14 Q All right. And -- well -- and I guess, did it have
15 to do with remediating coal ash ponds?

16 A (KERIN) Well, not the remediation of coal -- coal
17 ash ponds. The ABSAT team was established to take
18 a programatic look at our coal ash management
19 practices, looking at how we were going to
20 strategically close those basins and evaluating
21 those processes in accordance with the pending CCR
22 rule.

23 Q All right. So, would it be fair to say that as a
24 part of your responsibilities as general manager in
25 the ABSAT team, you had to familiarize yourself

1 with the various coal ash ponds operated and
2 maintained by Duke and Progress?

3 A (KERIN) That is correct.

4 Q And as a result of your responsibilities and your
5 experience, I understand your testimony to be, and
6 I'm looking at your -- simply looking at your
7 summary of a moment ago on Page 2 -- at each --
8 "Leading up to the CCR rule and the CAMA
9 implications on the coal ash pond maintenance and
10 operation, prior to that, at each step in the
11 environmental regulatory evolution process,
12 Progress has been in line with industry standards
13 and has reasonably and prudently managed CCRs and
14 its coal ash basins." That's your testimony, isn't
15 it?

16 A (KERIN) That is correct.

17 Q And directing your attention to the -- to the
18 Robinson coal ash pond, if I may, it's fair to say,
19 it is not, sir, that Progress's operation and
20 maintenance of the -- of the Robinson coal ash pond
21 has been in compliance with all state and federal
22 laws prior to its remediation, correct?

23 A (KERIN) That would be correct.

24 Q All right. And, for instance, it would be fair to
25 say that, at least prior to the consent order in

1 July of 2015, the Robinson coal ash pond met or
2 exceeded the -- the applicable regulatory
3 requirements; that's fair to say, isn't it?

4 A (KERIN) That is correct.

5 Q And -- and so, in -- in -- in meeting or exceeding
6 the applicable regulatory requirements, it would be
7 true that Progress managed its Robinson coal ash
8 pond to -- to maintain proper control of dust,
9 odors, litter, vectors, and fires or open burning?
10 That would be fair, wouldn't it?

11 A (KERIN) We managed that facility and that station
12 in compliance with the regulations.

13 Q And it would be -- and -- and in that regard, it
14 would be fair to say that the Company met or
15 exceeded the requirements that the -- that it
16 maintained the final 2-foot soil cover in place for
17 the coal ash pond; that's correct, isn't it?

18 A (KERIN) We have not closed that basin at the
19 Robinson Station.

20 Q Buy you wouldn't -- if -- if the Department of
21 Health and Environmental Control found that you
22 were -- that you were meeting or exceeding that
23 requirement, you wouldn't argue with DHEC, would
24 you, sir?

25 A (KERIN) I'm not sure I understand the question.

1 Can you clarify that for me?

2 Q Sure. You understand that in maintaining and
3 operating the coal ash pond at -- at Robinson, you
4 had to maintain a 2-foot soil cover in place on
5 that coal ash facility, correct?

6 A (KERIN) We have not closed that or capped that
7 facility yet.

8 Q So your -- your understanding is that you didn't
9 have to maintain the 2-foot soil cover in place
10 until -- until you closed the pond?

11 A (KERIN) Yeah. I'm not familiar with that specific
12 requirement on that issue.

13 Q Well, would you agree that -- that at all times up
14 to July of 2015, that the slopes of the pond -- the
15 top slopes and the side slopes were maintained in a
16 manner that met or exceeded regulatory
17 requirements?

18 A (KERIN) So you're -- you're talking about the dam
19 itself?

20 Q It's the entire structure or fill area, according
21 to the regulation. Yes, sir.

22 A (KERIN) The dam was maintained at the Robinson
23 Station in accordance with the requirements.

24 Q All right. And -- and it would be true, would it
25 not, sir, that the site was maintained and operated

1 in a manner to protect groundwater and surface
2 water quality at all times up to July of 2015;
3 isn't that true?
4 A (KERIN) Yeah. We maintained that facility in
5 accordance with the requirements.
6 Q All right. Now, sometime prior to July of 2015,
7 Progress employees negotiated a -- a settlement --
8 a consent agreement with DHEC concerning the
9 closure of that Robinson pond, didn't they?
10 A (KERIN) The Robinson facility, yes.
11 Q All right. And I think Mike Ruhe was responsible
12 in part for negotiating that consent agreement?
13 A (KERIN) Yeah. I was not part of those
14 negotiations. I know Mike Ruhe is a member of our
15 regulatory team. I'm not sure if he was involved
16 directly in that settlement.
17 Q All right. And you are aware, because it -- you
18 mention it in your testimony, that -- that Duke
19 Energy Progress and DHEC entered consent agreement
20 15-23-H -- HW, are you not?
21 A (KERIN) Yes. I am.
22 Q And as I understand your testimony, the Robinson
23 coal ash pond, and perhaps the Lee, but the
24 Robinson pond was not subject -- remediated subject
25 to the CCR rule or CAMA, but was rather a specific

1 South Carolina compliance obligation. That's your
2 testimony, isn't it?

3 A (KERIN) I think what you need to understand is
4 there's two facilities at the Robinson Station.
5 There is what we call the "lay of the land" area,
6 which is about 300,000 tons of ash. And that
7 happened prior to 1960, prior to the ash basin --
8 the active ash basin, or the basin at that station
9 being built. At that time, it was common practice
10 in the industry to take the ash -- this is in the
11 '40s and '50s -- from a facility and deposit them
12 in an area around the station that was to lay a
13 depression. So we did not build a dam. It was not
14 wet sluiced. It was ash that was staged or stored
15 at that location. So that's the "lay of the land"
16 area.

17 And then we have the Robinson ash basin, which
18 is also known as "the 1960 ash basin," that was
19 built late '50s, early '60s, and at that time we
20 started to send ash to that ash basin and ceased
21 sending ash to the -- what we consider the "lay of
22 the land" storage area.

23 Q Good. And thank you for that. And -- and both
24 those facilities met or exceeded DHEC's
25 requirements for those facilities; isn't that true?

1 A (KERIN) We operated those facilities in -- in
2 accordance with the requirements.

3 Q Now, I'm going to show you a copy -- my copy of
4 Consent Agreement 15-23-H -- HW. You may have a
5 copy that you prefer to read from, and I'll show --

6 MR. ERVIN: I've got a copy for counsel.

7 Q And I'd ask you, Mr. Kerin, if you recognize that
8 document.

9 A (KERIN) Yes. I do.

10 Q All right. And if it suits you to work from that
11 document, I'll put my copy on the screen. And at
12 first, I would draw the Commission's attention to
13 the label of the -- the document, and you tell me
14 if I'm reading this correctly, but it's in regards:
15 "Duke Energy Progress, Inc. HB Robinson Steam
16 Electric Plant, Darlington County." Have I read
17 that correctly?

18 A (KERIN) Yes. You have.

19 Q And it identifies the document as a "consent
20 agreement." Have I identified that correctly?

21 A (KERIN) That is correct.

22 Q And then we have the DHEC number assigned: "15-23-
23 H -- HW", correct?

24 A (KERIN) That is correct.

25 Q And this is the consent agreement by which Progress

1 -- and I call it "Progress" because it's easier for
2 me to remember "Progress" than "DEP" and "DEC" --
3 but by the consent agreement by which Progress
4 negotiated the closure of the Robinson coal ash
5 pond, correct?

6 A (KERIN) That is correct.

7 Q Now, I want to draw your attention, if I may, to
8 Page 2 of 12, please, sir. And beginning on Page
9 2, the "parties set out the findings of fact," am I
10 correct?

11 A (KERIN) That is correct.

12 Q Now, isn't it the case that there is no finding of
13 a violation of your permit with regard to the
14 regulation of the Robinson coal ash pond in this
15 consent agreement?

16 A (KERIN) Yeah. I'd have to review the entire
17 consent agreement again, but I do not believe there
18 was a notice of violation.

19 Q And -- and that would stand to make sense, because,
20 as you've testified, Progress was at all times in
21 compliance with the rules and regulations by DHEC
22 and met or exceeded all of the standards, correct?

23 A (KERIN) Yes. We were in compliance with the
24 regulations at the time.

25 Q All right. So -- and it would be fair to say that

1 there was no fine levied against Progress in this
2 consent agreement; isn't that true?

3 A (KERIN) I believe that is correct.

4 Q Now, I want to draw your attention, if I may,
5 please, to Page 10 of 12, and I want to draw your
6 attention in particular to Paragraph 16 first, but
7 I'm going to try to get it to perhaps where the
8 Commission can read it.

9 MR. ELLIOTT: That's about the best I can do,
10 gentlemen and lady.

11 Q And it reads: "Upon Duke's successful completion
12 of the terms of this consent agreement, the -- the
13 Company will submit to the Department in writing a
14 -- Department, a written final report. The final
15 report shall contain all necessary documentation
16 supporting Duke Energy's remediation of the site
17 and successful and completion -- complete
18 compliance with the consent agreement. Once the
19 Department has approved the final report, the
20 Department will provide Duke with a -- Duke Energy
21 with a written approval of completion that
22 provides" -- and I highlight -- "covenant not to
23 sue Duke Energy for the response actions
24 specifically covered in this consent agreement
25 approved by the Department and completed in

1 accordance with the approved work plan reports."

2 Do you see that language?

3 A (KERIN) It's under Item 16, yes.

4 Q Yes, sir. All right. And so, "Notwithstanding

5 other -- any other provisions of this consent

6 agreement, including the covenant not to sue, the

7 Department reserves the right to require Duke

8 Energy to perform any additional work at the site

9 or reimburse the Department for additional work if

10 Duke Energy declines to undertake such work." And

11 indulge me. I'll stop there. Have I read that

12 correctly? You can read more, if you like.

13 A (KERIN) That's Item 17?

14 Q Well, I stopped -- I meant to read just through 16.

15 A (KERIN) Okay.

16 Q So 16 provides that when you complete your work

17 here, DHEC won't sue you, right? That's what a

18 "covenant not to sue" is, correct?

19 A (KERIN) Yeah. I'm not an attorney, but I -- the

20 document speaks for itself.

21 Q Yes, sir. All right. Now I want to draw your

22 attention to Paragraph 18. "In consideration for

23 the Department's covenant not to sue, Duke Energy

24 agrees not to assert any claims or causes of action

25 against the Department arising out of response

1 activities undertaken at this site or to seek any
2 other costs, damages, or attorney's fees from the
3 Department arising out of response activities
4 undertaken at the site except for those claims or
5 causes of action resulting from the intentional or
6 grossly negligent acts or omissions of the
7 Department. However, Duke Energy Reserves all
8 available defenses not inconsistent with this
9 consent agreement to any claims or causes of action
10 asserted against Duke Energy arising out of
11 response activities undertaken at the site by the
12 Department." Have I read that correctly?

13 A (KERIN) Yes. You have.

14 Q All right. And then lastly, Mr. Kerin, I want to
15 draw your attention to Paragraph 19, if you see
16 that. It begins: "Employees of the Department,"
17 do you see that language?

18 A (KERIN) Yes. I do.

19 Q "Employees of the Department, their respective
20 consultants and contractors will not be denied
21 access during normal business hours or at any time
22 work under this consent agreement is being
23 performed or during any environmental emergency or
24 imminent threat situation as determined by the
25 Department or as allowed by applicable law,"

1 correct?

2 A (KERIN) That is correct under Statement 19.

3 Q All right. So, under -- under this -- under your

4 consent agreement that -- that you have negotiated,

5 key terms are that the Department, DHEC, has -- has

6 agreed or covenanted not to sue you, correct?

7 Paragraph 16, correct?

8 A (KERIN) That's what the document states.

9 Q Yeah. And under Paragraph 18, "Duke, however,

10 retains certain defenses and -- and an opportunity

11 to sue DHEC for gross recklessness," correct?

12 A (KERIN) It would -- that's what the document

13 states.

14 Q And then last, "the consent agreement provides that

15 DHEC will have access to your site during the

16 remediation," correct?

17 A (KERIN) That is correct.

18 MR. GUILD: Okay. I have no further

19 questions, Mr. Chairman.

20 CHAIRMAN RANDALL: Thank you. Nucor.

21 MR. SMITH: No questions.

22 CHAIRMAN RANDALL: Thank you, Mr. Smith. ORS.

23 MR. BATEMAN: No questions, Mr. Chairman.

24 CHAIRMAN RANDALL: Thank you. Commissioners,

25 questions? Commissioner Belser.

1	EXAMINATION
2	BY COMMISSIONER BELSER:
3	Q Good morning. How are y'all?
4	A (WRIGHT) Good morning.
5	A (KERIN) Good.
6	Q Mr. Kerin, I was reading or following you in your
7	summary, and in the first paragraph -- do you have
8	it?
9	A (KERIN) I have it. Yes.
10	Q Thank you. There's a sentence -- it's the second
11	sentence: "Duke Energy Progress's request does not
12	include any costs that -- have been incurred
13	related to fines, penalties, or guilty pleas." So
14	I would say -- I read that to say y'all are not
15	asking recovery of any fines or penalties; is that
16	a fair characterization of that statement?
17	A (KERIN) That is correct.
18	Q Okay. "Or any cost associated with events related
19	to those fines, penalties, or guilty pleas." Could
20	you explain that statement to me?
21	A (KERIN) Well, in that context, that would be the
22	cleanup of the event following Dan River: the
23	remediation costs that were involved in the work we
24	did with the river -- on the river.
25	Q Would any cost associated with events related in

1 those fines, penalties, or guilty pleas also
2 include legal expenses -- legal costs?
3 A (KERIN) Yeah. I can't speak to the legal costs.
4 Mr. Wright may be able to, but --
5 Q I'm just --
6 A (KERIN) -- I wouldn't believe they'd be in there.
7 Q -- I'm trying to understand your sentence.
8 A (KERIN) Yeah. My understanding is they would not
9 be in there for those cases where we pled guilty or
10 there were violations.
11 Q Any costs?
12 A (KERIN) Any cost.
13 Q The word is "any" costs.
14 A (KERIN) That's correct. "Any" costs.
15 Q Legal expense is cost?
16 A (KERIN) Yes. They are.
17 Q Thank you. I'm not trying to play "gotcha"; I'm
18 just trying to see where we are.
19 A (KERIN) I understand.
20 Q Dr. Wright, how are you this morning?
21 A (WRIGHT) Good morning.
22 Q I was looking and following along on your summary,
23 and on Page 4, at the top of your summary?
24 A (WRIGHT) Yes, ma'am.
25 Q I believe this is discussing your responding to ORS

1 witness Hamm, and you state, "and one category does
2 not relate to environmental violations at all and
3 the other category relates to ongoing litigation
4 that the Company is reasonably defending where
5 there are no finding -- where there has been no
6 finding of environmental violations." So, if it's
7 defending, but there has been no finding, does that
8 mean the case is concluded or not?

9 A (WRIGHT) The ones that Mr. Wittliff has in his
10 testimony, in his Exhibits 5 to 5.4, those cases
11 have been concluded. And in those cases, the State
12 actions that are part of the litigation expenses
13 that I understand that ORS is trying to disallow,
14 in those State actions, the Company was not found
15 guilty and there were no violations in any of those
16 findings.

17 So if you were to go to Mr. -- if you go to
18 Mr. Wittliff's testimony and go through those
19 exhibits, there's some that relate to Dan River and
20 then some that relate to other cases. And those
21 other cases were actually brought before CAMA.
22 They were brought by other parties. It wasn't the
23 State that was bringing those cases. But there
24 were settlements related to those cases, and in
25 those settlements there was no admission of guilt

1 or -- or no violations cited.

2 Q In -- in instances where a case is brought and the
3 Company has to defend itself, I understand that
4 they have to defend itself, but where -- but where
5 there is either a guilty plea or a finding of
6 violation of environmental law -- you were on the
7 Commission in North Carolina; is that correct?

8 A (WRIGHT) Yes, ma'am.

9 Q Would y'all have allowed legal expenses associated
10 where there was a violation?

11 A (WRIGHT) Well, I -- I don't recall, but I will say
12 that in my discussions with the Company, they have
13 said that in a situation where they have been found
14 guilty and the litigation is concluded, that, you
15 know, that -- that they would not seek recovery of
16 those types of costs. But in -- in the case that
17 we have here, the Company -- you know, they were
18 not found guilty, and there were no admissions of
19 guilt. The other litigation matter also was
20 related to the insurance claims. So that's the one
21 that's -- that I'm talking about that -- that
22 there's -- there -- there's no finding of
23 environmental -- well, does not relate to
24 environmental violations at all.

25 Q Thank you. I appreciate that.

1 And Mr. Kerin, I do have one other thing for
2 you. Were you involved with the -- with the
3 consent order with DHEC -- that was entered with
4 DHEC?

5 A (KERIN) With regards to Robinson?

6 Q Well, just in regard with cleanup -- with the
7 cleanup of the coal ponds.

8 A (KERIN) Yeah. I'm familiar with the one, but I
9 was not directly involved in those settlement
10 agreements.

11 Q Okay. My question is: That -- that -- those --
12 that consent agreement came about after CAMA was
13 passed, is it not -- did it not?

14 A (KERIN) Yeah. I think that was 2015 --

15 Q Okay.

16 A (KERIN) -- that we signed it.

17 Q Do you -- do you know who initiated discussions
18 with DHEC to enter into the consent agreement?

19 A (KERIN) I -- I don't know which party started that
20 conversation, but we were having conversations with
21 all of our regulators in that 2014 time frame.
22 They had questions about our operations, and we
23 were responding to those.

24 Q Okay. Thank you very much.

25 A (KERIN) You're welcome.

1 A (WRIGHT) And let me make sure I'm -- I'm perfectly
2 clear. On the litigation expenses, if there's an
3 appeal, then that case is not concluded. So, I
4 mean, you have to go to conclusion.

5 Q I agree with you on that.

6 A (WRIGHT) Okay.

7 Q Thank you. Thank you for clarifying.

8 A (WRIGHT) Thank you.

9 Q You're welcome

10 CHAIRMAN RANDALL: Commission Hamilton.

11 COMMISSIONER HAMILTON: Thank you, Mr.

12 Chairman.

13 EXAMINATION

14 BY COMMISSIONER HAMILTON:

15 Q Dr. Wright, this is for you, sir. On Page 12 of
16 your prefiled direct testimony, you referred to
17 order in Docket 2016 --

18 CHAIRMAN RANDALL: Get -- get in front of that
19 microphone, Commissioner. We can't hear you.

20 COMMISSIONER HAMILTON: We keep trying. We'll
21 get it right one day.

22 CHAIRMAN RANDALL: Getting better. All right.
23 Thank you, sir.

24 THE EXAMINATION BY COMMISSIONER HAMILTON CONTINUES.

25 Q And let's get back to Mr. -- Dr. Wright. On Docket

1 2016-227-E, and in this order -- this order the
2 Commission approved the coal ash removal over a 15-
3 year period. Now, I'm not going to question
4 whether this was a precedent or not, but what drove
5 the Company to change from the 5-year that we --
6 from the 15-year we had approved to recover the
7 costs to the 5-year?

8 A (WRIGHT) I'm not sure what -- what was the driver
9 of that, because I wasn't involved in those
10 accounting issues. But usually, what you're trying
11 to do is recover the costs as quickly as possible
12 so that you can save money for consumers, because
13 if -- the longer you -- you recover costs, you're
14 having a return on those costs, and so if you
15 recover them quicker, usually you can actually wind
16 up saving a little bit of money.

17 Q Okay. You can save it over the short term, but the
18 long term, it would -- the ratepayers would not be
19 paying as much and . . .

20 A (WRIGHT) Well, the ratepayers actually may wind up
21 paying more if you have a lot of carrying costs.

22 Q Okay. So there are two sides to the issue.

23 A (WRIGHT) There's -- yes, sir.

24 Q And that -- we -- again, we're not going to
25 question the precedent.

23 Now, if you look at what has happened around
24 the Southeast: In Virginia, they just recently
25 adopted legislation, and the -- they had actually

1 adopted the federal CCR, but the legislation they
2 adopted went beyond the federal CCR and required
3 excavation of all the Chesapeake Bay area coal-
4 fired facilities -- all of those -- all of those
5 CCR containment facilities.

6 If you look at what's happening in Tennessee,
7 the Department of Environmental Quality in
8 Tennessee adopted the federal CCR, but then went
9 beyond that and said, "We are going to also apply
10 our rules to inactive compounds, and we're going to
11 allow the Department of Environmental Quality in
12 Tennessee, if they do not agree with the -- with
13 the plans that TVA primarily submits to us, then we
14 may require additional remediation."

15 In Georgia, a similar thing happened. They
16 adopted the federal CCR, but then they went beyond
17 that. And Georgia has just recently -- they
18 started off by requiring, not only the CCR, but --
19 applying it to inactive sites -- but they required
20 Georgia Power to excavate 17 of 29 sites. Now
21 they've actually added two more sites, and those
22 two more sites are very large. Those two sites
23 being excavated at Georgia Power are the same
24 tonnage, basically around 29 million tons, as all
25 of the sites that VEPCO is excavating. So they're

1 very large sites.

2 Florida has already adopted various policies
3 on this. But Tampa Electric Company just decided
4 to excavate a site, which goes beyond the CCR, and
5 the department down there approved it.

6 In Alabama, I talked to the folks in Alabama,
7 and they said they are going to adopt the federal
8 CCR, but they are also going to have the leverage
9 to adopt something beyond that.

10 So when I looked at what all those other
11 states were doing. I said, "Well, chances are,
12 North Carolina would have maybe done something."

13 Plus, if you look at South Carolina, it's
14 interesting. I saw a newspaper article about this,
15 and it said that South Carolina was leading the
16 Southeast, because your preference, shown by the
17 settlements, is to go with -- with the excavation
18 of all of these sites.

19 So I thought, "Well, there's a really good
20 chance that -- and having served in the General
21 Assembly -- that the General Assembly in North
22 Carolina wouldn't have just sat back -- or the
23 Department of Environmental Quality people of North
24 Carolina -- wouldn't have just sat back and waited
25 and not done anything when all these other states

1 were doing something; that they would've probably
2 moved forward and done something."

3 And there's -- there's a final thing you have
4 to realize. North Carolina has always sort of been
5 out there and done stuff related to the
6 environment, sometimes before other states,
7 sometimes after, but it's not unusual.

8 When I was in the General Assembly, we had a
9 CAMA Act that went well beyond anything to do with
10 the -- what other states have. But it was the
11 "Coastal Area Management Act," and it related to
12 the beaches of North Carolina.

13 While I was in the General Assembly, we
14 adopted a -- an act that was related to the
15 mountains in North Carolina, because someone had
16 built a big huge condo at the top of the mountain
17 in Boone County, or in the ski district, up there
18 in Boone or wherever it was, and they said, "Wait.
19 We don't want this type of development on the top
20 of these mountains," because it was, you know, ten-
21 story, big huge condo. So we adopted something to
22 protect the skylines. I think it was called the
23 "Skyline Act." We also had the "Clean Smokestack
24 Act" in North Carolina.

25 So North Carolina has shown that it will move

1 forward and adopt policies like the current CAMA.
2 And so with that, I said, "Well, I don't think
3 North Carolina would have done nothing when all the
4 states around us were doing something." Plus,
5 given the historical basis that I had with what
6 North Carolina had done with the environment, I
7 just -- I just would conclude that they would've
8 adopted something. It may have been through the
9 legislature or just through the environmental
10 people, but they would've adopted something related
11 to policies specific to North Carolina. And I
12 think it would've been the federal CCR plus. It
13 would not have just been, you know, just the
14 federal CCR.

15 Q Thank you, Dr. Wright. To follow up on your --
16 your comments, do you believe Dan River had any
17 impact on any legislation coming -- or -- or policy
18 -- legislation policy changes of opinion coming out
19 of North Carolina?

20 A (WRIGHT) As I stated, in North Carolina, I'm sure
21 it impacted the timing. If you're in the General
22 Assembly and something like the accident at Dan
23 River happens, you're going to move forward. But
24 realize that in 2010, the EPA had already started
25 studying this issue. The TVA accident happened in

1 2008. So there was already something going on at
2 the federal level.

3 When you start introducing a bill like CAMA,
4 you had the accident at Dan River, you look and
5 make -- see what other states or what the federal
6 government is doing. So I'm sure that the
7 policymakers in -- in North Carolina saw what was
8 going on at the federal level and they started
9 looking at what policies they should adopt specific
10 to the State of North Carolina.

11 As to whether CAMA -- I mean, whether Dan
12 River changed CAMA or not, it's hard for anybody to
13 say. Like I said, I know it affected the timing
14 probably. But I -- I'm not sure that -- that you
15 would've seen anything much different.

16 And I'll -- and that's also buttressed by my
17 having lived in North Carolina and served in the
18 General Assembly. The people in the mountains of
19 North Carolina and Asheville are very protective of
20 the environment. The people on the coast are very
21 protective. The people around these rivers,
22 whether it's the Dan River or these other rivers,
23 they're very protective. And I can see where the
24 legislators in North Carolina would have had a lot
25 of input into any of these coal ash ponds near some

1 of these very scenic rivers and said, "Wait a
2 minute. We need to do something specific to this."

3 So I think Dan River certainly affected the
4 timing. I'm not sure how much it affected what
5 would have been different.

6 And, finally, I would just say: If you look
7 at what's going on around the Southeast right now,
8 everybody is moving towards excavation. You know,
9 there's -- there's a big move in all the
10 surrounding states to excavate all of these ponds.
11 So CAMA actually was less restrictive than that.

12 Q Thank you, Dr. Wright.

13 Moving to you, Mr. Kerin. On Page 9 of your
14 prefiled testimony, it discloses that "fines or
15 penalties incurred by Progress related to ash basin
16 closure or management are excluded from rates."
17 Are coal ash remediation costs related to
18 violations of the Clean Water Act or other state or
19 federal penalties included in rates?

20 A (KERIN) Yeah. The remediation we're doing at the
21 various sites is in accordance with the
22 regulations, not tied to violations or guilty
23 pleas, if that answers that.

24 Q I'm sorry. Could you -- could you say that again?

25 A (KERIN) Yeah. Can you -- you said Page 9?

1 Q Yes. Of your prefiled testimony.

2 A (KERIN) Yeah. Do you know, what -- what column
3 number or that line number? I want to make sure --

4 Q I do not have the line number.

5 A (KERIN) Okay. If you can -- I'm sorry. You can
6 ask me that again. I want to make sure I'm clear.

7 Q Are coal ash remediation costs related to
8 violations of the Clean Water Act or other state or
9 federal penalties included in rates?

10 A (KERIN) Yeah. If it was a -- like the Clean Water
11 Act, it was the plea agreement where there were
12 violations, the nine misdemeanors, across the
13 Company, those would not be included in these
14 costs.

15 Q Okay. What about outside of that plea agreement --
16 any violation outside of that plea agreement?

17 A (KERIN) If they were -- as I explained earlier --
18 violations that were -- or guilty pleas to
19 violations, they were excluded from these costs.

20 Q On Page 37 of your prefiled direct testimony, you
21 state that "Progress historically -- historical
22 handling of CCRs was reasonable, prudent, and
23 consistent with industry standards over time."

24 How does this square with the Dan River spill,
25 particularly if Witness O'Donnell's assertion of

1 the Company rejecting calls for video equipment to
2 scope the pipe is true?

3 A (KERIN) Yeah. I look at the overall time frame of
4 how long we operated these facilities, from the
5 '20s through today. So that's -- the Dan River
6 event, in my mind, was one fraction of time that we
7 overall managed these facilities. That was also
8 discussed in the North Carolina case where it
9 talked about -- the order talked about the Dan
10 River again. Those issues were a fraction of time
11 overall -- the overall almost a hundred years of
12 operating these facilities. So I feel we were in
13 operation -- we were maintaining those basins in
14 accordance with industry standards and in
15 compliance with the requirements when you look at
16 the overall timeline.

17 Q So is your testimony that even if Dan River
18 could've been completed or -- strike that.

19 Even if Dan River could've been prevented,
20 Progress Energy's -- Duke Progress Energy -- or
21 Duke Energy Progress, excuse me, their historical
22 handling of CCRs was still reasonable, prudent, and
23 consistent with industry standards?

24 A (KERIN) Yes. I -- I confirm that.

25 Q Thank you.

1 CHAIRMAN RANDALL: Commissioner Whitfield.

2 COMMISSIONER WHITFIELD: Thank you, Mr.

3 Chairman.

4 EXAMINATION

5 BY COMMISSIONER WHITFIELD:

6 Q Mr. Kerin, I guess for you first, just a point of
7 question here. Commissioner Williams just asked
8 you if the Company proposed to collect from
9 customers any noncompliance penalties, and I think
10 you just answered that. But to add onto his
11 question a little bit, does that also apply to any
12 associated attorney's fees due to the handling of
13 CCRs?

14 A (KERIN) Yeah. If it was a violation or a guilty
15 plea, those fees would not -- would be excluded
16 from the case.

17 Q Okay. Thank you.

18 Dr. Wright, a couple for you. On Pages 12 and
19 13 of your direct testimony -- I'll give you a
20 second to get there.

21 A (WRIGHT) Yes, sir. I'm there.

22 Q I'm on the bottom of 12, and you know, the top of
23 13. You -- you discuss the sharing of Duke Energy
24 Progress's environmental expenses and, if you
25 could, describe maybe in general how this

1 allocation is made. I know you go on to talk about
2 taxes being a little different on certain assets
3 and certain things. But, if you could, describe
4 this sharing or allocation, if you will.

5 A (WRIGHT) Well, generally speaking, when you're
6 looking at the allocation of costs, you -- the
7 first question you ask is, "Who benefits from these
8 costs?" And, obviously, if it's dealing with
9 electric power that is generated, whether it's
10 generated in North or South Carolina, it's supplied
11 to all the customers in the system. So those
12 costs, as they pertain to -- particularly
13 transmission generation are generally allocated and
14 usually, I believe, they're allocated based on the
15 energy cells. So environmental costs often --
16 especially something like reagents, are dependent
17 upon how many kilowatt-hours are sold. So that's
18 the -- that sort of designates how many tons of
19 coal you might burn or other fuels like that. So
20 that's how that -- that is allocated, usually.

21 I -- I would assume the other costs like taxes
22 and workers -- employees, all those benefits, I
23 assume those are generally allocated on energy,
24 too, but an accounting witness may tell you if they
25 allocate differently.

1 Q Yes. I -- I was also referring to those other
2 costs, other than -- other than environmental. I
3 mean, for instance, you talk about the rail --

4 A (WRIGHT) Yeah. The fuel and stuff like that.

5 Q -- being -- being cheaper with North Carolina being
6 closer to the mines.

7 Similarly, you -- you talk about DE Progress
8 receiving a revenue stream from reuse of coal ash
9 byproducts, and I think this came out earlier in
10 this case. That number was certainly much higher
11 than -- than I had -- had thought before, I think
12 it was closer to 90 percent -- high 80s -- 87
13 percent. Similarly, with that much being for reuse
14 -- similarly, are those revenue streams -- can you
15 discuss how they're allocated back among the
16 ratepayers of South Carolina and North Carolina?

17 A (WRIGHT) I'm not exactly sure how they would be
18 allocated. I'm not sure if Mr. Kerin knows,
19 because the accountants would do that. But it --
20 it may be based on energy, too. I'm just not sure.
21 Do you know, Jon?

22 Q Mr. Kerin.

23 A (KERIN) Yeah. I'm not sure how those -- how the
24 accounting takes place on that.

25 Q Is there another witness, maybe, that can address

1 that --

2 A (KERIN) Yeah. I would --

3 Q -- that we have left on the sheet?

4 A (KERIN) Bateman. I think Witness Bateman can

5 handle that.

6 Q Okay. I don't -- I think she was -- well, maybe

7 not now. But --

8 A (WRIGHT) If it helps, I -- I guess I could see if

9 we can volunteer a late-filed exhibit or something?

10 Q That -- that would be good.

11 A (WRIGHT) That -- would that suffice?

12 COMMISSIONER WHITFIELD: Would that, Mr.

13 Chairman?

14 CHAIRMAN RANDALL: Okay. We'll do that as

15 Late-Filed Exhibit Number 41.

16 COMMISSIONER WHITFIELD: Okay. Thank you.

17 Q And, Dr. Wright, I had one more question for you,

18 but, in talking with Chairman Randall, I think he's

19 going to ask it of you, so I'm done.

20 COMMISSIONER WHITFIELD: Thank you, Mr.

21 Chairman.

22 CHAIRMAN RANDALL: Thank you, Commissioner

23 Whitfield. Commissioner Howard.

24 EXAMINATION

25 BY COMMISSIONER HOWARD:

1 Q Dr. Wright, Mr. Kerin, good morning.

2 A (WRIGHT) Good morning.

3 Q Dr. Wright, ORS witness Zachary Payne recommended
4 that the deferral balance was being divided into
5 capital-related costs and operating-related costs.
6 With that in mind, are you recommending deferred
7 operating costs be charged to capital charging
8 costs -- related costs?

9 A (WRIGHT) Well, there's a cost of capital
10 associated with the dollars that were spent and
11 whether you charge them off as a capital or
12 operating cost, you -- you had to borrow the money
13 to pay those costs and then defer recovery of those
14 costs.

15 Now, generally speaking, what -- what happens
16 in a business and in regulation, if you have an
17 operating expense, you recover that on an ongoing
18 basis. Because we haven't recovered it on an
19 ongoing basis, there is a cost of capital. I mean,
20 you're -- you're deferring the recovery; you had to
21 provide the cash; the Company had to get the cash
22 somewhere; and there's a cost for money. So,
23 obviously, that's -- that's got to be recovered.
24 Otherwise, the Company will be underrecovered.

25 Q Okay. And I'm not saying that I -- I guess I don't

1 understand why the operating costs were carried
2 out. Why it wasn't part of the -- I guess I'm
3 questioning your answer to Witness Payne's dividing
4 it into two parts.

5 A (WRIGHT) Well, let me see if I can explain it this
6 way. Let's -- with -- with the operating cost and
7 the capital cost, generally speaking, a company
8 will recover their operating cost
9 contemporaneously.

10 And, actually, there will be some sort of
11 carrying charge often associated with that, based
12 on how much capital the company needs to operate
13 over a certain period of time. In this particular
14 case, by trying to designate this as an operating
15 cost and then three years down the road you put it
16 into deferred account, and now you're going to try
17 to recover it, but you don't get to recover a
18 return, well, it costs money to -- to borrow that
19 capital. So if you don't get the money that it
20 costs, then you're actually not allowed a chance to
21 recover what your true costs were. And that's a
22 violation of the Regulatory Compact. I mean, to me
23 it's pretty clear. If you -- if you're not allowed
24 to recover a return, then you're certainly not
25 allowed to -- an opportunity to recover your costs.

1 Q I'm with you now. Thank you.

2 Mr. Kerin.

3 A (KERIN) Yes, sir.

4 Q Give a timeline, if you don't mind, just for my
5 education, and I'll let you pick the starting date,
6 but how many ash pond breaches have there been in
7 some period of time and you pick that period of
8 time?

9 A (KERIN) Let's -- well, I'll go back to maybe year
10 2000 forward.

11 Q That's the year I came on the Commission, so I
12 wouldn't be responsible for anything before that.
13 That's a good term.

14 A (KERIN) So these -- I'm looking at industry-wide
15 events -- some of the significant industry-wide
16 events. Of course, there was TVA in December; I
17 think it was the 22nd of 2008. Also, in about the
18 20 -- 2005/2006 time frame, there was a significant
19 release on the Delaware River between Pennsylvania
20 and New Jersey, where a -- retainer gates failed
21 and released a significant amount of ash and water,
22 probably -- it's been identified as the second
23 largest release of ash into a river. It happened
24 in Delaware. And there was a Wisconsin event,
25 also, where they had a failure of an embankment.

1 And those are probably over about the last 15 or so
2 years.

3 Q Well, it might -- you answered my next question.
4 My next question is: What caused these particular
5 breaches at -- leading up to the Dan River breach?

6 Are there any inspections in place or how do
7 you inspect to see that a dam is -- has a potential
8 breach coming up, and how do you prevent it?

9 A (KERIN) The way we look at that is: We have
10 trained engineers -- professional engineers --
11 assigned to each of the basins. So, per the CCR
12 rule as well as CAMA, on a weekly basis, those
13 engineers do a detailed inspection of that basin.
14 They look at the complete walk-down of that basin.
15 They look at the activities of that basis. So that
16 gives us a weekly check from a professional
17 engineer that -- that looks at that basin.

18 We also do a very detailed annual, with a
19 third party that comes in and does an independent
20 inspection of those facilities. As part of the CCR
21 rule, and as part of what we did as -- with ABSAT
22 in 2014, we did a very detailed engineering
23 analysis of every one of our basins. It was
24 basically a reverse engineering reconfiguration.
25 We did core borings. We determined how that basin

1 was originally built, and we looked at any of the
2 factors of safety that could be impacted to that
3 basin. For instance, if it's applicable to a
4 seismic event, if the underlying soils of that
5 basin were acceptable to liquefaction -- and we see
6 that a lot -- a lot of times along the riverways,
7 that sandy soil along the river. You -- you build
8 a dam adjacent to those sandy soils, they can be
9 susceptible. We call it "liquefaction." Within an
10 earthquake-type event, it starts to shake and those
11 soils can liquefy. So we did a very detailed
12 analysis through core borings across our dams, if
13 we had any susceptibility to liquefaction at those
14 dams.

15 So we did this very detailed engineering
16 analysis, which has to be done every five years per
17 the CCR rule. We have the annual independent
18 engineer's analysis. We had the state regulators
19 come out at least annually to do their inspection
20 of the dams, and then we do our weekly inspection
21 with our civil engineers.

22 Q Well, let's talk about Dan River. There's some
23 confusion in mind as to whether the management of
24 Duke knew that the pipe was there. Did y'all know
25 the pipe was there?

1 A (KERIN) Yeah. That pipe -- well, there's two
2 actual pipes in that basin. There was a -- a
3 corrugated metal pipe, and then there was a
4 concrete reinforced pipe, both surface -- or
5 stormwater drains. So they -- we knew those pipes
6 were there. And in the early inspections, the
7 recommendations were to inspect the outfall of
8 those pipes for any turbidity. Was the water
9 clear? If you start to see any soil or anything
10 being carried in that water, that would be an
11 indication that you had a leak in that pipe from
12 the ash basin. So we were doing those inspections
13 from a turbidity standpoint.

14 Q Well, Commissioner Williams mentioned the cameras,
15 and apparently according -- I -- I -- apparently,
16 according to the witness that the Duke engineers
17 requested the money to do the video camera -- to
18 buy the camera, and they were denied by management.
19 Can you comment on that?

20 A (KERIN) I know in the plea agreement in the
21 statement of facts, there was a request -- it was
22 before my time -- in the -- and from one of the
23 engineers to do a video inspection of that pipe to
24 see if there was any degradation going on in that
25 pipe. I am familiar that there were e-mails and

1 that that was denied.

2 Q Well, do you feel like that the demitted

3 requirement was sufficient in determining whether

4 there was a leak in the pipe?

