PLACE: Held via Videoconference REDACTED

DATE: Wednesday, September 30, 2020

TIME: 1:31 P.M. - 4:31 P.M.

DOCKET NO.: E-2, Sub 1219

E-2, Sub 1193

BEFORE: Commissioner Daniel G. Clodfelter, Presiding

Chair Charlotte A. Mitchell

Commissioner ToNola D. Brown-Bland

Commissioner Lyons Gray

Commissioner Kimberly W. Duffley

Commissioner Jeffrey A. Hughes

Commissioner Floyd B. McKissick, Jr.

IN THE MATTER OF:

DOCKET NO. E-2, SUB 1219

Application by Duke Energy Progress, LLC,

for Adjustment of Rates and Charges Applicable to

Electric Utility Service in North Carolina

and

Noteworthy Reporting Services, LLC

DOCKET NO. E-2, SUB 1193

Application of Duke Energy Progress, LLC

for an Accounting Order to Defer Incremental Storm

Damage Expenses Incurred as a Result of Hurricanes

Florence and Michael and Winter Storm Diego

VOLUME 14

A P P E A R A N C E S:

FOR DUKE ENERGY PROGRESS, LLC:

Camal Robinson, Esq., Associate General Counsel
Brian Heslin, Esq., Deputy General Counsel
Duke Energy Corporation
550 South Tryon Street
Charlotte, North Carolina 28202

Lawrence B. Somers, Esq., Deputy General Counsel
Duke Energy Corporation
410 South Wilmington Street
Raleigh, North Carolina 27601

James H. Jeffries, IV, Esq.
McGuireWoods LLP
201 North Tryon Street, Suite 3000
Charlotte, North Carolina 28202

Andrea Kells, Esq.
McGuireWoods LLP
501 Fayetteville Street, Suite 500
Raleigh, North Carolina 27601

A P P E A R A N C E S Cont'd:

Molly McIntosh Jagannathan, Esq., Partner
Kiran H. Mehta, Esq., Partner
Troutman Pepper Hamilton Sanders LLP
301 South College Street, Suite 3400
Charlotte, North Carolina 28202

Brandon F. Marzo, Esq.
Troutman Pepper
600 Peachtree Street, NE, Suite 3000
Atlanta, Georgia 30308

FOR CAROLINA INDUSTRIAL GROUP FOR FAIR UTILITY RATES II and III:

Christina D. Cress, Esq.
Bailey & Dixon, LLP
Post Office Box 1351
Raleigh, North Carolina 27602

FOR CAROLINA UTILITY CUSTOMERS ASSOCIATION, INC.:

Robert F. Page, Esq.
Crisp & Page, PLLC
4010 Barrett Drive, Suite 205
Raleigh, North Carolina 27609

A P P E A R A N C E S Cont'd:

FOR NC JUSTICE CENTER, NC HOUSING COALITION, NATURAL RESOURCES DEFENSE COUNCIL and SOUTHERN ALLIANCE FOR CLEAN ENERGY:

Gudrun Thompson, Esq., Senior Attorney
David L. Neal, Esq., Senior Attorney
Tirrill Moore, Esq., Associate Attorney
Southern Environmental Law Center
601 West Rosemary Street, Suite 220
Chapel Hill, North Carolina 27516

FOR SIERRA CLUB:

Bridget Lee, Esq.
Sierra Club
9 Pine Street
New York, New York 10005

Catherine Cralle Jones, Esq.
Law Office of F. Bryan Brice, Jr.
127 W. Hargett Street
Raleigh, North Carolina 27601

A P P E A R A N C E S Cont'd:

FOR NC WARN:
Matthew D. Quinn, Esq.
Lewis & Roberts PLLC
3700 Glenwood Avenue, Suite 410
Raleigh, North Carolina 27612

FOR FAYETTEVILLE PUBLIC WORKS COMMISSION:
James West, Esq., General Counsel
955 Old Wilmington Road
Fayetteville, North Carolina 28301

FOR UNITED STATES DEPARTMENT OF DEFENSE AND ALL OTHER FEDERAL EXECUTIVE AGENCIES:
Emily Medlyn, Esq., General Attorney
United States Army Legal Services Agency
9275 Gunston Road, Suite 4300 (ELD)
Fort Belvoir, Virginia 22060

FOR VOTE SOLAR:
Thadeus B. Culley, Esq., Regulatory Counsel
Senior Regional Director
1911 Ephesus Church Road
Chapel Hill, North Carolina 27517

A P P E A R A N C E S Cont'd:

FOR NORTH CAROLINA LEAGUE OF MUNICIPALITIES:
Deborah Ross, Esq.
Fox Rothschild LLP
434 Fayetteville Street, Suite 2800
Raleigh, North Carolina 27601

FOR NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION:
Peter H. Ledford, Esq., General Counsel
Benjamin Smith, Esq., Regulatory Counsel
North Carolina Sustainable Energy Association
4800 Six Forks Road, Suite 300
Raleigh, North Carolina 27609

FOR THE COMMERCIAL GROUP:
Alan R. Jenkins, Esq.
Jenkins At Law, LLC
2950 Yellowtail Avenue
Marathon, Florida 33050

Brian O. Beverly, Esq.
Young Moore and Henderson, P.A.
3101 Glenwood Avenue
Raleigh, North Carolina 27622

A P P E A R A N C E S Cont'd:

FOR NORTH CAROLINA CLEAN ENERGY BUSINESS ALLIANCE:

Karen Kemerait, Esq.
Fox Rothschild LLP
434 Fayetteville Street, Suite 2800
Raleigh, North Carolina 27601

FOR HARRIS TEETER:

Kurt J. Boehm, Esq.
Jody Kyler Cohn, Esq.
Boehm, Kurtz, & Lowry
36 East Seventh Street, Suite 1510
Cincinnati, Ohio 45202

Benjamin M. Royster, Esq.
Royster and Royster, PLLC
851 Marshall Street
Mount Airy, North Carolina 27030

A P P E A R A N C E S Cont'd:

FOR HORNWOOD, INC.:

Janessa Goldstein, Esq.
Corporate Counsel
Utility Management Services, Inc.
6317 Oleander Drive, Suite C
Wilmington, North Carolina 28403

FOR THE USING AND CONSUMING PUBLIC AND ON BEHALF OF THE STATE AND ITS CITIZENS IN THIS MATTER THAT AFFECTS THE PUBLIC INTEREST:

Margaret A. Force, Esq., Assistant Attorney General
Teresa Townsend, Esq., Special Deputy Attorney General
North Carolina Department of Justice
Post Office Box 629
Raleigh, North Carolina 27603

A P P E A R A N C E S Cont'd:

FOR THE USING AND CONSUMING PUBLIC:

Dianna W. Downey, Esq.
Elizabeth D. Culpepper, Esq.
Layla Cummings, Esq.
Lucy E. Edmondson, Esq.
William E. Grantmyre, Esq.
Gina C. Holt, Esq.
Tim R. Dodge, Esq.
Megan Jost, Esq.
John D. Little, Esq.
Nadia L. Luhr, Esq.
Public Staff - North Carolina Utilities Commission
4326 Mail Service Center
Raleigh, North Carolina 27699-4300

T A B L E O F C O N T E N T S

E X A M I N A T I O N S

E X H I B I T S

P R O C E E D I N G S

COMMISSIONER CLODFELTER: Before, Mr. Mehta, you pick up your questioning, Ms. Force, let me correct one thing I misspoke on earlier. Because the Attorney General's Office is putting on additional evidence here in this separate proceeding, your witness Baudino's testimony in the consolidated case will be transcribed into this transcript at the beginning of your case presentation.

MS. FORCE: Oh, okay.

COMMISSIONER CLODFELTER: It will be at the beginning. It will appear in the transcript at the beginning of the Attorney General's presentation in the case.

MS. FORCE: Okay. Good. We had checked, and I was going to bring that up.

COMMISSIONER CLODFELTER: You're correct. I simply misspoke. What I said earlier applied only with respect to parties who had witnesses only in the consolidated portion but were not presenting any testimony in the separate DEP proceeding.

MS. FORCE: Right.

COMMISSIONER CLODFELTER: So you are clear. Okay.

MS. FORCE: Do you need anything from me in terms of --

COMMISSIONER CLODFELTER: No. We worked that out with the -- court reporter is keeping me straight on this, and she will get the testimony transcribed into the correct portion of the record.

MS. FORCE: And our great paralegal has been trying to keep us straight on it as well.

COMMISSIONER CLODFELTER: There you go.

MS. FORCE: Thank you.

COMMISSIONER CLODFELTER: With that, Mr. Mehta?

MR. MEHTA: Thank you, Commissioner Clodfelter. And actually, before I get to the questioning, I do have a question. This, again, deals with the issue of exhibits from the DEC proceeding that are being essentially stipulated in, assuming no objection, and assuming the Commission agrees to the DEP process. And I know you said yesterday that when -- the parties should provide the court reporter with the actual testimony that is being stipulated on an essentially daily basis, which we are -- we are doing. And I think, actually, the Company has sort of taken upon itself to do it for everybody, just for ease.

But do we need also to provide copies of the exhibits that are coming in to the DEP record, or will the Commission simply access those exhibits, assuming we give you the list of the exhibits -- and I'll get to that in just a moment -- assuming we give you that list in the course of this proceeding?

COMMISSIONER CLODFELTER: Mr. Mehta, let me hold your question until the afternoon break. I want to confer again with our court reporters. The reason we're requiring you to provide the actual transcript portions is so our court reporters don't have to take time to stop transcription in this proceeding, go back and dissect the prior transcripts and excerpt things from out of it. So it's really -- we're doing this really to make it possible for our court reporters to do their job most efficiently as we can. So let me confer with them during the break, and I'll get you an answer to that after the break.

MR. MEHTA: That's perfect. We just needed to understand what our obligations were on that.

COMMISSIONER CLODFELTER: I appreciate that and understand that, and it's a perfectly good question. Let me confer with Ms. Mitchell an her court reporter staff, and we'll get you an answer. Okay?

MR. MEHTA: Okay. And just as an update, we are in the process -- for the amended joint stipulation that was filed late in the day on Monday, we are in the process of putting together a matrix that will show for each of the witnesses in that -- that is a subject to that joint stipulation, what exhibits were marked in an original fashion as cross or redirect exhibits, what exhibits were simply referred to, and then either at that time or later brought into evidence, and also presumably the joint exhibits that were referred to so that the Commission will have readily at its fingertips exactly what happened with respect to each of those witnesses.

COMMISSIONER CLODFELTER: Thank you. That's great. And our -- Joann and her ever-efficient colleagues have already provided me by email an answer to your question. We don't need to wait until the afternoon break. And the answer is yes, they would like you to provide copies of the exhibits that are coming in pursuant to stipulation and motion in this case from the DEC case, as well as portions of the transcript excerpted from the DEC case. Okay? The exhibits as well.

MR. MEHTA: We will work with the parties on that. It may not be today that you get the ones for today's witnesses, simply because we still want to, I think, get the matrix worked out and any kinks in it worked out.

COMMISSIONER CLODFELTER: Absolutely, that's fine. And I think as we said yesterday, it doesn't have to be today. It could be today or the day after. So we're just trying to help them keep their work schedules in line and get you the transcript as efficiently as possible. Okay?

MR. MEHTA: Thank you, Commissioner Clodfelter.

COMMISSIONER CLODFELTER: Okay. I think that gives you the answer you needed, and we'll let you get back to your normal lawyering job of Q and A.

MS. FORCE: Commissioner Clodfelter, this is Margaret Force again.

COMMISSIONER CLODFELTER: Yes.

MS. FORCE: I just want to follow up on Mr. Mehta's comment, because we have had some questions from our paralegal about what we would be filing in connection with the testimony Mr. Hart is giving that relates to the stipulation. And I thought I heard you say, Mr. Mehta, that you were taking that on for other parties as well. So I think it would be good to get a clarification so we're not double doing work.

MR. MEHTA: Okay. I believe -- Mr. Robinson may correct me if I'm wrong -- that in the call with the parties yesterday lunchtime-ish, the Company undertook to ensure that the transcript references that were being stipulated in would be supplied to the court reporter. I don't think we dealt with the issue of exhibits at that time, because I don't think anybody was really focused on whether the physical copies of the exhibits needed to be -- needed to be delivered to the court reporter, but we will consult with the parties on that score.

MS. FORCE: That's fine. I just want to know we're all on the same page. And then in terms of what we would provide after the end of Mr. Hart's testimony, it sounds like you're saying, unless we hear differently, that that would be provided by Duke, as far as the transcript goes, and we're still going to be looking for the matrix to work out the exhibits that would be provided.

MR. MEHTA: And I'll let Mr. Robinson just to make sure that I haven't overstepped my bounds here.

MS. FORCE: That's fine. So we all understand it the same way.

MR. ROBINSON: Thank you. Commissioner Clodfelter, thank you. Camal Robinson. To be clear, so yes on transcript citations, we will provide the transcript as Kiran identified. In terms of stipulated cross examination exhibits, we will also take on that well as providing those. What we will not provide are any new exhibits as part of this case in terms of any additional DEP-specific exhibits. That will be handled by the parties as currently -- kind of the procedure is -- currently consists of.

So we'll take any of the stipulated live transcripts, any of the stipulated exhibits, we will make sure that those go into -- get filed with the Commission and provided to the Commission. Anything new that is specific to DEP, we will not handle, with the exception of ours.

MS. FORCE: Thank you for that clarification. I have --

MS. DOWNEY: That was my understanding as well.

COMMISSIONER CLODFELTER: I'm sorry, Ms. Downey?

MS. DOWNEY: That was my understanding as well.

COMMISSIONER CLODFELTER: Okay. Are we all clear?

MR. MEHTA: Yes, sir.

COMMISSIONER CLODFELTER: All right. Mr. Mehta.

MR. MEHTA: Thank you, Commissioner Clodfelter.

Whereupon,

STEVEN C. HART,

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

CONTINUED CROSS EXAMINATION BY MR. MEHTA:

Q. And good afternoon, Mr. Hart. Mr. Hart, had the -- let's just take the 1964 Asheville basin as an example, which I think you indicated was closed in 1982. If it was, quote, officially closed, it would have been closed in accordance with the standards of the day, and it would simply have been dewatered and a soil and vegetation cap would have been placed on top of it; isn't that correct?

A. Well, it depends on what DE's closure plan would have entailed, but that's something that would have been worked out with DEQ. Now, I can say, from my experience, I believe the closure would have included some sort of impermeable layer. It could be clay or it could be some sort of geotextile membrane covered with soil, you know, or a drainage layer, and then soil to keep the -- allow vegetation to grow, but also to keep stormwater from infiltrating.

Q. And are you saying, Mr. Hart, that in 1982, a clay or some kind of impermeable layer would have been on top of the waste and underneath the soil cap?

A. It's possible. But again, it depends on what the -- at the time, was approved. The idea being to minimize the infiltration of rainwater into the basin. And certainly that occurred, you know, at other facilities. And it may not be necessarily power plants, but certainly people have been going all along and closing out wastewater treatment ponds, residual solids ponds, and things of that nature over time. In fact, I gave an example of a facility in 1993 in my testimony that installed a liner -- with a geo membrane liner, so.

Q. Well, 1993 is not 1982, is it, Mr. Hart?

A. Well, and I didn't say it had to be closed in 1982. It could have been closed some, you know, reasonable time frame thereafter. But if you go back to Sutton, for example, is it reasonable to leave a wastewater pond open for 26 years when you've already gotten a notice of noncompliance for 2L standard violations outside of the compliance boundary in 1987? Is it reasonable to leave that open for 26 years so that you can use it later on for stormwater or some ash basin?

And my answer to that is no, it's not reasonable and prudent. You already knew you had groundwater contamination issues; you knew that you had a notice of noncompliance; you knew you had questions about the water supply well that was contaminated off site; you knew you had off-site contamination; and you knew the state considered it a source -- that the ash pond was a source of groundwater contamination. Why wouldn't you want to try to stop that source in accordance with the 2L regulations?

Q. Mr. Hart, if you go back further in time from 1982, the Cape Fear and the H.F. Lee inactive basins were not used for -- searching for a neutral term there -- back a lot earlier than 1982; were they not? For example, Cape Fear was 1956, 1963, and 1970.

A. Correct, yes.

Q. And are you saying that, in 1956, 1963, or 1970, those not-used basins would have been closed with an impermeable cap between the waste ash that was in the basin and the soil covering?

A. Well, I think it should have been closed sometime before 2019, absolutely. Now, whether it was 1956, 1963, probably not; but certainly in the 1980s or 1990s it was not uncommon to try to -- well, to close basins, especially when they were a potential source of groundwater contamination, as the industry was aware of.

Q. And would those -- would that closure, Mr. Hart, have entailed removing the ash and taking it somewhere else?

A. It could have. I would say probably in the '70s or '80s, it most likely would have been closed in place, which happened also as well. I mean, if you look at the Allen station, for example, they closed in place and built on -- an ash pond and built on top of it a landfill. There's no indication -- in fact, there's an agreement with DEQ, as I understand it, that that ash basin does not have to be removed.

So just because under some theory that you might have to remove it later on, that's not true. There's many waste disposal facilities in the state that were closed out a long time ago where the state has not required, under any circumstances -- in fact, I'm not aware of any where the state has gone back to a previously closed fill or pond and requested that be removed after it was closed properly.

Q. Mr. Hart, doesn't the agreement with DEQ that Duke Energy Progress and Duke Energy Carolinas signed at the end of last year require that inactive landfill at the Allen plant to be excavated and the ash put somewhere else?

A. I may have the facility wrong, but the RAB landfill, my understanding is that -- and it may not be the Allen plant, I'm not sure which plant it is -- is not required to be excavated.

Q. Mr. Hart --

A. It's a lined landfill, and it was placed on top of a closed ash basin, and neither the landfill nor the underlying ash basin has to be removed.

Q. And you're saying that a lined landfill would have been put in place some time in 1970 at Cape Fear, for example?

A. No. I'm pointing out that, if it was previously closed properly, it would not -- there is no indication, in my experience or in current day experience, that DEQ would require removal of that. It was these not-closed-out-previously basins that have been sitting there for years and years and years contributing to groundwater contamination and allowing rainwater to infiltrate that not only led to groundwater contamination but then the state wanted them excavated.

Q. Mr. Hart, let's take a look at your -- the calculations you made with respect to step B. As I --

and I guess we can take a look, if necessary, at the -- at your work papers which are now marked as Hart DEP Cross Examination Exhibit Number 11.

A. Okay.

Q. And as I read what you did in step B, which is the -- it's like the third box on the page, what you did was calculate the ratio of ash in the old basins to the entirety of excavated ash; is that right?

A. That's correct.

Q. And then you applied that ratio to the closure costs after you removed the permanent water supply costs, correct?

A. Correct. For the Cape Fear, H.F. Lee, Roxboro, and Sutton facilities where there were old ash basins.

Q. Yes. And for Asheville, that ratio ended up being 100 percent, because, in your view, all of the costs were associated with the excavation of the 1964 ash basin, correct?

A. That is correct. That's my understanding from reading -- when 1982 basin was excavated, and I think in 2016, '17. So those costs would not have been included, according to Ms. Bednarcik's testimony.

Q. And you did not -- when you made this calculation, Mr. Hart, you did not determine if, for example, engineering and design costs would have been different if applied only to what you call the new basins, correct?

A. Well, yeah. I use a simplified version. If Ms. Bednarcik, for example, had broken that out, then I could have done that. But my understanding is -- and people ask for that, I believe, in the questions -- in some of the questions. And we -- as I understand and read those answers to those questions, is those kind of things would not -- could not be broken out. It was done on a facility-wide basis. So I used a simplified approach and used the percent ratio of ash in the old basins compared to overall in all the basins.