5 A (KERIN) Typically, that's a standard practice,

6 both with whether it's a pipe or a seep. What you

7 look for: Is there any material -- is it clear

8 water or are there any particles being transferred

9 through that water? And we do that when we have a

10 seep, we look at that. When we look at that -- all

11 of our pipes, we look at that to see. It's a

12 common practice if you're having any material

13 that's being passed along with that water.

14 Q Hindsight is wonderful, but in hindsight, would you

15 have ordered the cameras?

16 A (KERIN) You know, I can't put myself in the place

17 of the management team but --

18 Q Yeah. Go ahead. Take a chance.

19 A (KERIN) Knowing what I know today --

20 Q Yes.

21 A (KERIN) -- and it probably would have been yes,

22 but that's knowing what I know today.

23 Q Well, that's -- that's hindsight. Thank you very

24 much.

25 Thank you both very much. I enjoyed your

1 testimony.

2 COMMISSIONER HAMILTON: Thank you, Mr.

3 Chairman.

4 CHAIRMAN RANDALL: Thank you. Commissioners?

5 Commissioner Ervin.

6 EXAMINATION

7 BY COMMISSIONER ERVIN:

8 Q Mr. Kerin, is Duke or Duke Energy Progress
9 currently or anticipating in the future to be in
10 litigation for any other Clean Water Act violations
11 related to CCR costs?

12 A (KERIN) Yeah. Not that I'm aware of.

13 Q Is there anyone else in the Company who would --
14 would know definitively?

15 A (KERIN) My understanding is, we don't have any
16 pending violations of the Clean Water Act.

17 Q All right, sir. Did you also -- or do you test the
18 groundwater to see if there's contamination
19 underneath the -- the coal ash?

20 A (KERIN) Yeah. There's -- there's two -- it's
21 groundwater monitoring that we do. It's -- the CCR
22 rule has requirements for groundwater monitoring
23 and so does CAMA, and that information is needed as
24 we prepare our closure plans and determine our
25 corrective action plan with groundwater.

1 The slight difference in those is: The CCR
2 rule has you test for groundwater at the waste
3 boundary or at the dam of the -- of the basin,
4 where the CAMA CCR or CAMA rules in this state,
5 very similar to South Carolina, requires to test,
6 typically, at the compliance boundary or around
7 areas of the site just to ensure that we don't have
8 secondary sources, that it's not background, and we
9 understand exactly any impacts from the basin
10 itself.

11 Q So are those -- those tests that you described, are
12 they -- are they ongoing or -- or have they been
13 completed, or . . .

14 A (KERIN) The initial tests have been completed.
15 And with regard to the CCR rule, those are posted
16 on our -- what we call our "operating record" as
17 well as our external public website. Those results
18 were posted in January of this year. So all the
19 results for all those basins -- all the detailed
20 analysis and the detailed -- if there's any
21 exceedances, are on that website today.

22 Q Just -- just to try to capture the big picture from
23 that data, how many sites have contaminated
24 groundwater?

25 A (KERIN) With regards to the CCR rule, my

1 understanding is the only site -- and I don't have
2 all the details in front of me, because they test
3 for a lot of constituents -- is the Mayo site did
4 not have any exceedances from our January
5 submittal. But our other sites did have
6 exceedances, various different constituents, from
7 our January submittal.

8 Q Would you be in compliance with CAMA if you put a
9 lined -- a lining and move the coal ash into a
10 lined basin on the same property?

11 A (KERIN) If we were to construct a new lined
12 facility for -- as an ash basin, but we're going
13 through the process of stopping all flows, going to
14 -- that the operating plans, we will go into dry
15 ash handling. That will be landfill into a
16 permanent landfill, but we would not open up a new
17 ash basin. In fact, I think our last ash basin
18 that we opened was in 1985.

19 Q So I -- I misspoke. I was thinking of landfill,
20 rather than transporting it out. Is -- is that an
21 option that you -- you can consider under the
22 regulations?

23 A (KERIN) We have landfills and we've been operating
24 landfills.

25 Q Yes, sir. I'm talking about lined landfills.

1 A (KERIN) All of our -- our landfills are lined.

2 Q Are all lined?

3 A (KERIN) Any new constructed landfill will be lined

4 and permitted per the State.

5 Q All right, sir. Thank you, sir.

6 Dr. Wright, how did the North Carolina

7 Commission come up with the \$30 million fine? Do

8 you know how they arrived at that?

9 A (WRIGHT) I don't know how they arrived at it. I

10 do know it was a fine related to the allowed

11 return. It was about 13 percent of -- of the

12 allowed return over a five-year period. So they --

13 they did not find any of the costs were imprudent

14 or unreasonable, but they said because of the

15 Company's admitted guilt in the Dan River incident,

16 that they should, you know, levy a fine. How they

17 came up with the -- you know, the 13 percent of the

18 allowed return, I don't know.

19 Q Thank you, sir.

20 COMMISSIONER ERVIN: Those are all the

21 questions I have.

22 CHAIRMAN RANDALL: Thank you.

23 EXAMINATION

24 BY CHAIRMAN RANDALL:

25 Q Just -- just a couple here.

1 Dr. Wright, and putting on -- and we've talked
2 Dan River a little bit and we've talked about the
3 fraction of time that the leak happened and, you
4 know, talking video rejection. With your regulator
5 hat on, if you were persuaded that negligence on
6 the part of Duke Energy led to the Dan River plant
7 leak, would you support the recovery of any of the
8 incremental costs due to CAMA from any ratepayers
9 in the state of South Carolina and North Carolina?

10 A (WRIGHT) Well, when I -- I had -- let me go back
11 and think about the -- what the North Carolina
12 Commission did and had I been on the Commission at
13 the time, ask myself the question, "Would I have
14 done that?"

15 I think the Company has already accepted
16 responsibility, and they -- they did pay a fine.
17 They were penalized for that, and they -- they
18 accepted all the cleanup costs. They aren't
19 charging any ratepayers that, and they accepted all
20 the other costs associated with the Dan River
21 spill.

22 But the North Carolina Commission -- and it's
23 on Page 204 of the recent DEP order -- they said,
24 "Further, the mismanagement to which DEP pled
25 guilty was only for a fraction of the time DEP

1 operated the impoundments. No evidence was
2 submitted that DEP's management was imprudent from
3 the initial date of operation."

4 When I read about the accident at Dan River, I
5 read all the accident reports -- I worked 12 years
6 in the chemical industry, and I worked at
7 Occidental Chemical Company and Corning Glass.
8 Things -- you have accidents happen. The Company
9 accepted their responsibility for their accident,
10 and they were penalized by the federal government.
11 I think to be penalized again by the North Carolina
12 Commission was a double penalty.

13 Now, let's back off from there and say, "Okay.
14 CAMA." No one in this case has said that CAMA is
15 an unreasonable law or unreasonable policy. So I
16 ask myself the question, "If you were in North
17 Carolina as a legislator or as a commissioner of --
18 on a utility commission, what would North Carolina
19 be doing today?"

20 And as I look around the Southeast, in
21 Virginia they're excavating all their sites. In
22 Tennessee, they're probably going to be excavating
23 all their sites, because there are lawsuits filed
24 right now. In Georgia, 17 of the 29 initial sites
25 were being excavated. Now an additional two are

1 being excavated, and those two are real large.
2 Florida has excavated all of -- well, actually,
3 they do beneficiation for most of theirs, but Tampa
4 Electric just said they're going to excavate one of
5 theirs that they don't have to excavate. They
6 could cap in place. And in South Carolina, you
7 have shown a preference. It's not an adopted
8 policy, but every -- every coal ash facility in the
9 state of South Carolina is being excavated.

10 So I ask myself the question, "Would North
11 Carolina have just sat there and done nothing or
12 would they have -- you know, would they have said,
13 'Okay. We've got to at least do what the CCR
14 requires'?" which is some potential cap-in-place
15 and some excavation, and -- and "Why is it right
16 for all these other states to have the excavation
17 at all of their sites, including South Carolina,
18 and yet North Carolina not be allowed the same type
19 of option for their -- for their citizens of their
20 state?"

21 So, I -- I just have to think that you have to
22 look around and ask yourself, "Well, is North
23 Carolina really different?"

24 South Carolina started the excavation in 2012,
25 and 2013 was SCE&G and Santee Cooper, long before

1 the CCR was passed, which was 2015. CAMA was
2 adopted in 2014. You know, in fact, the South
3 Carolina and SCE&G and Santee Cooper excavations
4 were before Dan River. So . . .

5 Q I understand. I understand all that, and that's a
6 little -- little past my -- my negligence question,
7 so let me -- let me ask you this, since we're
8 talking CAMA and CAMA -- sharing CAMA-related
9 costs, because other people have -- have been asked
10 this and . . .

11 On -- on 23 -- Page 23 of your prefiled direct
12 testimony, you state that "The costs related to
13 CAMA are in excess of CCR related costs, and they
14 are discussed by Witness Kerin." And on Page 30 of
15 Witness Kerin's prefiled direct testimony, he
16 suggested the issue is addressed in greater detail
17 in your testimony.

18 So that was a pretty good -- a pretty good
19 whip at that. But -- so let me just ask you this
20 question that other people have been asking, and
21 just to see what you say about it. And this is --
22 you can give this as a short explanation of why
23 Duke Energy Progress feels that the CAMA costs for
24 compliance in North Carolina should be borne by or
25 should be shared by the South Carolina customers?

1 A (WRIGHT) Okay. Let me answer part of the first
2 thing you said about us saying, you know, that he
3 did -- he did -- I can discuss CAMA and -- and the
4 costs at a very high level. But, in fact, what I
5 was referring to here on Page 23, Line 7, "Are
6 there any costs related to CAMA that are in excess
7 of the federal CCR rules?" Mr. Kerin can go plant
8 by plant and tell you if there are costs -- and
9 what, in my discussions with Mr. Kerin, he can --
10 he can follow up after I finish -- he said there's
11 not a whole lot of difference. When you start
12 doing the -- the actual analysis, the engineering
13 analysis as to, "Okay. How would we close this
14 under CCR?" he said there's -- there's not a whole
15 lot of difference. So let -- I'll let him go
16 through the plants and talk about that. That's
17 what I was referring to there.

18 Q Gotcha.

19 A (WRIGHT) Now, as far as the allocation of the
20 costs and -- and CAMA: The first thing you have to
21 do is ask, "Who benefits?" And I don't think
22 there's -- there's any question that the citizens
23 of the state of South Carolina have benefited from
24 the power produced by these coal ash facilities.
25 And, in fact, they started in 1920. So almost a

1 hundred years, almost a century. And those costs,
2 as I show in my -- my testimony -- my direct
3 testimony, have been a large part of why the state
4 of South Carolina has had electric rates below the
5 national average for many, many years. And you've
6 got low-cost reliable power, and it's helped
7 benefit every citizen in South Carolina with jobs,
8 with all sorts of benefits.

9 Now, when you ask yourself that, "Okay. Who
10 benefits?" The customers in both states. But at
11 the same time, as part of your obligation, when you
12 get to receive the benefits of this power, all the
13 citizens of North and South Carolina who receive
14 the low-cost power, all these customers, they also
15 have to pay for the life-cycle cost of a facility.
16 And part of that life cycle is the disposal of any
17 -- any byproduct or -- or any of these wastes, and
18 the disposal based on that -- on the current
19 standards. And, unfortunately, those standards
20 have changed.

21 Absent that, when -- then -- then, you know,
22 we -- we wouldn't be here, but that's -- that's --
23 that's what we're faced with today. So the Company
24 does not have a choice. They cannot pick and
25 choose which laws they -- they want to look at.

1 And, I think the third thing you have to ask
2 yourself, not only is CAMA reasonable -- nobody
3 said it's not -- "Who benefits?" All the
4 ratepayers. "Who should pay?" Anyone who -- and
5 "what should you pay?" All of the life-cycle
6 costs?

7 And then, finally, you have to ask, "What --
8 what happens if you don't share in these costs?"
9 And I think there are a lot of unintended
10 consequences if you don't share in these costs, and
11 I've discussed this in both my direct and -- and
12 rebuttal testimony. I think one of the -- one of
13 the unintended consequences is your cost of capital
14 is going to go up. The second consequence is North
15 Carolina may ask, "Well, doggone. If we're having
16 to pay all these costs, maybe we don't -- you know,
17 this sharing of these -- these facilities isn't a
18 good idea anymore." You know, so it's just a lot
19 of unintended consequences if we go down this road,
20 and I -- I don't think it's -- I just don't think
21 it's the right thing to do. Because, like I said,
22 the people who benefited were the citizens of both
23 states. And, unfortunately, the people who have to
24 pay for the life-cycle costs are also the citizens
25 of both states.

1 Q Thank you. Just one more question for Mr. Kerin.
2 And I'm going to -- we talked -- Witness
3 O'Donnell's Table 9. It's on Page 42. It
4 calculates the ratio of coal ash, asset retirement
5 obligations versus kWh as a coal generation, and
6 Progress's ratios -- and I think we've talked about
7 this before -- but Progress's ratios look much
8 higher than other electric utilities. What's the
9 -- tell us the reason for that.

10 A (KERIN) Yeah. And that's in regards to our
11 overall ARO at Progress. And what I stated in my
12 rebuttal, there have about 22 reasons that are
13 factors they get to take into consideration when
14 you're looking at ARO costs as to specific site.
15 Just by doing cost per megawatt, you've got to look
16 at the number of plants in that company's fleet.
17 You've got to look at the age of the plants and how
18 long those basins were operating. You've got to
19 look at -- did any of those sites utilize dry ash
20 handling early on, or when did they start dry ash
21 handling, the type of CCR basins in that fleet?

22 So those 22 factors, you really need to take
23 those into consideration before you can determine
24 if you're doing an apples-to-apples comparison.

25 And I will state that the majority of those

1 factors I state in my rebuttal testimony are
2 publicly available information. You can go to the
3 CCR or the EPA, CCR by-station website, or each
4 utility, and as I mentioned earlier, in our public
5 website. Each utility has to list all those
6 details on -- from a public website standpoint:
7 history of construction; number of basins; amount
8 of ash; acreage in those basins; how many
9 landfills; acreage in landfills. So you can go
10 through -- when you look at those different
11 stations, it's -- they're very unique, the
12 different companies will have.

13 So if you do that type of analysis and look at
14 those 22 factors I talked about, I think it will be
15 very clear, you just can't line them up and say,
16 "There's a lot more cost at Progress, so that must
17 -- they must be mismanaging or their costs are much
18 higher than the others." I think you've got to
19 look at all those 22 factors, and then you can draw
20 a conclusion on the individual cost and any
21 differences.

22 A (WRIGHT) May I add something real quick?

23 Q Sure.

24 A (WRIGHT) Because I think the other thing you have
25 to do is -- he took costs that are probably a year

1 or two old. For example, he said in Virginia, they
2 were going to spend \$624 million. The most recent
3 number for Virginia is 5.6 to over 8 billion,
4 because of the new law they passed. So that's some
5 ten to twelve times what he's estimated.

6 In Georgia, Georgia Power, he estimated the
7 cost at 1.42 billion. Right now, they're at 2
8 billion, which is a little bit higher, but that
9 doesn't include the last two sites that are as
10 large as all of Virginia's. So you add another 5
11 billion on top of that. Instead of being 1.4
12 billion, you're at 5 to 7 billion, 8 billion. I
13 mean, the costs are really, really different.

14 For Alabama Power, he said 324 million.
15 Alabama Power says right now -- and this is only if
16 they can cap in place some sites, it's 1.14
17 billion, some three times higher.

18 So you -- you've got to get the newest
19 numbers. And that's the problem. North Carolina
20 was ahead. South Carolina was ahead of everybody,
21 so the numbers just -- just aren't apples to apples
22 for that reason, too.

23 Q Thank you.

24 CHAIRMAN RANDALL: Okay. Any redirect?

25 MR. BURNETTE: No, sir.

1 CHAIRMAN RANDALL: Okay. Thank you. Okay.

2 Gentleman, thank you for your --

3 MR. ELLIOTT: Just briefly, Mr. Chairman. I
4 omitted to introduce DHEC Order 15-23-HW. The
5 witness vouched for it. I would like to move
6 it into as the next hearing exhibit.

7 CHAIRMAN RANDALL: We'll enter that as Exhibit
8 Number 42.

9 MR. ELLIOTT: Thank you, sir.

10 (WHEREUPON, Hearing Exhibit 42 was
11 marked and received in evidence.)

12 CHAIRMAN RANDALL: Okay. Anything else?

13 Gentleman, thank you for your testimony. You
14 may step down and be excused.

15 (Witnesses excused)

16 CHAIRMAN RANDALL: We're at the 12:37 time
17 frame, so we're going to break for lunch, and
18 we'll be back at 1:46.

19 (WHEREUPON, at 12:37 p.m. the proceedings
20 in the above-entitled matter were
21 adjourned, to reconvene on April 15,
22 2019, at 1:46 p.m.)

23 (WHEREUPON, Late-filed Hearing
24 Exhibit 41 shall be marked and
25 received in evidence upon receipt:

[Please note: The corrections noted herein reflect the testimony of the witness during the hearing in this matter.]

948-1

**BEFORE
THE PUBLIC SERVICE COMMISSION OF
SOUTH CAROLINA**

DOCKET NO. 2018-318-E

In the Matter of:	)	
	)	REVISED
Application of Duke Energy Progress,	)	REBUTTAL TESTIMONY OF
LLC for Authority to Adjust and Increase	)	ROBERT B. HEVERT FOR
Its Electric Rates and Charges	)	DUKE ENERGY PROGRESS, LLC

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REVISED REBUTTAL TESTIMONY OF ROBERT B. HEVERT
DUKE ENERGY PROGRESS, LLC

DOCKET NO. 2018-318-E

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1 allowed to recover the costs. As discussed below, Mr. Payne's recommendation is
2 counter to fundamental corporate finance principles.

3 **Q. MR. PAYNE ACCEPTS THE COMPANY'S PROPOSAL TO INCLUDE**
4 **CAPITAL-RELATED COSTS IN RATE BASE, BUT OPPOSES**
5 **OPERATING-RELATED COSTS BECAUSE IN HIS VIEW, IT WOULD**
6 **CAUSE THE COMPANY TO EARN A RETURN ON OPERATING**
7 **COSTS.¹⁶⁴ DO YOU AGREE WITH MR. PAYNE ON THAT POINT?**

8 **A.** No. The Company proposes to include operating-related deferred costs such as
9 operation and maintenance and property taxes in rate base to earn a fair return at
10 the Company's weighted-average cost of capital, which would only make it whole
11 on an economic basis. Because the expenditures required actual cash outflows, the
12 Company has incurred financing costs for these deferred costs. If it is not
13 authorized to include these costs in rate base and earn a return on them, the
14 Company will suffer a negative net present value, which would be borne by its
15 investors.

16 **Q. PLEASE EXPLAIN WHY THE COMPANY WILL INCUR A NET**
17 **PRESENT VALUE LOSS IF THE OPERATING-RELATED COSTS ARE**
18 **NOT INCLUDED IN RATE BASE.**

19 **A.** The Company's proposal to include operating-related regulatory assets in rate base

¹⁶⁴ Direct Testimony of Zachary J. Payne, at 12.

is analogous to corporate finance discounted cash flow valuation. Discounted cash flow valuation includes both the “return of” and “return on” to calculate the present value of an investment. The concepts of “return of” and “return on” can be seen in the methods used, for example, in valuing a bond. To derive the present value of a bond, the amortization, or “return of” principal, and the interest, or “return on”, both must be included to correctly calculate the value. Table 6, below, provides an illustrative example of that process for a hypothetical five-year bond valued at \$10 million.¹⁶⁵ Importantly, when interest is excluded from the calculation, there is a significant reduction in the present value (in this hypothetical case, 13.41 percent).

Table 6: Discounted Cash Flow Valuation of Hypothetical Bond¹⁶⁶

	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Total
Beginning Principal		\$10,000,000	\$8,000,000	\$6,000,000	\$4,000,000	\$2,000,000	
Amortization (5-Yr Straight-Line)		2,000,000	2,000,000	2,000,000	2,000,000	2,000,000	
Ending Principal	\$10,000,000	\$8,000,000	\$6,000,000	\$4,000,000	\$2,000,000	\$0	
Interest @ 5.00%		\$500,000	\$400,000	\$300,000	\$200,000	\$100,000	
Present Value of Amortization & Interest							
Amortization + Interest		\$2,500,000	\$2,400,000	\$2,300,000	\$2,200,000	\$2,100,000	
Discount Factor (1/(1+Interest) ^{Year})		0.95 x	0.91 x	0.86 x	0.82 x	0.78 x	
Present Value		\$2,380,952	\$2,176,871	\$1,986,826	\$1,809,945	\$1,645,405	\$10,000,000
Present Value of Amortization Only							
Amortization		\$2,000,000	\$2,000,000	\$2,000,000	\$2,000,000	\$2,000,000	
Discount Factor (1/(1+Interest) ^{Year})		0.95 x	0.91 x	0.86 x	0.82 x	0.78 x	
Present Value		\$1,904,762	\$1,814,059	\$1,727,675	\$1,645,405	\$1,567,052	\$8,658,953
Reduction in Present Value							-13.41%

¹⁶⁵ I have assumed straight-line amortization of 5-years, a coupon rate of 5.00 percent and year-end repayments.

¹⁶⁶ Please note that Equation [2], which provides the “intrinsic value” formula for common equity, is the same construct as that which is applied in Table 6.

1 This example illustrates the same concept as including operating-related costs in
2 rate base. The amortization, or “return of”, of the regulatory asset is not a
3 “sufficient level of cost recovery”, as Mr. Payne suggests. Rather, because the
4 Company has expended cash for these operating costs upfront, a carrying charge is
5 necessary to recover these expenditures at cost on a present value basis.

6 **Q. DO YOU AGREE WITH MR. PAYNE’S POSITION THAT INCLUDING**
7 **OPERATING-RELATED COSTS IN RATE BASE CAUSES THE**
8 **COMPANY TO EARN A RETURN ON THESE COSTS?**

9 A. No, I do not. Although the Company does accrue a carrying charge on those
10 deferred costs, carrying charges reflect the economic value required to avoid a loss
11 in present value. From a somewhat different (but related) perspective, the carrying
12 charge reflects the financing costs associated with the initial cash outlay. Absent
13 the carrying charge, the Company’s financial profile would be diminished.

14 **Q. MR. PAYNE ALSO CITES DEFERRED DEPRECIATION EXPENSE AS AN**
15 **OPERATING-RELATED COST THAT SHOULD NOT BE INCLUDED IN**
16 **RATE BASE.¹⁶⁷ DO YOU AGREE WITH MR. PAYNE’S POSITION?**

17 A. No, I view deferred depreciation expense as having financial implications
18 analogous to capital-related costs, in that both represent a cash outlay that must be
19 financed. Mr. Payne’s proposal to exclude depreciation-related regulatory assets

¹⁶⁷ Direct Testimony of Zachary J. Payne, at 11, 12, and 15.

1 from rate base prevents the Company from being able to earn a fair return on its
2 original capital costs that were deferred as a regulatory asset.

3 **Q. DO THE PRINCIPLES OF "RETURN OF" AND "RETURN ON"**
4 **DISCUSSED ABOVE APPLY TO DEFERRED DEPRECIATION**
5 **EXPENSE?**

6 **A.** Yes, they do. In Table 6 above, I illustrated how the amortization, or "return of",
7 and interest, or "return on", were both required to equate to the present value of a
8 bond. The same concepts apply to plant-related investments. If "depreciation" is
9 substituted for "amortization" and the "weighted average cost of capital" is
10 substituted for "interest" in Table 6, we arrive to the exact conclusion: Absent the
11 carrying charge component, the Company suffers a present value loss.

12 Similarly, I noted earlier that operation and maintenance expense, and
13 property taxes reflect actual cash outlays that financed by the Company. Deferred
14 depreciation expense is the same. The Company has incurred financing costs for
15 deferred depreciation expense, and without carrying charges would suffer a dilution
16 in value (that is, a negative net present value). The carrying charge simply offsets
17 those effects.

1 modification requests. Duke should be allowed to petition to open a separate docket
2 to consider the Company's proposal wherein this Commission may completely and
3 thoroughly examine the costs and benefits of grid updates as proposed by DEP.
4

5 **3. Coal Ash Costs**

6 **Q. MR. O'DONNELL, PLEASE EXPLAIN THE BACKGROUND THAT HAS**
7 **LED DEP TO REQUEST RECOVERY OF \$200 MILLION OF COAL ASH**
8 **COSTS IN THIS CASE.**

9 A. On February 2, 2014, DEC spilled a large amount of coal ash in the Dan River.
10 This spill made the national press. The Dan River spill will be cleaned up with
11 Duke stockholder funds. Information exposed in the Duke federal plea deal,
12 which is described below, revealed that on two separate occasions, Duke
13 engineers at the Dan River plant requested an immaterial amount of budget
14 funding to pay for video equipment to scope the pipe that later failed. Duke
15 engineers were denied the request.¹⁸
16

17 On September, 2014, in response to the Dan River spill, the North Carolina
18 Legislature passed the Coal Ash Management Act (CAMA) that required the
19 closure of existing coal ash ponds as well as conversion from wet ash to dry ash
20 handling. CAMA was the first such coal ash management law in the United States.
21 This initial legislation required basins at four Duke plants to be closed by 2019.
22

23 On December 19, 2014, the EPA issued the Coal Combustion Residual (CCR)
24 Order that provided minimum national criteria for CCR landfills, CCR surface
25 impoundments, and lateral expansion of coal-fired units. The CCR federal rule
26 was designated as "self-implementing," meaning that Duke was not under any
27 requirement to act UNLESS it is sued by a state or other entity and loses that
28 lawsuit.

¹⁸ United States District Court for Eastern District of North Carolina, Case Nos. 5:15-CR-62-H, 5:15-CR-67-G, 5:15-CR-68-H, ordering paragraphs 69-80

1 According to one of Duke Energy's top leaders, North Carolina's
2 2014 coal ash legislation didn't necessarily result from a company
3 ash spill in the Dan River.

4
5 Federal coal ash rules were already being drafted at the time, and
6 it's possible, Duke state President David Fountain testified
7 Monday during a rate increase hearing, that the North Carolina
8 General Assembly would have passed its law anyway.

9
10 Twice, Sierra Club attorney Matthew Quinn asked Fountain
11 whether the law was motivated, or partially motivated, by a spill
12 that turned parts of the river gray.

13
14 "I really can't admit that," Fountain replied.

15
16 State Rep. Pricey Harrison, D-Guilford, who saw her push for coal
17 ash regulations gain traction only after the spill, scoffed at this
18 Monday evening. When the bill passed in 2014, Senate negotiator
19 Tom Apodaca specifically said that, "When I saw the Dan River
20 thing, I said, 'We've got to do something.'" State Rep. Chuck
21 McGrady, R-Henderson, who negotiated the bill for the
22 House, told the Associated Press that, "unfortunately, sometimes
23 we wait until we have a really big problem before we address it."

24 "It makes sense for (Fountain) to say that, but he is flat wrong,"
25 Harrison said Monday. ²⁵

26 The importance of the above article should not go unnoticed by this Commission.
27 Two elected officials in North Carolina of opposing parties BOTH contradicted
28 the Duke executive.

29
30 **Q. DO YOU AGREE WITH DUKE'S POSITION THAT CONSUMERS**
31 **SHOULD PAY ALL THE COSTS OF CLEANUP?**

32 **A.** No. Duke management made specific decisions that resulted in the coal ash spill
33 in North Carolina that, in turn, led to the creation of the Coal Ash Management

²⁵ <http://www.wral.com/seeking-rate-increase-duke-energy-dodges-link-between-coal-ash-spill-and-coal-ash-bill/17145054/>

1 Act (CAMA). My analysis in North Carolina is that Duke stockholders should
2 pay 75%.

3
4 **Q. CAN YOU PUT DUKE'S COAL ASH COSTS INTO PERSPECTIVE**
5 **RELATIVE TO OTHER UTILITIES AROUND THE COUNTRY?**

6 **A.** Yes. Using data obtained from SNL Financial, I extracted AROs on the books of
7 utilities from across the country. I then ranked the utilities by AROs from largest
8 to smallest.

9
10 Table 7: Total AROs

Company Name	ARO 2017
Duke Energy Progress, LLC	\$ 4,673,454
Duke Energy Carolinas, LLC	\$ 3,609,220
Georgia Power Company	\$ 2,637,679
DTE Electric Company	\$ 2,124,863
Florida Power & Light Company	\$ 2,030,679
Alabama Power Company	\$ 1,583,682
Virginia Electric and Power Company	\$ 1,365,061
Indiana Michigan Power Company	\$ 1,321,774
Entergy Arkansas, LLC	\$ 981,213
Duke Energy Indiana, LLC	\$ 781,284
Duke Energy Florida, LLC	\$ 741,078
Arizona Public Service Company	\$ 670,719
Kansas Gas and Electric Company	\$ 343,408
Kansas City Power & Light Company	\$ 266,280
Kentucky Utilities Company	\$ 234,929
PacifiCorp	\$ 214,901
Mississippi Power Company	\$ 173,851
Portland General Electric Company	\$ 166,979
Public Service Company of New Mexico	\$ 145,707
Gulf Power Company	\$ 142,292
Appalachian Power Company	\$ 124,979
Southwestern Electric Power Company	\$ 92,758
Nevada Power Company	\$ 79,819
ALLETE (Minnesota Power)	\$ 77,391
Oklahoma Gas and Electric Company	\$ 75,106

**CAMA LEGISLATION ARE NOT HIGHER THEN THE FEDERALLY
MANDATED CCR RULE?**

A. The statements of Mr. Kerin and Dr. Wright conflict with statements from other Duke officials that have admitted CAMA costs are higher than CCR costs. On May 24, 2016, Utility Dive published a story entitled "Two years after EPA's coal ash rule, progress depends on states". Below is a portion of that article.

Duke Energy, the state's major investor-owned utility, has a total of 150 million tons of ash at its 14 coal plants in North Carolina. Mark McIntire, director of environmental policy at Duke, told Utility Dive the company faces more stringent standards from the CAMA rather than the federal regulation.

"The NC law came before the CCR [rule]," he said. "We find that NC CAMA that is specific to NC is generally driving decision making on a management perspective on coal ash ... From a comparison perspective the CAMA is generally a good bit more stringent."² (underline added)

Obviously, Duke's director of environmental policy, Mark McEntire, disagrees with Mr. Kerin and Dr. Wright in this case. The Commission needs and deserves a straight answer from Duke.

**Q. HOW DO YOU RESPOND TO THE POSITION OF MR. WHEELER
REGARDING REAL-TIME PRICING RATES?**

A. The fact that Duke's hourly pricing rates are higher than market rates is a reflection on Duke's regulated rates being above market costs. While I agree with Mr. Wheeler that Duke's RTP rates are marginal rates based on the Duke system production costs, I disagree with Mr. Wheeler that Duke should not offer its large customers the lower of market costs or Duke's hourly costs. Given Duke management's decision on future rate hikes to fund its grid plan and drive

² <https://www.utilitydive.com/news/two-years-after-epas-coal-ash-rule-progress-depends-on-states/419672/>, May 24, 2016

1 testimony, and you may step down and be
2 excused.

3 WITNESS RUOFF: Thank you.

4 (Witness excused)

5 CHAIRMAN RANDALL: Okay. Next witness.

6 MR. BATEMAN: ORS calls as its next witnesses
7 the panel of Dan Wittliff and Michael Seaman-
8 Huynh. And, while the witnesses are taking
9 the panel, ORS would like to thank the
10 Commission and the court reporter for allowing
11 us to present these witnesses via panel.

12 (Witnesses affirmed)

13 THEREUPON came,

14 MICHAEL L. SEAMAN-HUYNH,

15 DAN J. WITTLIFF,

16 called as witnesses, who, having been first duly
17 affirmed, were examined and testified as follows:

18 DIRECT EXAMINATION

19 BY MR. BATEMAN:

20 Q Mr. Seaman-Huynh, please state your full name and
21 occupation for the Commission.

22 A (SEAMAN-HUYNH) My name is Michael Seaman-Huynh. I
23 am a senior regulatory manager for the Office of
24 Regulatory Staff.

25 Q And are you the same Michael Seaman-Huynh who

1 prefiled 19 pages of direct testimony in this
2 docket, on March 4th, 2019?

3 A (SEAMAN-HUYNH) Yes. I am.

4 Q Do you have any changes, edits, or corrections to
5 your prefiled direct testimony?

6 A (SEAMAN-HUYNH) No. I do not.

7 Q And, if I asked you the same questions today as
8 those contained in your prefiled direct testimony,
9 would your answers remain the same?

10 A (SEAMAN-HUYNH) Yes. They would.

11 MR. BATEMAN: Mr. Chairman, ORS asks that Mr.
12 Seaman-Huynh's prefiled direct testimony be
13 entered into the record as if given orally
14 from the stand.

15 CHAIRMAN RANDALL: Mr. Seaman-Huynh's prefiled
16 direct testimony will be entered into the
17 record as though given orally from the stand.

18 MR. BATEMAN: Thank you.

19 Q And, Mr. Seaman-Huynh, did you file as an
20 attachment to your direct testimony a series of
21 exhibits marked Exhibit MSH-1 through Exhibit MSH-
22 5?

23 A (SEAMAN-HUYNH) Yes.

24 Q Do you have any changes, edits, or corrections to
25 any of those exhibits?

1 A (SEAMAN-HUYNH) No. I do not.

2 MR. BATEMAN: Mr. Chairman, I'd ask now that
3 Mr. Seaman-Huynh's Exhibits MSH-1 through MSH-
4 5, for his direct testimony, be entered into
5 the record as if -- be -- be marked for
6 identification and entered into the record as
7 the next composite hearing exhibits.

8 CHAIRMAN RANDALL: Mr. Seaman-Huynh's Exhibits
9 MSH-1 through MSH-5 will be entered into the
10 record as Hearing Exhibit Number 57.

11 (WHEREUPON, Hearing Exhibit 57 was
12 marked and received in evidence.)

13 MR. BATEMAN: Thank you.

14 Q And, Mr. Seaman-Huynh, did you also prepare 13
15 pages of surrebuttal testimony in this docket,
16 which was filed with the Commission on March 25th,
17 2019?

18 A (SEAMAN-HUYNH) Yes.

19 Q Do you have any changes, edits, or corrections to
20 your prefiled surrebuttal testimony?

21 A (SEAMAN-HUYNH) No. I do not.

22 MR. BATEMAN: Mr. Chairman, ORS would ask that
23 Mr. Seaman-Huynh's prefiled surrebuttal
24 testimony be read into the record as if given
25 orally from the stand.

1 CHAIRMAN RANDALL: Mr. Seaman-Huynh's prefiled
2 surrebuttal testimony will be entered into the
3 record as though given orally from the stand.

4 Q And, Mr. Seaman-Huynh, did you file a series of
5 exhibits along with your surrebuttal testimony,
6 identified as Surrebuttal Exhibit MSH-1 through
7 Surrebuttal Exhibit MSH-5?

8 A (SEAMAN-HUYNH) Yes.

9 Q Do you have any changes, edits, or corrections to
10 those exhibits?

11 A (SEAMAN-HUYNH) No. I do not.

12 MR. BATEMAN: Mr. Chairman, at this time, I'd
13 ask that Mr. Seaman-Huynh's Surrebuttal
14 Exhibits MSH-1 through Surrebuttal Exhibit
15 MSH-5 be marked for identification and entered
16 into the record as the next composite hearing
17 exhibit.

18 CHAIRMAN RANDALL: Mr. Seaman-Huynh's
19 Surrebuttal Exhibits MSH-1 through -5 will
20 entered as Hearing Exhibit Number 58.

21 (WHEREUPON, Hearing Exhibit 58 was
22 marked and received in evidence.)

23 MR. BATEMAN: Thank you. And, Mr. Chairman,
24 if it pleases the Commission, I have a few
25 questions and answers that summarize Mr.

1 Seaman-Huynh's direct and surrebuttal
2 testimonies filed in this docket.

3 Q Mr. Seaman-Huynh, can you please outline what you
4 address in your direct and surrebuttal testimonies?

5 A (SEAMAN-HUYNH) Yes. My testimony addresses
6 certain areas of ORS's examination of Duke Energy
7 Progress's application. Specifically, I address
8 the Company's cost-of-service study, depreciation
9 study, rate design, revenue verification and
10 revenue requirement distribution, the Company's pro
11 forma --

12 CHAIRMAN RANDALL: (To Witness Seaman-Huynh)
13 Hold on a second.

14 Do we have a copy of that, whatever we're
15 doing here?

16 THE COURT REPORTER: Sorry. I didn't see
17 that.

18 CHAIRMAN RANDALL: That's okay. They need to
19 put it in front of you -- or over on the side.

20 THE COURT REPORTER: Thank you.

21 MR. BATEMAN: Mr. Chairman, would it be
22 helpful if I repeated the question?

23 CHAIRMAN RANDALL: Certainly.

24 Q Mr. Seaman-Huynh, can you please outline what you
25 address in your direct and surrebuttal testimonies?

1 A (SEAMAN-HUYNH) Yes. My testimony addresses
2 certain areas of ORS's examination of Duke Energy
3 Progress's application. Specifically, I address
4 the Company's cost-of-service study, depreciation
5 study, rate design, revenue verification and
6 revenue requirement distribution, the Company's pro
7 forma adjustments pertaining to the Company's
8 calculation of the extra facilities charge, and
9 ORS's customer growth calculation, the distribution
10 of the additional revenue requirement, and the
11 proposed EDIT rider to customers, and the impact of
12 the proposed rates on customers' bills.

13 Q And, Mr. Seaman-Huynh, what are your conclusions
14 regarding ORS's review of the Company's cost-of-
15 service study?

16 A (SEAMAN-HUYNH) ORS analyzed the Company's cost-of-
17 service study and concluded that, for the purposes
18 of this application, the methodology is reasonable.
19 The methodology provides a reasonable assessment
20 and allocation of the Company's revenues, operating
21 expenses, and rate-based items.

22 Q Do you have any additional recommendations to the
23 Commission regarding the cost-of-service study?

24 A (SEAMAN-HUYNH) Yes. ORS recommends that the
25 Commission disallow recovery of coal ash management

1 and disposal expenses related to North Carolina
2 laws and regulations above and beyond federal
3 regulations. It is ORS's position that South
4 Carolina customers should be held harmless for
5 incremental cost difference attributed to the North
6 Carolina state laws. For South Carolina customers
7 to be subject to North Carolina state laws, where
8 they do not have a vote, is equatable to taxation
9 without representation.

10 Q And what is the resulting revenue increase
11 recommended by ORS?

12 A (SEAMAN-HUYNH) Based on ORS's adjustments, as
13 addressed by ORS witness Major and a 9.03 -- 9.30
14 percent ROE as recommended by ORS witness Parcell,
15 ORS initially recommended the Commission approve a
16 revenue increase to DEP of \$30,562,000 excluding
17 the refund from the EDIT rider. This
18 recommendation was updated in my surrebuttal
19 testimony. ORS's updated recommended revenue
20 increase to the Commission for DEP is \$32,130,000.
21 The revenue increases for ORS's recommendation, by
22 customer class, are reflected in my Surrebuttal
23 Exhibit MSH-1. ORS recommends that the revenues
24 generated by the billing determinants not exceed
25 the target revenue for each class as proposed in my

1 Surrebuttal Exhibit MSH-1. The overall retail
2 increase, including ORS's proposed adjustments and
3 the EDIT rider, is 3.88 percent.

4 My Surrebuttal Exhibit MSH-2 provides the
5 resulting rate of return by customer class, taking
6 into account ORS's proposed adjustments and
7 excluding the EDIT rider. The overall rate of
8 return for total retail is 5.68 percent. ORS
9 recommends that any increase granted by the
10 Commission be allocated in a manner such that the
11 rates of return by class are equitable.

12 Q And what is the ORS's recommendation regarding the
13 Company's proposed basic facilities charge?

14 A (SEAMAN-HUYNH) The Company has recommended changes
15 to its existing tariff structure, including
16 substantial increases to the basic facility charge
17 for residential and small general service
18 customers. ORS's -- excuse me -- the Company's
19 proposed increases do not follow the principle of
20 gradualism in designing rates and tariffs. ORS
21 recommends the Commission allow DEP to only
22 increase the BFCs for the residential, small
23 general service, and small general service constant
24 load customers to recover up to 25 percent of the
25 approved revenue increase. Using this methodology

1 and ORS's revenue recommendation, the BFC would be
2 \$11.78 per month for residential customers, \$12.34
3 per month for small general service customers and
4 \$11.31 per month for small general service constant
5 load customers as shown on Surrebuttal Exhibit MSH-
6 3.

7 Q And Mr. Seaman-Huynh, are you aware of a letter
8 filed by the Company on March 26th regarding the
9 proposed basic facility charges?

10 A (SEAMAN-HUYNH) Yes. I am.

11 Q For residential, small general service, and small
12 general service constant load customers?

13 A (SEAMAN-HUYNH) Yes.

14 Q Okay. And does that letter accurately reflect
15 ORS's position regarding the calculation of the
16 BFC?

17 A (SEAMAN-HUYNH) No. It does not.

18 Q Would you please explain?

19 A (SEAMAN-HUYNH) The Company is agreeing to the
20 basic facility charge figures that I just read to
21 this Commission. It is not ORS's recommendation
22 that those be the basic facility charges for
23 residential, small general service, and small
24 general service constant load customers.

25 Q Mr. Seaman-Huynh, are you aware of the letter filed

1 by the South Carolina Farm Bureau on April 9th
2 regarding the proposed basic facility charge for
3 medium general service customers?

4 A (SEAMAN-HUYNH) Yes. I am.

5 Q What is ORS's position regarding the proposal put
6 forth by the Farm Bureau?

7 A (SEAMAN-HUYNH) Following the night hearings held
8 in Florence and Sumter, ORS received inquiries and
9 calls from the agricultural community expressing
10 concern over the requested increase. Based on the
11 testimony at the night hearings and these contacts,
12 ORS supports the Farm Bureau's request to limit the
13 increase to medium general service basic facility
14 charge to an increase similar to that of the small
15 general service basic facility charge. Based on
16 ORS's adjustments, a 24.5 percent increase, as
17 recommended by the Farm Bureau, results in a \$21.38
18 basic facilities charge for the medium general
19 service class.

20 Q And please discuss ORS's position regarding the
21 proposed rate design changes put forth in the
22 Company's application.

23 A (SEAMAN-HUYNH) It is ORS's position that it is
24 premature to make the rate design changes proposed
25 by the Company as addressed in my surrebuttal

1 testimony. ORS recommends that the Commission
2 reject the changes I addressed as put forth by the
3 Company at this time. The Company should wait
4 until it has completed its deployment of advanced
5 metering infrastructure and incorporate the data
6 obtained from AMI into subsequent requests to
7 change rate designs. If the Company were to begin
8 making changes to its rate designs regarding
9 relationships between on-peak and off-peak and
10 seasonal energy and demand charges, customers may
11 respond and change their usage patterns. Then,
12 when the Company incorporates the information
13 available from AMI and customer -- Customer
14 Connect, and offer customers new rate designs,
15 customers who have adapted their usage, may be
16 confused and frustrated.

17 Q And what is the overall impact to a residential
18 customer's bill using ORS's proposed adjustments?

19 A (SEAMAN-HUYNH) Incorporating all of ORS's
20 adjustments and recommendations, the monthly bill
21 for the typical residential customer on Rate RES
22 using 1,000 kilowatt-hours, will increase by
23 approximately \$6.71 or 5.5 percent from \$122.49 to
24 approximately \$129.20.

25 Q Thank you, Mr. Seaman-Huynh.

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23 (PURSUANT TO PREVIOUS INSTRUCTION,
24 THE PREFILED DIRECT TESTIMONY OF
25 MICHAEL L. SEAMAN-HUYNH FOLLOWS.)

1 **DIRECT TESTIMONY AND EXHIBITS OF**
2 **MICHAEL L. SEAMAN-HUYNH**
3 **ON BEHALF OF**
4 **THE SOUTH CAROLINA OFFICE OF REGULATORY STAFF**
5 **DOCKET NO. 2018-318-E**
6 **IN RE: APPLICATION OF DUKE ENERGY PROGRESS, LLC**
7 **FOR ADJUSTMENTS IN ELECTRIC RATE SCHEDULES AND TARIFFS**
8 **AND REQUEST FOR AN ACCOUNTING ORDER**
9

10 **Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND OCCUPATION.**

11 **A.**My name is Michael Seaman-Huynh. My business address is 1401 Main Street,
12 Suite 900, Columbia, South Carolina 29201. I am employed by the State of South Carolina
13 as a Senior Regulatory Manager in the Utility Rates and Services Division of the Office of
14 Regulatory Staff ("ORS").

15 **Q. PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.**

16 **A.**I received my Bachelor's Degree in History from the University of South Carolina
17 in 1997. Prior to my employment with ORS, I was employed as an energy analyst with a
18 private consulting firm. I joined ORS in 2006 as an Electric Utilities Specialist and was
19 promoted to Senior Electric Utilities Specialist in 2010. When the Energy Regulation
20 Department was formed in August 2015, I assumed the position of Senior Regulatory
21 Analyst. In May 2016, the Utility Rates and Services Division was formed, and I was
22 promoted to the position of Senior Regulatory Manager.

23 **Q. HAVE YOU TESTIFIED BEFORE THE PUBLIC SERVICE COMMISSION OF**
24 **SOUTH CAROLINA ("COMMISSION")?**

THE OFFICE OF REGULATORY STAFF
1401 Main Street, Suite 900
Columbia, SC 29201

1 A. Yes. I have testified on numerous occasions before the Commission in connection
2 with hearings concerning annual fuel clause proceedings, general rate cases, and Utility
3 Facility Siting and Environmental Protection Act proceedings.

4 Q. WHAT IS THE MISSION OF ORS?

5 A. ORS represents the public interest as defined by the South Carolina General
6 Assembly as:

7 The concerns of the using and consuming public with respect to public
8 utility services, regardless of the class of customer, and preservation of
9 continued investment in and maintenance of utility facilities so as to provide
10 reliable and high-quality utility services.

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

12 A. The purpose of my testimony is to address certain areas of ORS's examination of
13 Duke Energy Progress, LLC's ("Company" or "DEP") application for adjustments in its
14 electric rates and charges under Docket No. 2018-318-E ("Application"). My testimony
15 will specifically address the Company's cost of service study ("COSS"), depreciation
16 study, rate design, revenue verification, and revenue requirement distribution.

17 I will also address the Company's pro forma adjustments pertaining to the
18 Company's calculation of the Extra Facilities Charge ("EFC") and ORS's Customer
19 Growth calculation. These adjustments, more fully discussed below, were provided by the
20 ORS Utility Rates and Services Division to the ORS Audit Department and are shown in
21 Audit Exhibit KLM-2 of ORS witness Major's Direct Testimony.

22 Additionally, I will address the distribution of the additional revenue requirement
23 and the proposed Excess Deferred Income Tax Rider ("EDIT Rider") to customers, ORS's
24 recommendation regarding the Company's proposed Phase 1 and 2 increase in base rates

1 to support the proposed Grid Improvement Plan ("GIP"), and the impact of the proposed
2 rates on customers' bills.

3 **I. COST OF SERVICE STUDY**

4 **Q. WHAT IS THE PURPOSE OF A COST OF SERVICE STUDY?**

5 **A.** The Company owns and operates an electric system which primarily provides retail
6 electric service to residential, general service, industrial and street lighting customers, as
7 well as wholesale customers. Each of these customer classes receives varying types of
8 service and contributes different load characteristics to the system. The COSS allocates –
9 or directly assigns – responsibility for the revenues, expenses and rate base items among
10 the individual customer classes. That is, the cost responsibility for expenses and rate base
11 items are allocated to the customer class(es) that caused the cost to be incurred. This
12 allocation methodology is referred to as "cost causation."

13 **Q. PLEASE EXPLAIN THE MAJOR COMPONENTS OF A COST OF SERVICE**
14 **STUDY.**

15 **A.** The major components utilized in the development of a fully distributed COSS are
16 functionalization, classification and allocation. Functionalization is the process of
17 categorizing cost according to its function, which is either production, transmission or
18 distribution. Classification is further dividing these costs into the type of service they
19 provide, namely demand, energy or customer. The allocation of these costs is based upon
20 the demand, energy or customer costs incurred by the individual classes.

21 **Q. PLEASE DESCRIBE THE ALLOCATION METHODOLOGY USED BY THE**
22 **COMPANY IN ITS COST OF SERVICE STUDY.**

1 **A.** The Company filed its COSS based on the summer peak day One-Hour Coincident
2 Peak Demand methodology, which was approved by the Commission in the Company's
3 last general rate case in 2016 (Order No. 2016-871). Allocation factors for demand related
4 costs are two-fold. The class coincident peak ("CP") allocator was developed based on
5 each customer class's contribution to the system's summer peak demand of 12,590
6 megawatts ("MW"), which occurred at 5:00 p.m. on July 13, 2017. The Company used
7 the system summer peak demand rather than the system peak demand of 14,407 MW that
8 occurred on January 9, 2017 at 8:00 am. ORS reviewed the Company's reasoning and
9 found their use of the summer peak demand to be reasonable in developing the CP allocator
10 for the proceeding.¹ This allocator was used for the allocation of production and
11 transmission investments to customer classes.

12 The class non-coincident peak ("NCP") allocator was developed based on the peak
13 demands of each customer class whenever they occurred during the test year ending
14 December 31, 2017 ("Test Year"). The NCP allocator was used for the allocation of
15 demand related distribution investments and expenses to customer classes. The CP and
16 NCP demand allocation methodology generally reflects how costs are incurred by the
17 Company to meet the demands customers place on the Company's system.

18 The energy related allocation factors were based on the annual kilowatt hour
19 ("kWh") sales for each customer class for the Test Year, adjusted for system losses. The
20 energy allocation methodology generally reflects the variable costs incurred by DEP, such
21 as fuel, to meet each customer class's energy consumption requirements placed on the
22 Company's system throughout the year.

¹ Company witness Hager's Direct Testimony, page 9.

1 The customer related allocation factors were based on the number of customers in
2 each respective class and used to allocate costs such as meters. In addition, costs such as
3 extra facilities that were identified as being attributable to a specific class of customer were
4 directly assigned to that customer class.

5 **Q. HAS THE COMPANY MADE ANY CHANGES TO ITS COST OF SERVICE**
6 **STUDY IN THIS PROCEEDING COMPARED TO ITS LAST RATE CASE?**

7 **A.** Yes. As discussed by Company witness Hager, DEP incorporated the Minimum
8 System Methodology into its COSS as part of the Application. In using the Minimum
9 System Method, DEP identified a portion of costs for distribution lines, poles, and
10 transformers, and allocated these costs based on customer related allocation factors rather
11 than demand factors. In the 2016 general rate proceeding, the Company did not use the
12 Minimum System Method and instead allocated costs using the Basic Customer method.
13 The Basic Customer method allocated service drops and meters based on the number of
14 customers and resulted in lower basic facility charges.²

15 **Q. DID ORS REVIEW THE DEPRECIATION RATES UTILIZED BY THE**
16 **COMPANY IN THIS CASE?**

17 **A.** Yes. ORS confirmed that the Company used the rates from its 2016 depreciation
18 study approved by the Commission in Order No. 2018-530 to determine the appropriate
19 cost levels for depreciation expense in its current filing. ORS found the study results and
20 methodologies to be reasonable and consistent with other electric utilities operating in
21 South Carolina and previously approved by the Commission.

² Company witness Hager's Direct Testimony, page 15.

1 Q. WHAT WERE THE FINDINGS OF ORS'S REVIEW OF THE COMPANY'S COST
2 OF SERVICE STUDY?

3 A. ORS concluded that, for the purposes of this Application, the methodology applied
4 in constructing the Company's COSS is reasonable. The methodology provides a
5 reasonable assessment and allocation of the Company's revenues, operating expenses and
6 rate base items.

7 Q. AS PART OF ORS'S REVIEW OF THE COMPANY'S COST OF SERVICE
8 STUDY, WERE CERTAIN COSTS DIRECTLY ASSIGNED TO THE
9 COMPANY'S NORTH CAROLINA OR SOUTH CAROLINA JURISDICTIONS?

10 A. Yes. DEP directly assigned certain costs to its North Carolina and South Carolina
11 jurisdictions. These included, but were not limited to, costs associated with South Carolina
12 Act 236 Distributed Energy Resources (South Carolina) and the North Carolina Renewable
13 Energy and Energy Efficiency Portfolio Standard (North Carolina). It is a common
14 practice for utilities operating in multiple jurisdictions to assign the costs related to certain
15 accounts directly to one jurisdiction. These costs are often derived from laws and
16 regulations that are specific to that jurisdiction. This follows the principle of cost causation
17 that I previously discussed. Adhering to this principle, it is appropriate for the total costs
18 associated with implementation and compliance with the laws and regulations of a
19 particular jurisdiction be allocated completely to that jurisdiction while holding the
20 customers of other jurisdictions harmless.

21 Q. WERE THERE NORTH CAROLINA JURISDICTIONAL COSTS ASSIGNED TO
22 SOUTH CAROLINA?

1 A. Yes. ORS determined that the Company allocated coal ash management and
2 disposal expenses to South Carolina customers that were incurred to comply with North
3 Carolina laws and regulations. ORS recommends the Commission disallow recovery of
4 these additional costs related to North Carolina laws and regulations. This issue and the
5 corresponding ORS recommendations are addressed by ORS witness Wittliff.

6 **II. REVENUE VERIFICATION, REVENUE REQUIREMENT DISTRIBUTION,**
7 **AND RATE DESIGN**

8 **Q. DID ORS VERIFY THE REVENUE COMPUTATIONS USED IN DETERMINING**
9 **THE VARIOUS TARIFF INCREASES?**

10 A. Yes. ORS verified the Test Year billing determinants for each current rate schedule
11 approved by the Commission. ORS also confirmed the use of these determinants as applied
12 to the proposed rates. The difference in the revenue generated by the current and proposed
13 rates produces the revenue increase the Company has requested in this proceeding. This is
14 a reasonable and appropriate method for determining the accuracy of the proposed rates.

15 **Q. PLEASE DISCUSS THE REVENUE REQUIREMENT AND HOW IT IS**
16 **DISTRIBUTED TO EACH CUSTOMER CLASS.**

17 A. The COSS was utilized to determine the proper cost allocation for each class. The
18 revenue requirement was then applied to each class to align the returns by class with the
19 overall rate of return. This is an appropriate and equitable method for allocating revenue
20 requirements and is an accepted regulatory practice consistent with previous Commission
21 orders.

22 Based on ORS's adjustments and a 9.30% return on equity ("ROE"), as
23 recommended by ORS witness Parcell, ORS recommends a reduction to DEP's proposed

revenue increase from \$68,668,000 (as filed in Company witness Bateman's Exhibit 1) to \$30,562,000, which equates to an approximate 56% reduction or approximately \$38,106,000, excluding the refund from the EDIT Rider. The revenue increases for ORS's recommendation by customer class and individual rate schedules are reflected in Exhibit MSH-1. ORS recommends that the revenues generated by the billing determinants not exceed the target revenue for each class as proposed in Exhibit MSH-1.

Exhibit MSH-1 demonstrates the percent increases proposed by ORS for each customer class. The retail increases by customer class, including ORS's proposed adjustments and the EDIT Rider, are as follows: 5.11% for Residential; 5.98% for Small General Service ("SGS"); 8.56% for SGS Constant Load; 1.13% for Medium General Service ("MGS"); 3.73% for Large General Service ("LGS"); -0.13% for Seasonal and Intermittent Service ("S&I"); 15.94% for Traffic Signal Service ("TSS"); -1.50% for Outdoor Lighting; and -8.69% for Sports Field Lighting Service ("SFLS"). The overall total retail increase is 3.61%.

Q. HOW DOES ORS'S DISTRIBUTION OF THE REVENUE REQUIREMENT IMPACT THE RATE OF RETURN BY CUSTOMER CLASS?

A. Exhibit MSH-2 provides the resulting rate of return by customer class, taking into account ORS's proposed adjustments and excluding the EDIT Rider. In developing Exhibit MSH-2, ORS attempted to limit cross-subsidization by employing a $\pm 10\%$ "band of reasonableness" relative to the overall retail rate of return. ORS was successful in making an incremental movement toward comparable rates of return for all customer classes. The returns by class are as follows: 4.52% for Residential; 4.42% for SGS; 2.78% for SGS Constant Load; 7.83% for MGS; 4.91% for LGS; 9.44% for S&I; -1.50% for TSS;

1 10.73% for Outdoor Lighting; and 21.24% for SFLS. The overall rate of return for total
2 retail is 5.60%. ORS recommends that any increase by the Commission granted be
3 allocated in a manner such that the returns by class represent an appropriate movement
4 toward comparable returns and bear a reasonable relations to the Company's overall rate
5 of return.

6 **Q. HAS THE COMPANY PROPOSED MODIFICATIONS TO ITS CURRENT**
7 **TARIFF STRUCTURE?**

8 **A.** Yes. The Company has proposed changes to the existing tariff structure as
9 described in Company witness Wheeler's direct testimony. I will address each of these
10 changes as well as ORS's recommendations for each of the proposed changes.

11 **Q. PLEASE DISCUSS THE COMPANY'S PROPOSED CHANGES TO ITS**
12 **RESIDENTIAL TARIFF STRUCTURE.**

13 **A.** The Company has proposed to increase the Basic Facility Charge ("BFC") from the
14 current charge of \$9.06 per month to \$29.00 per month for its residential rate schedules,
15 Schedules RES and R-TOUD. These substantial increases would allow DEP to recover all
16 of the customer related costs reflected in its COSS. Additionally, DEP requests a reduction
17 to the differential between the non-summer billing month energy block for energy usage
18 over 800 kWh and the non-summer billing month energy block for energy usage under 800
19 kWh from \$0.01/kWh to \$0.005/kWh for Schedule RES. Further, the Company proposes
20 to reduce the differential between the summer and non-summer demand rates for Schedule
21 R-TOUD from 30% to 20% and to reduce the differential between the on-peak and off-
22 peak energy rates from 22% to 15%.

1 Q. DOES ORS HAVE RECOMMENDATIONS REGARDING THE RESIDENTIAL
2 RATE STRUCTURE?

3 A. Yes. ORS recommends the Commission determine the rate design that balances
4 utility rate design principles. ORS disagrees with the Company's proposal to recover all
5 customer related costs through the BFC. The magnitude of the increase proposed by DEP
6 to the BFC does not promote a gradual transition to a new rate design. "Gradualism" is the
7 concept of progressively changing rates over time in a manner that mitigates rate shock to
8 customers. Increasing the BFC for residential customers by 220% (see Wheeler Exhibit
9 No. 2) in a single rate increase is extreme. Additionally, the impact to customers using
10 relatively small amounts of energy (e.g., low income and fixed income customers) would
11 be substantial.

12 ORS recommends DEP be allowed to increase the BFCs for the residential class to
13 recover up to twenty-five percent (25%) of the approved revenue increase assigned to the
14 residential class. This approach of gradualism mirrors the approach used by the NCUC in
15 the most recent DEP general rate proceeding.³ Using the ORS proposed revenue increase,
16 excluding the changes from the EDIT Rider, ORS recommends the BFC for residential
17 customers be increased to \$11.66 per month as shown on Exhibit MSH-3.

18 Regarding the changes to the differentials in energy and demand charges proposed
19 by Company witness Wheeler, ORS recommends the Commission reject the proposed
20 changes. The Company states it is in the process of deploying its Advanced Metering
21 Infrastructure ("AMI") program in its South Carolina territory.⁴ DEP intends to use
22 customer usage data gathered from the AMI program to develop and offer new rates to its

³ <https://starwl.ncuc.net/NCUC/ViewFile.aspx?Id=80a5a760-f3e8-4c9a-a7a6-282d791f3f23>

⁴ Company witness Schneider's Direct Testimony, page 8.

1 customers in the future. It is premature to make the changes described by Company witness
2 Wheeler. The Company should incorporate the additional data gathered from the AMI
3 program into any requests to change the differential between energy and demand charges.
4 The information from the AMI program should be analyzed by the Company, along with
5 demand side management and energy efficiency ("DSM/EE") and other programs, to
6 develop sustainable rate structures and rate designs based on customer's usage patterns.
7 ORS recommends the Commission reject the Company's proposal to change the
8 differential in energy block rates for Schedule RES, differential in summer and non-
9 summer demand rates for Schedule R-TOUD, and differential in on-peak and off-peak
10 energy rates for Schedule R-TOUD.

11 **Q. IF THE ORS RECOMMENDATION REGARDING THE RESIDENTIAL BFC**
12 **WAS APPROVED, HOW WOULD THE COMPANY RECOVER THE**
13 **REMAINING REVENUE REQUIREMENT FOR THE RESIDENTIAL CLASS?**

14 **A.** If the Commission were to approve ORS's recommendation that only twenty-five
15 percent (25%) of the approved revenue increase assigned to the residential class come from
16 an increase in the BFC, the remaining portion of the additional revenue requirement would
17 need to be recovered through the volumetric rates, those being the energy (¢/kWh) and
18 demand charges (\$/kilowatt ("kW")), which were noticed to the public and included in the
19 Company's Application.

20 **Q. PLEASE DISCUSS THE COMPANY'S PROPOSED CHANGES TO ITS SGS AND**
21 **SGS CONSTANT LOAD TARIFF STRUCTURES.**

22 **A.** As with the Residential class, DEP has proposed to update the BFCs for its SGS
23 and SGS Constant Load tariffs to collect all customer related costs included in the COSS.

1 Under the proposed tariffs, SGS and SGS Constant Load customers would realize a sizable
2 increase in the BFC, similar to residential customers.

3 Additionally, the Company proposes to increase the additional monthly charge for
4 three-phase service from \$6.00 to \$6.50, and to increase the rates for Rate GS
5 approximately 15% higher than the SGS class.

6 **Q. DOES ORS HAVE RECOMMENDATIONS REGARDING THE SGS AND SGS**
7 **CONSTANT LOAD TARIFF STRUCTURES?**

8 **A.** Yes. As with the Residential class, ORS recommends DEP be allowed to increase
9 the BFC for SGS and SGS Constant Load customers to recover up to twenty-five percent
10 (25%) of the approved revenue increase assigned to that class. Using the ORS proposed
11 revenue increase, excluding the changes from the EDIT Rider, ORS recommends the BFC
12 for SGS customers be increased to \$12.24 per month and \$11.25 per month for SGS
13 Constant Load customers as shown on Exhibit MSH-3. Additionally, ORS has reviewed
14 the additional recommendations made by Company witness Wheeler and finds them
15 reasonable.

16 **Q. IF THE ORS RECOMMENDATIONS REGARDING THE BFC FOR THE SGS**
17 **AND SGS CONSTANT LOAD CLASSES WERE APPROVED, HOW WOULD**
18 **THE COMPANY RECOVER THE REMAINING REVENUE REQUIREMENT**
19 **FOR SGS AND SGS CONSTANT LOAD?**

20 **A.** Like the Residential class, if the Commission were to approve ORS's
21 recommendation that only twenty-five percent (25%) of the approved revenue increase be
22 assigned to the SGS and SGS Constant Load classes through the BFC, the remaining
23 portion of the additional revenue requirement would need to be recovered through the

1 volumetric rates, those being the energy ($\text{\$/kWh}$) and demand charges ($\text{\$/kW}$), which were
2 noticed to the public and included in the Company's Application.

3 **Q. PLEASE DISCUSS THE COMPANY'S PROPOSED CHANGES TO ITS MGS**
4 **TARIFF STRUCTURES.**

5 **A.** As with the Residential class, DEP has proposed to update the BFCs for its MGS
6 tariffs to collect all customer related costs included in the COSS. The Company proposes
7 reducing the differentials between on-peak and off-peak energy rates in Schedule SGS-
8 TOU from 26% to 20%. Additionally, DEP proposes to increase the off-peak demand
9 charge for Schedule SGS-TOU from $\text{\$2.95/kW}$ to $\text{\$3.30/kW}$. Finally, the Company
10 proposes to increase the rates for Schedule SGS-TOU approximately 10% higher than the
11 increase to Schedule MGS.

12 **Q. DOES ORS HAVE RECOMMENDATIONS REGARDING THE MGS TARIFF**
13 **STRUCTURES?**

14 **A.** Yes. ORS recommends the Commission approve the Company's proposed BFCs
15 be designed to collect all customer related costs included in the COSS for the MGS class.
16 Customers in the MGS class are minimally impacted by the Minimum System Method
17 used in the Company's COSS.

18 Regarding the additional changes proposed by Company witness Wheeler, ORS
19 recommends the Commission reject the proposed changes. The Company should
20 incorporate the additional data gathered from the AMI program into any requests to change
21 the differential between energy and demand charges. The information from the AMI
22 program should be analyzed by the Company, along with DSM/EE and other programs, to
23 develop sustainable rate structures and rate designs based on customer's usage patterns.

1 Q. PLEASE DISCUSS THE COMPANY'S PROPOSED CHANGES TO ITS LGS
2 TARIFF STRUCTURES.

3 A. DEP has proposed to update the BFCs for its LGS tariffs to collect all customer
4 related costs included in the COSS. For Schedule LGS-TOU, the Company proposes to
5 increase on-peak demand rates by 50% and decrease the excess demand charge from
6 \$1.25/kW to 0.89/kW. Regarding Schedule LGS-RTP, DEP proposes to increase the
7 Administrative Charge from \$142.00/month to \$160.00/month. Additionally, DEP
8 proposes to adjust the Facilities Demand Charges.

9 Q. DOES ORS HAVE RECOMMENDATIONS REGARDING THE LGS TARIFF
10 STRUCTURES?

11 A. Yes. ORS recommends the Commission approve the Company's proposed BFCs
12 be designed to collect all customer related costs included in the COSS for the LGS class.
13 Customers in the LGS class are minimally impacted by the Minimum System Method used
14 in the Company's COSS. Additionally, ORS recommends that the Commission approve
15 the increase of the Administrative Charge for Schedule LGS-RTP.

16 Regarding the additional changes proposed by Company witness Wheeler, ORS
17 recommends the Commission reject the proposed changes. The Company should
18 incorporate the additional data gathered from the AMI program into any requests to change
19 the differential between energy and demand charges. The information from the AMI
20 program should be analyzed by the Company, along with DSM/EE and other programs, to
21 develop sustainable rate structures and rate designs based on customer's usage patterns.

22 Q. PLEASE DISCUSS THE COMPANY'S PROPOSED CHANGES TO ITS S&I
23 TARIFF STRUCTURES.

1 **A.** The Company proposes to increase the BFC for customers served under this class
2 to match that of Schedule MGS. The Company proposes to increase the Customer Seasonal
3 Charge consistent with its currently approved methodology.

4 **Q. DOES ORS HAVE RECOMMENDATIONS REGARDING THE S&I TARIFF**
5 **STRUCTURES?**

6 **A.** Yes. ORS recommends that the Commission approve the Company's proposed
7 changes to Schedule SI as proposed by Company witness Wheeler.

8 **Q. PLEASE DISCUSS THE COMPANY'S PROPOSED CHANGES TO ITS TSS**
9 **TARIFF STRUCTURES.**

10 **A.** The Company proposes to increase the BFC for customers served under Schedule
11 TFS, and the Minimum Bill for Schedule TSS, to match that of Schedule SGS.

12 **Q. DOES ORS HAVE RECOMMENDATIONS REGARDING THE TSS CONSTANT**
13 **LOAD TARIFF STRUCTURES?**

14 **A.** Yes. As with the SGS class, ORS recommends DEP be allowed to increase the
15 BFC for Schedule TFS and the Minimum Bill for Schedule TSS to recover up to twenty-
16 five percent (25%) of the approved revenue increase assigned to that class. ORS
17 recommends the BFC for TSS customers be increased to \$12.24 per month to match the
18 BFC for the SGS class.

19 **Q. IF THE ORS RECOMMENDATION REGARDING THE BFC FOR THE TSS**
20 **CLASS WAS APPROVED, HOW WOULD THE COMPANY RECOVER THE**
21 **REMAINING REVENUE REQUIREMENT FOR TSS?**

22 **A.** Like the SGS class, if the Commission were to approve ORS's recommendation
23 that only twenty-five percent (25%) of the approved revenue increase be assigned to the

1 TSS class through the BFC, the remaining portion of the additional revenue requirement
2 would need to be recovered through the volumetric rates, those being the energy (¢/kWh)
3 or fixture charges (\$/fixture), which were noticed to the public and included in the
4 Company's Application.

5 **Q. PLEASE DISCUSS THE COMPANY'S PROPOSED CHANGES TO ITS**
6 **OUTDOOR LIGHTING AND SFLS TARIFF STRUCTURES.**

7 **A.** Company witness Wheeler addresses numerous proposed changes to DEP's
8 Outdoor Lighting and SFLS tariffs to modernize and improve the administration of its
9 schedules. ORS reviewed these changes and found them to be reasonable and recommends
10 that the Commission approve the Company's proposed changes as proposed by Company
11 witness Wheeler.

12 **Q. HAS THE COMPANY PROPOSED ANY CHANGES TO ITS SERVICE RIDERS?**

13 **A.** Yes. Company witness Wheeler addresses several proposed changes to its Service
14 Regulations to better reflect current cost studies. ORS reviewed these changes and found
15 them to be reasonable with the exception of the proposed Prepaid Advantage (Pilot) Plan
16 tariff. This is addressed in ORS witness Johnson's Direct Testimony.

17 **Q. HAS THE COMPANY PROPOSED ANY CHANGES TO ITS SERVICE**
18 **REGULATIONS?**

19 **A.** Yes. Company witness Wheeler addresses several proposed changes to its Service
20 Regulations to better reflect current cost studies. Specifically, the Company is requesting
21 to increase the Service charge from \$15.00 to \$17.00, increase the Landlord Service Charge
22 from \$4.50 to \$5.35, and increase the Reconnect Charge from \$15.00 to \$19.00. DEP also

1 proposes to change the EFC calculation by reducing the monthly percent rate charge from
2 1.1% to 1.0%. ORS reviewed each of these changes and found them to be reasonable.

3 III. PRO-FORMA ADJUSTMENTS

4 Q. PLEASE EXPLAIN THE COMPANY'S PROPOSAL TO ADJUST OTHER
5 REVENUE.

6 A. In Company Adjustment #3, DEP proposes updates to its Service Regulations
7 discussed previously. Specifically, these are changes to the Company's Service Charge,
8 Landlord Service Charge, Reconnect Charge, and EFC calculation. ORS reviewed each of
9 these changes and found them to be reasonable. This information is reflected in ORS
10 witness Major's Adjustment #3.

11 Q. PLEASE EXPLAIN ORS'S CUSTOMER GROWTH CALCULATION
12 INCLUDING THE RESULTING CUSTOMER GROWTH FACTOR FOR THE
13 COMPANY.

14 A. ORS found an increase in the number of DEP customers in South Carolina when
15 comparing the end of the Test Year and the average number of customers during the Test
16 Year. To capture the additional revenues and expenses generated by customers added to
17 the Company's system, ORS included an adjustment for customer growth. The customer
18 growth factor is calculated by taking the difference between the total number of customers
19 at the end of the Test Year and the average number of customers during the year and
20 dividing the result by the average number of customers during the Test Year. This
21 methodology yields a retail customer growth factor of 0.0267% for the Company. This
22 customer growth factor is reflected in ORS witness Major's Adjustment #40.

23 IV. EDIT RIDER

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1401 Main Street, Suite 900
Columbia, SC 29201

1 **Q. HAS ORS REVIEWED THE COMPANY'S PROPOSED EDIT RIDER?**

2 **A.** Yes. ORS has reviewed the Company's EDIT Rider. ORS witness Schellinger
3 discusses ORS's review of the Company's calculations of the EDIT Rider. ORS
4 recalculated the first-year return based on a 9.30% ROE and 4.06% Cost of Debt, as
5 recommended by ORS witness Parcell, to arrive at a total return of EDIT Rider revenue of
6 \$9,983,536 for the first year. Exhibit MSH-4 allocates this total to the various customer
7 classes using the same methodology as discussed by Company witness Wheeler but
8 updated for corrected Test Year billing units.

9 **V. GIP**

10 **Q. DOES ORS HAVE A RECOMMENDATION REGARDING THE PHASE 1 AND 2**
11 **INCREASE IN BASE RATES TO SUPPORT THE COMPANY'S GIP?**

12 **A.** Yes. ORS recommends the phased-in rate proposed by the Company for the GIP
13 be denied. ORS witness Sandonato provides a detailed explanation of the ORS
14 recommendation in his direct testimony.

15 **VI. CONCLUSION**

16 **Q. HAS ORS REVIEWED THE EFFECT OF THE COMPANY'S PROPOSED RATES**
17 **ON THE TYPICAL RESIDENTIAL CUSTOMER'S MONTHLY BILL?**

18 **A.** Yes. Exhibit MSH-5 shows the typical monthly residential bill for a customer on
19 Rate RES with 1,000 kWh consumption for DEP's currently approved rates and the rates
20 proposed in this proceeding. For information purposes, ORS provided the same
21 information for South Carolina Electric & Gas Company ("SCE&G"), Duke Energy
22 Carolinas, LLC ("DEC"), Lockhart Power Company ("Lockhart"), South Carolina Public

1 Service Authority ("Santee Cooper"), and the most recent U.S. Energy Information
2 Administration ("EIA") data for the South Atlantic region of the United States.

3 **Q. AFTER INCORPORATING ORS'S ADJUSTMENTS AND**
4 **RECOMMENDATIONS INTO THE COMPANY'S APPLICATION, WHAT IS**
5 **THE NET EFFECT ON THE TYPICAL MONTHLY BILL FOR A TYPICAL**
6 **RESIDENTIAL CUSTOMER?**

7 **A.** The monthly bill for the typical residential customer on Rate RES using 1,000 kWh
8 ("Typical Bill") will increase by approximately \$8.57 from \$122.49 to \$131.06, or 7.0%,
9 exclusive of the EDIT Rider. Including the EDIT Rider, the Typical Bill would decrease
10 by an additional (\$2.26) for a net increase of \$6.31. Inclusive of all changes, the Typical
11 Bill would increase from \$122.49 to approximately \$128.80, or 5.1%.

12 **Q. WILL YOU UPDATE YOUR TESTIMONY BASED ON INFORMATION THAT**
13 **BECOMES AVAILABLE?**

14 **A.** Yes. ORS fully reserves the right to revise its recommendations via supplemental
15 testimony should new information not previously provided by the Company, or other
16 sources, become available.

17 **Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

18 **A.** Yes, it does.

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23 (PURSUANT TO PREVIOUS INSTRUCTION,
24 THE PREFILED SURREBUTTAL TESTIMONY
25 OF MICHAEL L. SEAMAN-HUYNH FOLLOWS.)

SURREBUTTAL TESTIMONY AND EXHIBITS OF

MICHAEL L. SEAMAN-HUYNH

ON BEHALF OF

THE SOUTH CAROLINA OFFICE OF REGULATORY STAFF

DOCKET NO. 2018-318-E

IN RE: APPLICATION OF DUKE ENERGY PROGRESS, LLC

FOR ADJUSTMENTS IN ELECTRIC RATE SCHEDULES AND TARIFFS AND

REQUEST FOR AN ACCOUNTING ORDER

10 **Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND OCCUPATION.**

11 **A.** My name is Michael Seaman-Huynh. My business address is 1401 Main Street,
12 Suite 900, Columbia, South Carolina 29201. I am employed by the State of South Carolina
13 as a Senior Regulatory Manager in the Utility Rates and Services Division of the Office of
14 Regulatory Staff ("ORS").

15 **Q. DID YOU FILE DIRECT TESTIMONY AND EXHIBITS IN THIS PROCEEDING?**

16 **A.** Yes. I filed direct testimony and five (5) exhibits with the Public Service
17 Commission of South Carolina ("Commission") on March 4, 2019.

18 **Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY IN THIS**
19 **PROCEEDING?**

20 **A.** The purpose of my surrebuttal testimony is to respond to certain portions of rebuttal
21 testimony of Duke Energy Progress, LLC ("DEP" or the "Company") witnesses Steve
22 Wheeler, Julius Wright, and Jon Kerin. My surrebuttal testimony provides an update to
23 ORS's recommendations regarding revenue requirement distribution, rate design, proposed

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1 Excess Deferred Income Tax Rider ("EDIT Rider"), and impacts to customers' bills based
2 on the Surrebuttal Testimony and Exhibits of ORS witness Kelvin Major.

3 **Q. PLEASE DESCRIBE THE COMPANY'S REBUTTAL POSITION ON**
4 **GRADUALISM IN RATE DESIGN.**

5 **A.** Company witness Wheeler acknowledges that the Company believes there is merit
6 to incorporating the principle of gradualism in designing its rates and tariffs. He further
7 offers a possible alternative to the Company's original proposal of increasing the
8 Residential Basic Facility Charge ("BFC") from \$9.06 per month to \$29.00 per month. He
9 states that "A possible approach to phasing in the correction was offered by the Company
10 in its recent North Carolina rate case where the increase in the Basic Facilities Charge rate
11 was set equal to 50% of the difference between the current rate and the cost basis. Adopting
12 this approach would reduce the proposed Basic Facilities Charge to \$19.03."¹

13 **Q. DOES ORS AGREE WITH THE "ALTERNATIVE" AS ADDRESSED BY**
14 **COMPANY WITNESS WHEELER?**

15 **A.** No. Under the "alternative" discussed by Company witness Wheeler, residential
16 customers would still see a 110% increase in their monthly BFC. Although the Company's
17 newly proposed alternative yields a slightly better result compared to the original proposal
18 in the Company's Application, this alternative is deaf to the concerns expressed by
19 customers who filed hundreds of letters with the Commission. The Company's
20 "alternative" does not go far enough to address the rate design concerns voiced by
21 intervenors and customers.