Q. And with respect to Cape Fear and H.F. Lee, where a significant amount of the costs are associated with the construction of beneficiation plants at those sites, you did not, with respect to those costs, determine whether the costs associated with the construction of the beneficiation plants would have been any different were they applied only to new basins, correct?

A. Well, the beneficiation plants, it's my understanding, don't discriminate between old basins and new basins. They're -- you're taking all the ash there, so I don't -- to the beneficiation plants once they're constructed. You don't segregate out and say, oh, we're only going to treat the new ash basin in the beneficiation plant.

Q. Well, if you'd hauled off the old ash back in 1970, you wouldn't have it around to use in the beneficiation plant; is that correct?

A. Well, yeah, that's correct, yes.

Q. Now, Mr. --

A. You'd still have to construct the beneficiation plant, potentially.

Q. And you would construct that beneficiation plant for the ash in the new basin, just like you're constructing the same beneficiation plant for the ash in the old and new basins, correct?

A. I'm not sure if you would or not.

Q. Well, you have to construct the beneficiation plant somewhere because the legislature told you to, didn't they?

A. Right. But you could have selected another facility, potentially, if there wasn't enough ash at the facility to make it feasible. It's very possible that, with the old ash gone in your scenario, hypothetical scenario, that one of these facilities would not have been selected for beneficiation.

Q. But some other facility would have been selected for beneficiation because beneficiation is required under the CAMA amendments; isn't that correct?

A. It is. I mean, yes, beneficiation is required, yes.

Q. Now, Mr. Hart, if you would, if you'll look at DEP Cross Exhibit 1, it is the Commission's order issued in the last DEC case. And just -- I want to just make sure you've got it. You obviously may have it in different forms or in a different way, but it is also DEP Cross Exhibit 1.

A. I have it.

MR. MEHTA: And, Commissioner Clodfelter, this, obviously, is something that the Commission either already has or could take judicial notice of, so I'm certainly not going to mark it as an exhibit.

COMMISSIONER CLODFELTER: Understood.

Q. And if you would look, Mr. Hart, at page 263 of the Commission's order in the last DEC case, which is Docket Number E-7, Sub 1146.

A. Okay.

Q. And on that page, the second full paragraph reads:

"Coal ash located within basins above levels saturated by water and unaffected by the contours of the bottom of the impoundment can be removed at a cost lower than coal ash at lower levels."

Do you see that?

A. Well, it says "coal at lower levels," it doesn't say coal ash.

Q. Okay. Coal at lower levels.

I suspect that's a typo, but it's the Commission, so I may not want to say that it's a typo.

A. Well, I don't know -- what this is in relation to? You're asking me to read this, but I don't have any context.

Q. Well, Mr. Hart, when you calculated the tonnage of coal ash in the old basins as a ratio to all of the basins, did you make any allowance for wet ash being more expensive to deal with than dry ash -- dryer ash?

A. (Witness peruses document.)

I mean, I don't even understand what this is saying. I don't know what -- it says "unaffected by the contours of the bottom of the impoundment." I don't know what that means. They're talking about saturated water, but then they're talking about the contours of the bottom of the impoundment. I don't even know what that means.

Q. Mr. Hart, let me just ask you the question directly, then.

Did you take into account, in your step B, any differentiation in the costs associated with excavation of ash in a saturated zone versus ash not in a saturated zone?

A. Well, not specifically, because I'm not sure where the saturated zone is in all of these ash facilities. I do believe, based upon looking at aerial photographs, that probably most of these old ash basins are pretty well saturated. There's water that's on top of them almost continuously. Even when they tried to -- as you can see in aerial photographs, when they try to dewater the -- I think it was the basins at Sutton, the water comes back two years later in the same location.

So that says to me that this ash has got a good deal of water in these closed basins, which makes a lot of sense, since they didn't ever dewater them or put a cap on them. So didn't really feel it was necessary because it's -- I think most of the ash is pretty wet anyway.

Q. Does that also apply -- well, did you hear Ms. Bednarcik's testimony earlier this -- I guess it was this morning, Mr. Hart?

A. I did. I did.

Q. And she indicated that the old basins at Cape Fear, and Robinson, and H.F. Lee were forested today. Are those all wet?

A. Yes, they are. You can see it in the aerial photographs. She never said that they had been -- she claimed they were dewatered, but she had no evidence of it.

Q. And --

A. She said they were forested, but there are plenty of forests that grow on wet. Those are what we call wetland forest.

Q. Do you have any evidence that they were not dewatered?

A. I don't. And neither does anyone else have any evidence that they were dewatered. And so it didn't matter if they were dewatered. If they didn't have a cap on them, they're just going to fill up with water again. If they didn't have an impermeable membrane or cap on them, they're going to fill up. And you can see that in the historical aerial photographs. There's wet areas on top of them consistently. You can see where they've dug in ditches in some cases so that water doesn't collect in certain areas.

So there's no indication that those basins were dewatered; or if they were, that they didn't just refill up with water.

Q. Thank you, Mr. Hart.

MR. MEHTA: Commissioner Clodfelter, I have no further questions of Mr. Hart at this time.

COMMISSIONER CLODFELTER: Thank you, Mr. Mehta. My notes are not showing any other party asking to reserve cross examination on Mr. Hart, but I will ask if there are any additional parties wishing to cross examine. If not, then the witness (sound failure.) I'm sorry, we're getting a lot of microphone -- it sounds like somebody is brushing against a microphone. Okay. We're back with the Attorney General on redirect.

MS. TOWNSEND: No redirect, Commissioner Clodfelter.

COMMISSIONER CLODFELTER: Okay. Let's see if there are questions from Commissioners, starting with Commissioner Brown-Bland.

COMMISSIONER BROWN-BLAND: I don't have any questions.

COMMISSIONER CLODFELTER: Commissioner Gray?

COMMISSIONER GRAY: No questions.

COMMISSIONER CLODFELTER: Commissioner Duffley? I'm sorry, Chair Mitchell, I see you back.

CHAIR MITCHELL: No questions.

COMMISSIONER CLODFELTER: Commissioner Duffley?

COMMISSIONER DUFFLEY: No questions.

COMMISSIONER CLODFELTER: Commissioner Hughes?

COMMISSIONER HUGHES: No questions.

COMMISSIONER CLODFELTER: Commissioner McKissick?

COMMISSIONER McKISSICK: No questions.

EXAMINATION BY COMMISSIONER CLODFELTER:

Q. Mr. Hart, I'm going to ask you a question that refers to a document, but you don't need to have the document because my question is just going to be a general one. In the 1988 EPA report to Congress on waste from the combustion of coal by electric utility power plants, there is an exhibit in that.

Are you familiar with that report generally?

A. Yes.

Q. Okay. There is an exhibit in the report, it's Exhibit 4-1, and it's a tabular exhibit about various -- various regulatory situations governing coal combustion waste in the different states. And so there's a line for North Carolina. And one of the column headings on that column is whether or not the state has closure conditions for coal waste facilities. And in that column, there is a "yes" from North Carolina. This was 1988.

Do you know from your experience in your study and your expertise, what the closure regulations for coal waste disposal facilities were in North Carolina in 1988? From your experience and your understanding of the history, do you know what those regulations were?

A. Well, I don't believe they had specific regulations. What we did have is the 2L standards which governs a lot of this. And what it says is, if you exceed the standards, then you have to develop a plan and submit it to DEQ for approval. Those are the standards that I'm aware of and have worked with historically.

This notion that DEP claims that you'd have to have guidance written by DEQ in order to close a basin is not correct. All the time we work in -- within the regulations and the statutes, and we don't have guidance for policy. What we do is go to DEQ and say, this is what we want to do, this is our approach, and is this reasonable and prudent. And we get with the regulators, and that's how we develop a plan. We don't say, well, there's no policy on this and no guidance on this, and therefore we don't have to do it. That's not how it works.

Q. Okay. Let me ask you one other question. I want to understand some of the discussion you had with Mr. Mehta. And I guess my question is really to you as an expert in it hydrogeology, because I'm not one.

So if I understood your testimony to Mr. Mehta right, it is possible, as a matter of engineering and hydrogeology, to put a soil cover over a coal waste impoundment and then vegetate that soil cover without dewatering the ash first; is that -- am I understanding you correctly?

A. Well, yes, it's certainly possible, because once you -- once you put that soil cover and impermeable layer on and divert stormwater away from it, then the water level will decline and seep the water table. So it will no longer have a hydraulic head component on it that keeps getting recharged from stormwater. So eventually, it will seek the level of groundwater. If there's in the coal ash in the groundwater, of course, that coal ash will continue to remain in the groundwater. But if there's coal ash that is not in the groundwater and had been saturated because of continual placement of wastewater streams in it, then it will dry out once that -- once the disposal of that wastewater stops to occur and you prevent stormwater infiltration.

Q. I think I understand as best a non-geologist can understand, so thank you for your answer. I want to ask you one last question, and I should have asked it of Ms. Bednarcik. I didn't think about it, so I'll ask it of her on rebuttal, but I've got you here right now.

And the question is really this: From your examination of the history and the documentary record that you've reviewed with respect to the coal ash impoundments at Duke Progress plants, when we talk about use -- the use of those impoundments for stormwater purposes, I want to understand exactly what we're talking about. Are we talking about using them as a receptacle where -- for stormwater that's collected from other portions of the property and then is funneled to that site to the basin? Or are we just talking about the normal flow of stormwater that runs off the land naturally without any attempt to collect it, and direct it, and divert it to any particular destination? What are we talking about?

A. My understanding, it would be both. So not only would stormwater fall naturally and collect on these basins, but they are also diverting stormwater from different areas of the plant to these areas.

Q. Okay. Thank you. That's all I have.

COMMISSIONER CLODFELTER: So we will go back on questions on Commissioners' questions. Mr. Mehta, anything from you?

MR. MEHTA: Nothing from DEP, Commissioner Clodfelter.

COMMISSIONER CLODFELTER: Okay. Ms. Townsend? Ms. Force?

MS. TOWNSEND: Nothing from the AGO.

COMMISSIONER CLODFELTER: Okay. What

motions do we need to hear at this point?

MS. TOWNSEND: The Attorney General's Office would move to admit Hart's 80 prefiled exhibits, please.

COMMISSIONER CLODFELTER: Without objection, they will be admitted.

MS. TOWNSEND: Thank you.

(Hart Exhibits 1 through 24, 24A and B, 25 through 30, 33 through 41, 42A through 50A, 42B through 50B, 42C, and 51 through 68; and Hart Confidential Exhibits 31 and 32 were admitted into evidence.)

COMMISSIONER CLODFELTER: Mr. Mehta?

MR. MEHTA: Commissioner Clodfelter, I would move on behalf of the applicant, the admission of Hart DEP Cross Examination Exhibit Number 10 and Number 11.

COMMISSIONER CLODFELTER: Is there any objection?

(No response.)

COMMISSIONER CLODFELTER: Hearing none, they will be so admitted.

(Hart DEP Cross Examination Exhibit

Numbers 10 and 11 were admitted into
evidence.)

COMMISSIONER CLODFELTER: Thank you, Mr. Mehta.

MR. MEHTA: Thank you.

MS. TOWNSEND: Commissioner Clodfelter, I would also ask that Mr. Hart be dismissed, as this is his final hoorah in this webcast hearing.

COMMISSIONER CLODFELTER: Is there any objection to excusing the witness? If not, Mr. Hart, thank you for being with us. You're excused.

THE WITNESS: Thank you, everybody.

COMMISSIONER CLODFELTER: All right. Ms. Townsend, Ms. Force, anything further from the Office of the Attorney General?

MS. TOWNSEND: No, that's all, Commissioner Clodfelter.

COMMISSIONER CLODFELTER: Okay. With that -- and I'm going to do -- unless there's some violent objection, I'm going to take something out of order here. I am going to hear from Mr. West who has asked to be heard out of order. And I believe he may be the only party situated in his particular circumstance. So I'm going to try to take him out of order and hope I don't unleash the floodgates.

So, Mr. West, you are recognized at this point.

MR. PAGE: Mr. Clodfelter, this is Bob Page. Can you give us some idea of how long this interruption is going to take? Because my witness is next.

COMMISSIONER CLODFELTER: Probably one minute or less, Mr. Page.

MR. PAGE: Thank you very kindly.

COMMISSIONER CLODFELTER: Yes, sir. I don't intend to take people out of order in the normal course of events, but I have had a specific request, and I think we can dispose of Mr. West very quickly here.

MR. WEST: Thank you very much, Commissioner Clodfelter. I appreciate you hearing us now. Fayetteville PWC does not have a live witness to offer during this phase of the hearing. We did submit witness testimony and exhibits for Mr. Brunault. They were previously addressed in a Commission order, but I have been directed by staff to move to admit the testimony and exhibits here in the live portion of the hearing, I assume to keep the record clear. And so it wasn't clear to me when you wanted to do that. We'll be happy to do that now. It will take 10 seconds. If you'd like me to do it later --

COMMISSIONER CLODFELTER: Let's do it right now, Mr. West, because I am advised that you are the only party in this particular situation, so please make your motion.

MR. WEST: Thank you. Since all parties have waived cross examination of Gary Brunault, I therefore move into the record his direct testimony consisting of 28 pages of testimony, some of which has been designated as confidential, and seven exhibits premarked as GDB-1 through GDB-7, all of which was filed April 13th. And I ask to have it copied into the record as if given orally from the stand today.

COMMISSIONER CLODFELTER: Any party have any objection to Mr. West's motion?

(No response.)

COMMISSIONER CLODFELTER: If not, it will be so ordered.

MR. WEST: Thank you.

COMMISSIONER CLODFELTER: Thank you, Mr. West.

(GDB-1 through GDB-7 were admitted into evidence.)

(Whereupon, the prefiled direct testimony of Gary D. Brunault was copied into the record as if given orally from the stand.)

PUBLIC REDACTED VERSION

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1219

In the Matter of:

Application of Duke Energy Progress, LLC	)	**DIRECT TESTIMONY OF**
For Adjustment of Rates and Charges	)	**GARY D. BRUNAULT**
Applicable to Electric Service	)	**FOR FAYETTEVILLE**
in North Carolina	)	**PUBLIC WORKS**
		COMMISSION

DIRECT TESTIMONY OF
GARY D. BRUNAULT

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EXHIBITS

DIRECT TESTIMONY OF
GARY D. BRUNAULT

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, business address, and title.

A. My name is Gary D. Brunault. My business address is 111 North Orange Avenue, Suite 710, Orlando, Florida 32801. I am a Principal and the Regional Manager of the Orlando office of GDS Associates, Inc. ("GDS"). GDS is a multi-disciplinary engineering and consulting firm that provides technical and financial consulting services to municipal and cooperative electric utilities, public service commissions, large consumers of electricity, and others.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of Fayetteville Public Works Commission ("FPWC"), a public authority under North Carolina law that operates the electric, water, and wastewater utilities in the City of Fayetteville, North Carolina and surrounding areas.

Q. Is FPWC a retail customer of Duke Energy Progress ("DEP")?

A. Yes, FPWC is a retail customer of DEP.

Q. Please provide a brief description of your experience and education.

A. I have over 35 years of experience providing rates and regulatory consulting services to the electric utility industry. I have advised clients in the areas of power supply planning, generating asset valuation, municipal finance, power purchase agreements, investor-owned electric utilities' cost-of-service projections, utility mergers, wholesale rates and other regulatory matters. I have analyzed cost-of-service studies and depreciation studies filed by investor-owned electric utilities with the Federal Energy Regulatory Commission ("FERC") and performed detailed reviews of FERC-jurisdictional production and transmission formula-based rates of investor-owned utilities. I earned a Bachelor of Science degree in Civil Engineering from Tufts University in 1979. My current resume, summarizing my electric utility experience, along with my record of testimony since 2010 is attached hereto as Exhibit No. GDB-1.

Q. Are you familiar with the Duke Energy Progress system?

A. Yes. Since 2015, I have been engaged by FPWC in the review of DEP's production and transmission formula rates under which FPWC takes service from DEP at the wholesale level. In addition, I am particularly familiar with DEP's production fleet of generators because, for several decades, I have been consulting with North Carolina Eastern Municipal Power Agency who, until 2015, jointly owned nuclear and coal-fired generation with DEP and who currently is one of DEP's largest wholesale customers.

II. PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your testimony?

A. FPWC requested that I review DEP's "2018 Depreciation Study – Calculated Annual Depreciation Accruals Related to Electric Plant as of December 31, 2018" prepared by Gannett Fleming Valuation and Rate Consultants, LLC ("Gannett Fleming") filed in this rate proceeding and identified as Spanos Exhibit 1 in the pre-filed Direct Testimony of DEP witness John J. Spanos (the "2018 Depreciation Study"). The purpose of my testimony is to recommend adjustments to certain assumptions relied upon for purposes of the 2018 Depreciation Study that have caused DEP's proposed depreciation rates to be overstated.

Q. Please summarize your recommendations.

A. I am recommending two changes of assumptions used in the 2018 Depreciation Study.

First, I recommend that Gannett Fleming adjust the life spans on the Mayo, Roxboro Unit 3, and Roxboro Unit 4 coal-fired generating plants to be consistent with the retirement dates in DEP's Integrated Resource Plan (Update Report) filed with the North Carolina Utilities Commission ("NCUC") on September 3, 2019 pursuant to Docket No. E-100, Sub 157 ("DEP's 2019 IRP). For purposes of the 2018 Depreciation Study, DEP has informally advised Gannett Fleming that those three generating units will be retired well before their currently planned retirement dates.

Second, I recommend that Gannett Fleming reduce the contingency allowance from 20% to 10% on the Burns and McDonnell dismantlement cost estimates prepared for DEP's non-nuclear production fleet of generating plants.

To the extent the NCUC agrees with my recommendations, it should require DEP to update its 2018 Depreciation Study to reflect these changed assumptions and recompute depreciation rates that would become effective upon a final rate order.

III. DEPRECIATION STUDY ASSUMPTIONS

A. Assumed Early Retirement of Coal Units

Q. How did you discover that the life spans on Mayo, Roxboro Unit No. 3 and Roxboro Unit No. 4 coal-fired generating units had been shortened?

A. In his direct testimony (on page 10) in connection with identifying what life span estimates have changed since the last study was conducted, DEP witness Spanos reports that:

> "Mayo Unit 1 and Roxboro Units 3 and 4 have life spans that are planned to be shorter than currently approved".

Q. How much were the life spans of the three generating plants shortened?

A. The life span was shortened since Gannett Fleming prepared the last depreciation study by 6 years for Mayo Unit 1, and by 4 years for each of the Roxboro Units 3 and 4. A comparison of the probable retirement dates for the plants reflected in the 2018 Depreciation Study vs. the previously approved depreciation study, based on DEP's response to FPWC Data Request No. 1-17 (Exhibit No. GDB-2) is as follows:

Generating Unit	2016 Study	2018 Study
Mayo Unit 1	06-2035	06-2029
Roxboro Unit 3	06-2033	06-2029
Roxboro Unit 4	06-2033	06-2029

Q. What retirement dates did DEP report for these units in DEP's 2019 IRP, filed with the NCUC in September 2019?

A. DEP's 2019 IRP reflected expected retirement dates of 2035 for Mayo Unit 1 and 2033 for both Roxboro Units 3 and 4.

Q. Shouldn't DEP's 2019 IRP represent its official generation expansion plans and reflect an accurate estimate of the planned retirement dates for its generating units, particularly given that these three coal-fired units represent more than 2,000 MW of base-load generation on the DEP system, representing about 15% of all generation on the system?