¹ Company witness Wheeler's Rebuttal Testimony, p. 10.

1 Q. PLEASE EXPLAIN THE CORE PRINCIPLES THAT GUIDE UTILITY RATE
2 DESIGN.

3 A. In developing electric rates, both utilities and utility commissions, including this
4 Commission, have relied upon ten (10) rate design principles from Dr. James C. Bonbright
5 ("Bonbright Principles"). These principles are:

6 *Revenue-related Attributes:*

- 7 1. Effectiveness in yielding total revenue requirements under the fair-
8 return standard without any socially undesirable expansion of the rate
9 base or socially undesirable level of product quality and safety.
- 10 2. Revenue stability and predictability, with a minimum of unexpected
11 changes seriously adverse to utility companies.
- 12 3. Stability and predictability of the rates themselves, with a minimum of
13 unexpected changes seriously adverse to ratepayers and with a sense of
14 historical continuity. (Compare "The best tax is an old tax.")

15 *Cost-related Attributes:*

- 16 4. Static efficiency of the rate classes and rate blocks in discouraging
17 wasteful use of service while promoting all justified types and amounts
18 of use:
 - 19 a. In the control of the total amounts of service supplied by the
20 company,
 - 21 b. In the control of the relative uses of alternative types of service
22 by ratepayers (on-peak versus off-peak service or higher quality
23 versus lower quality service).
- 24 5. Reflection of all of the present and future private and social costs and
25 benefits occasioned by a service's provision (i.e., all internalities and
26 externalities).
- 27 6. Fairness of the specific rates in the apportionment of the total costs of
28 service among the different ratepayers so as to avoid arbitrariness and
29 capriciousness and to attain equity in three dimensions: (1) *horizontal*
30 (i.e., equals treated equally); (2) *vertical* (i.e., unequals treated
31 unequally); and (3) *anonymous* (i.e., no ratepayer's demands can be
32 diverted away uneconomically from an incumbent by a potential
33 entrant).
- 34 7. Avoidance of undue discrimination in rate relationships so as to be, if
35 possible, compensatory (i.e., subsidy free with no intercustomer
36 burdens).

8. Dynamic efficiency in promoting innovation and responding economically to changing demand and supply patterns.

Practical-related Attributes:

9. The related, practical attributes of simplicity, certainty, convenience of payment, economy in collection, understandability, public acceptability, and feasibility of application.

10. Freedom from controversies as to proper interpretation.²

Q. DOES THE COMPANY'S ALTERNATIVE RATE DESIGN ACHIEVE THE CORE BONBRIGHT PRINCIPLES?

A. The Company's proposal in the Application and the "alternative" discussed by Company witness Wheeler do address some of the Bonbright Principles; however, it falls far short in attributes 3, 4, 8, and 9. The Company's alternative rate design proposal does not have customer or intervenor support. The lack of public acceptability and drastic change in relation to the Company's historical rates fail to meet attributes #3 and #9 of the Bonbright Principles. The shifting of most costs to the fixed monthly BFC, and away from energy and demand charges, does not promote conservation (Bonbright Principle #4) and fails to promote new innovation and economic changes in demand and supply patterns (Bonbright Principle #8).

Q. DO YOU HAVE ANY ADDITIONAL REMARKS REGARDING THE COMPANY'S ALTERNATIVE PROPOSAL?

A. Yes. I would point out that the "alternative" discussed by Company witness Wheeler is based on the Company's initial approach in Docket E-2, Sub 1142 in its North Carolina application. In that docket, the Company requested fifty percent (50%) of what

² See James C. Bonbright, Albert L. Danielsen and David R. Kamerschen, "Principles of Public Utility Rates, 2nd Edition", Public Utilities Reports (March, 1988).

1 the Company thought they were entitled to in North Carolina.³ However, in South
2 Carolina, the Company requested 100% of the BFC increase in this proceeding. Company
3 witness Wheeler mischaracterizes the final order from the North Carolina Utility
4 Commission ("NCUC") when he states on page 10 of his rebuttal "[w]here the increase in
5 the Base Facilities Charge rate was set equal to 50% of the difference between the current
6 rate and cost basis." The final order from the NCUC approved an increase of the residential
7 BFC to \$14.00 per month⁴ which was not proposed by the Company.

8 **Q. COMPANY WITNESS WHEELER TESTIFIES THAT THE COMPANY'S**
9 **PROPOSAL REGARDING THE BFCS IS INTENDED TO ELIMINATE CROSS-**
10 **SUBSIDIZATION BETWEEN CUSTOMERS.^{5,6} DO YOU HAVE ANY REMARKS**
11 **REGARDING THIS?**

12 **A.** Yes. Company witness Wheeler does not discuss how the Company's proposal will
13 shift risk away from the Company and on to customers. By raising the fixed monthly BFC,
14 the Company's proposal will guarantee a larger stream of revenue from its customers, even
15 in the mild spring and fall months when customer usage is low. This issue of risk shift is
16 discussed in the Surrebuttal Testimony of ORS witness Dr. Ruoff.

17 **Q. WHAT IS ORS'S RECOMMENDATION REGARDING THE COMPANY'S**
18 **RESIDENTIAL, SMALL GENERAL SERVICE ("SGS"), AND SGS CONSTANT**
19 **LOAD BFCS?**

³ Company witness Wheeler's Direct Testimony in Docket E-2, Sub 1142, p. 15.

⁴ <https://starw1.ncuc.net/NCUC/ViewFile.aspx?id=d2b2a1a0-dae1-45de-af9c-c987d4aeddcc8>

⁵ Company witness Wheeler's Direct Testimony, pp. 8-9.

⁶ Company witness Wheeler's Rebuttal Testimony, p. 3.

1 A. ORS recommends that DEP be allowed to increase the BFCs for the residential,
2 SGS, and SGS Constant Load customers to recover up to twenty-five percent (25%) of the
3 approved revenue increase assigned to those classes.

4 Q. PLEASE DISCUSS ORS'S POSITION REGARDING THE RATE DESIGN
5 PROPOSALS DISCUSSED BY COMPANY WITNESS WHEELER?

6 A. It is premature to make the other rate design changes proposed by Company witness
7 Wheeler which include:

- 8 • Reducing the differential between the declining block in the winter months for
9 Schedule RES;
- 10 • Reducing the differential between summer and winter demand rates for Schedule
11 R-TOUD;
- 12 • Reducing the differential between summer and winter demand rates for Schedule
13 SGS-TOU;
- 14 • Reducing the differential between on-peak and off-peak energy rates for Schedule
15 SGS-TOU;
- 16 • Increasing the off-peak excess demand charge from \$2.95/kilowatt ("kW") to
17 \$3.30/kW rather than the same percentage as other demand charges for Schedule
18 SGS-TOU;
- 19 • Decreasing the off-peak excess demand charge from \$1.25/kW to \$0.89/kW rather
20 than the same percentage as other demand charges for Schedule LGS-TOU; and,
- 21 • Increasing the on-peak demand charge by only 50% of the energy rate rather than
22 the same percentage as the energy rate for Schedule LGS-TOU.

1 Upon completion of the deployment of Advanced Metering Infrastructure (“AMI”),
2 the Company should incorporate the additional data obtained from AMI into subsequent
3 requests to change rate designs. ORS recommends the Commission reject the proposals
4 put forth by Company witness Wheeler in his rebuttal testimony under the heading “Rate
5 Design Proposals.”⁷ If the Company were to begin making changes to its rate designs
6 regarding relationships between on-peak and off-peak and seasonal energy and demand
7 charges, customers may respond and change their usage patterns. Then, when the
8 Company incorporates the information available from AMI and Customer Connect and
9 offers customers new rate designs in a year or two, customers, who have adapted their
10 usage, may be confused and frustrated. The rate designs proposed by the Company in this
11 rate case may only be available for a short-term and provide limited benefit to the customer.

12 The Company’s AMI program and Customer Connect consolidation project will
13 give both DEP and the customers a higher degree of visibility into customer usage patterns.
14 Both DEP and the customer should leverage that enhanced data and benefit from the new
15 technology. If the Company’s proposal is accepted, it may cause customer confusion in
16 the future and inhibit the customer’s ability to leverage the enhanced data and benefit from
17 the new technology. Customers may see how they use energy and may be able to change
18 their usage patterns to better control their bills. DEP will have the opportunity to see how
19 their customers use energy, and should create and offer new innovative rate designs to
20 better meet customers’ needs. These new rate designs could include changes to BFCs,
21 energy and demand charges, seasonal rates and time-of-use rates. Company witness
22 Wheeler states that: “The Rate Design Team is working closely with the billing and

⁷ Company witness Wheeler’s Rebuttal Testimony, pp 12-15.

1 metering projects to ensure that they will support the types of rate designs that our
2 customers will need in the future.”⁸

3 **Q. IS IT ORS’S RECOMMENDATION THAT SOUTH CAROLINA CUSTOMERS**
4 **SHOULD NOT BE REQUIRED TO PAY FOR COSTS ASSOCIATED WITH**
5 **COAL ASH REMEDIATION AND DISPOSAL ACTIVITIES AT THE**
6 **COMPANY’S NORTH CAROLINA COAL PLANTS?**

7 **A.** No. ORS recommends that South Carolina customers be held harmless for the
8 incremental cost differences attributed to North Carolina state laws. This is discussed in
9 the Direct and Surrebuttal Testimony of ORS witness Wittliff.

10 **Q. IS IT ORS’S POSITION THAT NO SHARING OF COSTS BETWEEN DEP’S**
11 **SOUTH CAROLINA AND NORTH CAROLINA CUSTOMERS SHOULD**
12 **OCCUR?**

13 **A.** No. Company witness Wright has mischaracterized ORS’s position in this
14 proceeding. Proper cost of service allocations should be used for determining the costs to
15 serve each jurisdiction. His rebuttal testimony provides examples of costs that were
16 attributed to Federal, not state, requirements, and therefore, Company witness Wright’s
17 examples are misleading and should be rejected. Company witness Wright goes on to state
18 that the “Company acknowledges, and I [Company witness Wright] agree, that there are
19 times that direct allocation of costs between jurisdictions is appropriate.”⁹

20 **Q. HAS THE COMPANY EXCLUDED COSTS FROM THIS PROCEEDING THAT**
21 **HAVE BEEN INCURRED DUE TO NORTH CAROLINA LAW THAT SHOULD**
22 **NOT BE ALLOCATED TO SOUTH CAROLINA CUSTOMERS?**

⁸ Company witness Wheeler’s Direct Testimony, p 11.

⁹ Company witness Wright’s Rebuttal Testimony, p. 24.

1 A. Yes. The Company is not seeking recovery of certain costs that are associated with
2 the provision of drinking water to North Carolina residents.¹⁰ In addition, the Company
3 has excluded the costs to comply with the North Carolina Clean Smokestacks Act, North
4 Carolina Renewable Portfolio Standards, and the North Carolina Competitive Energy
5 Solutions for NC (HB.589) laws. ORS's recommendations to limit cost recovery for coal
6 ash is similar to the Company's initiatives to limit cost recovery attributed to North
7 Carolina legislation and programs that only benefit North Carolina customers.

8 Q. IN HIS REBUTTAL TESTIMONY, COMPANY WITNESS KERIN STATES THAT
9 THIS ISSUE HAS BEEN LITIGATED IN DOCKET NO. E-2, SUB 1142 AND
10 RULED ON BY THE NCUC. DOES THE RULING BY THE NCUC PRECLUDE
11 THIS COMMISSION FROM DETERMINING THE REASONABLENESS OF AND
12 RESPONSIBILITY FOR COAL ASH COSTS RECOVERY THAT IMPACTS
13 SOUTH CAROLINA CUSTOMERS?

14 A. No. The NCUC's determination of prudence, reasonableness, and allocation do
15 not restrict this Commission from making its own determinations regarding the prudence
16 and cost recovery responsibility for these costs. A decision in another state jurisdiction is
17 not binding on South Carolina. In Order No. 81-840, the Commission recognized that, in
18 matters under its discretion, it is not bound to follow the example of other jurisdictions.¹¹
19 The Commission has long asserted its authority over the South Carolina operations of Duke
20 Energy, and its predecessors, while recognizing that the NCUC has authority over DEP's
21 and Duke Energy Carolinas, LLC's ("DEC") North Carolina operations.^{12,13}

¹⁰ Company witness Kerin's Direct Testimony, p. 37.

¹¹ <https://dms.psc.sc.gov/Attachments/Order/f48ae6bc-b430-1d0f-e6aeed83c8b6b53d>, pp. 7-8.

¹² <https://dms.psc.sc.gov/Attachments/Order/7d88552b-eb08-d759-a7d786eddd18d7f3>, pp. 1-2.

¹³ <https://dms.psc.sc.gov/Attachments/Order/182e5fac-a002-61be-66ae5e6f3674f628>, p. 8.

1 **Q. PLEASE DISCUSS THE REVENUE REQUIREMENT AND HOW IT IS**
2 **DISTRIBUTED TO EACH CUSTOMER CLASS.**

3 **A.** Based on ORS's adjustments and a 9.30% return on equity ("ROE"), as
4 recommended by ORS witness Parcell, ORS recommends a reduction to the Company's
5 proposed revenue increase from \$68,668,000 (as filed in Company witness Bateman's
6 Exhibit 1) to \$32,130,000, which equates to an approximate 53% reduction or
7 approximately \$36,538,000, excluding the refund from the EDIT Rider. The revenue
8 increases for ORS's recommendation by customer class and individual rate schedules are
9 reflected in Surrebuttal Exhibit MSH-1. ORS recommends the revenues generated by the
10 billing determinants not exceed the target revenue for each class as proposed in Surrebuttal
11 Exhibit MSH-1.

12 Surrebuttal Exhibit MSH-1 demonstrates the percent increases proposed by ORS
13 for each customer class. The retail increases by customer class, including ORS's proposed
14 adjustments and the EDIT Rider, are as follows: 5.44% for Residential; 6.37% for SGS;
15 9.05% for SGS Constant Load; 1.32% for Medium General Service ("MGS"); 3.98% for
16 Large General Service ("LGS"); 0.06% for Seasonal and Intermittent Service ("S&I");
17 15.94% for Traffic Signal Service ("TSS"); -1.32% for Outdoor Lighting; and -8.69% for
18 Sports Field Lighting Service ("SFLS"). The overall total retail increase is 3.88%.

19 **Q. HOW DOES ORS'S DISTRIBUTION OF THE REVENUE REQUIREMENT**
20 **IMPACT THE RATE OF RETURN BY CUSTOMER CLASS?**

21 **A.** Surrebuttal Exhibit MSH-2 provides the resulting rate of return by customer class,
22 taking into account ORS's proposed adjustments and excluding the EDIT Rider. In
23 developing Exhibit MSH-2, ORS attempted to limit cross-subsidization by employing a

1 ±10% “band of reasonableness” relative to the overall retail rate of return. ORS was
2 successful in making an incremental movement toward comparable rates of return for all
3 customer classes. The returns by class are as follows: 4.60% for Residential; 4.51% for
4 SGS; 2.87% for SGS Constant Load; 7.89% for MGS; 4.99% for LGS; 9.49% for S&I;
5 -1.37% for TSS; 10.77% for Outdoor Lighting; and 21.24% for SFLS. The overall rate of
6 return for total retail is 5.68%. ORS recommends that any increase by the Commission
7 granted be allocated in a manner such that the returns by class represent an appropriate
8 movement toward comparable returns and bear a reasonable relationship to the Company’s
9 overall rate of return.

10 **Q. WHAT IS THE IMPACT OF THESE UPDATES ON ORS’S**
11 **RECOMMENDATIONS REGARDING THE COMPANY’S RESIDENTIAL, SGS,**
12 **AND SGS CONSTANT LOAD BFCS?**

13 **A.** Incorporating the updates from ORS witness Smith, and using the methodology
14 detailed in my Direct testimony, ORS recommends the BFC be increased to \$11.78 per
15 month for residential customers, \$12.34 per month for SGS customers, and \$11.31 per
16 month for SGS Constant Load customers as shown on Surrebuttal Exhibit MSH-3.

17 **Q. HAS ORS UPDATED ITS RECOMMENDATION REGARDING THE**
18 **COMPANY’S PROPOSED EDIT RIDER?**

19 **A.** Yes. ORS has updated its calculations of the first-year return of the proposed EDIT
20 Rider based on a 9.30% ROE and 4.16% Cost of Debt, as recommended by ORS witness
21 Parcell in his surrebuttal testimony, to arrive at a total return of EDIT Rider revenue of
22 (\$9,977,484) for the first year. Supplemental Exhibit MSH-4 allocates this total to the
23 various customer classes.

1 Q. HAS ORS REVIEWED THE IMPACT OF THE COMPANY'S PROPOSED RATES
2 ON THE TYPICAL RESIDENTIAL CUSTOMER'S MONTHLY BILL?

3 A. Yes. Surrebuttal Exhibit MSH-5 shows the typical monthly residential bill for a
4 customer on Rate RES with 1,000 kilowatt-hours ("kWh") consumption for DEP's
5 currently approved rates and the rates proposed in this proceeding. For information
6 purposes, ORS provided the same information for South Carolina Electric & Gas Company
7 ("SCE&G"), DEC, Lockhart Power Company ("Lockhart"), South Carolina Public Service
8 Authority ("Santee Cooper"), and the most recent U.S. Energy Information Administration
9 ("EIA") data for the South Atlantic region of the United States.

10 Q. AFTER INCORPORATING ORS'S ADJUSTMENTS AND
11 RECOMMENDATIONS INTO THE COMPANY'S APPLICATION, WHAT IS
12 THE NET IMPACT ON THE TYPICAL MONTHLY BILL FOR A TYPICAL
13 RESIDENTIAL CUSTOMER?

14 A. The monthly bill for the typical residential customer on Rate RES using 1,000 kWh
15 ("Typical Bill") will increase by approximately \$8.97 from \$122.49 to \$131.46, or 7.3%,
16 exclusive of the EDIT Rider. Including the EDIT Rider, the Typical Bill would decrease
17 by an additional (\$2.26) for a net increase of \$6.71. Inclusive of all changes, the Typical
18 Bill would increase from \$122.49 to approximately \$129.20, or 5.5%.

19 Q. WILL YOU UPDATE YOUR SURREBUTTAL TESTIMONY BASED ON
20 INFORMATION THAT BECOMES AVAILABLE?

21 A. Yes. ORS fully reserves the right to revise its recommendations via supplemental
22 testimony should new information not previously provided by the Company, or other
23 sources, become available.

- 1 Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?
- 2 A. Yes, it does.

1 THE EXAMINATION BY MR. BATEMAN CONTINUES.

2 Q Mr. Wittliff, would you please state your full name.
3 and occupation?

4 A (WITTLIFF) I'm Dan Wittliff, managing director of
5 Environmental Services for GDS Associates in
6 Austin, Texas.

7 Q And are you the same Dan Wittliff who prefiled 46
8 pages of direct testimony in this docket on March
9 4th, 2019?

10 A (WITTLIFF) Yes.

11 Q Do you have any changes, edits, or corrections to
12 your prefiled direct testimony?

13 A (WITTLIFF) Yes. Oh, I'm sorry. No. I beg your
14 pardon. No.

15 Q And if I asked you today the same questions as
16 those contained in your prefiled direct testimony,
17 would your answers remain the same?

18 A (WITTLIFF) Yes.

19 Q Okay.

20 MR. BATEMAN: At this time, Mr. Chairman, ORS
21 asks that Mr. Wittliff's prefiled direct
22 testimony be read into the record as if given
23 orally from the stand.

24 CHAIRMAN RANDALL: Mr. Wittliff's prefiled
25 direct testimony will be read into the record

1 as though given orally from the stand.

2 MR. BATEMAN: Thank you.

3 Q And Mr. Wittliff, did you file as an attachment to
4 your direct testimony a series of exhibits marked
5 Exhibit DJW-1 through DJW-9 -- 9.3, excuse me?

6 A (WITTLIFF) Yes.

7 Q Thank you. And do you have any changes, edits, or
8 corrections to any of those exhibits?

9 A (WITTLIFF) Yes. I would like to remove Exhibit
10 5.2.1 and change the effective date in Exhibit
11 4.7.1, Row 2, Column 3 from 10/06/2016 to
12 10/19/2015.

13 Q Thank you, Mr. Wittliff.

14 MR. BATEMAN: Mr. Chairman, may we approach
15 the court reporter?

16 CHAIRMAN RANDALL: Yes.

17 MR. BATEMAN: Mr. Chairman, we're currently
18 handing the court reporter Mr. Wittliff's
19 direct testimony exhibits, which are quite
20 voluminous. We have separated them via
21 paperclip. Additionally -- additionally,
22 they're labeled up top and -- and on these
23 binders in an effort to assist the court
24 reporter.

25 At this time we would ask that these

1 exhibits be marked for identification and
2 entered into the record as the next composite
3 hearing exhibit.

4 CHAIRMAN RANDALL: Mr. Wittliff's exhibits
5 with the corrections noted in his last
6 statement will be entered as Exhibit Number
7 59.

8 MR. BATEMAN: Thank you, Mr. Chairman.

9 (WHEREUPON, Hearing Exhibit 59 was
10 marked and received in evidence.)

11 THE EXAMINATION BY MR. BATEMAN CONTINUES.

12 Q And Mr. Wittliff, did you also prepare 11 pages of
13 surrebuttal testimony in this docket which was
14 filed with the Commission on March 25th, 2019?

15 A (WITTLIFF) Yes.

16 Q Do you have any changes, edits, or corrections to
17 your prefiled surrebuttal testimony?

18 A (WITTLIFF) Yes. I do. On Page 7, Line 3, 2.16
19 million should be changed to 2.016 million. And,
20 additionally, on Page 7, Line 5, 2.16 million
21 should be changed to 2.016 million.

22 Q Thank you, Mr. Wittliff.

23 MR. BATEMAN: Mr. Chairman, ORS requests that
24 Mr. Wittliff's prefiled surrebuttal testimony
25 be read into the record as if given orally

1 from the stand.

2 CHAIRMAN RANDALL: Mr. Wittliff's prefiled
3 surrebuttal testimony will be entered into the
4 record as though given orally from the stand.

5 MR. BATEMAN: Thank you.

6 Q And, Mr. Wittliff, did you also file, as an
7 attachment to your surrebuttal testimony, a series
8 of exhibits marked as Surrebuttal Exhibit DJW-1
9 through Surrebuttal Exhibit DJW-4?

10 A (WITTLIFF) Yes.

11 Q Do you have any changes -- changes, edits, or
12 corrections to any of those exhibits?

13 A (WITTLIFF) No.

14 MR. BATEMAN: Mr. Chairman, at this time, I'd
15 ask that Mr. Wittliff's Surrebuttal Exhibits
16 DJW-1 through Surrebuttal Exhibit DJW-4 be
17 marked for identification and entered into the
18 record as the next composite hearing exhibit.

19 CHAIRMAN RANDALL: Mr. Wittliff's Surrebuttal
20 Exhibits DJW-1 through 4 will be entered as
21 Hearing Exhibit Number 60.

22 MR. BATEMAN: Thank you, Mr. Chairman.

23 (WHEREUPON, Hearing Exhibit 60 was
24 marked and received in evidence.)

25 MR. BATEMAN: Mr. Chairman, if it pleases the

1 Commission, I have a few questions and answers
2 that summarize Mr. Wittliff's direct and
3 surrebuttal testimonies.

4 THE EXAMINATION BY MR. BATEMAN CONTINUES.

5 Q Mr. Wittliff, have you ever testified before the
6 South Carolina Public Service Commission?

7 A (WITTLIFF) Yes. I testified before the South
8 Carolina Public Service Commission on March 25th,
9 2019 in the matters relating to Duke Energy
10 Carolinas rate case in Docket Number 2018-319-E.

11 Q Mr. Wittliff, briefly describe your background and
12 experience.

13 A (WITTLIFF) I have a bachelor's degree in
14 mechanical engineering from Southern Methodist
15 University and a master's degree in business
16 administration from the University of Oklahoma.
17 I'm a licensed professional engineer, licensed to
18 practice in Texas, Tennessee, and South Carolina.
19 I've been a licensed professional engineer since
20 1980. I'm also a board-certified environmental
21 engineer with the American Academy of Environmental
22 Engineers and Scientists, where I served as a
23 trustee from 2010 to 2015. I am past president of
24 the Texas Society of Professional Engineers and a
25 past president of the National Society of

1 Professional Engineers, where I currently chair the
2 Committee on Policy and Advocacy, which promotes
3 positions of interest to professional engineers
4 around the country.

5 My career in power began in 1981 when I went
6 to work for West Texas Utilities as a results
7 engineer. I was an assistant superintendent;
8 that's the operations supervisor for a gas plant.
9 And then I became the plant engineering supervisor
10 at a coal plant during the startup and initial
11 operations. I was promoted to environmental
12 manager for the utility where I served until 1995,
13 when I moved to Austin to become the first chief
14 engineer of the Texas Natural Resource Conservation
15 Commission. That's the senior technical officer in
16 an organization second in size to EPA as an
17 environmental regulator.

18 I was there for 4 1/2 years as the chief
19 engineer, and then I went into consulting. I've
20 been with GDS, my current employer, since 2007.

21 Q And when were you retained by ORS?

22 A (WITTLIFF) We were approached and retained in the
23 spring of 2017, but our work didn't actually begin
24 until May 2017.

25 Q And Mr. Wittliff, what was the purpose of your

1 review in this docket?

2 A (WITTLIFF) GDS was engaged by ORS to answer a wide
3 array of -- a wide array of questions regarding the
4 cost impacts of the Company's CCR disposal and
5 remediation activities. More specifically, we were
6 asked by -- we were asked to determine the marginal
7 impact of the North Carolina Coal Ash Management
8 Act of 2014 and any subsequent amendments on CCR
9 remediation and disposal costs. CAMA was passed in
10 response to the February 2014 ash spill at Duke --
11 Duke's Dan River generating plant and six decades
12 of ash mismanagement in North Carolina.

13 Q Mr. Wittliff, under what underlying principle did
14 you base your review?

15 A (WITTLIFF) GDS relied upon the South Carolina
16 regulatory context provided by ORS early on in our
17 work. As stated my direct testimony, I understood,
18 "It is the position of ORS that costs incurred as
19 the result of jurisdictional laws should not lead
20 to increased costs outside that jurisdiction."

21 This matter is addressed in the cost-of-
22 service testimony of ORS witness Seaman-Huynh.
23 CAMA being too costly did not play a role in my --
24 my recommendations.

25 Q Mr. Wittliff, was determining the impacts of CAMA a

1 complicated process?

2 A (WITTLIFF) Yes. The costs associated with CCR
3 remediation and closure are affected in material
4 ways by a complex set of court cases, consent
5 agreements, Commission decisions, federal rules,
6 state regulations as well as state laws such as
7 CAMA and the subsequent amendments.

8 While determining with great precision the CCR
9 cost increases created by CAMA, above and beyond
10 what the federal rules require, is a difficult
11 task. I made what I believe is a good-faith
12 calculation of those impacts.

13 Q And in what ways has CAMA increased coal combustion
14 residual costs?

15 A (WITTLIFF) I found that CAMA increased CCR-related
16 costs in three ways at DEP plants. First,
17 expenditures of -- for plants not covered at all by
18 the CCR rules, and that would include Cape Fear as
19 falling into that category.

20 The second, is for closure/excavation options
21 not required under the CCR -- CCR rules, but
22 required under CAMA or North Carolina court
23 decisions. Cape Fear, HF Lee, Weatherspoon fall
24 into this category.

25 And third, expenditures for the actions that

1 would not have been required at this time under the
2 CCR rules but are subject to accelerated schedules
3 under CAMA. Asheville and Sutton fall under this
4 category.

5 Q And Mr. Wittliff, what information did you rely on
6 to make your recommendations?

7 A (WITTLIFF) In quantifying these cost impacts, I
8 relied on information obtained during my site
9 visits to the Company's coal-fired power plants and
10 CCR impoundments, my review of relevant and --
11 state and federal laws and regulations, my
12 evaluation of Company responses to data requests
13 relevant to CCR management practices and my review
14 of other documents relevant to CCR management and
15 remediation.

16 Some or all of the expenses sought by DEP for
17 compliance at five DEP plants result solely from
18 CAMA or South Carolina -- and South Carolina
19 ratepayers should not have to pay for increased
20 costs due solely as a result of North Carolina
21 laws.

22 Q And can -- can you please explain Table 5.4 from
23 your direct testimony?

24 A (WITTLIFF) Table 5.4 in my direct testimony is
25 what is being sought for recovery, my recommended

1 disallowances, and the premise on which that
2 recommendation is based. I recommend that the
3 Commission disallow at this time \$333,480,308 of
4 the \$635,040,092 in ARO deferrals being requested
5 by the Company in this proceeding.

6 Please note that no disallowance is
7 recommended for Mayo or Roxboro at this time whose
8 closures were not increased as a result of CAMA in
9 this proceeding.

10 In addition, no disallowance was recommended
11 for Robinson, which was closed under a consent
12 agreement with South Carolina DHEC.

13 Q Mr. Wittliff, is your calculation of allowable
14 costs reliable and supportable?

15 A (WITTLIFF) Yes. I've had sufficient time to
16 analyze the data provided by the Company and an
17 additional year of data on which to base my
18 recommendation.

19 Q And under what basis are you recommending a
20 disallowance at the Cape Fear site?

21 A (WITTLIFF) The current CCR rules apply only to
22 sites that were active as of October 19th, 2015.
23 Cape Fear was not impacted by the CCR rule, and it
24 was designated for closure under CAMA. Cape Fear
25 was designated as a beneficiation site under CAMA

1 and all of the costs incurred to date at Cape Fear
2 were entirely the result of CAMA.

3 Q Mr. Wittliff, under what basis are you recommending
4 a disallowance at the HF Lee and Weatherspoon
5 sites?

6 A (WITTLIFF) HF Lee and Weatherspoon had additional
7 costs associated with beneficiation above and
8 beyond what the federal rules -- federal CCR
9 requirements. I would also like to note that I do
10 not recommend for disallowance all of the costs at
11 these sites, only the additional incremental costs
12 that I have identified were above and beyond the
13 federal CCR requirements.

14 Q Is beneficiation generally more expensive than
15 other closure options?

16 A (WITTLIFF) Yes.

17 Q Were you able to identify any net savings at Cape
18 Fear and the HF Lee sites as compared to closure
19 without beneficiation?

20 A (WITTLIFF) No. And -- and no supporting
21 information was provided that could substantiate
22 the claim. The -- further, the basis for
23 comparison was not provided and is not likely --
24 not a likely direct comparison to the federal CCR
25 requirements.

1 Q Mr. Wittliff, why do you recommend a disallowance
2 of costs at Asheville and Sutton?

3 A (WITTLIFF) Much of the cost at Asheville and
4 Sutton were the result of accelerated time lines
5 and caused by being designated high-priority sites
6 by CAMA. The designation of a high-priority site
7 under CAMA required DEP to meet a August 1st, 2019
8 closure deadline to dispose of the CCR at these
9 sites. I would like to -- to note that I did not
10 recommend a disallowance of all the costs at these
11 sites, only additional incremental incurred costs
12 that I have identified were the direct result of
13 CAMA.

14 Q And was that August 1st, 2019 deadline an
15 accelerated deadline?

16 A (WITTLIFF) Yes.

17 Q Mr. Wittliff, can you provide an example of the
18 additional costs that were incurred at Sutton as a
19 result of CAMA?

20 A (WITTLIFF) Yes. An example of those costs is the
21 -- the 2.016 million tons of CCR that were hauled
22 by truck or rail to the Brickhaven mine from Sutton
23 to meet the accelerated August 1st, 2019 deadline
24 at Sutton.

25 Q Thank you, Mr. Wittliff.

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23 (PURSUANT TO PREVIOUS INSTRUCTION,

24 THE PREFILED DIRECT TESTIMONY OF

25 DAN J. WITTLIFF FOLLOWS.)

DIRECT TESTIMONY AND EXHIBITS OF**DAN J. WITTLIFF, P.E., BCEE****ON BEHALF OF****THE SOUTH CAROLINA OFFICE OF REGULATORY STAFF****DOCKET NO. 2018-318-E****IN RE: APPLICATION OF DUKE ENERGY PROGRESS, LLC****FOR ADJUSTMENT IN ELECTRIC RATE SCHEDULES AND TARIFFS****AND REQUEST FOR AN ACCOUNTING ORDER****TABLE OF CONTENTS**

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I. INTRODUCTION**Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A. My name is Dan Wittliff. My business address is 919 Congress Avenue, Suite 1110,
Austin, Texas 78701.

Q. PLEASE OUTLINE YOUR FORMAL EDUCATION.

THE OFFICE OF REGULATORY STAFF
1401 Main Street, Suite 900
Columbia, SC 29201

1 A. I am a 1972 graduate of Southern Methodist University where I earned a Bachelor
2 of Science degree in mechanical engineering and membership in Pi Tau Sigma mechanical
3 engineering honorary. In 1975, I earned a Master of Business Administration from the
4 University of Oklahoma where I was elected to membership in the Beta Gamma Sigma
5 business honorary society.

6 Q. WHAT IS YOUR PRESENT POSITION?

7 A. I am Managing Director of Environmental Services for GDS Associates, Inc.
8 ("GDS") in Austin, Texas.

9 Q. WOULD YOU PLEASE DESCRIBE GDS?

10 A. GDS is an engineering and consulting firm headquartered in Marietta, Georgia with
11 offices in Austin, Texas; Auburn, Alabama; Manchester, New Hampshire; Madison,
12 Wisconsin; and Orlando, Florida. GDS provides technical and financial consulting services
13 to a nationwide base of clients including utilities, Public Service Commissions, large
14 consumers of energy, and various agencies. Areas of expertise include power generation
15 support and management consulting, power supply and transmission planning, rate
16 consulting, distribution services, least cost planning, environmental including permitting
17 and compliance, and litigation support. Power generation support services provided by the
18 firm include plant operational monitoring on behalf of co-owners of fossil and nuclear
19 power plants, plant ownership feasibility studies, plant management audits, plant
20 construction cost and schedule analyses, evaluations of power plant O&M costs and
21 budgeting practices, production cost modeling and plant outage and replacement power
22 cost evaluations, and environmental compliance.

23 Q. PLEASE STATE YOUR PROFESSIONAL EXPERIENCE.

1 A. I have been employed by GDS since January 2007. I manage complex and multi-
2 media (e.g., air, water, wastewater, and solid waste) environmental projects including
3 natural gas and coal power plant development, operations, and compliance. Experience
4 previous to joining GDS includes serving as the first Chief Engineer for the Texas Natural
5 Resource Conservation Commission, now known as the Texas Commission on
6 Environmental Quality, which is second only to the Environmental Protection Agency in
7 terms of size. During my four and half years as Chief Engineer, I advised the
8 commissioners of the agency on all aspects of environmental permitting and compliance.
9 This scope spanned the full range of utility plant operations including coal plant operations.
10 In addition, I oversaw the functions of innovative technology, toxicology, and pollution
11 control property tax abatements. Further, as Chief Engineer, I resolved technical
12 disagreements between permittees and the agency and within the agency. Before my
13 service with the Texas Natural Resource Conservation Commission, I served in numerous
14 supervisory positions with West Texas Utilities Company, headquartered in Abilene,
15 Texas, managing the company's multi-media environmental compliance program and
16 overseeing power station performance including issues related to air pollution, water
17 treatment, industrial hygiene, and solid waste disposal. Coal-fired plant operations and
18 compliance were a major part of my responsibilities. Immediately prior to joining GDS
19 Associates, I was Principal of Dan Wittliff Consulting, PLLC. This firm provided
20 professional environmental engineering services that focused on related engineering,
21 regulatory affairs, and energy systems operations, management, and compliance including
22 coal-fired plant operations and compliance. I am a Board Certified Environmental
23 Engineer through the American Academy of Environmental Engineers and Scientists,

1 where I served as a member of the Board of Trustees from 2010 through 2015. I am also
2 a licensed professional engineer. My resume and list of publications are included as
3 Exhibit DJW-1.

4 **Q. HAVE YOU SERVED IN LEADERSHIP ROLES RELATED TO THE**
5 **ENGINEERING PROFESSION?**

6 **A.** Yes. I served in various state and national positions with the National Society of
7 Professional Engineers ("NSPE"). I served as president of NSPE from 2012 to 2013 and
8 served on the Board of Directors for eight years. I also served as president of the Texas
9 Society of Professional Engineers from 2002 to 2003. From 2017 to 2018, I served as
10 President of the Engineers' Week Foundation Board of Directors. Since 2015, I have
11 chaired NSPE's Committee on Policy and Advocacy, which develops policy and position
12 statements on key issues affecting licensed engineers across the country. My committee
13 and I recently rewrote the organization's professional policies for Energy and Environment
14 along with eight other policies.

15 **Q. HAVE YOU SERVED IN LEADERSHIP ROLES OUTSIDE OF YOUR**
16 **PROFESSION?**

17 **A.** Yes. I retired from the Air Force Reserve in 2002 at the rank of Colonel. I served
18 nine years on active duty and 21 years in the reserves. The majority of my active duty was
19 spent in communications maintenance and operations culminating in a stint as commander
20 of a unit on a mountaintop in Central Turkey. When I transferred to the reserves, I joined
21 a combat civil engineering squadron as chief of utilities and structures. From 1996 to 2002,
22 I returned to environmental and civil engineering first as Senior Individual Mobilization
23 Augmentee ("IMA") to the Environmental Director for the Ogden Air Logistics Center,

1 then as Senior IMA to the Commander of the Civil Engineering Group at Hill Air Force
2 Base ("AFB"), finishing my career as Senior IMA to the Command Civil Engineer of Air
3 Force Materiel Command. At Hill AFB, I advised senior leadership on issues related to
4 pollution plume remediation and interfaced with the Utah environmental regulators on air
5 permitting and emissions from engines at the base.

6 **Q. PLEASE DISCUSS YOUR COAL COMBUSTION RESIDUALS EXPERIENCE.**

7 **A.** My coal combustion residuals experience includes the initial startup and testing of
8 fly ash removal, storage, and disposal facilities when I was plant engineering supervisor at
9 Oklaunion Power Station, a 720 MW coal-fired plant near Vernon, Texas from 1985 to
10 1990. When I served as manager of environmental services for West Texas Utilities
11 Company, from 1991 to 1995, I chaired the Solid Waste Task Force for the Electric
12 Reliability Council of Texas from 1994 to 1995 and participated in the Texas Coal Ash
13 Utilization Group from 1993 to 1995. When I became chief engineer of Texas Natural
14 Resource Conservation Commission in 1995, I led the resolution of coal ash beneficial
15 reuse issues between the state's various electric utilities and the agency's solid waste
16 program management and policy staff. I have also delivered a paper, "Regulatory
17 Advances in Texas," Workshop on Coal Combustion Products, American Coal Ash
18 Association. In the paper, I delineated the results of work between the agency and industry
19 to further define and expand beneficial reuses of coal ash.