A. Yes. Under Commission Rule R8-60 (Integrated Resource Planning and Filings), as part of its Integrated Resource Plan ("IRP") process, DEP is obligated to determine an integrated resource plan that offers the least cost combination (on a long-term basis) of reliable resource options for meeting the anticipated needs of its system. In its annual IRP filing, DEP must specify the expected date of retirement of each of its generating units. Of course, the retirement dates of existing generation have a direct impact on the need for new generating resources to be added to the system as part of the IRP. The NCUC compiles the IRPs of the various North Carolina utilities and submits to the Governor and appropriate committees of the General Assembly a report of its analysis of the long-range needs for the expansion of facilities for the generation of electricity in North Carolina and a report on its plan for meeting those needs. The NCUC filed such report on December 31, 2019 reflecting DEP's 2019 IRP. As such, DEP's 2019

IRP represents the Company's official generation expansion plan until modified or updated in subsequent years.

Q. Did DEP's 2019 IRP assume an expectation of future carbon emissions in developing their resource plans?

A. Yes, DEP states (on page 8 of their 2019 IRP) their commitment to reducing their carbon emissions, and that:

> "over the next decade, we are on track in the Carolinas to reduce carbon emissions by over 50% relative to a 2005 baseline level. Beyond 2030 even further reductions are attainable with continued technology development in the areas of carbon free generation and energy storage."

Also on page 8 of DEP's 2019 IRP, DEP reports that their "Base Case" includes the expectation of future carbon legislation, and accordingly has modeled carbon costs starting in 2025 (see page 11 of DEP's 2019 IRP) in arriving at their proposed 15-year generation expansion plans. These excerpts from DEP's 2019 IRP are included as Exhibit No. GDB-3.

Q. Shouldn't the assumed life spans of generating units for purposes of developing depreciation rates be consistent with DEP's most current IRP?

A. Yes, they should. DEP's IRP is produced each year after a robust process involving sophisticated modeling of both demand-side and supply-side resource alternatives, taking into account many different scenarios and assumptions about the future. The plans produced from such analyses should represent the Company's official plans and as such, depreciation rates should be established based on life spans that are consistent with the planned retirement dates of DEP's generating units.

Q. With regard to the 2018 Depreciation Study, what did Mr. Spanos attribute the shortening of life spans for the Mayo and Roxboro generating units to?

A. Mr. Spanos did not specifically address the reasons for the change. Rather, on page 10 of his testimony, when asked if the new life spans for the these generating units were consistent with Company plans, he answered in the affirmative, stating:

> "During the conduct of this depreciation study, DE Progress personnel identified the revised life spans for some steam units."

Q. Did DEP offer any other testimony that addressed the shortening of the life spans on these generating plants?

A. Yes, DEP witness Stephen G. De May (on page 7 of his testimony) stated that:

> "The company is actively working towards achieving a lower carbon future by taking steps to… reduce our reliance on coal-fired generation." He goes on to say "As part of our strategy to reduce our reliance on coal, we have taken a fresh look at the viability of several of our coal-fired plants and have concluded that making shifts in the expected remaining depreciable lives of some of our coal-fired assets is a reasonable action to take now, while we continue to monitor the changing industry landscape and impacts of market forces."

Q. Did FPWC request that DEP explain the basis for the statements in witness De May's testimony?

A. Yes, and in DEP's response to FPWC Data Request No. 1-23 (Exhibit No. GDB-4), DEP explained that:

> "Through a Present Value of Revenue Requirements ("PVRR") analysis, the Company determined that the impact of early retirement of these units would be better than, or near, break-even versus continuing to run to the original retirement dates for these units in the majority of the scenarios analyzed. Given the changing industry landscape and market forces, and the favorable PVRR analysis, the Company determined the acceleration of these assets was reasonable."

Q. Did DEP provide that PVRR analysis to FPWC, and have you reviewed it?

A. Yes, in response to FPWC Data Request No. 1-25, DEP provided the confidential analysis as support for the change in life span estimates for Mayo Unit 1, Roxboro Unit 3, and Roxboro Unit 4, and I have reviewed such analysis.

Q. Please describe DEP's PVRR analysis.

A. **[BEGIN CONFIDENTIAL:** REDACTED

REDACTED

REDACTED

END CONFIDENTIAL]

Q. Did DEP offer any physical evidence to establish that the life spans of the three coal-fired generating units should be shortened, since the 2016 Depreciation Study had been performed?

A. No, in fact, as documented on page 35 of 632 of Spanos Exhibit 1 (Gannett Fleming's 2018 Depreciation Study) under Part III: Service Life Considerations, the most recent field trips to the Mayo and Roxboro Generating Stations date back to December 6-7, 2016 in connection with the 2016 Depreciation Study. So, it appears that the only basis that DEP is offering for assuming a shortening of the life spans of these three generating units is the PVRR analysis.

Q. Have you reviewed DEP's PVRR analysis in detail, and do you agree that it is an accurate analysis of the impact on revenue requirements

that would result from the early retirement of the three generating units?

A. I have reviewed the analysis, but do not agree that it is an accurate analysis of the impact on revenue requirements that would result from the early retirements. In fact, it is significantly flawed.

Q. Please elaborate.

A. **[BEGIN CONFIDENTIAL:** REDACTED

REDACTED

REDACTED

REDACTED

REDACTED

END CONFIDENTIAL]

Q. Are you familiar with the Clean Energy Plan put forth by the North Carolina Department of Environmental Quality ("NCDEQ")?

A. Yes, generally. The NCDEQ released their final version of the Clean Energy Plan ("CEP") on September 27, 2019, soon after DEP filed their 2019 IRP. The CEP includes a recommendation for developing:

> "carbon reduction policy designs for accelerated retirement of uneconomic coal assets and other market-based and clean energy policy options".

There were several questions and requests for information related to the CEP that the NCUC, in its August 27, 2019 Order Accepting Integrated

Resource Plans, ordered DEP and Duke Energy Carolinas ("DEC") respond to. On November 4, 2019, Duke Energy, on behalf of DEP and DEC, submitted its response. Attached (as Exhibit No. GDB-5) is the portion of Duke Energy's response that addresses Request No. 3 regarding DEC's and DEP's most current strategic plans to reduce carbon dioxide (CO_2) emissions and changes to such resource portfolio strategy that could achieve the carbon reduction goals in the CEP.

Q. How did Duke Energy respond to such requests?

A. Although Duke Energy had several questions regarding the 70% target reduction in Greenhouse Gas emissions by 2030 specified in the CEP, they prepared two illustrative scenarios that would accomplish a 60% and 64% reduction in CO_2 emissions by 2030, and compared those scenarios to their Base Case (i.e., the 2019 IRP plans submitted by DEP and DEC), which Duke Energy claims is projected to achieve a 50% reduction in CO_2 emissions. Under both illustrative scenarios, the Mayo Plant and Roxboro Units 3 and 4, among other coal units, were assumed retired by 2029 and replacement capacity included a combination of wind, solar, new gas-fired CTs, and energy storage.

Q. What did Duke Energy's analysis of those two illustrative scenarios show?

A. Duke Energy's analysis showed that the PVRR through the year 2034 under the 60% CO_2 reduction and 64% CO_2 reduction scenarios would increase by \$2.0 billion and \$5.1 billion, respectively, as compared to the Base Case. Duke Energy pointed out that such analysis excluded the network transmission costs needed to implement the system changes as well as the incremental cost of pipeline infrastructure to support incremental gas generation above what is in the Base Case, both of which could materially impact the economics in the presented scenarios.

Q. What point are you trying to make by bringing these analyses to our attention?

A. My point is that Duke Energy's CO2 reduction scenarios, which result in significant increases in system revenue requirements, are in direct conflict with the results of DEP's Accelerated Retirement Case. This evidence further reinforces my claim that DEP's conclusions related to the cost impacts of retiring the Mayo and Roxboro Units early are flawed.

Q. So, by pointing out that the results of DEP's analyses related to reduced CO2 emissions, which model the coal-fired units being retired early, are you against reducing carbon emissions in the Carolinas?

A. Absolutely not. In fact, I commend the State of North Carolina for its good stewardship of the environment over the years, including the NCDEQ's development of the CEP which details policy and action recommendations that are focused, among other things, at the goal of reducing greenhouse gas emissions. However, I believe the additional cost to DEP's customers associated with the proposed early retirement of the Mayo and Roxboro 3 and 4 generating units could be significant and may easily outweigh the environmental benefits that DEP is hoping to achieve with the proposed early retirements. To be clear, the Commission should reject DEP's flawed PVRR analysis in support of early retirement of these coal units and any assertion by DEP that the Mayo Plant and Roxboro Units 3 and 4 are "uneconomic coal assets", as such term is used in the CEP. Footnote 82 from the CEP, states:

> "There are potentially multiple ways to define "uneconomic" and a decision to pursue retirement of utility assets will need to be closely analyzed by the NCUC. For purposes of the discussion in this report, uneconomic assets are those that could have their output replaced by other resources (or a combination of resources) at an all-in cost that is lower than the existing resource's current costs (both capital and operating costs). That is, ceasing operation of an existing power plant and replacing it with another resource would result in lower costs and risks to ratepayers." The CEP's next steps "recognize that certain strategies and actions will require additional deeper dives and detailed analysis when considering new legislation or amending existing policies/practices".

Given all of this, it would be premature to assume that the Mayo Plant and Roxboro Units 3 and 4 will be retired earlier than their planned retirement dates.

Q. What is your recommendation regarding the life spans that should be used by Gannett Fleming for purposes of computing updated depreciation rates for Mayo Unit No. 1, Roxboro Unit No. 3, and Roxboro Unit No. 4?

A. Given the lack of support offered by Gannett Fleming (or DEP's other witnesses) for concluding that "making shifts in the expected remaining depreciable lives of some of our coal-fired assets is a reasonable action to take now", my recommendation is to assume the life spans of the three subject coal-fired generating units consistent with the 2016 Depreciation Study and DEP's 2019 IRP recently filed with the NCUC. Although the NCUC has previously indicated that depreciation studies are the proper forum for useful lives to be set or reset (from the useful lives relied upon in the electric utility's most recently approved IRP), in this case, Gannett Fleming has not visited the generating plants at issue since 2016 and the only cited basis for the proposed resetting of useful lives is a PVRR analysis that is clearly invalid.