20 **Q. HAVE YOU GIVEN TESTIMONY BEFORE?**

21 **A.** Yes. I filed direct testimony before the South Carolina Public Service Commission
22 on behalf of the South Carolina Office of Regulatory Staff in the matter of Docket No.
23 2018-319-E on February 25, 2019. I also filed direct testimony and testified before the

North Carolina Utilities Commission in No. E-7 Sub 1146 on January 23, 2018 and in Docket No. E-2 Sub 1142 on December 4, 2017. Recently, I also offered testimony before the Texas State Office of Administrative Hearings, Docket No. 473-14-2252, PUC Docket No. 42087, and before the Florida Public Service Commission, Docket No. 150075-EI.

II. PURPOSE AND SUMMARY OF TESTIMONY

Q. BY WHOM HAVE YOU BEEN RETAINED IN THIS PROCEEDING?

A. GDS has been retained by the South Carolina Office of Regulatory Staff ("ORS").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to address the certain issues regarding Duke Energy Carolinas, LLC's ("DEC" or "Company") and Duke Energy Progress, LLC's ("DEP") (collectively the "Companies") management of their Coal Combustion Residuals (CCR) impoundments including any related legal, regulatory, and cost consequences stemming from that management including:

- 1) The evolution of coal ash management and its regulations;
- 2) The evolution of the Coal Combustion Residuals Final Rule;
- 3) Company History & Current Activities;
- 4) North Carolina's Coal Ash Management Act ("CAMA") History;
- 5) A determination whether the Company met environmental compliance and/or best engineering/environmental management practices and if not, whether any resulting cost consequences were either avoidable or unreasonably high; and
- 6) A determination of the extent and timing of ash removal and other compliance costs attributable solely to North Carolina's CAMA or North Carolina court decisions.

1 Q. WHAT COAL ASH MANAGEMENT MATERIAL DID YOU REVIEW AND
2 RELY ON TO DEVELOP YOUR TESTIMONY?

3 A. My review included:

- 4 • Information gained from site visits to DEP's Asheville ("Asheville"), Cape Fear ("Cape
5 Fear"), H.F. Lee ("H.F. Lee"), Mayo ("Mayo"), Robinson ("Robinson"), Roxboro
6 ("Roxboro"), Sutton ("Sutton"), and Weatherspoon ("Weatherspoon") Steam Stations
7 in North and South Carolina and associated CCR facilities;
- 8 • DEP responses to data requests addressing the Company's past and current coal
9 combustion residual practices at each applicable Company facility;
- 10 • Inspection reports related to dam safety of CCR impoundments;
- 11 • Remediation options analyses;
- 12 • Ash Pond Closure plans;
- 13 • Testimonies of Company officials and representatives before the South Carolina Public
14 Service Commission ("Commission") related to these matters;
- 15 • Relevant Court Orders, including but not limited to Federal and State Orders related to
16 the Company's failure to comply with Federal and State laws regarding the
17 management of coal ash prior to the enactment of CAMA;
- 18 • Environmental Protection Agency ("EPA") and other governmental reports;
- 19 • Utilities Solid Waste Activities Group documents;
- 20 • The rationale for the enactment of the federal CCR Rule and the enactment of CAMA
21 contained in those and associated preambles;

- 1 • Insurance documents of the Company from 1996 that indicate the Company understood
- 2 it had a significant legal exposure regarding discharges of pollutants from ash/coal
- 3 combustion residual ponds at its coal-fired power plants;
- 4 • Information and documents provided by the Company in response to data requests;
- 5 • Duke Energy's SEC 10-K filings for the years 2008-2016; and
- 6 • Minutes of Environmental Review Commission of the North Carolina General
- 7 Assembly meetings for the years 2010 through 2014.

8 I also relied on my professional training and experience as a licensed engineer with
 9 over thirty (30) years of experience at coal-fired power plants including environmental
 10 controls, regulations, and compliance from the diverse perspectives of industry, regulatory
 11 agency, and consultant.

12 **Q. PLEASE SUMMARIZE YOUR TESTIMONY IN THIS PROCEEDING.**

13 **A.** In my testimony, I will lay out the evolution of coal ash management regulations to
 14 provide context for the development of the Federal CCR Rules and the North Carolina
 15 CAMA. I will also describe the role that the February 2014 spill at Dan River Steam
 16 Electric Station played in the development of CAMA. Additionally, I will delineate the
 17 CCR management solutions employed by coal-fired power plants generally and DEP
 18 specifically.

19 For more discussion on these jurisdictional allocations, please see ORS witness
 20 Seaman-Huynh's testimony regarding cost of service, and specifically the discussion
 21 related to jurisdictional allocations. While many of the costs requested by DEP in this case
 22 resulted from the necessity to comply with the federal CCR Rules or with requirements
 23 established by South Carolina authorities and have been recommended for recovery, some

1 or all the expenses sought by DEP for compliance at Asheville, Cape Fear, H.F. Lee,
2 Sutton, and Weatherspoon result solely from CAMA or the North Carolina Mountain
3 Energy Act of 2015 and South Carolina ratepayers haven't traditionally had to pay for costs
4 incurred solely as a result of North Carolina laws.

5 Please note that, while I reviewed the CCR expenses (for both Asset Retirement
6 Obligation ("ARO") and non-ARO) provided by DEP through December 31, 2018 and
7 forecasts beyond that time, my recommendations for allowances and disallowances are
8 based on the actuals for ARO deferrals submitted by DEP in Kerin Exhibit 10 (see Exhibit
9 DJW-3.1.2) and Non-ARO Expenses in DEP Schedule 1803 (see Exhibit DJW-3.5.1)
10 through September 30, 2018. Any deferral amounts beyond that date should be addressed
11 in a subsequent proceeding.

12 Regarding the non-ARO expenses claimed in Schedule 1803 (Exhibit DJW-3.5.1),
13 the data for DEP non-ARO expenses lacks granularity sufficient to do a detailed analysis
14 of these costs. However, the \$6,279,603 claimed through September 30, 2018 appears
15 reasonable and I recommend it be allowed. Any non-ARO expenses beyond that date
16 should be addressed in a subsequent proceeding.

17 Tables 5.2 and 5.4, below, summarize what is being sought for recovery, my
18 recommended disallowances, and the premise on which these recommendations are based.
19 I recommend that the Commission disallow \$333,480,308 of the \$635,040,092¹ in ARO
20 deferrals being requested by the Company in this proceeding.

¹ This number includes \$202,062,063 of spend from 01/01/15 through 06/30/16, requested in Docket No. 2016-227-E, and recovered by DEP pursuant to a Settlement Agreement approved in Commission Order No. 2016-871. Pursuant to Order No. 2016-871 and the Settlement Agreement, "inclusion of certain coal ash expenses in [that] case has no precedential effect and will not prejudice the position of any Party in any future proceeding before the Commission."

1 **III. EVOLUTION OF COAL ASH MANAGEMENT REGULATIONS**

2 **Q. HOW DID COAL ASH MANAGEMENT AND ITS REGULATIONS EVOLVE?**

3 **A.** Federal Surface Water and Wastewater Regulations – The Federal Water Pollution
4 Control Act of 1948 was the first major U.S. law to address water pollution. Growing
5 public awareness and concern for controlling water pollution led to sweeping amendments
6 in 1972. As amended in 1972, the law became commonly known as the Clean Water Act
7 (“Clean Water Act”). Wastewater from steam electric power generating units is regulated
8 under the Clean Water Act National Pollutant Discharge Elimination System (“NPDES”).

9 The 1972 Clean Water Act established the basic structure for regulating pollutant
10 discharges into the waters of the United States and gave the EPA the authority to implement
11 pollution control programs such as setting wastewater standards for the electric utility
12 industry based on the fact that CCRs and coal ash wastewater are pollutants. The Clean
13 Water Act maintained existing requirements to set water quality standards for all
14 contaminants in surface waters and made it unlawful for any person to discharge any
15 pollutant from a point source into navigable waters unless a permit was obtained under its
16 provisions.

17 In accordance with 40 CFR 122.41, the following standard conditions are
18 incorporated into all NPDES permits:

- 19 • **Duty to comply.** The permittee must comply with all conditions of this permit. Any
20 permit noncompliance constitutes a violation of the Clean Water Act and is grounds
21 for enforcement action; for permit termination, revocation and reissuance, or
22 modification; or denial of a permit renewal application. (see 40 CFR 122.41(a))

- 1 • **Duty to mitigate.** The permittee shall take all reasonable steps to minimize or prevent
2 any discharge or sludge use or disposal in violation of this permit which has a
3 reasonable likelihood of adversely affecting human health or the environment. (see 40
4 CFR 122.41(d))
- 5 • **Proper operation and maintenance.** The permittee shall at all times properly operate
6 and maintain all facilities and systems of treatment and control (and related
7 appurtenances) which are installed or used by the permittee to achieve compliance with
8 the conditions of the permit. (see 40 CFR 122.41(e))
- 9 • **North Carolina Groundwater (2L) Rules** – In 1979, North Carolina established rules
10 (2L Rules) to protect, maintain, preserve, and enhance the quality of the groundwaters
11 of the State, prevent and abate pollution and contamination of the waters of the state,
12 and to protect public health. These rules require that all entities, including the utility
13 industry, conducting or controlling an activity resulting in the discharge of a waste or
14 hazardous substance to the groundwaters of the State take immediate action to
15 terminate and control the discharge, mitigate any hazards resulting from exposure to
16 the pollutants and notify the Department of Environmental Quality of any such
17 discharge. If as the result of any entity conducting or controlling an activity not
18 permitted by the North Carolina Department of Environmental Quality (“NC DEQ”)
19 which results in an increase in the concentration of a substance in excess of the 2L
20 standards, that entity must implement an approved corrective action plan for restoration
21 of groundwater quality.
- 22 • **1979 Los Alamos Report** – In May 30, 1979, the Department of Energy (“DOE”)
23 directed the University of California’s Los Alamos Scientific Laboratory to prepare a

1 paper on the topic of the disposal and reclamation of coal and uranium wastes (Exhibit
2 DJW-4.8). The report indicated that there was a growing awareness that the discarded
3 wastes from coal combustion were a serious potential source of surface and
4 groundwater contamination and that the wastes have the potential for causing great
5 environmental damage if not properly handled. Regarding disposal in ash basins, the
6 authors concluded:

7 The control of contaminated leachates and seepages from disposal ponds for fly ash
8 and scrubber sludge represents, perhaps, the most significant environmental problem
9 facing the southwestern coal and utilities industries. Many trace contaminants that are
10 present in the fly ash or sludge can be mobilized by the waters in the ponds. The transport
11 of contaminants from the disposal ponds into shallow or deep aquifers could result in the
12 degradation of the quality of these waters. Frequently, ash and sludge disposal areas are
13 lined with impermeable materials to reduce the loss of water from them. Nonetheless,
14 careful monitoring of the surface and subsurface effluents from disposal ponds is a
15 necessity in a well-planned disposal and reclamation scheme for coal combustion wastes.

- 16 • **1988 EPA Report to Congress** - The EPA submitted its report to Congress on “Wastes
17 from the Combustion of Coal by Electric Utility Power Plants” in February 1988. This
18 report addressed CCR from electric utility power plants, voicing concerns over the
19 “substantial quantities of wastes” produced by these plants because of the “increasing
20 reliance on coal for producing electricity.” (see Exhibit DJW-4.6 p ES-2) The report
21 forecasted a growth in the production of coal ash and flue gas desulfurization waste from
22 a combined 80 million tons per year in 1984 to 170 million tons in 2000.

1 The report also observed that “[t]he primary concern regarding the disposal of
2 wastes from coal-fired power plants is the potential for waste leachate to cause ground-
3 water contamination” from the potentially toxic metals in the ash. (see Exhibit DJW-4.6 p
4 ES-3) Furthermore, the report observed that “[m]ost utility waste management facilities
5 were not designed to provide a high level of protection against leaching.” (see Exhibit
6 DJW-4.6 p ES-3) In 1988, only about twenty-five percent (25%) of all facilities had liners
7 of any kind (e.g., clay, synthetic, or composite), although that number had increased to
8 forty percent (40%) of facilities built since 1975. (see Exhibit DJW-4.6 p ES-3)

- 9 • **Federal Coal Combustion Residual Rule** – Throughout the evolution of the CCR Rule,
10 beginning with the enactment of the Resource Conservation and Recovery Act (“RCRA”)
11 on October 21, 1976 and ending with the EPA publication of a final rule correcting the
12 effective date of the disposal of coal combustion residuals final rule to October 19, 2015,
13 the primary concern expressed in reports to Congress and others was that coal combustion
14 residuals or products posed a growing environmental risk of groundwater contamination if
15 left unattended.

16 From the beginning of this evolution, the EPA saw the country’s increasing reliance
17 on coal as a fuel for electrical power generation as presenting significant environmental
18 concerns, as reflected in its February 1988 “Report to Congress on Wastes from the
19 Combustion of Coal by Electric Utility Power Plants.”

20 On December 22, 2008, a dike used to contain coal ash at the dewatering area of
21 the Tennessee Valley Authority (“TVA”) Kingston Fossil Plant in Roane County,
22 Tennessee failed. Approximately 5.4 million cubic yards of coal ash was released into
23 Swan Pond Embayment and three adjacent sloughs, eventually spilling into the main

1 Emory River channel. The release extended approximately 300 acres outside of the fly ash
2 dewatering and storage areas of the plant.

3 As a result of this failure, the EPA initiated comprehensive inspections of more
4 than 500 CCR impoundments across the country to determine the condition and risk posed
5 by a dam failure. These inspections took place from 2009 through 2011 and included all
6 of the Company's surface impoundments. Among the risks posed by dam failures are: loss
7 of life, injury to people and wildlife, loss or significant damage to public and private
8 property, environmental damage to wetlands and waterways, and damage to infrastructure
9 such as roads and bridges.

10 On March 9, 2009, the EPA began mailing information request letters to electric
11 utilities and corporations that had surface impoundments or similar units that contained
12 coal combustion residuals. These letters requested information to assist the EPA in
13 evaluating the structural integrity of these management units.

14 On June 21, 2010, the EPA proposed regulations under RCRA to address the risks
15 from the disposal of CCRs generated from the combustion of coal at electric utilities and
16 independent power producers. This proposal contained two (2) regulatory options, due to
17 the significant and technical policy issues involved in regulating these wastes. Under the
18 first, the EPA proposed to list these residuals as special wastes subject to regulation under
19 Subtitle C of RCRA, when they are destined for disposal in landfills or surface
20 impoundments. Under the second option, the EPA proposed to regulate disposal of such
21 materials under Subtitle D of RCRA by issuing national minimum criteria. Under both
22 alternatives, the EPA proposed to establish dam safety requirements to address the
23 structural integrity of surface impoundments to prevent catastrophic releases. After

1 extensive study and examination of all comments received during the rulemaking process,
2 the EPA established regulations under Subtitle D of RCRA (Source EPA web site
3 <https://www.epa.gov/coalash/coal-ash-rule>).

4 On December 19, 2014, the EPA signed the final rule on disposal of coal
5 combustion residuals from electric power plants. The EPA finalized national regulations
6 providing a comprehensive set of requirements for the disposal of coal combustion
7 residuals as solid waste under subtitle D of RCRA. On April 17, 2015, the EPA published
8 the final rule on disposal of coal combustion residuals from electric utilities in the *Federal*
9 *Register*. On July 2, 2015, the EPA published a final rule correcting the effective date of
10 the disposal of coal combustion residuals final rule to October 19, 2015.

11 **Q. WHAT WAS THE SIGNIFICANCE OF DEC'S IMPOUNDMENT FAILURE AT**
12 **DAN RIVER?**

13 **A.** From February 2, 2014 through February 8, 2014, the unpermitted discharge of
14 approximately 27 million gallons of coal ash wastewater and an estimated 39,000 tons of
15 coal ash into the Dan River occurred through two pipes from Dan River's primary coal ash
16 basin. The coal ash from the release traveled more than 62 miles down the Dan River.
17 Until this event, the draft federal CCR Rule was the driving force in coal combustion
18 residual remediation and closure, and the proposed CCR Rule provided latitude in
19 remediating or closing coal combustion residuals impoundments. The Dan River spill,
20 however, played a deciding role in the development of North Carolina's CAMA in its
21 present form, not only accelerating the timing of action required, but also limiting the
22 options to remediate and close coal combustion residuals impoundments more than would
23 eventually occur under the CCR Rule. In fact, Dr. Wright on page 17, lines 5-7 of his

1 testimony (see Exhibit DJW-3.6), says that there is no doubt that the Dan River spill
2 certainly helped prompt the North Carolina General Assembly to examine the State's and
3 national coal ash disposal policies and regulations.

4 As is demonstrated by DEC's own admissions and the Court's findings in the
5 federal criminal actions, criminal negligence on the part of DEC at Dan River and
6 Riverbend and state environmental rule violations at Dan River and Riverbend, as well as
7 DEP's Asheville, Cape Fear, and H.F. Lee plants resulted in damage to the environment.
8 Specifically, DEP "failed to maintain the riser structures in two of the coal ash basins at
9 the Cape Fear Steam Electric Plant, resulting in the unauthorized discharge of leaking coal
10 ash wastewater into the Cape Fear River." In addition, DEP allowed unauthorized
11 discharges via "seeps" from ash basins into waters of the US at the Asheville and H.F. Lee
12 Stations. The seeps were "naturally occurring" and channeled to engineered drains,
13 ditches, and waters of US (see Section II of Exhibit DJW -5.0). In state court lawsuits,
14 DEP was also charged with excavating the CCR, placing the CCR in a compliant landfill
15 or reused beneficially, and achieving compliance with the State's 2L Groundwater Rules
16 (see Exhibit DJW-5.3.1 Items 44 to 71). In addition to language contained within North
17 Carolina's CAMA and legislative drafts of what eventually became CAMA, the court cases
18 and subsequent plea agreements (see Exhibits DJW-5.1 – DJW-5.4) demonstrate that DEC
19 and DEP were criminally and civilly negligent in their operations and maintenance of the
20 impoundments for years prior to the enactment of CAMA, confirming that DEC and DEP
21 failed to responsibly address and correct these issues adequately -- and consequently in a
22 much less costly -- manner than it is currently being required to do.

1 Q. HAVE THERE BEEN ANY SUBSEQUENT LEGAL ACTIONS THAT WOULD
2 CAUSE THE EPA TO ALTER THE WAY CLOSURE WAS OR WILL BE
3 HANDLED AT SITES THAT WERE INACTIVE AS OF APRIL 17, 2015? IF SO,
4 PLEASE EXPLAIN.

5 A. Yes. On August 21, 2018, the DC Circuit Court found that the EPA had allowed
6 utilities to close inactive ponds at coal plants which were shut down on or before April 17,
7 2015 to be capped in place without regard to whether the ponds were excavated, dewatered,
8 or lined in some way so as to prevent contamination of groundwater by the inactive pond.
9 The Court remanded the portion of the rule on inactive ponds at inactive sites to the EPA
10 for reconsideration. However, until this issue has been addressed by the EPA, the current
11 CCR Rules remain in effect.

12 Q. DID THE COMPANY'S ACTIONS IMPACT THE ENACTMENT OF CAMA IN
13 ANY WAY? IF SO, PLEASE EXPLAIN.

14 A. Yes. In the aftermath of the 2008 CCR impoundment failure at TVA's Kingston
15 Fossil plant and after the EPA's dam safety inspections of DEC's and DEP's coal-fired
16 power plants in 2009, the Federal initiatives on CCR Rule development became the driving
17 force in changes to coal ash management. Environmental lawsuits filed in State Courts in
18 2013 and 2014 brought issues associated with seepage, unpermitted discharges,
19 groundwater violations, and drinking water impacts from Asheville and Sutton to the
20 forefront. However, it was DEC's February 2014 impoundment failure at Dan River
21 causing a release of as much as 39,000 tons of CCR and 27 million gallons of CCR
22 wastewater into the Dan River that brought a prompt response by the North Carolina

1 General Assembly as reflected in the preamble of an early May 14, 2014 version (see
2 Exhibit DJW-4.4) of the Coal Ash Management Act (Senate Bill 729) which states:

3 Whereas, the issue of coal ash storage has not been adequately addressed in
4 North Carolina for more than six decades; and

5 Whereas, on February 2, 2014, an estimated 39,000 tons of coal ash was
6 released into the Dan River following the failure of a stormwater pipe under
7 a utility coal ash impoundment pond in Eden, North Carolina; and

8 Whereas, the Department of Environment and Natural Resources
9 ("Department") finds that coal combustion products have settled into the
10 sediment of the river bottom and will require an extensive clean-up plan to
11 complete remediation; and

12 Whereas, the Department is in the process of reassessing previous efforts at
13 achieving compliance at coal ash facilities and developing short term and
14 long term policies in light of the Dan River spill, violations discovered in
15 light of increased inspections of coal combustion products disposal facilities
16 and anticipated new federal regulations on coal combustion products; and

17 Whereas, it is the intent of the Department to ensure that spills of
18 wastewater are reported to the Department in a defined and adequate time
19 frame; and

20 Whereas, it is the intent of the Department to protect surface water and
21 groundwater resources for their best usage; and

22 Whereas, it is the intent of the Department to ensure that all unpermitted
23 wastewater discharges are eliminated or addressed in an environmentally
24 responsible manner; and

25 Whereas, it is the intent of the Department to equally subject all dams under
26 jurisdiction of G.S. 143-215.23 to the requirements of statute and
27 administrative code; and

28 Whereas, it is the intent of the Department for the owners of all dams under
29 jurisdiction of G.S. 143-215.23 deemed intermediate and high hazard by the
30 Department to prepare at their own cost documents that describe full and
31 adequate response to emergency situations at their dams and to submit those
32 documents to the Department; and

33 Whereas, it is the intent of the Department to ensure that emergency
34 situations at dams are reported to the Department in a defined and adequate
35 time frame; and

1 Whereas, the it is the intent of the Department to increase oversight of dam
2 structure integrity to protect the health and safety of the public; and

3 Whereas, state law exempts coal combustion products removed from
4 impoundments from being defined as a solid waste; and

5 Whereas, the Department finds that consistent environmental standards
6 should apply to coal combustion products removed from impoundments for
7 management or disposal and coal combustion products managed or
8 disposed of as a solid waste; and

9 Whereas, the Department finds the federal Environmental Protection
10 Agency is under consent decree to complete new regulations by December
11 2014 for coal combustion products that are proposed to bring consistency
12 to requirements for large fills such as structural fills and landfills; and

13 Whereas, the Department finds that conversion and closure of coal ash
14 storage ponds is necessary for protection of the health and safety of the
15 public;

16 While the sentiment expressed in this document leaves no doubt in my mind that
17 the spill from Dan River was the seminal event in stimulating the development of CAMA,
18 the other examples of ash mismanagement also played a role in making CAMA as stringent
19 as it became. As is demonstrated by the Company's own admissions and the Court's
20 findings in federal criminal actions, criminal negligence on the part of the Company at
21 Cape Fear, H.F. Lee, Asheville, Cliffside, and Sutton (see Section IV of Exhibit DJW-5.0
22 Items 98 to 192) resulted in damage to the environment. All of these negligent actions on
23 the part of the Company played a significant role in making CAMA more prescriptive and
24 more stringent than enabling state environmental laws had been in North Carolina for a
25 number of years immediately preceding its enactment.

26 **Q. WAS THE NORTH CAROLINA GENERAL ASSEMBLY CONSIDERING**
27 **LEGISLATION TO REGULATE COAL ASH DISPOSAL PRIOR TO THE DAN**
28 **RIVER SPILL?**

1 A. As noted in the preamble to CAMA included earlier in my testimony, the General
2 Assembly acknowledged that the “issue of coal ash storage has not been adequately
3 addressed in North Carolina for more than six decades.” In addition, my research of the
4 minutes of the Environmental Commission of the North Carolina General Assembly for
5 the three (3) years prior to the Dan River spill and the month immediately preceding the
6 spill led me to conclude that no legislation was being seriously considered up until the time
7 of the failure. In fact, the only mentions of coal ash in the minutes from February 2010
8 through January 2014 were as follows:

9 January 18, 2011

10 Ms. Sullins said the effect of coal ash on groundwater was being reviewed
11 as part of the renewal of permits for groundwater. Concerning the issue of
12 coal ash, the EPA issued new [draft] rules for coal combustion residuals [in
13 2010] after the failure of an impoundment in Tennessee. Because of the
14 types of containment of the residuals, the North Carolina Division of Waste
15 Management, Division of Water Quality and the Division of Land
16 Resources are severally involved in this issue. The three Divisions
17 reviewed the EPA rules and submitted comments to the federal agency. The
18 Division considers the EPA rules unsatisfactory, therefore the Division
19 seeks to have EPA treat coal combustion residuals as solid waste and
20 provide states with financial incentives to regulate them as solid waste to
21 recognize state permitting requirements for the substances.

22 Representative Harrison asked if the Division felt confident that toxins
23 contained in recycled coal ash remained inert. Mr. Matthews said that the
24 technical standards for hazardous and solid waste are similar and should be
25 effective.

26 December 13, 2012

27 Representative Samuelson asked about the differences in types of landfills,
28 specifically industrial landfills. Mr. Scott explained that sanitary landfills
29 include municipal solid waste landfills, construction demolition landfills,
30 and industrial landfills. In North Carolina, there are 16 industrial landfills,
31 mostly for the power industry, coal ash, pulp and paper, and one specifically
32 for battery products.

33 October 9, 2013

1 Representative Harrison wanted more information on the coal ash ponds
2 and potential groundwater contamination by the power companies? Mr.
3 Gillespie explained that North Carolina has filed a lawsuit against the power
4 companies on this issue and the Southern Environmental Law Center has
5 joined the suit. DENR has followed the guidelines when imposing fines on
6 Progress Energy. The penalty DENR has imposed is five times higher than
7 normal.

8 **Q. HAS SOUTH CAROLINA PASSED LEGISLATION SIMILAR TO CAMA?**

9 **A.** No. In fact, SC Code Regs 61-79.261 establishes regulations for CCR
10 impoundments as exempt from solid waste designation. A table of my research into state-
11 specific rules on CCR management and impoundments is included as Exhibit DJW-4.7.2
12 which shows that, in the region around North Carolina, Kentucky, West Virginia, and
13 Georgia adopted the Federal CCR Rules. That said, on January 24, 2019, the State of
14 Virginia reached a bipartisan agreement to move forward on a bill that would require
15 Dominion Energy to excavate all the coal ash at their Virginia coal plants. See Exhibit
16 DJW-9.1.

17 **Q. HAVE YOU PREPARED A COMPARISON OF THE REQUIREMENTS**
18 **CONTAINED WITHIN THE EPA'S CCR RULE AND CAMA?**

19 **A.** Yes. Exhibit DJW-4.7.1 is a side-by-side comparison of the Federal CCR Rule,
20 CAMA, and subsequent amendments. Table 4.1 in Exhibit DJW-4.7.1 summarizes and
21 compares the provisions of CAMA and the CCR Rule. As indicated in the narrative below,
22 CAMA is significantly more restrictive and stringent than the federal CCR Rule.

23 1) CLOSURE MANDATES. From this side-by-side comparison, it is readily apparent
24 that CAMA focuses on basin closure for any impoundment not rated as "low risk"
25 compared to the CCR Rule. CAMA requires closure only for active basins which
26 cannot meet the various safety and environmental criteria, with a high priority on the
27 stability evaluation. While none of the DEP impoundments were originally listed as

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“low risk” under CAMA, the Company was able to change the classifications of impoundments at Mayo and Roxboro by providing a water supply or water treatment system to neighboring communities) on ground water (see Exhibit DJW-8.5). Kerin’s Exhibit 10 (Exhibit DJW-3.1.2) indicated that DEP has removed \$3,144,456 in “CAMA-related” from this request for reimbursement. See Table 3.1 below. We concur that these costs should not be reimbursed and nor should other “CAMA-related” costs that result from rules that are more stringent than the Federal CCR Rules.

Table 3.1: DEP Changes in Risk Classifications and Drinking Water Supply Spends				
Plant	Basin	Risk Classification May 18, 2016	Risk Classification Nov 14, 2018	CAMA Water Supply Costs (source - discovery response 9-06)
Asheville	1964 Ash Basin	High	no change	\$186,054
	1982 Ash Basin	High	no change	
Cape Fear	1956 Ash Pond	Intermediate	no change	\$11,756
	1963 Ash Pond	Intermediate	no change	
	1970 Ash Pond	Intermediate	no change	
	1978 Ash Pond	Intermediate	no change	
HF Lee	Active Ash Pond	Intermediate	no change	\$603,002
	Polishing Pond	Intermediate	no change	
	Ash Pond #1	Intermediate	no change	
	Ash Pond #2	Intermediate	no change	
Mayo	Ash Pond #3	Intermediate	no change	\$334,703
	Ash Pond	Intermediate	Low	
Roxboro	East Ash Pond	Intermediate	Low	\$1,697,802
	West Ash Pond	Intermediate	Low	
Sutton	1971 Ash Pond	High	no change	\$156,699
	1984 Ash Pond	High	no change	
Weatherspoon	Ash Pond	Intermediate	no change	\$154,440
TOTAL				\$3,144,456

1 2) CLOSURE METHODS. CAMA allows only "low risk" coal combustion residuals
2 basins to be closed by cap in place while the CCR Rule allows for cap-in-place closure
3 for a wider range of impoundments.

4 3) COMPLIANCE TIMING. CAMA directs accelerated timelines for compliance in
5 comparison to the CCR Rule. Many of the expenditures for which DEP is seeking
6 recovery in this proceeding would not be required until a number of years in the future,
7 and others not required to be incurred had CAMA not been passed in reaction to the
8 Dan River spill. At Asheville and Sutton, CAMA originally required closure by August
9 1, 2019. Asheville's CAMA compliance date was extended to 2022 to accommodate
10 the construction of gas-fired combined cycle replacement energy on site in accordance
11 with the North Carolina Mountain Energy Act of 2015. Sutton, on the other hand, was
12 left with the original compliance date. At Asheville, 4.1 million tons of ash were
13 beneficially reused as structural fill at the Asheville airport. Additionally, 233 thousand
14 tons of CCR were hauled to the DEC Cliffside Landfill and 1.7 million tons were
15 hauled from Asheville to a landfill in Homer, Georgia. At Sutton, the ash ponds were
16 decanted, dewatered, excavated (using hydraulic dredges in the later stages), and
17 stacked out on site. Because of the timeline involved with permitting a lined on-site
18 landfill, DEP shipped 2 million tons of the CCR by rail or truck to the Brickhaven Mine
19 to achieve the required CAMA scheduled completion at considerable cost in excess of
20 what DEP would have been required to incur.

21 4) APPLICABILITY TO INACTIVE SITES. Because the CCR Rule currently applies
22 only to sites that were active as of October 19, 2015. Cape Fear was not impacted by
23 the CCR Rule and was designated for closure under CAMA.

1 5) BENEFICIATION REQUIREMENTS. A North Carolina court order and CAMA
2 require ash beneficiation at three (3) sites. As it relates to CCR and the requirements
3 of CAMA (see Exhibit DJW-4.9), beneficiation is the physical treatment of excavated
4 CCR with suitable chemical properties (e.g., loss on ignition and particle size) so that
5 the processed CCR can be beneficially reused in cementitious products. Two DEP sites,
6 Cape Fear and H.F. Lee, were designated as beneficiation sites. In addition,
7 Weatherspoon was also qualified as a beneficiation site even though the CCR is hauled
8 to cement kilns in South Carolina where it is beneficiated. The Federal CCR Rules do
9 not require beneficiation.

10 6) CONVERSION TO DRY ASH DISPOSAL. CAMA requires dry fly ash disposal by
11 December 2018 and dry bottom ash disposal by December 2019. The CCR Rule does
12 not expressly address conversion to dry ash disposal. However, in some cases,
13 conversion is driven by basin closure requirements. Furthermore, the EPA extended
14 timelines to accommodate Steam Electric Effluent Limitations Guidelines that propose
15 to require conversion to dry ash disposal. No such extension has been made available
16 in CAMA.

17 7) HIGH PRIORITY SITES. CAMA identified two (2) of the Company's facilities,
18 Asheville and Sutton, as "**HIGH PRIORITY**" sites, requiring that the time frame for
19 the removal of all ash and the closure of those sites be further accelerated. As is
20 apparent from Kerin's Exhibit 10 (Exhibit DJW-3.1.2), approximately 71 percent
21 (\$440 million out of the total Asset Retirement Obligation ("ARO") 2015-September
22 30, 2018 expenditures of \$635 million) of the monies spent by the Company in 2015-
23 September 2018 were incurred due to an accelerated closure schedule of these two sites.

1 On May 18, 2016, the NC DEQ released proposed classifications (Exhibit DJW-9.2)
2 for all coal ash ponds in NC, while asking the General Assembly to allow the
3 reconsideration of those classifications in 18 months. Table 3.1 lists the Company's
4 High Priority sites designated by CAMA in 2014 (Asheville and Sutton) that must be
5 closed by August 1, 2019, and proposes the rest be classified as intermediate priority
6 for which closure would be required by December 31, 2024.

7 On November 14, 2018, the NC DEQ (Exhibit DJW-9.3.) issued another press
8 release which states that none of the DEP impoundments met the low-risk classification
9 criteria set forth in CAMA. That left Cape Fear, H.F. Lee, Mayo, Roxboro, and
10 Weatherspoon with their original intermediate risk ratings.

11 **IV. INDUSTRY AND COMPANY COAL ASH MANAGEMENT**

12 **Q. WHAT SOLUTIONS HAS THE INDUSTRY IMPLEMENTED FOR**
13 **COMPLIANCE AND PROTECTION OF THE ENVIRONMENT FROM THE**
14 **IMPACTS OF COAL ASH DISPOSAL?**

15 **A.** Since the 1970's, industry practices have shown a shift away from surface
16 impoundments and towards landfills and from unlined impoundments towards lined waste
17 management units. In the EPA's 1988 and 1999 reports to Congress, the agency observed
18 the percentage of generating units with lined landfills increased from thirty percent (30%)
19 to fifty-seven percent (57%) between 1975 and 1995. Over the same time frame, lined
20 surface impoundments rose from seventeen percent (17%) to twenty-eight percent (28%).

21 In my experience with coal plants and CCR management, which includes both wet
22 and dry components, liners were placed in new ponds built since the mid-1980's and were

- 1 placed in Subtitle D compliant landfills built since the mid-1990's. Table 4.1 below
- 2 illustrates the Company's CCR handling and disposal methods employed at their facilities.

Table 4.1: Coal Ash Disposal Basins at Duke Energy Progress Coal Fired Power Plants

Plant	Coal Plant Size (MW)	Basins	Combined Basin Surface Area (acres)	Basins Built	Lined (Y/N)	Type and Thickness Liner	Type of Disposal (Wet/Dry)	Total Ash Impounded (million tons)	NDPES Permit
Asheville (NC) Steam Electric Generating Station (operating)	376	2	91	1964 and 1982				3.163	NC0000396
		A-1	45	1964	N	N/A	Wet	2.536	
		A-2	46	1982	N	N/A	Wet	0.627	
Cape Fear (NC) Steam Electric Plant (retired)	316	5	160	1956 (I), 1963 (I), 1970 (I), 1978 (I), and 1985 (I)				5.67	NC0003433
		CF-1	12	1956 (I)	N	N/A	Wet	0.42	
		CF-2	21	1963 (I)	N	N/A	Wet	0.76	
		CF-3	30	1970 (I)	N	N/A	Wet	0.84	
		CF-4	37	1978 (I)	N	N/A	Wet	0.83	
		CF-5	60	1985 (I)	N	N/A	Wet	2.82	

Table 4.1: Coal Ash Disposal Basins at Duke Energy Progress Coal Fired Power Plants

Plant	Coal Plant Size (MW)	Basins	Combined Basin Surface Area (acres)	Basins Built	Lined (Y/N)	Type and Thickness Liner	Type of Disposal (Wet/Dry)	Total Ash Impounded (million tons)	NDPES Permit
H.F. Lee (NC) Steam Electric Plant (1951-2012, retired)	382	4	295	4 inactive (late 1950's through early 1960's and 1 in late 1970's)				5.89	NC0003417
		HFL-1		1950	N	N/A	Wet	0.19	
		HFL-2	76	1955	N	N/A	Wet	0.44	
		HFL-3	87	1962	N	N/A	Wet	0.67	
		HFL-4	132	1982	N	N/A	Wet	4.59	
Mayo (NC) Steam Electric Plant (operating)	727	1	140	1983				6.35	NC0038377
		M-1	140	1983	N	N/A	Wet	6.35	
Robinson (SC) Steam Electric Plant (retired)		1	75	1960 fill area and Ash Basin				3.9	SC0002925
		RSC-1	75	1960	N	N/A	Wet	3.9	
Roxboro (NC) Steam Electric Plant (operating)	2,417	2	374	1966 and 1989				19.42	NC0003425
		R-1	134	1965	N	N/A	Wet	6.96	
		R-2	240	1973	N	N/A	Wet	12.46	
Sutton (NC) Electric Plant (retired)	575	2	139	1971 (unlined) and 1984 (12" clay) plus Lay of Land Area and				7.152	NC0001422
		S-1	54	1971	N	N/A	Wet	3.54	
		S-2	85	1984	Y	12" Clay	Wet	2.78	
Weatherspoon (NC) Steam Electric Plant (retired)	171	1	52	Began ops in 1949. Two coal units added in				1.53	NC0005363
		W-1	52	1979	N	N/A	Wet	1.53	
TOTAL	4,964	18	1,326					53.075	

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1 Q. HAS THE COMPANY KEPT PACE WITH THE REST OF THE INDUSTRY IN
2 ITS COMPLIANCE WITH ITS PERMITS AND WITH ENVIRONMENTAL
3 LAWS GOVERNING COAL ASH MANAGEMENT?

4 A. No. The Company has been disposing of CCR for at least sixty (60) years. The
5 Company built its first coal-fired power plant (Cape Fear) in 1923 and built the first of its
6 currently listed surface impoundments (H.F. Lee Ash Pond Number 1) in 1950. Except for
7 impoundments and landfills built in response to CAMA and the federal CCR Rule the
8 Company did not vary from its established practice of building, expanding, and continuing
9 to utilize unlined wet surface impoundments despite the increasing concerns reported in
10 industry studies, noted above, with potential ground water impacts from CCR
11 impoundment seeps and leachate. During my December 2018 site visits to the eight (8)
12 DEP plants in North and South Carolina, Company officials contended that the flow
13 coming from the seeps is a small fraction of the flow coming out of the ash basin outfalls
14 permitted under NPDES. While this contention appeared to be true, this does not relieve
15 the Company from complying with the terms of its permits. It is also noteworthy that the
16 engineered (constructed) seeps have been included as permitted outfalls in each plant's
17 NPDES permit while non-constructed seeps have been largely addressed through agreed
18 orders for each plant.

19 Q. PLEASE SUMMARIZE THE CLOSURE OPTIONS CONSIDERED BY THE
20 COMPANY TO ADDRESS ITS CCR IMPOUNDMENTS AND LANDFILLS.

21 A. There are essentially four options to closing CCR impoundments: (1) Cap-In-Place,
22 (2) Hybrid Closure, (3) Excavate and Landfill On-Site, and (4) Excavate and Dispose of

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1 Off-Site. In addition, there is a process to remove and beneficiate the ash for resale to
2 concrete plants. A description of the closure options follows:

3 1) OPTION 1: HYBRID CLOSURE – Consists of excavating ash materials from the
4 proposed Closure-by-Removal Areas and the subsequent placement of these ash
5 materials within the proposed consolidated Hybrid Ash Closure Area. Following these
6 excavation and placement activities, the Hybrid Ash Closure Area will be capped with
7 an infiltration barrier/cap system meeting the requirements of the Federal CCR Rule
8 and CAMA.

9 2) OPTION 2: CLOSURE-IN-PLACE – Consists of leaving the ash material within the
10 Ash Basin, which will be capped with an infiltration barrier/cap system meeting the
11 requirements of the Federal CCR Rule and CAMA.

12 3) OPTION 3A: CLOSURE-BY-REMOVAL TO EXISTING ON-SITE LANDFILL –
13 Consists of the excavating all ash materials from the proposed Closure-by-Removal
14 Area and placing these ash materials in a new phase of liner within the Existing On-
15 Site Landfill. The existing landfill will be capped with an infiltration barrier/cap
16 system meeting the requirements of the Federal CCR Rule and CAMA.

17 4) OPTION 3B: CLOSURE-BY-REMOVAL TO EXISTING & NEW ON-SITE
18 LANDFILLS – Consists of excavating ash materials from the proposed Closure-by-
19 Removal Area, placing those ash materials in a new phase of liner within the Existing
20 On-Site Landfill. Once the new Industrial Landfill is permitted and constructed,
21 excavated ash materials from the proposed Closure-by-Removal Area can subsequently
22 be placed within the new Industrial Landfill. The new phase of the existing landfill

1 and the new Industrial Landfill will be capped with an infiltration barrier/cap system
2 meeting the requirements of the Federal CCR Rule and CAMA.

3 5) OPTION 4: CLOSURE-BY-REMOVAL TO OFF-SITE THIRD-PARTY LANDFILL
4 – Consists of excavating the entire Ash Basin and the disposal of the ash material in an
5 existing, off-site, and appropriately lined landfill system.

6 **Q. HOW DID THE CAMA RULES IMPACT ASH BASIN CLOSURE COSTS,**
7 **STRATEGY, AND SCHEDULE?**

8 **A.** The CAMA rules required accelerated closure schedules for **HIGH PRIORITY**
9 Sites (i.e., Asheville and Sutton) which had the effect of removing cap-in-place as a viable
10 closure strategy at these sites. This, in turn, forced some sites such as Asheville and Sutton,
11 to excavate and ship train and truck loads of CCR from the ash ponds to an off-site landfill
12 as much as 145 miles away. Consequently, the CAMA rules resulted in costs exceeding
13 what would have been the costs under the Federal CCR Rules alone.

14 **V. EXPENDITURES ATTRIBUTABLE ONLY TO CAMA**

15 **Q. SHOULD SOUTH CAROLINA RATEPAYERS BE REQUIRED TO REIMBURSE**
16 **DEP FOR EXPENDITURES INCURRED SOLELY DUE TO NORTH**
17 **CAROLINA'S CAMA OR NORTH CAROLINA COURT DECISIONS?**

18 **A.** No. It is the position of ORS that costs incurred as a result of jurisdictional laws
19 should not lead to increased costs to ratepayers outside of that jurisdiction. This matter is
20 addressed in the cost of service testimony of ORS witness Seaman-Huynh.

21 As identified by DEP witness Kerin, DEP has attempted to isolate specific costs
22 associated with CAMA and is not seeking recovery of those costs from South Carolina
23 ratepayers. However, the costs set aside by DEP largely encompass providing bottled

1 water or other water supplies. Additional costs above and beyond those identified by DEP
2 solely attributable to CAMA are further identified below. ORS is not taking the position
3 that South Carolina ratepayers should not pay any costs related to environmental
4 compliance and cleanup at DEP's coal fired generation facilities, only that North Carolina
5 law and court decisions, over which South Carolina ratepayers have no meaningful input,
6 should not place an additional burden on the ratepayers of South Carolina.

7 **Q. WHAT TYPE OF EXPENDITURES HAVE YOU IDENTIFIED AS BEING**
8 **SOLELY ATTRIBUTABLE TO CAMA?**

9 **A.** I have identified the following types of expenditures as being solely attributable to
10 CAMA and not the Federal CCR rules:

- 11 1) Expenditures for plants and impoundments not covered at all by the CCR rules. For
12 DEP, Cape Fear falls into this category.
- 13 2) Expenditures for closure and/or excavation options not required under the CCR Rules,
14 but required under CAMA or North Carolina court decisions. Asheville, Cape Fear,
15 H.F. Lee, Sutton, and Weatherspoon fall in this category.
- 16 3) Expenditures for actions that would not have been required at this time under the CCR
17 rules, but are subject to **accelerated schedules** under CAMA or other state law. Sutton
18 and Asheville fall into this category.

19 **Q. WHAT TYPE OF EXPENDITURES DO YOU CONSIDER TO BE FULLY**
20 **RECOVERABLE?**

21 **A.** Prudently incurred expenditures for actions which are required by and fulfill the
22 Federal CCR Rules or the requirements of the State of South Carolina. Mayo, Roxboro,
23 and Robinson fall into this category.

1 Q. WHICH, IF ANY DEP PLANTS ARE NOT COVERED BY THE FEDERAL CCR
2 RULES?

3 A. Company witness Kerin's Exhibit 10 (Exhibit DJW-3.1.2) states "Cape Fear is not
4 currently subject to CCR provisions regarding basin closure." While witness Kerin goes
5 on to state "[h]owever, in response to the United States Court of Appeals for the District
6 of Columbia Circuit's August 21, 2018 decision in *USWAG vs. EPA* (No. 15-1219), the
7 EPA is expected to undertake a rulemaking that would regulate inactive impoundments at
8 closed power plants, including the Cape Fear basin", this statement is irrelevant to this
9 proceeding because the EPA has not yet issued its final ruling.

10 Q. WOULD THE REGULATION OF INACTIVE INPOUNDMENTS NECESSARILY
11 LEAD TO THE FORCED CLOSURE AND/OR EXCAVATION OF THE CAPE
12 FEAR IMPOUNDMENTS IN A MANNER SIMILAR TO THAT DIRECTED BY
13 CAMA?

14 A. No. Any speculation as to what regulations the EPA will issue in response to the
15 Court Order is solely that – speculation – and should not be considered in this proceeding.

16 Q. HOW MUCH HAS DEP REQUESTED IN THIS PROCEEDING FOR THE
17 RECOVERY OF EXPENDITURES AT CAPE FEAR?

18 A. As noted in Table 5.1, below, the Company is requesting the recovery of
19 \$33,631,199 for specified actions (see Exhibit DJW-3.1.2) at Cape Fear. This entire
20 amount should be disallowed for recovery from South Carolina ratepayers absent any
21 federal regulations directing the actions taken by DEP or for any similar actions.

Q. WHAT EXPENDITURES FOR CLOSURE AND/OR EXCAVATION OPTIONS NOT REQUIRED UNDER THE CCR RULES, BUT REQUIRED UNDER CAMA, HAS THE COMPANY REQUESTED IN THIS PROCEEDING?

A. The actions covered by the Company's request are summarized in Kerin Exhibit 10 (Table 5.1) (Exhibit DJW-3.1.2), below (copied from DEP's response to SCORS DEP 10-08) delineates the CCR costs being requested by the Company in their filing in the column labeled "Total Costs Incurred 1/1/15 -9/30/18":

	Total Project Costs (2015+)	Total Costs Incurred 1/1/15 - 9/30/18	2015	2016	2017	1/1 - 9/30/18	Total CF Forecast	10/1 - 12/31/18
DEP								
Operating								
Asheville	\$ 452,038,793	\$ 191,934,196	\$ 24,187,676	\$ 82,788,175	\$ 40,931,030	\$ 44,027,315	\$ 260,104,597	\$ 22,261,993
Mayo	206,749,586	25,384,168	7,342,989	7,524,374	5,880,434	4,636,371	181,365,418	9,165,451
Roxboro	349,803,401	34,070,691	7,806,769	12,563,556	7,167,110	6,533,256	315,732,710	6,366,469
Total Operating Plants	1,008,591,780	251,389,055	39,337,434	102,876,105	53,978,574	55,196,942	749,360,288	37,793,913
Retired								
Cape Fear	504,918,488	33,631,199	7,705,330	8,346,981	6,815,029	10,763,860	471,287,289	18,325,181
HF Lee (NC)	568,383,919	54,775,180	7,260,508	13,498,675	13,416,419	20,599,578	513,608,739	21,923,632
Robinson (SC)	179,561,777	11,431,675	2,581,604	3,834,014	2,090,145	2,925,911	168,130,102	10,866,681
Sutton	493,219,171	255,525,554	37,189,549	79,669,346	104,689,533	33,977,126	237,693,617	19,844,924
Weather spoon	209,724,346	28,287,429	4,631,236	4,489,006	9,438,277	9,728,910	181,436,918	7,036,705
Total Retired Plants	1,955,807,702	383,651,037	59,368,227	109,838,022	136,449,403	77,895,385	1,572,156,665	77,997,123
Total Duke Energy Progress	\$ 2,964,399,482	\$ 635,040,092	\$ 98,705,661	\$ 212,714,127	\$ 190,427,977	\$ 133,192,326	\$ 2,329,359,390	\$ 115,791,036

As shown in Table 5.2 below, three of the plants (Mayo, Robinson, and Roxboro) are pursuing closure options and schedules in compliance with the Federal CCR Rules, and I recommend that all prudently incurred expenditures for these plants be allowed. In addition, Robinson pursued closure options that were coordinated with and approved by the South Carolina Department of Health and Environmental Control ("DHEC"). I recommend that all prudently incurred expenditures for this plant also be allowed.

Table 5.2: Summary of Closure Options and Recommended Disallowances			
Plant	Amount Requested (1/1/15-9/30/18, SCORS DEP 10-08)	Closure Option Compliance with Federal CCR Rules	Recommended Disallowance
Asheville	\$ 191,934,196	CAMA High Priority - Accelerated Schedule -- Allow Engineering and Planning	\$ 98,220,932
Cape Fear	\$ 33,631,199	No Federal CCR Requirements	\$ 33,631,199
HF Lee	\$ 54,775,180	Beneficiation - CAMA Only -- Allow Engineering and Planning	\$ 9,207,711
Mayo	\$ 25,384,168	Federal CCR Compliant	\$ -
Robinson	\$ 11,431,675	Federal CCR Compliant and SCDHEC Requirements	\$ -
Roxboro	\$ 34,070,691	Federal CCR Compliant	\$ -
Sutton	\$ 255,525,554	CAMA High Priority - Accelerated Schedule -- Allow Engineering and Planning	\$ 186,376,226
Weatherspoon	\$ 28,287,429	Excavation and Beneficiation Off-Site -- CAMA -- Allow E&P Through 9/30/17 and Half Costs 10/01/17 through 9/30/18	\$ 6,044,240
Total	\$ 635,040,092		\$ 333,480,308

The three other plants (Asheville, H.F. Lee, and Sutton) shown in Table 5.2 were compelled by the provisions of CAMA or the North Carolina Mountain Energy Act to act faster (Sutton) or take actions not required by the Federal CCR Rules (Asheville, H.F. Lee,

1 Sutton, and Weatherspoon). Asheville and Sutton were designated as **HIGH PRIORITY**
2 sites by CAMA and compelled by CAMA to complete closure by August 2019. From a
3 Federal CCR Rules perspective, Sutton would not have been required to even begin closure
4 until 2020.

5 **Q. REGARDING H.F. LEE, WHAT EXPENDITURES FOR CLOSURE AND/OR**
6 **EXCAVATION OPTIONS NOT REQUIRED UNDER THE CCR RULES, BUT**
7 **REQUIRED UNDER CAMA, HAS THE COMPANY REQUESTED IN THIS**
8 **PROCEEDING?**

9 **A.** As noted in Table 5.1 above, DEP is currently requesting \$54,775,180 for costs
10 incurred through September 30, 2018 at H.F. Lee. In his Exhibit 10, Mr. Kerin describes
11 the work completed to date at H.F. Lee as including: "CAMA & CCR wells; dam stability;
12 EHS groundwater & permitting; ash beneficiation; landfill; planning and overheads; bulk
13 dewatering system; dewatering operations; dewatering engineering; wetland delineation
14 report; closure plan development; basin closure engineering". CAMA alone required
15 beneficiation of CCR at several plant sites in North Carolina. As noted above, Cape Fear
16 and H.F. Lee are designated as **INTERMEDIATE PRIORITY** sites under CAMA, and
17 CAMA requires their impoundments to be been addressed through beneficiation, a process
18 not shown as a requirement under the Federal CCR Rules. Mr. Kerin further observes in
19 several instances that "Engineering and project planning at the current time are needed to
20 synchronize work between all of the coal ash sites being closed in the next 20 years, as
21 well as to gain synergies between excavation/capping plans for all the sites." I concur with
22 this assessment. However, these added costs should only be imposed on South Carolina
23 ratepayers when the actual construction work associated with each site is attributable to the

1 CCR rules only and not due to schedule or scope changes imposed by CAMA. DEP's
2 beneficiation project at H.F. Lee clearly falls under the "CAMA-only" category, and the
3 ratepayers of South Carolina should not have to reimburse the Company for expenses
4 related to the CAMA-only beneficiation requirement.

5 **Q. WHAT PORTION OF DEP'S CLAIMED EXPENDITURES AT H.F. LEE SHOULD**
6 **BE ALLOWED IN THIS PROCEEDING?**

7 **A.** In reviewing the Company's actual and projected costs laid out in Kerin Exhibit 10
8 (Exhibit DJW-3.1.2), and other information provided through discovery, I observed that
9 DEP has not described the costs claimed for H.F. Lee in enough granularity to determine
10 which and how much of the costs incurred at H.F. Lee are associated with appropriate
11 engineering and planning activities, Federal CCR Rules compliance, and compliance with
12 CAMA or other state only requirements. To arrive at a good-faith estimate of engineering
13 and planning costs associated with impoundment closures, I assumed that engineering and
14 planning activities at all eight (8) DEP coal-fired power plants were accomplished at the
15 same time between 2015 and 2017. As I previously noted, Table 5.3 below includes the
16 data from DEP's response to ORS Discovery Request 10-08 (Exhibit DJW 3.4) used to
17 estimate engineering and planning as a percentage of engineering and planning costs.

18 During my December 2018 site visit to H.F. Lee, I learned that the beneficiation
19 plants are to be built and commissioned between 2019 and 2021. Out of spec ash will be
20 landfilled off-site and qualifying ash will largely be sold to concrete plants. Based upon
21 this information and my observations during my site visit, I concluded that most of the
22 costs incurred in 2018 appear to be related to beneficiation efforts and not compliance with
23 the Federal CCR Rules. For this reason, I recommend disallowing the difference between

the 2018 spend through September 30 (\$20,599,578) and the average of the previous three (3) years \$11,391,867 for a total disallowance of \$9,207,711.

Q. WHAT EXPENDITURES FOR ACTIONS THAT WOULD NOT HAVE BEEN REQUIRED AT THIS TIME UNDER THE CCR RULES, BUT ARE SUBJECT TO ACCELERATED SCHEDULES UNDER CAMA, HAVE BEEN REQUESTED FOR RECOVERY BY DEP IN THIS PROCEEDING?

A. Kerin Exhibit 10 states "Sutton is subject to the CCR rule provisions requiring basin closure. 40 CFR § 257.102(b) required a written closure plan by October 17, 2016. On July 6, 2016, the placement of waste streams in the Sutton 1971 Basin and 1984 Basin ceased and closure of the basins commenced pursuant to 40 CFR § 257.102(e)(1)(i). Pursuant to ¶ 5.e. of the Order Granting Motion for Partial Summary Judgment dated June 1, 2016 (13-CVS-11032), a written Site Analysis and Removal Plan was due by December 31, 2016. Sections 3(b) and 3(c) of CAMA require excavation of the Sutton basins, with the ash disposed of in either an off-site or on-site landfill. (Sutton is a high-priority site, with ash basin closure required by August 1, 2019.)"

Q. DID THE CCR RULE REQUIRE THE CLOSURE OF SUTTON?

A. No. Unlike Asheville where the basins did not meet aquifer and wetland conditions which triggered actions under the CCR Rules, there is no mention of noncompliance in Kerin 10 regarding Sutton. It is therefore reasonable to conclude that the Sutton closure was directed by CAMA and the North Carolina court orders Mr. Kerin mentions in his Exhibit 10. It follows that any subsequent actions performed under the CCR Rules as a result of closing the impoundments at Sutton were the result of DEP's requirements to comply CAMA and North Carolina court orders.

1 Q. SHOULD SOUTH CAROLINA RATEPAYERS BE HELD RESPONSIBLE FOR
2 REIMBURSING DEP FOR EXPENSES THAT WOULD NOT HAVE BEEN
3 INCURRED AT THIS TIME ABESENT CAMA?

4 No. It is readily apparent that the CCR rules would not have required closure
5 actions at Sutton to even **commence** until October 31, 2020, while closure is required to
6 be **completed** by August 1, 2019 under CAMA and the noted North Carolina Partial
7 Summary Judgment.

8 Q. WHAT AMOUNT HAS DEP CLAIMED FOR CLOSURE AND EXCAVATION
9 EXPENDITURES AT SUTTON?

10 A. DEP has requested recovery of \$255,525,554 in this proceeding (see Table 5.1).

11 Q. ARE YOU CONTENDING THAT THIS ENTIRE AMOUNT SHOULD BE
12 DISALLOWED?

13 A. No. DEP should be allowed to recover in this proceeding any planning and
14 engineering costs that would have been required for compliance with the CCR Rules as
15 they now stand and should be further allowed to seek recovery after 2020 for prudently
16 incurred actual construction and transportation expenditures related to CCR compliance.

17 Q. WHY IS IT REASONABLE TO ALLOW DEP TO RECOVER ENGINEERING
18 AND PLANNING COSTS?

19 A. As Company witness Kerin notes several times in Kerin Exhibit 10 (Exhibit DJW-
20 3.1.2), "Engineering and project planning at the current time are needed to synchronize
21 work between all of the coal ash sites being closed in the next 20 years, as well as, to gain
22 synergies between excavation/capping plans for all the sites." I concur with this
23 assessment. However, the actual construction work associated with each site should only

be allowed if is attributable to the CCR rules only and not due to schedule or scope changes imposed by CAMA.

Q. HOW MUCH OF THE COMPANY'S REQUEST FOR SUTTON WOULD YOU ESTIMATE IS PLANING AND ENGINEERING THAT SHOULD BE ALLOWED FOR RECOVERY IN THIS PROCEEDING?

A. Table 5.3 below includes data from DEP's response to SCORS Discovery Request 10-08 (see Exhibit DJW-3.4) used to estimate engineering and planning as a percentage of engineering and planning costs.

Table 5.3: Estimating Engineering and Planning Costs for DEP Plants							
Plant	Cost Data from Company Response to SCORS 10-08	2015	2016	2017	2018 thru 9/30	10/1/18 to 12/31/18	
Mayo	Spend to Date	\$ 25,384,167.79	\$ 7,342,989.00	\$ 7,524,374.00	\$ 5,880,434.13	\$ 4,636,370.66	\$ -
	Remaining Current Year Forecast	\$ 9,165,450.92	\$ -	\$ -	\$ -	\$ -	\$ 9,165,450.92
	Total Pre-Construction (E&P)	\$ 34,549,618.71					
	Total Project Costs	\$ 206,749,586.20					
	Percentage E&P of Total	16.71%					
Robinson	Spend to Date	\$ 11,431,675.28	\$ 2,581,604.00	\$ 3,834,014.49	\$ 2,090,145.33	\$ 2,925,911.46	\$ -
	Remaining Current Year Forecast	\$ 10,866,680.83	\$ -	\$ -	\$ -	\$ -	\$ 10,866,680.83
	Total Pre-Construction (E&P)	\$ 22,298,356.11					
	Total Project Costs	\$ 179,561,777.32					
	Percentage E&P of Total	12.42%					
Roxboro	Spend to Date	\$ 34,070,691.00	\$ 7,806,769.00	\$ 12,563,556.00	\$ 7,167,110.01	\$ 6,533,255.99	\$ -
	Remaining Current Year Forecast	\$ 6,366,469.49	\$ -	\$ -	\$ -	\$ -	\$ 6,366,469.49
	Total Pre-Construction (E&P)	\$ 40,437,160.49					
	Total Project Costs	\$ 349,803,400.59					
	Percentage E&P of Total	11.56%					
Weatherspoon	Spend to Date	\$ 28,287,428.60	\$ 4,631,236.00	\$ 4,489,006.00	\$ 9,438,276.66	\$ 9,728,909.94	\$ -
	Remaining Current Year Forecast	\$ 7,036,705.16	\$ -	\$ -	\$ -	\$ -	\$ 7,036,705.16
	Total Pre-Construction (E&P)	\$ 35,324,133.76					
	Total Project Costs	\$ 209,724,346.36					
	Percentage E&P of Total	16.84%					
TOTAL DEP	Spend to Date	\$ 99,173,962.66	\$ 22,362,598.00	\$ 28,410,950.49	\$ 24,575,966.13	\$ 23,824,448.04	\$ -
	Remaining Current Year Forecast	\$ 33,435,306.41	\$ -	\$ -	\$ -	\$ -	\$ 33,435,306.41
	Total Pre-Construction (E&P)	\$ 132,609,269.07					
	Total Project Costs	\$ 945,839,110.47					
	Percentage E&P of Total	14.02%					

The weighted average of engineering and planning as a percentage of total project costs for the three (3) Federal CCR Rules compliant plants (i.e., Mayo, Robinson, and Roxboro) and Weatherspoon which has many elements of CCR compliance was 14.02 percent during the period from 2015 through September 30, 2018. Applying this percentage to DEP's estimated total Sutton project costs (\$493,219,171), I estimate that

1 reasonable engineering and planning activities for the Sutton Steam Electric Station is
2 \$69,149,328 from 2015 through September 30, 2018. Based on the limited information
3 provided, I concluded that the remainder of the \$255,525,554 requested by DEP in this
4 proceeding was incurred due to the accelerated schedule and other requirements imposed
5 by CAMA on **HIGH PRIORITY** sites. Therefore, I recommend that \$186,376,226 of the
6 Company's request for reimbursement at Sutton be disallowed.

7 **Q. WHAT ADDITIONAL REQUIREMENTS WERE IMPOSED BY CAMA AND**
8 **OTHER ACTIONS ON THE COMPANY'S ASHEVILLE PLANT BY THE STATE**
9 **OF NORTH CAROLINA?**

10 **A.** While the timing of compliance actions at Asheville was not impacted by CAMA
11 since the plant's impoundments did not meet federal wetlands and uppermost aquifer
12 restrictions, the extent of the compliance measures required (excavation and removal vs.
13 cap in place) and the costs associated with required measures were much greater than they
14 would have been under CAMA alone.

15 **Q. BASED ON THE INFORMATION AVAILABLE, WHAT DO YOU DETERMINE**
16 **WOULD HAVE BEEN REASONABLE COSTS INCURRED FOR CCR RULE**
17 **COMPLIANCE ONLY AT ASHEVILLE?**

18 **A.** I believe that it would be reasonable for DEP to recover expenses prudently
19 incurred for engineering and planning and for "cap-in-place" disposal of ash at Asheville.

20 **Q. DO YOU BELIEVE IT WOULD HAVE BEEN PRACTICAL TO IMPLEMENT**
21 **CAP-IN-PLACE AT ASHVILLE ABSENT NORTH CAROLINA LEGISLATION**
22 **AND REGULATIONS DIRECTING OTHERWISE?**

1 A. Yes. The North Carolina Mountain Energy Act of 2015 required the installation of
2 a natural gas-fired combined cycle facility at Asheville. Had that not been required, there
3 would have been ample room for on-site disposal of ash impounded at Asheville.

4 Q. HOW HAVE YOU DETERMINED THE AMOUNT OF COSTS WHICH WOULD
5 HAVE BEEN INCURRED BY DEP HAD IT PURSUED A CAP-IN-PLACE
6 OPTION AT ASHEVILLE RATHER THAN EXCAVATING IMPOUNDMENTS
7 AND SHIPPING ASH OFF SITE.

8 A. To estimate appropriate costs incurred to date for Asheville, I multiplied the
9 estimated total costs per ton (including engineering and planning) estimated by DEP for
10 compliance at Robinson (\$169,561,777/3,900,000 tons = \$43.48/ton; see Table 5.1 and
11 Table 4.1 above) to the total tons removed through September 30, 2018 at Asheville
12 (2,144,448 tons; SCORS DEP 11-07) to calculate the costs that would reasonably have
13 been incurred under the CCR Rules alone (\$93,713,264).

14 Q. WHY IS IT REASONABLE TO USE ROBINSON COSTS TO APPROXIMATE
15 COSTS REASONABLY INCURRED AT ASHEVILLE?

16 A. As shown in Table 4.1 above, the total amount of ash expected to be removed from
17 Asheville is 3.163 million tons, while the amount at Robinson is 3.9 million tons, which is
18 to be placed in a separate on-site landfill rather than capped in place. Removal costs at
19 Mayo and Robinson, where much more ash had to be dealt with, were considerably lower
20 on a dollars per ton basis than Robinson, partially due to economies of scale and partially
21 due to the use of a more expensive disposal method. However, since the disposal
22 requirement (in tons) at Asheville most closely resembled that at Robinson, I

1 conservatively chose the higher dollars per ton amount to apply to Asheville tonnage
2 despite the additional costs imposed by the methodology chosen for Robinson.

3 **Q. WHAT IS YOUR RECOMMENDED DISALLOWANCE FOR ASHEVILLE**
4 **BASED ON THE CONCLUSIONS STATED ABOVE?**

5 **A.** I recommend that \$98,220,932 of the \$191,934,196 requested by DEP in this proceeding
6 be disallowed.

7 **Q. ARE YOU RECOMMENDING ANY DISALLOWANCES FOR CCR COSTS AT**
8 **WEATHERSPOON?**

9 **A.** Yes. During my December 2018 site visit, I saw how DEP was addressing the
10 closure of its CCR impoundment at Weatherspoon (see Exhibit DJW-2.8). The closure
11 plan includes the following steps: (a) decant the free or bulk water down to the bottom
12 three feet and maintain this level until dewatering begins; (b) excavate the ash, allow to
13 dry, and screen the ash for size; (c) build piles of material (Active and Reserve); (d) seal
14 the Reserve Pile with EcoGreen; and (e) truck ash from the screened and dry Active Pile
15 to the cement kilns in South Carolina. Once the ash is completely excavated from the
16 impoundments, the bottom will be confirmed for clean closure.

17 While there are similarities to the processes being employed at sites using
18 excavation and placement in an on-site impoundment, there other aspects of this process
19 which are not required under the Federal CCR Rules. These aspects include (1) screening
20 of the ash for size, (2) building active and reserve piles, and (3) shipping the processed
21 CCR to cement kilns about 150 miles away. DEP has represented efforts at Weatherspoon
22 as beneficiation, which is not required under the Federal CCR Rules but is part of the North
23 Carolina CAMA provisions.

1 In assessing the calculation of disallowances for Weatherspoon, I sought first to
2 determine the allowance for engineering and planning. Because the excavation work at
3 Weatherspoon began in September 2017 and continues today, I used the total expenditures
4 from 2015 and 2016 as well as three-fourths of the costs in 2017 (see Exhibit DJW-3.4) as
5 a good faith estimate of engineering and planning costs. This came to a total of
6 \$16,198,949. To allow for costs that would be required under the Federal CCR Rules, I
7 reviewed the costs submitted in DEP's response to SCORS 10-08 and Kerin Exhibit 10.
8 Unfortunately, this data lacked the granularity to determine how much of the costs were
9 for beneficiation and how much was for work required under the Federal CRC Rules.
10 Therefore, I estimated the allowable Federal CCR Rules work as half of the calculated
11 fourth quarter 2017 expenses and half of the first through third quarters of 2018. This
12 process resulted in an allowance for Federal CCR work of \$6,044,240.

13 Taking the total of calculated engineering and planning (\$16,198,949) and Federal
14 CCR work (\$6,044,240), I estimated \$22,243,189 in allowances for Weatherspoon. I then
15 subtracted this allowance from what DEP spent (\$28,287,429 through September 30, 2018
16 in Exhibit DJW-3.4) at Weatherspoon. As a result, I recommend the difference between
17 the expenditures and the allowance for a total disallowance of \$6,044,240 for disallowance.
18 The allowable expenses should be allowed for recovery from South Carolina ratepayers to
19 the extent they were prudently incurred.

20 **Q. ARE THERE ANY DEP PLANTS FOR WHICH YOU RECOMMEND NO**
21 **DISALLOWANCES?**

22 **A.** Yes. The "Cap-In-Place" options chosen at Mayo and Roxboro are consistent with
23 the Federal CCR Rules, and North Carolina state law does not impose additional

1 requirements at these sites. Therefore, the South Carolina pro rata share of the Company's
2 total spend for these two sites should be allowed to the extent they were prudently incurred.

3 Because Robinson CCR impoundment was closed and remediated pursuant to a
4 negotiated agreement with the South Carolina DHEC, the costs associated with this project
5 should be approved for recovery from South Carolina ratepayers to the extent they were
6 prudently incurred.

7 **Q. HAVE YOU PREPARED A SUMMARY OF YOUR RECOMMENDED**
8 **DISALLOWANCES?**

9 **A.** Yes. Table 5.4 below summarizes my recommendations for disallowance in the
10 current request for reimbursement. Of the \$635,040,092 currently being requested by the
11 Company for reimbursement, I recommend that the Commission disallow \$333,480,308
12 for recovery from ratepayers.

Table 5.4: Duke Energy Progress Reimbursement Request and Disallowances					
Plant	Cost Data				
	Total Project (from SCORS DEP 10-08)	Amount Requested (1/1/15-9/30/18, SCORS DEP 10-08)	Disallowance	Rationale	Allowance
Asheville	\$ 452,038,793	\$ 191,934,196	\$ 98,220,932	CAMA High Priority - Accelerated Schedule -- Allow what would have been incurred for "Cap-In-Place" only	\$ 93,713,264
Cape Fear	\$ 504,918,488	\$ 33,631,199	\$ 33,631,199	No Federal CCR Requirements	\$ -
HF Lee	\$ 568,383,919	\$ 54,775,180	\$ 9,207,711	Beneficiation - CAMA Only -- Allow Engineering and Planning	\$ 45,567,469
Mayo	\$ 206,749,586	\$ 25,384,168	\$ -	Federal CCR Compliant	\$ 25,384,168
Robinson	\$ 179,561,777	\$ 11,431,675	\$ -	Federal CCR Compliant and SCDHEC Requirements	\$ 11,431,675
Roxboro	\$ 349,803,401	\$ 34,070,691	\$ -	Federal CCR Compliant	\$ 34,070,691
Sutton	\$ 493,219,171	\$ 255,525,554	\$ 186,376,226	CAMA High Priority - Accelerated Schedule -- Allow Engineering and Planning	\$ 69,149,328
Weatherspoon	\$ 209,724,346	\$ 28,287,429	\$ 6,044,240	Excavation and Beneficiation Off-Site -- CAMA -- Allow E&P Through 9/30/17 and Half Costs 10/01/17 through 9/30/18	\$ 22,243,189
TOTAL	\$ 2,964,399,482	\$ 635,040,092	\$ 333,480,308		\$ 301,559,784

1

2 Q. ARE YOU RECOMMENDING THAT DEP BE PRECLUDED FROM
3 RECOVERING COSTS DISALLOWED IN THIS PROCEEDING IN FUTURE
4 PROCEEDINGS?

5 A. Not necessarily. If DEP can demonstrate that it has prudently incurred expenses
6 dictated by compliance with the CCR Rules as they stand at the time of its next rate case,
7 any expenses required by the CCR Rule as a stand-alone document (i.e. absent CAMA)
8 and determined to be prudently incurred should be considered for recovery in that forum.

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Columbia, SC 29201

1 However, as noted in my testimony above, many of DEP's claimed expenses are not yet
2 ripe for recovery under the CCR Rules as they stand.

3 **Q. WILL YOU UPDATE YOUR TESTIMONY BASED ON INFORMATION THAT**
4 **BECOMES AVAILABLE?.**

5 **A.**Yes. ORS fully reserves the right to revise its recommendations via supplemental
6 testimony should new information not previously provided by the Company, or other
7 sources, become available.

8 **Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

9 **A.**Yes.

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DAN J. WITTLIFF, BCEE
EXHIBIT LIST
DUKE ENERGY PROGRESS, LLC
DOCKET NO. 2018-318-E

DJW-1	Resume of Dan Wittliff
DJW-2.1	Site Visit Asheville Plant
DJW-2.2	Site Visit Mayo Plant
DJW-2.3	Site Visit Roxboro Plant
DJW-2.4	Site Visit Cape Fear Plant (NC)
DJW-2.5	Site Visit HF Lee Plant (NC)
DJW-2.6	Sutton Plant (NC)
DJW-2.7	Robinson Plant (NC)
DJW-2.8	Weatherspoon Plant (NC)
DJW-3.1.1	November 8, 2018, Jon Kerin Testimony
DJW-3.1.2	November 8, 2018, Jon Kerin Exhibits 3-8 and 10
DJW-3.2	DEP Response to SCORS Interrogatory 1-22
DJW-3.3	DEC and DEP Response to SCORS Interrogatory 9-06
DJW-3.4.0	Summary and Footnotes of ARO Cash Flows
DJW-3.4.1	Asheville ARO Cash Flows
DJW-3.4.2	Mayo ARO Cash Flows
DJW-3.4.3	Roxboro ARO Cash Flows
DJW-3.4.4	Cape Fear ARO Cash Flows
DJW-3.4.5	HF Lee ARO Cash Flows
DJW-3.4.6	Robinson ARO Cash Flows
DJW-3.4.7	Sutton ARO Cash Flows
DJW-3.4.8	Weatherspoon ARO Cash Flows
DJW-3.5.0	Schedule 1802 submitted by DEP
DJW-3.5.1	Schedule 1803 submitted by DEP
DJW-3.5.2	Schedule 1804 submitted by DEP
DJW-3.5.3	Schedule 1805 submitted by DEP
DJW-3.6	November 8, 2018, Dr. Julius Wright Testimony

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DAN J. WITTLIFF, BCEE
EXHIBIT LIST
DUKE ENERGY PROGRESS, LLC
DOCKET NO. 2018-318-E

DJW-3.7	DEP Response to SCORS 31-1 Non-ARO Ash Projects
DJW-4.4	North Carolina Coal Ash Management Act of 2014
DJW-4.5	Mountain Energy Act 2015
DJW-4.6	1988 Report to Congress
DJW-4.7.1	Side-by-Side Comparison of Legal Requirements
DJW-4.7.2	CCR and State Regulations
DJW-4.8	Los Alamos Report
DJW-4.9	CAMA 2016
DJW-5.0	Summary Findings of Fact in DE CCR Impoundments
DJW-5.1	Federal Court Case and Plea Agreement
DJW-5.2	May 14, 2015 Joint Factual Statement
DJW-5.2.1	May 14, 2016 Joint Factual Statement
DJW-5.3.1	June 1, 2016 Four Plant Order and Exhibits
DJW-5.3.2	June 9, 2017 Amended Order Granting Motion for Partial Summary Judgement
DJW-5.4	Subsequent Enforcement Actions – Executed Settlement Agreement
DJW-6	DEP Timeline
DJW-7.1.1	Mayo Closure Options Analysis
DJW-7.1.2	Mayo Analysis
DJW-7.2	Robinson Closure Options Analysis
DJW-7.3	Roxboro Closure Options Reports
DJW-7.4	Sutton Closure Options Analysis
DJW-7.5	Weatherspoon Closure Option Analysis
DJW-8.1.1	Discovery Analysis – Closure Options
DJW-8.1.2	Discovery Analysis – Recommended Disallowances
DJW-8.3	SOC's and Closure Info by Site
DJW-8.4	Original Versus Updated Risk Classifications
DJW-8.5	Analysis of Risk Classifications and Water Spends
DJW-9.1	January 25, 2019 Article by Catherine Morehouse in <i>Utility Dive</i>

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DAN J. WITTLIFF, BCEE
EXHIBIT LIST
DUKE ENERGY PROGRESS, LLC
DOCKET NO. 2018-318-E**

- DJW-9.2 May 18, 2016 NC DEQ Proposed Classifications for all Coal Ash Ponds in North Carolina
- DJW-9.3 November 14, 2018 NC DEQ Low Risk Classifications for Allen, Belews Creek, Buck, Cliffside, and Marshall Coal Ash Ponds

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22 (PURSUANT TO PREVIOUS INSTRUCTION,
23 THE PREFILED SURREBUTTAL TESTIMONY,
24 INCLUDING CORRECTION/AMENDMENT,
25 OF DAN J. WITTLIFF FOLLOWS.)

[Please note: The corrections noted herein reflect the testimony of the witness during the hearing in this matter.]

1117-1

Surrebuttal Testimony of Dan. J. Wittliff
March 25, 2019

Docket No. 2018-318-E

Duke Energy Progress, LLC
Page 1 of 11

SURREBUTTAL TESTIMONY AND EXHIBITS OF

DAN J. WITTLIFF, P.E., BCEE

ON BEHALF OF

THE SOUTH CAROLINA OFFICE OF REGULATORY STAFF

DOCKET NO. 2018-318-E

IN RE: APPLICATION OF DUKE ENERGY PROGRESS, LLC

FOR ADJUSTMENT IN ELECTRIC RATE SCHEDULES AND TARIFFS

AND REQUEST FOR AN ACCOUNTING ORDER

10 **Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND OCCUPATION.**

11 **A.** My name is Dan Wittliff. My business address is 919 Congress, Suite 1110, Austin,
12 Texas 78701. I am employed by GDS Associates, Inc. as Managing Director of
13 Environmental Services.

14 **Q. DID YOU FILE DIRECT TESTIMONY AND EXHIBITS RELATED TO THIS**
15 **PROCEEDING?**

16 **A.** Yes. I filed direct testimony and nine (9) exhibits with the Public Service
17 Commission of South Carolina ("Commission") on March 11, 2019.

18 **Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?**

19 **A.** The purpose of my surrebuttal testimony is to respond to the rebuttal testimony
20 filed by Duke Energy Progress, LLC ("DEP" or "Company") witness Kerin on March 18,
21 2019.

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1401 Main Street, Suite 900
Columbia, SC 29201

ELECTRONICALLY FILED - 2019 March 25 4:18 PM - SCPSC - Docket # 2018-318-E - Page 1 of 316

1 Q. ON PAGE 3, LINES 11-13 OF COMPANY WITNESS KERIN'S REBUTTAL
2 TESTIMONY HE STATES: "MR. WITTLIFF CONTENDS THAT SOUTH
3 CAROLINA CUSTOMERS SHOULD NOT PAY FOR THAT COMPLIANCE
4 BECAUSE, IN HIS VIEW, CAMA IS TOO EXPENSIVE." DOES THAT
5 ACCURATELY REFLECT YOUR TESTIMONY?