Q. What is else supports your recommendation?

A. In Docket No. E-2, Sub 1142 (DEP's last general rate case) DEP requested and the NCUC approved a regulatory asset be established for the remaining net book value of the Asheville Coal Facility as of December 31, 2019, the planned early retirement date which was well in advance of its planned December 2027 retirement date. Depreciation rates were established in 2018 based on a remaining life span of 10 years (2018-2027), despite the anticipated and official plans to retire Asheville early. Likewise, over the period 2011 through 2013, DEP retired several of its coal-fired generating units including generation at its Cape Fear, Lee, Robinson, Sutton, and Weatherspoon plants, well before their planned retirement dates. In each case, DEP established regulatory assets to recover the undepreciated net book investment and associated cost of removal and amortized those remaining costs over 10 years, rather than establishing updated depreciation rates that shortened the life spans of the respective units. I see no difference in circumstances between DEP's past accounting practices for its early-retired coal plants and the current situation involving the Mayo Plant and Roxboro Units 3 & 4. DEP should continue to depreciate the three coal-fired generating plants through their remaining useful lives, and if retired early, then establish regulatory assets for the unrecovered net book investment and amortize those assets over an appropriate time period, given the circumstances at the time of retirement.

Q. What is the impact on depreciation expense as a result of DEP's decision to accelerate retirement dates and reduce the life spans on the three subject generating units?

A. I have estimated the impacts of the reduced life spans on each of the generating units that we have been discussing (see Exhibit No. GDB-6). Below are the results of my analysis, which shows that reducing the life spans increases the total annual depreciation expense of the three units by almost 50%.

Unit Affected	**Reduced Life Spans**	**Unchanged Life Spans**	**Difference**
Mayo Unit 1	64,687,309	41,373,330	(23,313,979)
Roxboro Unit 3	31,324,202	22,425,689	(8,898,513)
Roxboro Unit 4	22,139,052	15,892,563	(6,246,489)
Roxboro Common	34,466,529	24,828,257	(9,638,272)
Total	152,617,092	104,519,839	(48,097,253)
	Increase due to Early Retirement:		46%

B. Contingency Allowance Included in Decommissioning Cost Study

Q. Have you reviewed the non-nuclear decommissioning cost estimates reflected in Gannett Fleming's 2018 Depreciation Study?

A. Yes, the Decommissioning Cost Estimate Study was prepared by Burns & McDonnell Engineering Company, Inc. ("Burns & McDonnell) and is dated April 19, 2017. It is the same decommissioning cost study that Gannett Fleming relied upon in connection with DEP's 2016 Depreciation Study filed in NCUC Docket No. E-2, Sub 1142.

Q. How have the decommissioning cost estimates been reflected in Gannett Fleming's 2018 Depreciation Study?

A. The decommissioning cost estimates are the basis for Gannett Fleming's terminal net salvage values. The decommissioning cost estimates, which are stated in 2016 dollars, were escalated by Gannett Fleming to the projected year of retirement utilizing a 2.5% annual escalation rate for each of the non-nuclear generating units.

Q. Did Burns & McDonnell include a contingency in its cost estimates?

A. Yes, Burns & McDonnell included a 20% contingency adder on all direct costs.

Q. What was the contingency factor intended to cover?

A. According to the Burns & McDonnell study, the 20% contingency was included to cover "unknowns".

Q. Was the 20% contingency factor an issue in DEP's last general rate case (NCUC Docket No. E-2, Sub 1142)?

A. Yes, both the NCUC Public Staff and FPWC witnesses, through direct testimony, challenged the reasonableness of the contingency factor.

Q. What was the outcome of the last general rate case as it relates to the contingency factor reflected in final approved depreciation rates?

A. DEP, through a stipulation, agreed to reduce the 20% contingency allowance to a 10% contingency, which was ultimately reflected in the final depreciation rates approved by the NCUC. The NCUC found and concluded that the 10% contingency factor agreed to by DEP was reasonable and appropriate for use.

Q. Has the NCUC addressed the reasonableness of including a contingency factor on decommissioning cost estimates in any other dockets?

A. Yes, in its Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction in Docket E-7, Sub 1146 (Application of DEC for Adjustment of Rates and Charges) date June 22, 2018, the NCUC addressed that very issue. In that docket, Burns & McDonnell was the engineering firm that prepared the decommissioning study for DEC, and had included a 20% contingency factor for future "unknowns" in that depreciation study as well.

Q. What did the NCUC order in that docket?

A. After considering several arguments that the Public Staff made in that case including, but not limited to, the possibility that scrap prices may increase or that the production plant may be repurposed or sold, the NCUC concluded that including a contingency factor of 10% should be utilized by DEC.

Q. What is the impact on depreciation expense of utilizing a 10% contingency factor on dismantlement costs, as compared to 20%?

A. Assuming the life spans on the Mayo and Roxboro Units are adjusted based on my recommendation discussed above, I have estimated the additional impacts of the reduction in contingency factor on plant dismantlement costs on each of the generating units involved (see Exhibit No. GDB-7). The table below summarizes the impacts.

Plant Affected	20% Contingency	10% Contingency	Difference
Steam Production Plant	164,086,299	164,086,299	-
Hydro Production Plant	5,213,027	5,143,803	(69,224)
Other Production Plant	158,732,404	157,526,087	(1,206,317)
Total	328,031,731	326,756,190	(1,275,540)

IV. CONCLUSION

Q. Please summarize your recommendations.

A. First, I recommend eliminating DEP's shortening of the life spans of Mayo Unit 1, Roxboro Unit 3 and Roxboro Unit 4 and retain the life spans contained in the 2016 Depreciation Study. DEP has not provided sufficient support for the shortening of the life spans, and the NCUC has not approved of plans that include early retirement dates for these units, nor approved plans for installing new generation to replace the capacity. Rather than increasing current depreciation rates, to the extent future decisions are made to accelerate the retirement of such units, the proper accounting and ratemaking approach would be for DEP to establish regulatory assets to recover any remaining undepreciated plant investment at the time of retirement.

Second, I recommend that Gannett Fleming reduce the contingency allowance from 20% to 10% on the Burns and McDonnell dismantlement cost estimates prepared for DEP's non-nuclear production fleet of generating plants.

Q. What are the combined impacts of your recommended adjustments to the assumptions relied upon by Gannett Fleming in the 2018 Depreciation Study?

A. The table below summarizes the combined impacts of my recommended adjustments.

Plant Affected	As Filed	As Adjusted	Difference
Steam Production Plant	212,170,895	164,086,299	(48,084,596)
Hydro Production Plant	5,213,027	5,143,803	(69,224)
Other Production Plant	158,732,404	157,526,087	(1,206,317)
Depreciable Land Rights	3,123,751	3,111,093	(12,658)
Total	379,240,077	329,867,283	(49,372,794)

Q. Do you have any other recommended adjustments to the 2018 Depreciation Study?

A. No. Although these are the only two adjustments I am recommending, one should not interpret that I agree with all other aspects of the 2018 Depreciation Study simply because I have only addressed these two areas.

Q. What are you requesting of the NCUC?

A. To the extent the NCUC agrees with my recommendations, it should require DEP to update its 2018 Depreciation Study to reflect these changed assumptions and recompute depreciation rates that would become effective upon a final rate order.

Q. Does this conclude your testimony?

A. Yes, it does.

MR. JENKINS: Commissioner, this is Alan Jenkins.

COMMISSIONER CLODFELTER: Did I open the floodgates?

MR. JENKINS: Just that you said no other party has a situation. I believe the Commercial Group has testimony that everyone has waived cross examination, and as a result, we had testimony brought in in the other case, but not this case. And so I would move to ask to copy into the record the direct testimony and seven exhibits of Steve W. Chris on behalf of the Commercial Group. Those exhibits were premarked as Chris Exhibits 1 through 7.

COMMISSIONER CLODFELTER: All right. Mr. Page, my apologies to you. I had an incomplete list. But I will take Mr. Jenkins' motion at this time just so we can take care of as many parties as we can.

Is there any objection to Mr. Jenkins' motion?

(No response.)

COMMISSIONER CLODFELTER: If not, Mr. Jenkins, the testimony will be admitted into the record in this case and copied into the transcript as if given orally from the stand. Thank you very much.

MR. JENKINS: Thank you.

(Chriss Exhibits 1 through 7 were admitted into evidence.)

(Whereupon, the prefiled direct testimony with Appendix A of Steve W. Chriss was copied into the record as if given orally from the stand.)

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Exhibits

Chriss Exhibit 6: Examination of SGS-TOU and Remainder of MGS Subclass Usage Data

Chriss Exhibit 7: Functional Revenue Per Duke Energy Progress Cost of Service Study Versus Proposed Revenue Recovery

Introduction

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

A. My name is Steve W. Chriss. My business address is 2608 SE J St., Bentonville, AR 72716-5530. My title is Director, Energy Services, for Walmart Inc.

Q. PLEASE DESCRIBE YOUR EDUCATION AND EXPERIENCE.

A. In 2001, I completed a Master of Science in Agricultural Economics at Louisiana State University. From 2001 to 2003, I was an Analyst and later a Senior Analyst at the Houston office of Econ One Research, Inc., a Los Angeles-based consulting firm. My duties included research and analysis on domestic and international energy and regulatory issues. From 2003 to 2007, I was an Economist and later a Senior Utility Analyst at the Public Utility Commission of Oregon in Salem, Oregon. My duties included appearing as a witness for PUC Staff in electric, natural gas, and telecommunications dockets. I joined the energy department at Walmart in July 2007 as Manager, State Rate Proceedings. I was promoted to Senior Manager, Energy Regulatory Analysis, in June 2011. I was promoted to my current position in October, 2016 and the position was re-titled in October, 2018. My Witness Qualifications Statement is included herein as Appendix A.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY BEFORE THE NORTH CAROLINA UTILITIES COMMISSION ("NCUC" OR "COMMISSION")?