6 A. No. Kerin mischaracterizes my position as: South Carolina customers should not
7 pay for CCR costs associated with CAMA because it is "too expensive." My actual
8 position, as clearly stated in my testimony, is that South Carolina customers should not pay
9 for the incremental increases in costs imposed by North Carolina's CAMA legislation over
10 and above the federal requirements. South Carolina customers should reasonably expect
11 to pay their fair share of the base amount required to comply with federal CCR Rules but
12 not the incremental increase imposed by North Carolina law on plants in that state's
13 jurisdiction. The Company's proposal is not equitable because it requires its South Carolina
14 customers to pay for costs imposed by a government over which its South Carolina
15 customers had limited input. However, South Carolina ratepayers should also reasonably
16 expect to pay their fair share of any CCR approaches negotiated with or required by the
17 State of South Carolina.

1 Q. ON PAGE 4, LINES 12-13 OF HIS REBUTTAL TESTIMONY, COMPANY
2 WITNESS KERIN, REFERRING TO YOUR TESTIMONY IN NORTH
3 CAROLINA, GOES ON TO STATE: "THOSE ARGUMENTS WERE FULLY
4 LITIGATED, AND FOR GOOD REASONS REJECTED IN THE NORTH
5 CAROLINA CASE." DOES THIS ACCURATELY REFLECT THE DECISION
6 MADE BY THE NORTH CAROLINA UTILITY COMMISSION ("NCUC")?

7 A. No. Finding of Fact #55 in NCUC Docket No. E-2, Sub 1142 (Surrebuttal Exhibit
8 DJW-1) states: "Under the present facts, a management penalty in the approximate sum of
9 \$30 million is appropriate with respect to DEP for in the earlier established Asset
10 Retirement Obligation (ARO) with respect to costs incurred through the end of the test
11 year, as adjusted." The fact that a significant management penalty was imposed by the
12 NCUC can only lead to the conclusion that my arguments regarding the Company's actions
13 were strongly considered by the NCUC.

14 Q. ON PAGE 6, LINES 1 THROUGH 11 OF DEP WITNESS KERIN'S REBUTTAL
15 TESTIMONY, HE STATES THAT "THE FIRST TWENTY-NINE PAGES OF MR.
16 WITTLIFF'S TESTIMONY LARGELY MIRROR HIS TESTIMONY IN THE
17 NORTH CAROLINA CASE AND THE RHETORIC RECYCLED IN THOSE
18 PAGES HAS NOTHING AT ALL TO DO WITH THE THEORY THAT HE IS
19 ATTEMPTING TO ADVANCE HERE." DO YOU AGREE WITH THIS
20 CHARACTERIZATION?

21 A. No, I do not. While a good deal of the information on pages 10 through 30 of my
22 Direct Testimony was also presented in the North Carolina hearing on this case, the

1 primarily historical information in Sections III and IV is presented in this docket to provide
2 background and context to the Commission. None of the historical information provided
3 in my direct testimony has changed. In this manner, the Commissioners are informed as to
4 how we got to this place and time. This rate case and the parallel case filed by Duke Energy
5 Carolinas, LLC are the first time this Commission will deal in a dispositive manner with
6 the CCR costs being accumulated in the ARO and non-ARO accounts. This historical
7 information is useful for evaluation of the expenditures DEP claims for reimbursement.
8 While the fact that I presented much of the same information in the North Carolina case as
9 I do here is irrelevant, I do find it interesting that despite DEP witness Kerin's criticism,
10 he himself lifted more than three-quarters of his testimony in this proceeding from his
11 earlier testimony in the DEP rate case in North Carolina.

12 **Q. ON PAGE 8, LINES 2 AND 3 OF DEP WITNESS KERIN'S REBUTTAL**
13 **TESTIMONY, HE STATES THAT "MR. WITTLIFF'S POOR POLICY**
14 **PROPOSAL LACKS FUNDAMENTAL FAIRNESS." IS THAT ASSERTION**
15 **CORRECT?**

16 **A.** Not at all. I used the cost and schedule data provided by DEP through their filed
17 exhibits and responses to eleven (11) rounds of interrogatories as the foundation of my
18 recommendations for allowances and disallowances of claimed costs. Furthermore, I relied
19 on Witness Kerin's approach for conducting CCR closure engineering and planning
20 activities simultaneously across the system to determine how much of the costs related to
21 engineering and planning should be allowed at this time. While I recommended that the
22 CCR costs associated with Cape Fear to date be disallowed, I recommended DEP be

1 allowed to seek reimbursement of these and other costs associated with H.F. Lee and
2 Weatherspoon should the federal CCR rules change to require such closure methods.
3 Specifically, I stated in my Direct Testimony “[i]f DEP can demonstrate that it has
4 prudently incurred expenses dictated by compliance with the CCR Rules as they stand at
5 the time of its next rate case, any expenses required by the CCR Rule as a stand-alone
6 document (i.e., absent CAMA) and determined to be prudently incurred should be
7 considered for recovery in that forum.” To allow DEP to seek additional recovery should
8 the federal CCR rules or applicable conditions change in the future is fair. DEP should not
9 be allowed recovery now for speculative changes in the federal CCR rules.

10 **Q. ON PAGE 11, LINES 17-20 OF DEP WITNESS KERIN’S REBUTTAL**
11 **TESTIMONY, HE STATES: “THE SUGGESTION THAT DE PROGRESS COULD**
12 **OR WOULD HAVE TAKEN A ‘DO NOTHING’ APPROACH TO CAPE FEAR’S**
13 **ASH BASINS, WHILE AT THE SAME TIME CLOSING ALL OF ITS OTHER**
14 **ASH BASINS IN SOUTH CAROLINA AND NORTH CAROLINA DEFIES**
15 **REGULATORY REALITY.” DO YOU CONCUR WITH THIS STATEMENT?**

16 **A.** No. Given Duke Energy’s past performance, especially as evidenced by the Dan
17 River ash release and the Cape Fear discharge structure, it is reasonable to assume that the
18 Company would have continued its “do nothing” approach absent any regulation forcing it
19 to do otherwise. The works undertaken at W.S. Lee and Robinson which witness Kerin
20 cites later in his rebuttal testimony were imposed upon the Company by two consent
21 agreements [SCDHEC Consent Agreement 14-13-HW issued on September 29, 2014
22 (Surrebuttal Exhibit DJW-2) and SCDHEC Consent Agreement 15-23-HW issued July 16,

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1 2015 (Surrebuttal Exhibit DJW-3)]. As noted previously, the lawsuits resulting in the
2 consent agreements occurred as a direct result of Duke Energy's admitted negligence at
3 Dan River and Cape Fear. Had the Dan River incident and the Cape Fear discharges not
4 occurred, it is entirely reasonable to conclude that compliance at Cape Fear would have
5 been limited by the CCR Rules, which, as I stated in my direct testimony, currently do not
6 require any action at Cape Fear.

7 **Q. ON PAGE 15, LINES 17-18 OF HIS REBUTTAL TESTIMONY COMPANY**
8 **WITNESS KERIN ASKS: "WOULD MR. WITTLIFF'S PROPOSED TIMELINE**
9 **FOR SUTTON CLOSURE UNDER THE CCR RULE HAVE REDUCED**
10 **CLOSURE COSTS?" ARE YOU CONTENDING THAT ADHERENCE TO THE**
11 **CCR TIMELINE WOULD HAVE REDUCED SUTTON CLOSURE COSTS?**

12 **A.** No. My contention is that most of the costs incurred to date would not have been
13 incurred prior to September 30, 2018, which ends the period for recovery of actual costs in
14 this proceeding. Regarding his rebuttal testimony on Sutton, Witness Kerin is correct that
15 the Federal CCR Rules (40 CFR 257.61) relating to existing impoundments located in
16 wetlands required the Company begin closure activities at Sutton within 30 days after it
17 received its last waste (July 6, 2016) [40 CFR §257.102(e)(1)(i)]. Furthermore, 40 CFR
18 §257.102(f)(1)(ii) requires that closure be completed within five years or by August 5,
19 2021. This timeline is included in Surrebuttal Exhibit DJW-4. However, because Sutton
20 was designated as a HIGH PRIORITY CAMA site, closure was required to be completed
21 two years earlier - by August 1, 2019 instead of August 5, 2021 – than it would have been
22 in accordance with the Federal CCR Rules.

During my site visit to Sutton on December 11, 2018 (direct testimony Exhibit DJW 2.7), Company representatives pointed out the following factors that made it necessary to haul the first ^{2.016}~~2.116~~ million tons of ash to the Brickhaven Mine: (1) the tight time constraints imposed by CAMA (i.e., complete by August 1, 2019), (2) the extended time to permit and build an on-site landfill, and (3) the costs associated with other options. Of the ^{2.016}~~2.116~~ million tons of ash hauled to the Brickhaven Mine, the first 14,000 tons were trucked to Brickhaven while the balance was shipped by rail. All of the rest of the ash will be landfilled on site (direct testimony Exhibit DJW-3.7). I do not, at this time, recommend disallowance of future recovery of reasonably incurred expenditures for Sutton, but do believe costs incurred solely as a result of CAMA and court orders should not be recovered in this proceeding.

Q. ON PAGE 10, LINES 9-16 OF HIS REBUTTAL TESTIMONY DEP WITNESS KERIN, STATES: "MR. WITTLIFF'S TESTIMONY LACKS ANY FACTUAL SUPPORT FOR HIS ALTERNATIVE CLOSURE PROPOSALS AND DOES NOT DEMONSTRATE ANY ANALYSIS OF SITE-SPECIFIC CONDITIONS, INCLUDING: ENGINEERING ANALYSIS DEMONSTRATING THE TECHNICAL AND PRACTICAL FEASIBILITY OF CAP-IN-PLACE OR AN ONSITE LANDFILL, THE PRECISE LOCATION AND SIZE OF AN ON-SITE LANDFILL; COST ESTIMATES FOR CAP-IN-PLACE OR AN ON-SITE LANDFILL; PERMITTING REQUIREMENTS FOR CAP-IN-PLACE OR ON-SITE LANDFILL; OR THE LIKELIHOOD OF OBTAINING REQUISITE FEDERAL, STATE, AND LOCAL PERMITTING APPROVAL FOR CAP-IN-

1 **PLACE OR AN ON-SITE LANDFILL.” HOW DO YOU RESPOND TO THIS**
2 **STATEMENT?**

3 **A.** DEP’s lack of responsive information regarding the costs of various alternatives
4 considered on a site-by-site basis (despite twelve rounds of information requests by
5 SCORS between July 2017 and March 2019) required me to develop surrogate cost
6 estimates. In his rebuttal, Mr. Kerin carefully avoids providing any alternative cost
7 estimates for actions that would have been required in the absence of CAMA, a tactic that
8 DEP has adopted throughout this proceeding and proceedings in North Carolina. Rather
9 than the estimate I developed for my direct testimony, I could have relied upon an
10 escalation of the cost estimates provided in DEP’s response to SCORS 6-1 (DEP 6-1
11 Financial Forecast – Xcel), which showed that DEP projected total project Asheville cap-
12 in-place costs of \$29,954,662 in 2012, when only federal CCR regulations were
13 anticipated. These regulations changed very little between 2012 and their eventual issue in
14 2015. Escalating these costs to 2018 at 2.5% annually for six years would result in a total
15 estimated project cost of \$34,738,224, an amount approximately one sixth of the
16 \$191,934,196 claimed by DEP for compliance actions required by CAMA. My surrogate
17 estimate is much more reasonable as I recommend the Company be allowed to recover
18 \$93,713,264 at this time for Asheville related to CCR ARO costs.

1 Q. ON PAGE 14, LINES 7-10 OF DEP WITNESS KERIN'S REBUTTAL
2 TESTIMONY, HE STATES: "FOR THE CAPE FEAR AND H.F. LEE SITES,
3 BENEFICIATION UNDER CAMA IS PROVIDING AN ESTIMATED NET
4 SAVINGS COMPARED TO CLOSURE WITHOUT BENEFICIATION OF
5 APPROXIMATELY \$703 MILLION ON A TOTAL SYSTEM BASIS." DO YOU
6 AGREE WITH THIS STATEMENT?

7 A. Absolutely not. First, Mr. Kerin's statement is totally unsubstantiated, and he
8 provides no supporting information. Second, Mr. Kerin does not state whether the
9 "estimated net savings" are in comparison to CCR requirements or to other additional
10 CAMA requirements that might have been imposed on Cape Fear and H.F. Lee in place of
11 beneficiation.

12 Q. ON PAGE 18, LINES 4-7 OF DEP WITNESS KERIN'S REBUTTAL TESTIMONY,
13 HE STATES: "DE PROGRESS IS NOT BENEFICIATING ASH UNDER CAMA
14 AT WEATHERSPOON AS MR. WITTLIFF SUGGESTS AND INSTEAD IS
15 SELLING RAW, UNPROCESSED ASH TO BUYERS WHO CAN USE IT TO
16 OFFSET SOME OF THE COSTS FOR CLOSING THAT SITE." WHAT IS YOUR
17 RESPONSE TO WITNESS KERIN?

18 A. During my December 12, 2018 site visit to Weatherspoon (direct testimony Exhibit
19 DJW 2.8) I was briefed by Company representatives on the CCR processes in place at the
20 plant regarding the 2.45 million tons of ash remaining in the Ash Pond, before the Company
21 removed 280 thousand tons of ash between September 2017 and September 2018. The
22 Company has contracted with two cement kilns, Argos and Olsen, about 150 miles south

1 of Weatherspoon in South Carolina to supply between 230 and 280 thousand tons of graded
2 (< 1 inch) and dried ash (about 25 percent water) per year total. Beneficiation of the ash
3 basin ash is required by CAMA to be completed by 2029. Company personnel indicated
4 that the Weatherspoon ash beneficiation could be finished in six to eight years. Water levels
5 in the basins have been lowered through decanting and this process is now complete. The
6 Company plans to excavate the ash from the basins for use in the beneficiation process.
7 Out of spec ash will be landfilled off-site. The closure plan includes the following steps:
8 (a) Decant the free or bulk water down to the bottom three feet and maintain this level until
9 dewatering begins; (b) Excavate the ash, allow to dry, and screen the ash for size; (c) Build
10 piles of material (Active and Reserve); (d) Seal the Reserve Pile with EcoGreen; and (e)
11 Truck ash from the screened and dry Active Pile to the cement kilns in South Carolina.
12 Once the ash is completely excavated from the impoundments, the bottom will be
13 confirmed for clean closure.

14 Witness Kerin says DEP is not beneficiating CCR at Weatherspoon under CAMA.
15 The process that I saw and the description provided satisfied me that at least some of the
16 work at Weatherspoon was part of a beneficiation process.

17 **Q. DID YOU CONTEND IN YOUR DIRECT TESTIMONY THAT CAMA'S**
18 **BENEFICIATION REQUIREMENTS ARE UNREASONABLE?**

19 **A.** I did not, and DEP witness Kerin has provided no citation to back his contention
20 that I have done so.

21 **Q. DID SOUTH CAROLINA CUSTOMERS BENEFIT MORE FROM CAMA THAN**
22 **THEY WOULD HAVE UNDER FEDERAL CCR REQUIREMENTS?**

1 **A.** No. On page 14 of my testimony, I included the preamble of the May 14, 2014
2 version of the North Carolina Coal Ash Management Act (Senate Bill 729) (direct
3 testimony Exhibit DJW-4.4) as a measure of legislative intent. It is abundantly clear from
4 this language that the members of the General Assembly were concerned about (among
5 other things) (1) six decades of ash mismanagement in North Carolina, (2) the failure and
6 release of CCR into the Dan River in February 2014, and (3) protection of North Carolina
7 surface water and ground water resources for their best usage. Consequently, CAMA was
8 appropriately focused on protecting public health and safety as well as the environment in
9 North Carolina. Accordingly, CAMA includes protections above and beyond what is
10 required in the federal CCR Rules and these protections accrue primarily to the benefit of
11 North Carolina residents with an unquantifiable, but minimal, benefit to South Carolina
12 residents from the early mitigation of risks posed by DEP North Carolina plants near the
13 South Carolina border.

14 **Q. WILL YOU UPDATE YOUR SURREBUTTAL TESTIMONY BASED ON**
15 **INFORMATION THAT BECOMES AVAILABLE?**

16 **A.** Yes. ORS fully reserves the right to revise its recommendations via supplemental
17 testimony should new information not previously provided by the Company, or other
18 sources, become available.

19 **Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?**

20 **A.** Yes.

1 MR. BATEMAN: Mr. Chairman, Mr. Wittliff and
2 Mr. Seaman-Huynh are available for questions
3 from opposing counsel and the Commission.

4 CHAIRMAN RANDALL: Okay. We'll get to that
5 after we have a break. Now, Ms. Grundmann,
6 did you have a request?

7 MS. GRUNDMANN: Just at the lunch break, Mr.
8 Chairman. I -- I -- at this time I don't
9 believe I have any cross for any remaining
10 witnesses and was going to request, when we
11 broke for lunch, to be released.

12 CHAIRMAN RANDALL: Okay. You want to do from
13 lunch?

14 MS. GRUNDMANN: Yes, please.

15 CHAIRMAN RANDALL: Okay. I just thought we
16 might -- it was going to be at the break, so I
17 just wanted to make sure we got you going if
18 you needed to be.

19 Okay. We're going to break for about ten
20 minutes. Thank you. Then we'll -- we'll
21 resume.

22 (Off the record from 11:15 a.m.
23 until 11:28 a.m.)

24 CHAIRMAN RANDALL: Please be seated. Okay.
25 Welcome back. We'll call this back to order.

1 Let's see. And, Ms. Grundmann, you said no?

2 MS. GRUNDMANN: No cross.

3 CHAIRMAN RANDALL: Okay. Ms. Ferguson? Mr.
4 Neal?

5 MR. NEAL: Yes, Mr. Chairman.

6 CROSS-EXAMINATION

7 BY MR. NEAL:

8 Q Good morning, Mr. Seaman-Huynh.

9 A (SEAMAN-HUYNH) Good morning.

10 Q My questions will be for you. It's good to see you
11 again.

12 A (SEAMAN-HUYNH) You, as well.

13 Q So you noted in your direct testimony in this case
14 that, in the 2016 Duke Energy Progress general rate
15 case, that the Company did not use the minimum
16 system method, and instead, allocated costs using
17 the basic customer method; is that right?

18 A (SEAMAN-HUYNH) Yes.

19 Q And, further, you testified that, I quote, "The
20 basic customer method allocated service drops and
21 meters based on the number of customers and
22 resulted in lower basic facilities charges"?

23 A (SEAMAN-HUYNH) Yes.

24 Q Now, that 2016 rate case that you referred to was
25 Docket Number 2016-227-E. Does that ring a bell?

1 A (SEAMAN-HUYNH) Yes. It does.

2 Q In fact, you provided testimony in that case, did
3 you not?

4 A (SEAMAN-HUYNH) I did.

5 Q I've just put on the ELMO the cover page of -- of
6 your testimony in -- in Docket Number 2016-227-E,
7 and in that case for the Office of Regulatory
8 Staff, you also reviewed Duke Energy Progress's
9 cost-of-service study, did you not?

10 A (SEAMAN-HUYNH) Yes. We did.

11 Q Now, turning your attention to your testimony from
12 2016, to Page 4 of that testimony -- and I'm going
13 to try to put it up on the screen, and I can give
14 you a copy of it, if you need it -- you testified
15 that "the methodology applied in constructing the
16 Company's cost-of-service study, or COSS, provides
17 a reasonable assessment and allocation of the
18 Company's revenues, operating expenses, and rate
19 base items, which produces a rate of return by
20 customer class." Do you recall providing that
21 testimony?

22 A (SEAMAN-HUYNH) Yes. I do.

23 Q And, again, your conclusion in 2016 was based on
24 the Company's cost-of-service study that did not
25 use the minimum system method, right?

1 A (SEAMAN-HUYNH) Yes.

2 Q Turning your attention to the EDIT, or EDIT rider,
3 it's my understanding that ORS recommended
4 adjustments to the EDIT rider, but used the basic
5 methodology set forth by DEP; is that right?

6 A (SEAMAN-HUYNH) That is correct. We made
7 adjustments to update for billing units and also
8 for an updated rate of -- cost of debt, I believe.

9 Q Okay. And, under Mr. Wheeler for Duke Energy
10 Progress, his Exhibit 1, which I've put on the
11 ELMO, Page 84 shows the Company's proposed EDIT
12 rider. Did you review that as part of your work in
13 this case?

14 A (SEAMAN-HUYNH) Yes. I did.

15 Q And so you would agree -- and I believe ORS follows
16 -- that -- follows this basic approach -- that the
17 EDIT rider applies only to the volumetric portion
18 of a customer's bill?

19 A (SEAMAN-HUYNH) We are recommending that the EDIT
20 rider be returned -- those funds be returned to
21 customers through the volumetric rates.

22 Q Thank you. That's -- that's a more precise way of
23 saying it. So, for example, under the Company's
24 proposal, for a residential customer, they would
25 receive the EDIT rider at a rate of .227 cents per

1 kilowatt-hour?

2 A (SEAMAN-HUYNH) Is there a question there?

3 Q Yes. Just making sure I'm reading this right.

4 A (SEAMAN-HUYNH) That is the Company's proposal.

5 Q Right.

6 A (SEAMAN-HUYNH) Yeah. That is not ORS's

7 recommendation.

8 Q Which would mean, for example, that a residential

9 customer who used 1,000 kilowatt-hours would

10 receive a \$2.27 credit, essentially, on their bill

11 under -- under the Company's proposed EDIT rider?

12 A (SEAMAN-HUYNH) That is correct.

13 Q Okay. Now, step -- taking a step back, as you

14 described your proposed methodology for calculating

15 a basic facilities charge, am I correct that your

16 recommendation is that the Company receive -- or

17 that the Company put no more than 25 percent of the

18 allowed revenue increase for the residential class

19 into the basic facilities charge?

20 A (SEAMAN-HUYNH) That recommendation is for the

21 residential class, the small general service class,

22 and the small general service constant load class.

23 Q And that calculation -- that 25 percent

24 calculation, that was made before any adjustments

25 from the EDIT rider?

1 A (SEAMAN-HUYNH) That is correct.

2 Q Now, you would agree, would you not, that the
3 accumulated deferred income tax that's the -- the
4 basis for the EDIT rider was -- is the result of
5 collections from revenue the Company has received
6 from customers over the years based -- based on,
7 you know, customers paying their bills and
8 generating revenue to the Company?

9 A (SEAMAN-HUYNH) I am familiar with it, that that
10 was addressed by, I believe it was ORS witness
11 Schellinger, and I support his testimony and have a
12 -- an understanding of his testimony, and that is
13 my understanding, yes.

14 Q So, in other words, when a customer, some years
15 ago, paid Duke Energy Progress a \$120 bill, some
16 portion of that revenue to the Company was for the
17 payment of taxes, and some of those taxes were
18 deferred, and that's sort of the subject of the
19 EDIT rider?

20 A (SEAMAN-HUYNH) That's my understanding, yes.

21 Q And so some of that revenue from customers came
22 from the volumetric charge and some from the basic
23 facilities charge, correct?

24 A (SEAMAN-HUYNH) I can't speak to that.

25 Q Well, it would stand to reason that the -- the

1 revenue received from customer bills is -- is sort
2 of -- it's the subject of where that money came
3 from? I mean, we just established that, right, I
4 mean, that that revenue came from customers from
5 paying their bills?

6 A (SEAMAN-HUYNH) It came from customers. I can't
7 tell you whether it came from a energy charge,
8 demand charge, or a basic facilities charge.

9 Q And, but we do know, regardless of where it came
10 from, that right now, as it currently stands, the
11 EDIT rider only flows back to the volumetric rate?
12 Or --

13 A (SEAMAN-HUYNH) That is --

14 Q Or it only falls back on a volumetric basis?

15 A (SEAMAN-HUYNH) That is our recommendation, yes.

16 Q You would agree, if -- if we did the EDIT
17 calculations before calculating the basic
18 facilities charge under ORS's recommended
19 methodology, it would result in some lower amount
20 to the basic facilities charge?

21 A (SEAMAN-HUYNH) Yes. But I don't believe that that
22 would be appropriate, to include any revenue
23 refunds from the EDIT rider in calculating the
24 basic facilities charges.

25 Q Now, if -- if -- if it -- I appreciate that you're

1 not sure about this, but if it turns out to be true
2 that -- that the revenue that came from customers
3 that is the source of this deferred income taxes,
4 if a portion of that came from customers' fixed
5 charges, wouldn't it be fair to return a portion of
6 it in their fixed charges?

7 A (SEAMAN-HUYNH) I don't believe that it's
8 appropriate to divide out the revenue from the EDIT
9 give-back into different categories. I think the
10 most efficient way is to return it through one
11 method, and the most appropriate method would be
12 through a volumetric rate, specifically the energy
13 charge.

14 Q Regardless of how that money was collected --

15 A (SEAMAN-HUYNH) Yes.

16 Q -- from customers?

17 A (SEAMAN-HUYNH) Yes.

18 MR. NEAL: Thank you for your testimony.

19 CHAIRMAN RANDALL: Mr. Guild?

20 MR. GUILD: No questions, Mr. Chairman. Thank
21 you.

22 CHAIRMAN RANDALL: Thank you. Mr. Elliott?

23 MR. ELLIOTT: Please.

24 CROSS-EXAMINATION

25 BY MR. ELLIOTT:

1 Q Mr. Seaman-Huynh, just a few for you, if I may,
2 first. Now, Mr. Seaman-Huynh, you are the senior
3 regulatory manager in the Utility Rates & Services
4 Division of the ORS, correct?
5 A (SEAMAN-HUYNH) I am one of two senior regulatory
6 managers in Utility Rates & Services.
7 Q And you've offered testimony in this proceeding
8 concerning the rates proposed by the Company,
9 correct?
10 A (SEAMAN-HUYNH) Correct.
11 Q And you are aware, in your capacity as senior
12 regulatory manager, that the Company has proposed
13 to recover certain forecasted costs to -- to cover
14 inflation and contingency in this case, are you
15 not?
16 A (SEAMAN-HUYNH) I am.
17 Q All right. Could you please explain to the
18 Commission the ORS's position on the recovery of
19 contingency costs and what the ORS -- the basis of
20 the ORS position is?
21 A (SEAMAN-HUYNH) Are there specific contingency
22 costs, what you're referring to?
23 Q Well, I'm -- I'm referring to the contingency costs
24 as pertaining to the Customer Connect proposition.
25 But you're aware, are you not, that the -- that the

1 law in this state precludes recovery of contingency
2 costs, aren't you?
3 A (SEAMAN-HUYNH) I'm not an attorney, Mr. Elliott,
4 but it is my understanding that that is correct..
5 Q And that stems from a Supreme Court decision of
6 about ten years ago pertaining to some contingency
7 costs approved by this Commission, but overturned
8 by the -- by the South Carolina Supreme Court,
9 correct?
10 A (SEAMAN-HUYNH) Yes, sir.
11 Q All right. And does that Supreme Court decision
12 form, in part or in whole, the ORS position on
13 contingency costs?
14 A (SEAMAN-HUYNH) I would say in part, yes.
15 Q All right. Thank you. Mr. Wittliff?
16 A (WITTLIFF) Yes, sir.
17 Q In your testimony, you reference a consent
18 agreement between Duke and DHEC at -- bearing the
19 number 15-23-HW. Do you recall that?
20 A (WITTLIFF) Yes.
21 Q And if it would help, I draw your attention to your
22 surrebuttal, Page 5, Lines 21 and 22.
23 A (WITTLIFF) All right. Get to it. Page number
24 again, please?
25 Q Yes, sir. Page 5 in your surrebuttal, according

1 to --

2 A (WITTLIFF) Got it.

3 Q -- my notes --

4 A (WITTLIFF) I'm there.

5 Q -- Lines 21 and 22. Just look at the footnote.

6 A (WITTLIFF) Yes, sir.

7 Q And you see -- you -- actually, there, you

8 reference the -- the Lee station consent agreement,

9 and I'm drawing your attention to the Robinson

10 plant consent agreement. Do you see that?

11 A (WITTLIFF) Yes, sir.

12 Q And, as I recall, the Robinson plant consent

13 agreement between DHEC and Duke is maybe the --

14 Exhibit 3 to your surrebuttal testimony?

15 A (WITTLIFF) Yes, sir. It is.

16 Q And so it's fair to say that you are familiar with

17 the consent agreement, 15-23-HW, pertaining to the

18 Robinson Steam Electric plant?

19 A (WITTLIFF) Yes, sir.

20 Q And if I place here on the ELMO the front page of a

21 copy of a document with a similar label, I would

22 ask you if you recognize it. And if you would like

23 to refer to your exhibit, fine, but I represent to

24 you that this is the consent agreement 15-23-HW

25 entered into between Duke and DHEC.

1 A (WITTLIFF) Okay. Yes, sir.

2 Q Now, because you're familiar with the terms of this
3 order, you are aware that the -- excuse me -- it's
4 not an order, it's an agreement -- you are aware
5 that there were certain findings of fact set out in
6 this consent agreement, are you not?

7 A (WITTLIFF) Yes, sir.

8 Q And I would ask you whether -- based on your review
9 of this consent agreement, whether DHEC found Duke
10 in violation of any of the terms of its permit.

11 A (WITTLIFF) I don't recall this being associated
12 with any violations.

13 Q And I would like to ask you -- because I was
14 intrigued with your testimony of just a moment ago,
15 I would ask you, given your background, I think as
16 a -- as a upper-level staff member at the -- at the
17 Texas National Resource Department -- what was your
18 title?

19 A (WITTLIFF) I was chief engineer of the Texas
20 Natural Resource Conservation Commission that is
21 now the Texas Commission on Environmental Quality.

22 Q All right, sir. And you would be aware, based on
23 your work experience and your consulting experience
24 and your review of the matters in this docket, that
25 -- that DHEC, as the regulator of this waste

1 landfill, has the authority to make inspections to
2 determine whether or not Duke is in compliance with
3 its permit, correct?

4 A (WITTLIFF) Well, that's customary in all permits
5 and in anything that the agency would sign off on,
6 is that they would be granted access.

7 Q And, based on your experience, it's typical that
8 the -- that DHEC would make quarterly inspections
9 of these landfills, correct?

10 A (WITTLIFF) I can't speak to that. It was -- it's
11 different in different places.

12 Q But they'd be routine in any event, would they not?

13 A (WITTLIFF) They would be normal and routine.

14 Q All right. And -- and, had there been a violation
15 of any of the terms of the permit, based on your
16 experience, you would expect a finding of fact to
17 reflect a -- a violation of the permit, would you
18 not?

19 A (WITTLIFF) If the -- if the reason for the consent
20 agreement is because of -- of some sort of
21 source -- original violation of the permit, then
22 that generally would be covered in the findings of
23 fact.

24 Q Thank you. Now -- and actually, you -- were --
25 were you here yesterday when Mr. Kerin testified?

1 A (WITTLIFF) I was.

2 Q Do you recall that Mr. Kerin testified that, at all
3 times relevant to our inquiry, that the Robinson
4 coal ash pond was compliant with DHEC regulations?

5 A (WITTLIFF) I believe that's what he said.

6 Q Yes, sir. Now, referring you, if I may, within
7 this -- this agreement, which I would note is in
8 the record as a separate agreement and -- and now
9 is an exhibit as a part of your testimony, I'd like
10 to draw your attention, if I may, to Page 10,
11 Paragraph 16 of this consent agreement. And I put
12 it on the ELMO, and do you see where I've
13 highlighted some language?

14 A (WITTLIFF) Yes, sir. I see the language.

15 Q And I'm going to read it as best I can and ask you
16 for -- to confirm for me that I've read it
17 correctly. I'm reading the highlighted language.
18 "Once the Department has approved the final report,
19 the Department will provide Duke Energy a written
20 approval of completion that provides covenant not
21 to sue to Duke Energy for the response actions
22 specifically covered in this consent agreement
23 approved by the Department and completed in
24 accordance with the approved work plans and
25 reports." Have I read that correctly?

1 A (WITTLIFF) I believe you have.

2 Q And you would recognize that by, sort of, its
3 nomenclature, a covenant not to sue, would you not,
4 sir?

5 A (WITTLIFF) I think -- you know, I need to caveat
6 the answers: I'm not a lawyer but that's what
7 that says.

8 Q It does, indeed. And, based on your experience in
9 Texas and as a consultant, and -- and based upon
10 your review of the matters in this docket, would it
11 be fair to say that, in a typical consent order
12 issued by a regulatory body, that the regulator
13 would not agree to a covenant not to sue? Isn't
14 that your experience?

15 A (WITTLIFF) I can't say that with the certainty
16 that -- that you might seek. If it's an order, it
17 stems from a violation. It's an enforcement
18 action, and I -- I can't speak to whether you would
19 include language like that in -- in -- in an
20 enforcement order.

21 Q But you would agree with me that it's unusual,
22 based on your experience, to find a covenant not to
23 sue in a consent agreement or a consent order,
24 would -- isn't that true, sir?

25 A (WITTLIFF) From -- from my experience, that's an

1 unusual clause to have. It may not be here, but it
2 -- it -- it is where I come from.

3 Q Very fine. Now, let me draw your attention in that
4 consent agreement to Page 11, Paragraph 19, and
5 I've highlighted it. Can you make that out on the
6 ELMO, Mr. Wittliff?

7 A (WITTLIFF) Okay. These graduated bifocals haven't
8 been calibrated in a while, so give me a second
9 here.

10 Q Well, I have the same problem.

11 A (WITTLIFF) That's good. You got it now.

12 Q All right. I'm -- I'm going to publish Paragraph
13 19, and -- and would first ask you to confirm
14 whether I've accurately done so. It reads,
15 "Employees of the Department, their respective
16 consultants and contractors, will not be denied
17 access during normal business hours or at any time
18 under this consent agreement -- at any time work
19 under this consent agreement is being performed or
20 during any environmental emergency or imminent
21 threat situation as determined by the Department or
22 as allowed by applicable law." Have I read that
23 correctly?

24 A (WITTLIFF) Yes.

25 Q And isn't it your experience, both in Texas and as

1 a consultant, and at least as -- insofar as you've
2 considered and investigated the facts in this case,
3 isn't it -- isn't it -- aren't you of a view that
4 it's -- it's unusual for the regulatory agency to
5 request authority to inspect work such as the --
6 the -- DHEC has done here?

7 A (WITTLIFF) Well, first of all, I -- I can't speak
8 to why it would specifically be here, but at the
9 same time, that's a -- that is a requirement under
10 -- under the laws in most states that I know of,
11 that you have to grant access during normal
12 business hours or during any emergency to -- to
13 duly-appointed environmental regulatory staff.
14 They've got to have access so they can verify
15 compliance.

16 Q And you would agree with me, however, that Duke --
17 that DHEC felt compelled to make that a provision
18 of their consent agreement with Duke in this case?
19 Do you agree with me there?

20 A (WITTLIFF) I -- I think it's in -- it's in the
21 consent agreement, so they must've felt it
22 important to include.

23 Q Yes, sir. Now, as I understand your testimony,
24 Duke is requesting recovery of \$179 million -- it
25 might help you here, if you can read it. It's --

1 it's from Page 45 of -- I think it's your direct.
2 But can you read that figure? Under -- for
3 Robinson, Duke is requesting recovery of
4 \$179,561,777 for the Robinson plant, correct?
5 A (WITTLIFF) No. That -- that right there is the
6 total project cost, what they're asking for now,
7 for Robinson. Actual expenses is \$11,431,600 --
8 okay -- now that's where I got it -- \$691.
9 Q All right. So the total cost is one -- 179.5
10 million. They're requesting 11 million in this
11 case, correct?
12 A (WITTLIFF) Correct.
13 Q Now, you are aware, are you not, that, at the time
14 the testimony was submitted in this case, that the
15 Duke -- that Duke anticipated its total coal ash
16 remediation cost to be about \$5.6 billion for the
17 Carolinas? Do you understand that was the
18 projection at the time you filed your testimony?
19 A (WITTLIFF) Yes.
20 Q Now, you also understand that, based on some action
21 by the North Carolina -- Department of
22 Environmental Quality, I think, is the name of the
23 agency -- Duke has been ordered to perform
24 additional coal ash excavation that, by Duke's
25 reckoning, would add approximately 4 billion to 5

1 billion dollars to the current estimate of \$5.6

2 billion? That's correct, isn't it?

3 A (WITTLIFF) That's what it says there.

4 Q And -- and so we can agree, can we not, that, if

5 Duke -- if Duke's estimates bear out and the costs

6 double, virtually, from \$5.6 billion to 10 billion,

7 that the -- that the -- the risks to their

8 ratepayers double, as well, can we -- can we not?

9 A (WITTLIFF) I'm not sure about the risk, but I

10 think the cost will certainly increase

11 proportionately.

12 Q And so the stakes have just gotten higher for

13 Duke's ratepayers, have they not?

14 A (WITTLIFF) Yes.

15 MR. ELLIOTT: Thank you. No further

16 questions, Mr. Chairman. Thank you very much.

17 CHAIRMAN RANDALL: Thank you. Nucor, Mr.

18 Smith?

19 MR. SMITH: No questions, Mr. Chairman.

20 CHAIRMAN RANDALL: Company?

21 CROSS-EXAMINATION

22 BY MR. BURNETT:

23 Q Good morning, gentlemen. Mr. Wittliff --

24 A (WITTLIFF) Good morning.

25 Q -- I only have questions for you. And, Mr. Seaman-

1 Huynh, Mr. Anthony will follow me with any
2 questions that he may have for you, sir.

3 Mr. Wittliff, you agree with me, do you not,
4 that you have not alleged anywhere in your
5 testimony or exhibits that Duke Energy Progress
6 acted imprudently or unreasonably in complying with
7 the North Carolina Coal Ash Management Act,
8 correct?

9 A (WITTLIFF) Yes.

10 Q You also agree with me, do you not, that you have
11 not alleged anywhere in your testimony or exhibits
12 that Duke Energy Progress acted imprudently or
13 unreasonably in complying with the federal coal
14 combustion residuals rule, correct?

15 A (WITTLIFF) Yes.

16 Q And you further agree with me that not \$1 of your
17 proposed \$333,480,308 disallowance of coal ash
18 environmental costs in this matter is based on any
19 allegation of imprudent or unreasonable actions by
20 DE Progress; isn't that right?

21 A (WITTLIFF) Yes.

22 Q You also agree with me that, if we want to go to
23 what I would call the "bottom line" of what you are
24 recommending in this case regarding the recovery of
25 coal ash costs, we could turn to Page 45 of your

1 March 4 direct testimony or the summary that you
2 just provided to the Commission and look at Table
3 4.5; isn't that right?

4 A (WITTLIFF) We could.

5 Q And, as we see for that Table 4.5, again, right
6 here in that summary that you handed out to the
7 Commission, your proposed disallowances in this
8 matter are based on the theory that the Company
9 should only be allowed to recover costs that it
10 would've spent to comply with the federal CCR rule;
11 isn't that right?

12 A (WITTLIFF) It's based on the position of ORS that
13 was clearly -- clearly stated earlier.

14 Q And right. And, just to be clear, that is that
15 only costs to comply with the federal CCR rule
16 should be recovered; isn't that right?

17 A (WITTLIFF) Yes.

18 Q Okay. Now, Mr. Wittliff, I want to use Table 4.5
19 to ask you some questions about each one of your
20 proposed disallowances, and let's turn first to the
21 Asheville site that's the first one there on your
22 Table 5.4. You agree with me, do you not, that
23 your proposal is that the Company only recover what
24 it would've spent to cap the ash basins on that
25 site in place, rather than excavate them; isn't

1 that correct?

2 A (WITTLIFF) And we're talking Asheville?

3 Q Yes, sir.

4 A (WITTLIFF) Yes.

5 Q And you agree with me that a fundamental assumption
6 for your proposed disallowance for Asheville is
7 that a cap-in-place methodology would've been
8 acceptable under the federal CCR rule for the
9 Asheville site; isn't that right?

10 A (WITTLIFF) Yes.

11 Q And, logically, Mr. Wittliff, you would agree with
12 me that if cap-in-place is not an acceptable
13 closure method for Asheville under the federal CCR
14 rule, then your proposed allowance for only the
15 cap-in-place closure costs on Table 4.5 would be
16 invalid; isn't that right?

17 A (WITTLIFF) Yes.

18 Q You agree with me, though, don't you, Mr. Wittliff,
19 that you have not conducted any independent
20 engineering analysis to determine whether site
21 conditions at Asheville would have allowed for cap-
22 in-place closure to be used at that site, despite
23 your extensive pedigree and record that -- of your
24 career that you gave to the Commission earlier;
25 isn't that right?

1 A (WITTLIFF) I did not conduct an -- an extensive
2 engineering analysis to the level that I think
3 you're inferring. What I did do was honor the
4 charge that I was given by the South Carolina
5 Office of Regulatory Staff, and that was to
6 determine what incremental cost increases were
7 imposed by CAMA above and beyond what the federal
8 CCR rules require, and I stayed as tightly as I
9 could within those parameters.

10 Q Mr. Wittliff, isn't it true that, in your direct
11 testimony, and for that matter anywhere else in
12 your testimony, the only support you provide for
13 your assertion that the Company could've used a
14 cap-in-place closure method in Asheville is -- is
15 found on Page 41 of your direct testimony, Lines 1
16 through 3, where you contend that, had the Company
17 not built a new national -- natural gas plant at
18 the Asheville site, there would've been ample room
19 for on-site disposal of ash at Asheville; isn't
20 that right?

21 A (WITTLIFF) Yes. I believe that's right.

22 Q You agree with me, don't you, Mr. Wittliff, that
23 having ample room for a cap-in-place closure is not
24 the only factor that one considers when determining
25 whether it's an appropriate closure methodology for

1 an ash basin; isn't that right?

2 A (WITTLIFF) Yes. That's -- there are siting
3 restrictions.

4 Q That's right. And, in addition to siting
5 restrictions, Mr. Wittliff, you would agree with me
6 that, to determine whether cap-in-place was
7 appropriate at Asheville, one would've had to have
8 considered at least the soil conditions there at
9 the site, correct?

10 A (WITTLIFF) Correct.

11 Q The seismic stability of the site; isn't that
12 correct?

13 A (WITTLIFF) Correct.

14 Q The proximity to water sources for flooding
15 considerations; isn't that correct?

16 A (WITTLIFF) Correct.

17 Q The age of the basins there?

18 A (WITTLIFF) That could be a factor.

19 Q The stability of the basins there, correct?

20 A (WITTLIFF) Well, it depends on whether you're
21 going to -- to do some kind of hybrid or whether
22 you're going to -- the general gist of what you're
23 saying is right.

24 Q Okay. And, finally, the constituents that the dam
25 is actually made of -- or -- or the basins? You'd

1 have to consider that --

2 A (WITTLIFF) Oh, sure.

3 Q -- too, correct?

4 A (WITTLIFF) Yes.

5 Q And, again, you have not considered, nor do you

6 discuss, any of these factors for the Asheville

7 site in your testimony; isn't that right?

8 A (WITTLIFF) That's correct.

9 Q Now, turning to the Cape Fear site that is the

10 second location on Table 4.5 that we're -- have in

11 your direct testimony and in your summary, you

12 recommend that the Company not recover any costs

13 for work at Cape Fear because the federal CCR rule,

14 as currently drafted, would not have required work

15 to be done at that ash basin, correct?

16 A (WITTLIFF) Well, the federal rules are final, but

17 as you -- yes.

18 Q Okay. However, you do not take a position in your

19 direct or surrebuttal testimony, do you, sir, as to

20 what the proper closure method would have been for

21 Cape Fear, if it were covered by the CCR rule;

22 isn't that right?

23 A (WITTLIFF) That's correct.

24 Q And, as you sit here today, sir, you cannot say

25 whether excavation, cap-in-place, or any other

1 method would be the proper closure method at Cape
2 Fear should the CCR rule ever be amended to cover
3 those basins, because you've not done an analysis
4 to make that determination; isn't that right?

5 A (WITTLIFF) That's correct.

6 Q Not withstanding this fact, though, you do take
7 issue with Witness Kerin's assertion that the ash
8 beneficiation requirement under CAMA has made
9 closure costs at Cape Fear cheaper than they
10 would've otherwise been, had that requirement not
11 existed; isn't that right?

12 A (WITTLIFF) I think I got lost in your question.
13 Can you repeat it, please?

14 Q Right. Well, I'll ask it another way. Let's go to
15 your summary that you provided to the Commission on
16 Page 6 through 7. Do you -- do you have your
17 summary with you that you provided today?

18 A (WITTLIFF) Right here.

19 Q Okay. Let's go to Line 7, where you say, "Is
20 beneficiation generally more expensive than other
21 closure options?" "Yes."

22 And then you say, "Were you able to identify
23 any net savings at Cape Fear and HF Lee sites as
24 compared to the closure without beneficiation?"

25 And you say, "No. No supporting information

1 was provided that could substantiate that claim";
2 isn't that right?

3 A (WITTLIFF) Yes. That's what I said.

4 Q Okay.

5 MR. BURNETT: Mr. Chairman, I'd like to mark
6 an exhibit. It's got three documents, but if
7 it's -- if it suits you, sir, we could just
8 put them together and make it a composite
9 exhibit for the -- for the next hearing?

10 CHAIRMAN RANDALL: Okay. We'll mark it as
11 Exhibit Number 61.

12 MR. BURNETT: And bear with me while my
13 assistant here helps me pass these out.

14 (WHEREUPON, Hearing Exhibit 61 was
15 marked in evidence.)

16 A (WITTLIFF) Thanks.

17 Q Mr. Wittliff --

18 MR. BURNETT: Oh, let me make sure counsel has
19 a copy. I'm sorry, sir.

20 Q Mr. Wittliff, I'm showing you three documents that
21 I've now marked as Composite Exhibit -- Hearing
22 Exhibit Number 61, and I'll give you a second to
23 look these over and ask you, have you ever seen any
24 of these documents before?

25 MR. BATEMAN: Mr. Chairman, I have a -- a

1 brief question. I see, of these three
2 documents, two are data request responses to
3 ORS and one is a North Carolina Public Staff
4 data request. I'm -- I'm not sure, without
5 reviewing it, what relevance this has to this
6 proceeding.

7 MR. BURNETT: Mr. Chairman, I'd be happy to
8 address it. So if you would take the -- the
9 document that is the ORS request 5-1, you'll
10 see, if you flip that over, that ORS asked the
11 Company to provide to them, in discovery,
12 every document that was provided to North
13 Carolina Commission that had to do with coal
14 ash. The document that counsel referenced was
15 provided pursuant to that request, so it is
16 relevant because ORS asked for it.

17 CHAIRMAN RANDALL: Okay.

18 MR. BATEMAN: Thank you.

19 CHAIRMAN RANDALL: We'll allow it.

20 Q So, Mr. Wittliff, my pending question was, have you
21 ever seen one or any of these documents before?

22 A (WITTLIFF) No.

23 Q Okay. Well, if you would turn to me -- with the
24 document that is entitled "1-95," you'll see, on
25 that front page there, it says it's a response to

1 1-95 due November 8, 2018.

2 A (WITTLIFF) Right.

3 Q If you turn to Page -- well, it's -- it's -- it
4 says, "Page 2 of 1" -- that should've been "2 of
5 2" -- I want to draw your attention to a paragraph
6 there. Do you see there where the Company provided
7 information to ORS back in November of 2018 that
8 says, for Cape Fear, the savings are \$302 million
9 for customers, HF Lee savings are \$401 million of
10 savings to customers, and Buck is \$131 million of
11 cost, and that South Carolina customers will be
12 allocated their share of these net savings? Do you
13 see that there?

14 A (WITTLIFF) Yes. I see that.

15 Q So, as I believe you just testified, you didn't
16 have that information when you made the statement
17 today to the Commission that no supporting
18 information was provided to substantiate these
19 claims; isn't that right?

20 A (WITTLIFF) Yes. I did not have that information.

21 Q And, similarly, when ORS asked the Company to
22 provide all the information that it had provided to
23 the North Carolina Commission regarding coal ash in
24 Request 5-1, I assume, because you testified you
25 had never seen it today, that you would be equally

1 unaware of the response that the Company provided,
2 wherein it provided the beneficiation savings
3 analysis there in that Excel spreadsheet, and then
4 also said, "See responses to 5-4, DRs 111, 120, and
5 121"; isn't that right?

6 A (WITTLIFF) That would be it, yes.

7 Q And, again, no fault of yours, but you had no idea,
8 because you had never seen these documents before,
9 that your statement in your summary this morning
10 that no supporting information was provided that
11 could substantiate those claims was not true; isn't
12 that right?

13 A (WITTLIFF) That's right.

14 MR. BURNETT: Mr. Chairman, since I've done a
15 couple times, I would ask that this exhibit go
16 ahead and be moved into evidence so I don't
17 forget it at the end and you have to remind
18 me.

19 CHAIRMAN RANDALL: Okay. This will be moved
20 into evidence as Exhibit Number 61.

21 (WHEREUPON, Hearing Exhibit 61 was
22 received in evidence.)

23 Q And, Mr. Wittliff, to move to the next basin
24 that -- that you recommended disallowance for,
25 which is HF Lee, we will also see that you don't

1 take any position in your direct or surrebuttal
2 testimony as to what the proper closure method
3 would've been for HF Lee under the CCR rule; isn't
4 that right?

5 A (WITTLIFF) I believe that's right.

6 Q And, as you sit here today, you similarly cannot
7 say whether excavation, cap-in-place, or another
8 method would be the proper method of closure at HF
9 Lee under the CCR rule because you have not done an
10 -- an analysis to make that determination; isn't
11 that right?

12 A (WITTLIFF) That is correct.

13 Q And, again, you dispute whether there are any
14 savings at the HF Lee site for beneficiation, but
15 back to that first document in Composite Hearing
16 Exhibit Number 61, we'll see there that HF Lee
17 provides a \$401 million savings to customers
18 according to this document; isn't that right?

19 A (WITTLIFF) That's what it says.

20 Q Now, there was some testimony from Witness
21 O'Donnell yesterday -- I don't know if you were
22 here for that -- wherein ORS counsel was asking his
23 opinion as to how beneficiation could possibly
24 provide savings, and I'd like to do some math with
25 you here. So if we take a \$302 million savings for

1 Cape Fear, and we do a \$401 million savings for
2 DEP, you would agree with me, mathematically, that
3 adds up to a \$703 million savings, assuming the
4 facts here are correct?

5 A (WITTLIFF) Assuming those facts are correct. And
6 I've been advised that doing math from the stand is
7 probably not the best thing to do, but --

8 Q Or -- or from here.

9 A (WITTLIFF) All right.

10 Q For my own, too.

11 A (WITTLIFF) It looks like \$703 million. That's
12 where the number comes from.

13 Q That's right. And -- and if I -- if I wanted --
14 realizing that Buck is a DEC site, but if I wanted
15 to subtract that \$131 million -- to get a South
16 Carolina view, if I subtract that 131,
17 mathematically, that'd be a net \$572 million
18 savings, if -- again, assuming the information here
19 is correct?

20 A (WITTLIFF) Again, with the appropriate advisory
21 about doing math from the stand.

22 Q Yes, sir. Understood. Subject to check, as
23 always.

24 A (WITTLIFF) Okay.

25 Q Now, continuing on Table 4.5 of your direct

1 testimony, the next site you propose a disallowance
2 for is Sutton site; is that correct?
3 A (WITTLIFF) Yes.
4 Q And, at Sutton, you take the position that CAMA
5 imposed an accelerated schedule that made the
6 Company incur more costs than it would've otherwise
7 incurred under the federal CCR rule; isn't that
8 right?
9 A (WITTLIFF) That's correct.
10 Q And, in your surrebuttal testimony, you state that,
11 under the CCR rule, Duke Energy Progress would've
12 had two more years to close Sutton than it would've
13 had under the CAMA rule; isn't that right?
14 A (WITTLIFF) Yes.
15 Q If I accept, for argument's sake, Mr. Wittliff,
16 that the Company would've had those two extra years
17 to close the Sutton basins under the federal CCR
18 rule, as you testify, please walk me through what
19 you contend the Company would've done in those two
20 years to save customers \$186,376,226.
21 A (WITTLIFF) The rationale here -- excuse me -- is
22 that, once you stop the waste flow to the
23 impoundment, under the CCR rules, you had 30 days
24 to begin the closure activities, and, even then,
25 once those closure activities occur or begin, you

1 have five years to complete, which would've put the
2 compliance deadline for the CCR rules at August
3 5th, 2021, which is essentially two years longer to
4 complete the work. And one of the components in
5 that 186 is basically because we said it would not
6 have started that within the period that we were
7 in. And, so, in this particular perspective, that
8 number would need to be revisited because you have
9 -- you had to start -- you had to start the
10 remediation activities in 2016, and -- but it's the
11 fact that you had to finish earlier, and that's a
12 more accelerated timeline.

13 Q I'm -- I probably asked you a bad question, Mr.
14 Wittliff, so I'm going to try that one one more
15 time. If you would, look at your Table 5.4 for me,
16 right, for Sutton?

17 A (WITTLIFF) I'm looking at the table. Well, I'm
18 looking -- let me get at the right table here.

19 Q Do you see right there that I've highlighted where
20 you state that CAMA caused an accelerated schedule?

21 A (WITTLIFF) Yes.

22 Q Do you see right there, under your "Sutton" line,
23 where I've -- I've highlighted that \$186 million or
24 so disallowance that you're recommending?

25 A (WITTLIFF) Right.

1 Q And you see, when I go to your surrebuttal
2 testimony, that you note that, had the CCR rule
3 only applied, the Company could have started
4 closure at Sutton in August 5 of 2021, rather than
5 August 1 of 2019, right?

6 A (WITTLIFF) No. Wait a minute. Let's look at that
7 a minute. What -- what page are you on?

8 Q That is Page 6 of your rebuttal testimony -- your
9 surrebuttal.

10 A (WITTLIFF) Page 6 of the surrebuttal, okay. But
11 it's discussed, back in the . . .

12 Q Mr. Wittliff, if you could -- if you could just
13 tell me, is this, indeed, your surrebuttal
14 testimony, and is that testimony that you provided
15 here, sir, that I've highlighted? I can read it if
16 you're having trouble.

17 A (WITTLIFF) Yes.

18 Q It is your testimony or you're having trouble
19 reading it?

20 A (WITTLIFF) It's kind of all of the above, I
21 suppose. That's the summary. Maybe this -- the
22 surrebuttal is back here.

23 Q I have a copy of your surrebuttal. If you need it,
24 sir, I could hand that --

25 A (WITTLIFF) No. I got it --

1 Q -- to you.

2 A (WITTLIFF) -- right here.

3 Q Okay.

4 A (WITTLIFF) I got it. Yes. That looks to be in my
5 testimony.

6 Q Okay. And my question is, is that you note a
7 two -- two-year differential between CAMA and the
8 CCR rule, and my question is, during those two
9 years, if CAMA never existed and I didn't start
10 closure until August 5, 2021, as you state, rather
11 than August 1, 2019, what could my company have
12 done with specificity to save customers \$186
13 million?

14 A (WITTLIFF) Well, hold -- hold on a second. I -- I
15 think that maybe we're both talking at cross
16 purposes here. What I'm contending is, is that it
17 would've had two more years to finish, not to
18 begin, okay. So it would've still -- it would've
19 still had to start in 2016, but instead of being on
20 a timeline that said, "You only -- you -- you got
21 to get it finished in three years," you'd have had
22 five, okay.

23 Q Okay. Mr. Wittliff, well, the two additional years
24 to finish, can you tell me, with specificity, what
25 my company would've done in those two additional

1 years to save customers \$186 million?

2 A (WITTLIFF) In this particular case, what I'm
3 saying is that the -- the first thing that happened
4 was, because they had to haul about 2 million tons
5 of this stuff off to Brickhaven, so -- because they
6 were having trouble getting the landfill permitted
7 in a timely fashion and they had to meet the CAMA
8 deadline, they -- they sent those 2 million tons,
9 14,000 by truck and -- and just a shade over 2
10 million by rail, at a cost of in the ballpark of
11 \$19.20 -- 28 cents per ton to Brickhaven, which is
12 above and beyond what it would've cost had they had
13 the landfill already available and set up, which
14 works out to about \$39 million just on that one
15 factor alone. The rest of that is basically timing
16 and, without prejudice, would allow the -- the
17 Company to come back and resubmit those whenever
18 they were ripe under the CCR rule.

19 So what we did do was we -- we went through
20 and looked at the engineering and planning
21 activities in trying to figure out what engineering
22 planning had to happen, what's a good -- what's a
23 good allowable for that. It wasn't specifically
24 called out by a number. We just had to -- we used
25 a weighted average from the sites that did have the

1 engineering planning activities before they
2 commenced construction. And so we used those as a
3 surrogate to try to determine what's a logical
4 allowance for engineering and planning during that
5 time, so that's -- that's the reason or that's the
6 -- the short answer as I can get without going into
7 a lot of gruesome detail.

8 Q Oh, I -- I think I got what I needed there. Thank
9 you, sir.

10 Turning to the last basin on your Table 5.4,
11 you contend that costs should be disallowed at the
12 Weatherspoon site because the Company is selling
13 ash there to concrete kilns in South Carolina for
14 beneficial re-use; isn't that right?

15 A (WITTLIFF) Because it's not an option under --
16 under CCR rules, it -- it was represented to me --
17 now, I know Mr. Kerin has a disagreement with that
18 -- but it was represented to me during the site
19 visit by Company staff -- perhaps one of them spoke
20 or more of them spoke, but this is what I heard and
21 understood, and -- and -- and just figured I needed
22 to tease out how much of that was for the
23 beneficiation, and that's -- there's a description
24 of that methodology that's in there, in the -- in
25 the testimony.

1 Q I see. Well, before we get to the question of
2 whether Weatherspoon is a CAMA beneficiation site
3 or not, let me ask you, do you have any problem at
4 all with the Company selling ash and giving
5 customers the proceeds of this ash rather than
6 burying it at a landfill?

7 A (WITTLIFF) I personally don't have a problem with
8 that and it would -- but that was not within the
9 scope of my charges: Is it an -- an increase in
10 terms of the processing cost? And I did the best
11 that I could to determine what I thought that extra
12 adder was.

13 Q And if Mr. Seaman-Huynh needs to take this one on,
14 fair enough, but if it comes to pass that selling
15 ash to these cement kilns down here in South
16 Carolina has actually saved customers about \$59
17 million, South Carolina customers should get their
18 pro rata share of that savings. Wouldn't that be
19 right?

20 A (SEAMAN-HUYNH) I can't speak to any amounts, but I
21 can say that the Company has been selling coal ash
22 and other coal byproducts to gypsum plants, to
23 cement factories, and that, by the state law and
24 regulations of the state, the proceeds from that,
25 the appropriate allocated portion, has flowed

1 through to reduce the Company's base rates.

2 Q Thank you, sir. Now, Mr. Wittliff, back to you,
3 please. If we could go ahead to the -- the
4 disagreement that you and Mr. Kerin have as to
5 whether Weatherspoon is being beneficiated pursuant
6 to CAMA.

7 MR. BURNETT: Mr. Chairman, if I could get the
8 next number for identification, please. I
9 believe it's 62.

10 CHAIRMAN RANDALL: Sixty-two.

11 MR. BURNETT: Mr. Chairman, while we're
12 handing this out, I -- I believe I have maybe
13 15 minutes or so, just to let you --

14 CHAIRMAN RANDALL: Okay.

15 MR. BURNETT: -- know -- 15/20.

16 CHAIRMAN RANDALL: Fifteen is good.

17 (WHEREUPON, Hearing Exhibit 62 was
18 marked in evidence.)

19 Q Mr. Wittliff, I've shown you what has been marked
20 as Hearing Exhibit 62. There are several documents
21 here. I just want to start with the first several
22 pages. Do you recognize the first three pages of
23 Hearing Exhibit 62 as a portion of what the -- is
24 the North Carolina Coal Ash Management Act?

25 A (WITTLIFF) It seems -- this seems appropriate.

1 Q Okay. And if you turn to Page 2 of -- unnumbered
2 Page 2 of Hearing Exhibit 62, you'll see some
3 language that I've highlighted there. Do you see
4 that --
5 A (WITTLIFF) That's --
6 Q -- in yellow?
7 A (WITTLIFF) That's actually Page 23?
8 Q Yes, sir. Yes, sir.
9 A (WITTLIFF) Okay. Got it. Yes.
10 Q Now, if I draw your attention to this Subsection A
11 there, there's a lot of language there, and -- and
12 I've highlighted here on the ELMO in pink the --
13 the requirement that -- by January 1, 2017, you see
14 that CAMA required the Company to designate two
15 sites for beneficiation according to this rule --
16 this law. Do you see that?
17 A (WITTLIFF) (No response.)
18 Q And that two-site requirement will really jump out
19 at you there. If you look on the ELMO, you could
20 pick it up.
21 A (WITTLIFF) Well, I guess whenever you highlight it
22 with pink, it sort of does, doesn't it? There you
23 go. Two sets, got it.
24 Q Right. And if you go down to the Subsection B,
25 you'll see there that it further says that, on July

1 1 -- on or before July 2017, we're -- we would have
2 to designate one more additional site under this
3 CAMA beneficiation requirement.

4 A (WITTLIFF) Correct.

5 Q Do you see that?

6 So two and one, of course, is three. I --

7 A (WITTLIFF) Right.

8 Q I can do that math, even. So, now I want to stay
9 with Hearing Exhibit 61, and I want to take you to
10 -- it'd be the fourth page of that exhibit. Looks
11 like this.

12 A (WITTLIFF) Got it.

13 Q And you'll see here that this is a press release
14 where the Company designated the Cape Fear site as
15 one of the three for the CAMA beneficiation. Do
16 you see that language there that I've highlighted
17 up on the --

18 A (WITTLIFF) I do.

19 Q And if I turn a little bit further in Hearing
20 Exhibit 61 -- I'll show you what it looks like
21 there on the ELMO -- I'm looking for the HF Lee.
22 It's got a picture here.

23 A (WITTLIFF) Got it.

24 Q And you see there that, in this second press
25 release that's part of Hearing Exhibit 61, you'll

1 see where the Company has designated HF Lee as the
2 second of its three plants for beneficiation. Do
3 you see that?

4 A (WITTLIFF) Correct.

5 COMMISSIONER ERVIN: Aren't we on 62?

6 MR. BURNETT: Sixty-two, yes, sir. I'm --

7 I -- I think I've said "61" a few times. I --

8 62. Thank you, Commissioner.

9 Q And then, if you continue on through this
10 exhibit -- I should've numbered these pages -- but
11 we get to the Buck press -- press release, and
12 you'll see --

13 A (WITTLIFF) I have it.

14 Q -- and you'll see some language where the Company
15 designated Buck as the third site for
16 beneficiation. Do you see that?

17 A (WITTLIFF) Yes.

18 Q So, with the benefit of the review that we did with
19 hearing Exhibit 62 today, do you still contend that
20 the Weatherspoon site is being beneficiated under
21 the CAMA beneficiation requirement, knowing now
22 that the Company had a requirement to designate
23 three sites, and they did designate three sites
24 that -- which did not include Weatherspoon?

25 A (WITTLIFF) First of all, I did not, to -- to my

1 knowledge, call Weatherspoon a "beneficiation
2 site." I mean, the -- the -- the language and the
3 decisions are plain that -- that -- that HF Lee,
4 Cape Fear, and Buck were the three beneficiation
5 sites.

6 But, when I went to the plant and talked with
7 the people and did the on-site visit/inspection
8 just to kind of get a sense of what they were doing
9 and how it was going to flow, it was represented to
10 me that they were -- while it may not have been an
11 official beneficiation site, and it certainly
12 wasn't committed under CAMA, that they were doing
13 beneficiation activities there and, like I said,
14 did the best I could to tease out what -- what
15 those costs would be, because there's so many
16 things that -- when you're -- when you're
17 excavating a -- an impoundment and dewatering it,
18 there's a lot of things you're doing that are in
19 common with what you would do whether you're going
20 to take it and haul it off-site, landfill it, or
21 put it in an off-site landfill, or if you're going
22 to beneficiate it.

23 But, when you go to the extent -- the
24 additional work of putting it out, putting it in
25 drying stacks, and then taking it and then running

1 it through sizing machines, and then setting up
2 reserve piles, protecting those piles with Posi
3 liner to crest them so that they don't wash away,
4 it's preserving a resource. That looked a lot like
5 beneficiation to me, and that was consistent with
6 the representation. It -- it wasn't that I formed
7 that conclusion that it was the word
8 "beneficiation," and I know that, during this
9 proceeding -- and, Mr. Burnett, I think you --
10 we've all had the problem of talking about
11 beneficial re-use, which this is, and
12 beneficiation. And so there may've been somebody
13 that misspoke.

14 Q Thank you, sir. I've got, I think, two more topics
15 to go over with you, Mr. Wittliff, and I'm done.
16 So if we could turn back to Page 39 of your direct
17 testimony, please.

18 A (WITTLIFF) Yes, sir.

19 Q I'd like to draw your attentions to -- your
20 attention to Line 11 and 12, where you speak of the
21 weighted average of engineering planning and -- as
22 a percentage of total project cost to determine
23 your disallowance for the Sutton plant. Do you see
24 that there?

25 A (WITTLIFF) Correct.

1 MR. BURNETT: Mr. Chairman, if I could mark, I
2 think, a final exhibit as Number 63.

3 CHAIRMAN RANDALL: Sixty-three.

4 (WHEREUPON, Hearing Exhibit 63 was
5 marked in evidence.)

6 A (WITTLIFF) Thank you.

7 Q Uh-huh.

8 MR. BATEMAN: Mr. Chairman, without any -- any
9 detailed review, this appears to be the
10 transcript of the DEP hearing in North
11 Carolina, which, you know, the DEP hearing in
12 North Carolina was completely different than
13 the hearing occurring in this case. Issues
14 were generally different. Mr. Wittliff's
15 charge was certainly different. We'd object
16 to this introduction on grounds of relevancy.

17 MR. BURNETT: Mr. Chairman, two things. One,
18 this is, in fact, the North Carolina
19 transcript and this methodology that Mr.
20 Wittliff just testified that he used to
21 calculate disallowances for Sutton in this
22 site, as you will see if I'm allowed to
23 question him on this Exhibit 63, is the same
24 methodology that he used in North Carolina and
25 rejected and said it was too unreliable to be

1 presented to the Commission. Also, I would
2 note that Mr. Wittliff has interjected the
3 North Carolina proceeding into this and opened
4 the door by attaching the entire North
5 Carolina order to his surrebuttal testimony
6 and raising the mismanagement penalty that was
7 brought into this case. So, by making that
8 entire order an exhibit, he certainly opened
9 the door.

10 CHAIRMAN RANDALL: Okay. We'll allow it.

11 MR. BATEMAN: Mr. Chairman, is this a -- is
12 this a certified copy of the transcript?

13 MR. BURNETT: It is. It should say so --
14 "Official Copy" on the first page.

15 MR. BATEMAN: All right.

16 THE EXAMINATION BY MR. BURNETT CONTINUES.

17 Q So, Mr. Wittliff, if I could draw your attention to
18 Page 85 of what has just been marked as Hearing
19 Exhibit Number 63.

20 MR. BURNETT: And, Mr. Chairman, before I
21 forget, may I move 62 into evidence?

22 CHAIRMAN RANDALL: Okay. Yeah. Sixty-two
23 will be entered into evidence as 62.

24 MR. BURNETT: Okay.

25 (WHEREUPON, Hearing Exhibit 62 was

1 received in evidence.)

2 Q So, Mr. Wittliff, on Page 85 of Hearing Exhibit 63,
3 starting at Line 7, you'll see where Commissioner
4 Brown-Bland asked you "Just one follow-up, I -- is
5 I believe your earlier testimony, you did not
6 perform any dollar-for-dollar analysis versus
7 different options other than those that are in
8 CAMA, and given that's the case, why do you say
9 there are options that would have or could've been
10 a lower dollar cost? How certain are you of that
11 opinion?" Did I read Commissioner Brown-Bland's
12 question correctly?

13 A (WITTLIFF) Yes.

14 Q And if you would flip over to Page 86 of that
15 Exhibit Number 63, starting on Line 3, you see that
16 you say there "I will tell you that we -- we spent
17 some time doing, well, let's take the weighted
18 average. Let's try to see if that will work and
19 then apply it," and you go on there?

20 A (WITTLIFF) Yes.

21 Q And do you see, on Line 15 -- and I'm going to --
22 I'm not going to read this whole thing in, since
23 it's in evidence, but I'll just note some specific
24 lines. You see, on Line 15, you say, "We couldn't
25 get comfortable with making that data, and we would

1 want to bring you and say, 'This is the number'?"

2 A (WITTLIFF) Yes.

3 Q And do you see, on Page 87, on Line 9, where you
4 say, "Frankly, I just would not want to bring, nor
5 would our client want to bring you this to the
6 Commission and say, 'The number -- this is the
7 number you need to hang your hat on'?"

8 A (WITTLIFF) Yes.

9 Q Okay.

10 MR. BURNETT: Mr. Chairman, may I move Exhibit
11 63 into evidence?

12 CHAIRMAN RANDALL: Sixty-three has been marked
13 and entered.

14 (WHEREUPON, Hearing Exhibit 63 was
15 received in evidence)

16 Q Okay. Almost done, Mr. Wittliff. And, lastly, in
17 your surrebuttal testimony, on Page 3, if you would
18 join me there, you'll note, at Line 7, you mention
19 the \$30 million mismanagement penalty that the
20 Commission imposed in its order under Finding of
21 Fact Number 55; isn't that right?

22 A (WITTLIFF) I'm sorry. What page in the
23 surrebuttal?

24 Q Page 3 of 11.

25 A (WITTLIFF) Three of eleven. Yes, sir.

1 Q And you would agree with me that -- again, putting
2 you at the disadvantage of doing math on the stand
3 here, that the Commission's \$30 million
4 mismanagement penalty there where the costs in
5 question were \$232 million of the North Carolina
6 allocated cost, that equates roughly to about a 13
7 percent disallowance; isn't that right?

8 A (WITTLIFF) A shade under.

9 Q And that is not the same as your recommended 53
10 percent disallowance of coal ash costs in this
11 case, correct?

12 A (WITTLIFF) Yes. And the difference is, is that my
13 -- my recommended disallowances are not in
14 perpetuity; they're not permanent. They are
15 basically to say, at the time that the rules
16 changed, that we resubmitted, so potentially, all
17 of that could be reclaimed, but based on the -- not
18 the methodology -- the position statement from ORS,
19 my calculations said that this is -- this is
20 consistent with that directive. And --

21 Q So, Mr. Wittliff, I put that Paragraph 55 that you
22 mention in your surrebuttal testimony up on the
23 ELMO here so everyone can see it. And you see, if
24 the Commission here were inclined to do a
25 mismanagement penalty in the same manner that the

1 North Carolina Commission did, that \$232,390,000
2 number would have to -- using your numbers -- I'm
3 going to -- this is -- this is a mathematical
4 hypothetical -- I would replace that \$232,390 with
5 the South Carolina allocated share of coal ash
6 cost; isn't that right?

7 A (WITTLIFF) Subject to check, but yeah.

8 Q Okay. And if I take your \$635 million system
9 number that you mention in your testimony and
10 allocate that down about 10 percent, 10 percent of
11 635 million is about 63 million, right?

12 A (WITTLIFF) Correct.

13 Q And then, if I utilize that 13 percent
14 disallowance, I would take 13 percent of that 63.5
15 million, and that'd be about, roughly 8.2 million
16 that I would fill in right there in Paragraph 55 of
17 the Commission's order and replace with that 8.2.
18 Do you agree with that?

19 A (WITTLIFF) That -- that's logical.

20 Q Okay. And then that \$6 million for five years you
21 see there, if I'm doing my math right, that roughly
22 would be 1.6 million per year that would be taken
23 off the return that the Company would be allowed,
24 if -- if this Commission were inclined to do what
25 the North Carolina Commission did. That sound

1 right? Again, using your numbers, hypothetically.

2 A (WITTLIFF) Based on -- based on the allocations
3 that you've described and assuming those are
4 correct, yes. That would make sense.

5 MR. BURNETT: Thank you. I appreciate your
6 time, sir. And again, Mr. Seaman-Huynh, I
7 believe Mr. Anthony might have questions for
8 you after the lunch break.

9 CHAIRMAN RANDALL: Okay. All right. So we
10 will -- we will take a break for lunch. We
11 will come back -- and I think Mr. Anthony will
12 be up -- we will come back at one -- about
13 1:43. No. I lied. Let's come back about
14 1:48.

15 MS. GRUNDMANN: Mr. Chairman?

16 CHAIRMAN RANDALL: Yes, ma'am?

17 MS. GRUNDMANN: At this time, may Walmart be
18 released from the hearing?

19 CHAIRMAN RANDALL: You may be excused, Ms.
20 Grundmann. Thank you.

21 MS. GRUNDMANN: Thank you. Thank you.

22 CHAIRMAN RANDALL: And we are adjourned till
23 whenever I said.

24 (Off the record from 12:36 p.m.
25 until 1:49 p.m.)

1 AFTERNOON PROCEEDINGS

2 CHAIRMAN RANDALL: Please be seated. Okay.

3 Welcome back. We'll call us back to order,
4 and I believe, Mr. Anthony, you're up.

5 MR. ANTHONY: Thank you, Mr. Chairman, members
6 of the Commission.

7 THEREUPON came,

8 MICHAEL L. SEAMAN-HUYNH,

9 DAN J. WITTLIFF,

10 re-called as witnesses, who, having been previously duly
11 affirmed, were examined and testified further as
12 follows:

13 CROSS-EXAMINATION

14 BY MR. ANTHONY:

15 Q Mr. Seaman-Huynh, how you been?

16 A (SEAMAN-HUYNH) Good, Mr. Anthony.

17 Q I haven't gotten a chance to spend time with you
18 since we were kicked out of the Brunswick plant
19 together, so . . .

20 A (SEAMAN-HUYNH) It's been a long time since then.

21 Q Nice to see you.

22 MR. ANTHONY: We'll tell you that story
23 someday about the -- the -- what -- what we
24 did there.

25 Q We're going to talk about CAMA and the

1 environmental remediation costs that CAMA has
2 imposed upon DEP, okay. First, to set the context
3 and the -- and the ground rules of this, the ORS
4 does not dispute that it's prudent for DEP to
5 comply with CAMA. We ought to obey the law, right?

6 A (SEAMAN-HUYNH) I don't believe that that's in
7 dispute.

8 Q Okay. Just making sure that you're -- you're not
9 suggesting that we should violate the law and pay
10 penalties if that's the cheaper thing to do. Do
11 you expect the utilities of this state to comply
12 with what the law says?

13 A (SEAMAN-HUYNH) We expect Duke to -- Duke Progress
14 to abide by all state and federal laws.

15 Q Okay. So it's prudent to comply with the law?

16 A (SEAMAN-HUYNH) Yes.

17 Q All right. And I haven't seen anywhere where the
18 ORS has taken issue with the costs that DEP is
19 spending to comply with CAMA. You're not saying
20 those costs are unjust and unreasonable?

21 A (SEAMAN-HUYNH) That wasn't part of my review in
22 this case. That could better be addressed by Mr.
23 Wittliff.

24 Q I -- I did hear Mr. Wittliff -- I thought, in
25 response to questions from Mr. Burnett, you -- you

1 agreed that -- that the costs that had been
2 incurred are reasonable to comply with CAMA, Mr.
3 Wittliff?

4 MR. BATEMAN: Mr. -- Mr. Chairman, Mr.
5 Wittliff was available for questions from Mr.
6 Burnett if --

7 CHAIRMAN RANDALL: Oh, he was available for
8 questions. I mean, they just said they were
9 going to talk to either one of them. I mean,
10 are we holding down who can talk to whom?

11 MR. BATEMAN: I -- I --

12 CHAIRMAN RANDALL: This is cross-examination,
13 so . . .

14 MR. ANTHONY: The -- the record speaks for
15 itself. That's what --

16 CHAIRMAN RANDALL: Okay.

17 MR. ANTHONY: -- Mr. Wittliff said, and
18 I'll -- I'll rely upon --

19 CHAIRMAN RANDALL: Okay.

20 MR. ANTHONY: -- what's -- what's --

21 CHAIRMAN RANDALL: Thank you.

22 MR. ANTHONY: -- already in the transcript.
23 Thank you.

24 Q Unless Mr. Wittliff wants to disagree with -- with
25 what I've just said?

1 A (WITTLIFF) No.

2 Q All right. Thanks. All right. So that takes us
3 to what I understand to be the fundamental basis
4 for the ORS's recommendation that these CAMA-
5 related costs be disallowed, and that being because
6 that's a North Carolina law that caused those costs
7 to be incurred, and the ORS doesn't see that South
8 Carolinians are realizing any benefit from DEP
9 incurring those environmental remediation costs; is
10 that right?

11 A (SEAMAN-HUYNH) I don't believe that that's what is
12 in my testimony. I believe what I said and
13 testified to is that South Carolina should -- South
14 Carolina ratepayers should not be held responsible
15 for the additional cost between CAMA and federal
16 CCR.

17 Q And -- and tell me why they shouldn't be held
18 for -- responsible for this CAMA cost.

19 A (SEAMAN-HUYNH) North Carolina is -- has invoked a
20 law requiring additional costs for coal ash
21 management and disposal that is beyond the
22 requirements of the federal law. They are -- has
23 told the Company that, "You have to do this."
24 South Carolina ratepayers, who have no vote for
25 anyone in the North Carolina legislature, are being