A. Yes, in the Duke Energy/Progress Energy Merger proceeding, Docket E-2, Sub 998/E-7, Sub 986, and the rate cases of Duke Energy Carolinas, Docket No. E-7, Sub 989, Docket No. E-7, Sub 1026, Docket No. E-7, Sub 1146, Docket No. E-7, Sub 1214 and Duke Energy Progress, Docket No. E-2, Sub 1023 and Docket No. E-2, Sub 1142.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS DOCKET?

A. I am testifying on behalf of the Commercial Group, an ad hoc group of commercial customers of Duke Energy Progress, LLC (the "Company" or "DEP"). In this proceeding, the Commercial Group is composed of BJ's Wholesale Club, Inc., Food Lion, LLC, Ingles Markets, Inc., JC Penney Corp., Inc., and Walmart Inc.

Q. HAVE YOU PREPARED ANY EXHIBITS?

A. Yes. We have prepared the exhibits listed in the table of contents

Purpose of Testimony and Recommendations

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. In this testimony, I present the Commercial Group's general concerns regarding the Company's proposed revenue requirement, cost of service and revenue allocation, meter data access, and the positive impact Commercial Group members have on the State of North Carolina.

Q. WHAT IMPACTS DO THE COMPANIES IN THE COMMERCIAL GROUP HAVE ON THE NORTH CAROLINA ECONOMY?

A. The companies in the Commercial Group have a significant positive impact on the North Carolina economy. My understanding is that two of the top three, and three of the top fourteen, private employers in the state are members of the Commercial

Group, according to the latest information published on the North Carolina Department of Commerce web site.[1] Both Food Lion and Ingles have their headquarters in North Carolina.

Q. AS AN EXAMPLE, PLEASE DESCRIBE WALMART'S OPERATIONS IN NORTH CAROLINA.

A. As shown on Walmart's website, as of October 2019, Walmart had 216 retail facilities and distribution centers, and over 59,000 associates in North Carolina.[2] Per the North Carolina Department of Commerce web site cited above, Walmart is the largest private employer in the state.

Q. HAS COMMERCIAL GROUP COUNSEL PROVIDED YOU WITH INFORMATION ON THE NORTH CAROLINA OPERATIONS OF THE OTHER COMMERCIAL GROUP MEMBERS?

A. Yes. Food Lion has approximately 500 facilities and employs approximately 34,000 employees in North Carolina and is listed as the third largest private employer in the state. Ingles employs over 10,000 employees in North Carolina, making Ingles the 14th largest private employer in North Carolina. In all, members of the Commercial Group directly employ well over 100,000 North Carolina workers and support the employment of over 100,000 other North Carolina workers through the billions of dollars members of the Commercial Group spend for merchandise and services in the state each year.

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[1] https://files.nc.gov/nccommerce/documents/LEAD/Top-Employers/Top_300_Employers_Manufacturing_and_Nonmanufacturing_2019_Corrected.pdf
[2] *See* http://corporate.walmart.com/our-story/locations/united-states#/united-states/north-carolina

Q. GENERALLY, WHY ARE UTILITY CUSTOMERS, INCLUDING RETAILERS AND OTHER COMMERCIAL CUSTOMERS, CONCERNED ABOUT DEP'S PROPOSED RATE INCREASE?

A. Electricity represents a significant portion of retailers' operating costs. When rates increase, that increase in cost to retailers puts pressure on consumer prices and on the other expenses required by a business to operate, which impacts retailers' customers and employees. Rate increases also directly impact retailers' customers, who are DEP's residential and small business customers. Given current economic conditions, a rate increase is a serious concern for retailers and their customers, and the Commission should consider these impacts thoroughly and carefully in ensuring that any increase in DEP's rates is only the minimum amount necessary for the utility to provide adequate and reliable service.

Q. PLEASE SUMMARIZE THE COMMERCIAL GROUP'S RECOMMENDATIONS TO THE COMMISSION.

A. The Commercial Group's recommendations to the Commission are as follows:

1) The Commission should closely examine the Company's proposed revenue requirement increase and the associated proposed increase in ROE, especially when viewed in light of: (1) the customer impact of the resulting revenue requirement increase as discussed above; (2) recent rate case ROEs approved by the Commission; and (3) recent rate case ROEs approved by commissions nationwide.

2) The Commercial Group does not take a position on the Company's proposed cost of service model at this time. However, to the extent that

alternative cost of service methodologies or modifications to the Company's methodology are proposed by other parties, the Commercial Group reserves the right to address any such changes in accordance with the Commission's procedures in this docket.

3) The Commercial Group does not oppose the Company's proposed revenue allocation to the major customer classes. However, due to the concerns regarding the kWh usage data used for Small General Service-Time of Use ("SGS-TOU") and the remainder of the Medium General Service ("MGS") subclasses in DEP's proposed cost of service study, the Commission should require the percentage base rate increase for each subclass equal the overall increase for MGS.

4) If the Commission determines that the appropriate revenue requirement is less than that proposed by the Company, the Commission should (a) use the reduction in revenue requirement to move each customer class closer to its respective cost of service while ensuring that all classes see a reduction from DEP's initially proposed increases and (b) require the percentage base rate increase for each subclass equal the overall increase for MGS.

5) For the purposes of this docket, the Commercial Group recommends the following for SGS-TOU rate design:

   a) The Commercial Group does not oppose the Company's proposed SGS-TOU customer charge or an increase in the off-peak excess demand charge to align that charge with distribution unit cost;

b) The Commercial Group does not oppose the Company's proposal to maintain the time-of-use and seasonal relationships between the on-peak and off-peak energy charges or the proposal to maintain the seasonal relationship between the on-peak demand charges; and

c) The Commission should require any remaining increase to the SGS-TOU subclass to be allocated only to the on-peak demand charges in a manner that maintains the seasonal relationships between those charges.

Q. DOES THE FACT THAT YOU MAY NOT ADDRESS AN ISSUE OR POSITION ADVOCATED BY THE COMPANY INDICATE THE COMMERCIAL GROUP'S SUPPORT?

A. No. The fact that an issue is not addressed herein or in related filings should not be construed as an endorsement of, agreement with, or consent to any filed position.

Revenue Requirement and Return on Equity

Q. WHAT REVENUE REQUIREMENT INCREASE HAS THE COMPANY PROPOSED IN ITS FILING?

A. The Company has proposed a total base rate revenue requirement increase of approximately $586 million, based on the test year ending December 31, 2018. *See* Smith Exhibit 1, page 1.

Q. WHAT IS YOUR UNDERSTANDING OF THE COMPANY'S OPERATING INCOME BEFORE THE PROPOSED INCREASE?

A. My understanding is that the Company's filed operating income before the proposed increase is approximately $356 million. *See* Smith Exhibit 1, page 1.

Q. WHAT IS YOUR UNDERSTANDING OF THE COMPANY'S PROPOSED OPERATING INCOME?

A. My understanding is that the Company filed a proposed operating income of $804 million. *See* Smith Exhibit 1, page 1.

Q. WHAT PERCENT INCREASE IN OPERATING INCOME IS THE COMPANY REQUESTING?

A. The Company is requesting an increase in its operating income of approximately 126 percent. *See* Chriss Exhibit 1.

Q. WHAT IS THE COMPANY'S PROPOSED ROE IN THIS DOCKET?

A. The Company presents testimony to support a ROE of 10.5 percent, based on a range of 10.0 percent to 11.0 percent. *See* Direct Testimony of Robert B. Hevert, page 3, line 18 to page 4, line 1. However, the Company's proposed ROE is 10.3 percent, which they present to the Commission as a "rate mitigation measure." *See* Direct Testimony of Karl W. Newlin, page 7, line 11 to line 15. The requested ROE at the Company's proposed capital structure of 53 percent equity results in a proposed overall rate of return of 7.41 percent. *See* Smith Exhibit 1, page 1 and page 2.

Q. WHAT ARE THE CURRENTLY APPROVED ROE AND EQUITY RATIO FOR DEP?

A. The currently effective ROE approved by the Commission for DEP is 9.9 percent and the currently effective equity ratio is 52 percent. *See* Order Accepting Stipulation, Deciding Contested Issues, and Granting Partial Rate Increase, Docket No. E-2, Sub 1142, page 56 and page 86.

Q. IS THE COMMERCIAL GROUP CONCERNED THAT THE COMPANY'S PROPOSED ROE AND OPERATING INCOME INCREASE ARE EXCESSIVE?

A. The Commercial Group is concerned that the Company's proposed ROE of 10.3 percent and operating income increase of 126 percent are excessive, especially in light of: (1) the customer impact of the resulting revenue requirement increase as discussed above; (2) recent rate case ROEs approved by the Commission; and (3) recent rate case ROEs approved by commissions nationwide.

Customer Impact of the Proposed Increase in ROE

Q. **WHAT IS THE REVENUE REQUIREMENT IMPACT OF THE COMPANY'S PROPOSED INCREASE IN ROE AND EQUITY RATIO?**

A. Using the Company's proposed cost of debt, the revenue requirement impact of the Company's proposed increases in ROE and equity ratio from those approved in Docket No. E-2, Sub 1142 is approximately $38.5 million, or approximately 6.5 percent of the Company's proposed revenue requirement increase. *See* Chriss Exhibit 2.

Recent ROEs Approved by the Commission

Q. IS THE COMPANY'S PROPOSED ROE SIGNIFICANTLY HIGHER THAN THE ROES APPROVED BY THE COMMISSION FROM 2016 TO PRESENT?

A. Yes. During this time period the Commission has issued orders with stated ROEs in four dockets, including the DEP rate case noted above, with the average of the ROEs approved equal to 9.86 percent. *See* Chriss Exhibit 3.

Q. IN WHICH OTHER DOCKETS DID THE COMMISSION ISSUE ORDERS WITH STATED ROES?

A. The Commission issued orders with stated ROEs in the following dockets:

- Docket No. E-22, Sub 562, the Virginia Electric & Power Company general rate case decided in February, 2020, in which the Commission approved an ROE of 9.75 percent. *See* Order Accepting Public Staff Stipulation in Part, Accepting CIGFUR Stipulation, Deciding Contested Issues, and Granting Partial Rate Increase, page 42.
- Docket No. E-22, Sub 532, the Virginia Electric & Power Company general rate case decided in 2016, in which the Commission approved an ROE of 9.9 percent. *See* Order Approving Rate Increase and Cost Deferrals and Revising PJM Regulatory Conditions, Docket No. E-22, Sub 532, page 81.
- Docket No. E-7, Sub 1146, Duke Energy Carolinas Inc. general rate case, in which the Commission approved an ROE of 9.9 percent. *See* Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue

Reduction, Docket No. E-7, Sub 1146, page 32.

As such, the Company's proposed 10.3 percent ROE is counter to recent Commission actions regarding ROE.

National Utility Industry ROE Trends

Q. IS THE COMPANY'S PROPOSED ROE SIGNIFICANTLY HIGHER THAN THE ROES APPROVED BY OTHER UTILITY REGULATORY COMMISSIONS IN 2016, 2017, 2018, 2019, AND SO FAR IN 2020?

A. Yes. According to data from S&P Global Market Intelligence, a financial news and reporting company, the average of the 154 reported electric utility rate case ROEs authorized by commissions to investor-owned utilities in 2016, 2017, 2018, 2019, and so far in 2020, is 9.61 percent. The range of reported authorized ROEs for the period is 8.4 percent to 11.95 percent, and the median authorized ROE is 9.6 percent. The average and median values are significantly below the Company's proposed ROE of 10.3 percent. *See* Chriss Exhibit 3. As such, the Company's proposed 10.3 percent ROE is counter to broader electric industry trends.

Q. SEVERAL OF THE REPORTED AUTHORIZED ROES ARE FOR DISTRIBUTION-ONLY UTILITIES OR FOR ONLY A UTILITY'S DISTRIBUTION SERVICE RATES. WHAT IS THE AVERAGE AUTHORIZED ROE IN THE REPORTED GROUP FOR VERTICALLY INTEGRATED UTILITIES?

A. In the group reported by S&P Global, the average ROE for vertically integrated utilities authorized from 2016 through present is 9.74 percent, and the trend in these averages has been relatively stable. The average ROE authorized for vertically integrated utilities in 2016 was 9.77 percent; in 2017 it was 9.80 percent; in 2018 it was 9.68 percent; in 2019 it was 9.73 percent; and thus far in 2020 it was 9.72 percent. *Id.* As such, the Company's proposed 10.3 percent ROE is counter to broader electric industry trends and, in fact, as shown in Figure 1, would be equal to the fourth highest approved ROE for a vertically integrated utility from 2016 to present if approved by the Commission.

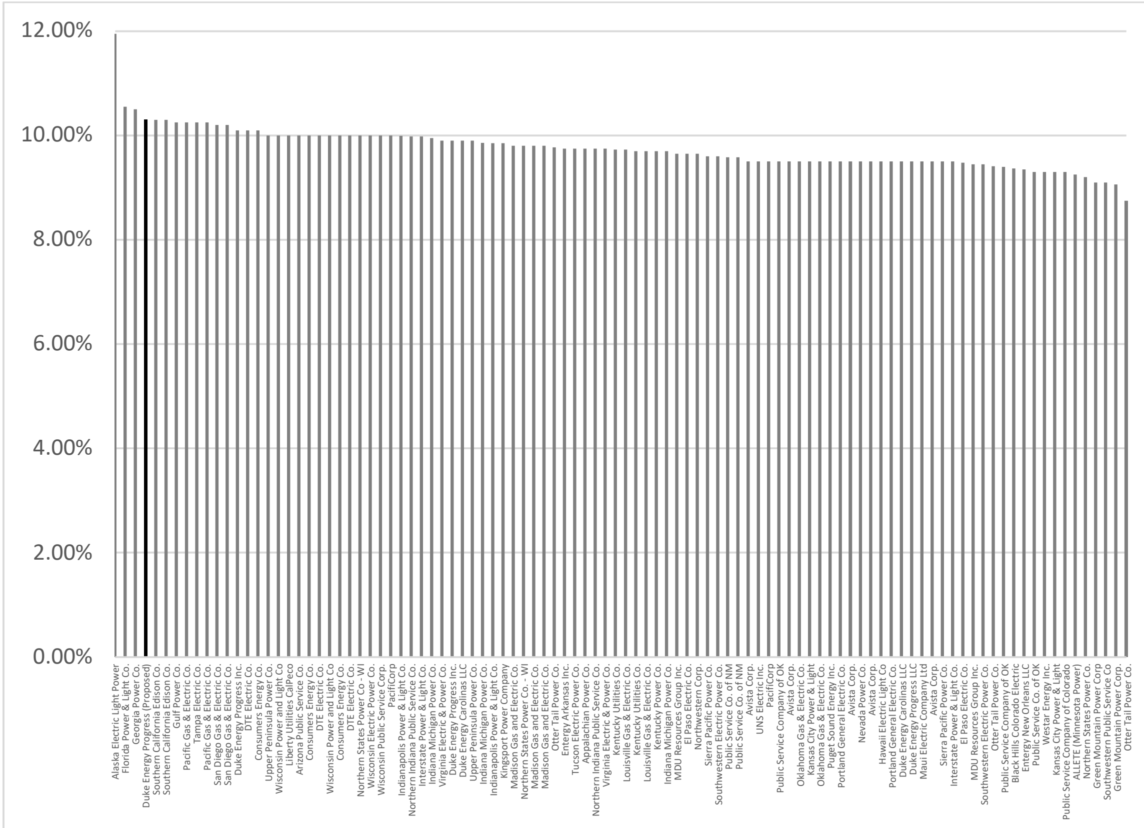

Figure 1. DEP Proposed ROE Versus Authorized ROEs for Vertically Integrated Utilities, 2016 to present. Source: Chriss Exhibit 3.

Q. WHAT IS THE REVENUE REQUIREMENT IMPACT IF THE COMMISSION WERE TO AWARD AN ROE OF 9.75 PERCENT, THE AVERAGE ROE AWARDED FOR VERTICALLY INTEGRATED UTILITIES FROM 2016 TO PRESENT?

A. Assuming Company's proposed cost of debt and equity ratio, authorizing DEP an ROE of 9.74 percent instead of the requested 10.3 percent would result in a reduction to the requested base revenue requirement increase, inclusive of taxes, of about $42 million. This represents about a 7.1 percent reduction of the Company's requested base revenue requirement increase. *See* Chriss Exhibit 4.

Q. IS THE COMMERCIAL GROUP RECOMMENDING THAT THE COMMISSION BE BOUND BY ROEs AUTHORIZED BY OTHER STATE REGULATORY AGENCIES?

A. No. Decisions of other state regulatory commissions are not binding on the Commission. Additionally, each commission considers the specific circumstances in each case in its determination of the proper ROE. The Commercial Group is providing this information to illustrate a national customer perspective on industry trends in authorized ROE. In addition to using recent authorized ROEs as a general gauge of reasonableness for the various cost-of-equity analyses presented in this case, the Commission should consider how its authorized ROE impacts customers relative to other jurisdictions.

Conclusion

Q. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION IN REGARDS TO THE COMPANY'S PROPOSED ROE?

A. The Commission should closely examine the Company's proposed revenue requirement increase and the associated proposed increase in ROE, especially when viewed in light of: (1) the customer impact of the resulting revenue requirement increase as discussed above; (2) recent rate case ROEs approved by the Commission; and (3) recent rate case ROEs approved by commissions nationwide.

Cost of Service and Revenue Allocation

Q. WHAT IS THE COMMERCIAL GROUP'S POSITION ON SETTING RATES BASED ON THE UTILITY'S COST OF SERVICE?

A. The Commercial Group advocates that rates be set based on the utility's cost of service for each rate class. This produces equitable rates that reflect cost causation, send proper price signals, and minimize price distortions.

Q. DOES THE COMMERCIAL GROUP TAKE A POSITION ON THE COMPANY'S PROPOSED COST OF SERVICE METHODOLOGY AT THIS TIME?

A. No. However, to the extent that alternative cost of service methodologies or modifications to the Company's methodology are proposed by other parties, the Commercial Group reserves the right to address any such changes in accordance with the Commission's procedures in this docket.

Q. HOW DOES THE COMPANY REPRESENT WHETHER RATES FOR A CUSTOMER CLASS ACCURATELY REFLECT THE UNDERLYING COST CAUSATION?

A. The Company represents this relationship in their cost of service results through the use of class-specific rates of return. These rates of return can be converted into unitized rates of return ("UROR"), which is an indexed measure of the relationship of the rate of return for an individual rate class to the total system rate of return. A UROR greater than 1.0 means that the rate class is paying rates in excess of the costs incurred to serve that class, and a UROR less than 1.0 means that the rate class is paying rates less than the costs incurred to serve that class.

As such, those rate classes with a UROR greater than 1.0 shoulder some of the revenue responsibility burden for the classes with a UROR less than 1.0.

Q. HAVE YOU CALCULATED A UROR FOR EACH MAJOR CUSTOMER CLASS BASED ON THE COMPANY'S COST OF SERVICE RESULTS?

A. Yes, as shown in Table 1 below:

Table 1. Unitized Rates of Return, Present Rates, DEP Proposed Cost of Service Study Results.

Customer Class	Rate of Return (%)	UROR
RES	2.74	0.83
SGS	2.53	0.77
SGSCLR	1.57	0.48
MGS	4.00	1.21
LGS	3.44	1.04
SI	8.18	2.48
TSS	2.35	0.71
ALS, SLS	8.73	2.65
SFL	8.49	2.57
Total Company	**3.30**	**1.00**
Source: Pirro Exhibit 4, Page 1		

It should be noted that DEP does not break out rates of return at the subclass level in the cost of service study results presented in testimony. *See* Pirro Exhibit 4, Page 1.

Q. DID DEP PROVIDE A BREAKOUT FOR SGS-TOU IN DISCOVERY?

A. Yes. The breakout of SGS-TOU (labeled "MGS-TOU") from the remainder of MGS subclasses appears to show SGS-TOU as providing for a rate of return lower than the remainder of MGS subclasses. *See* DEP Response to Commercial Group Data Request No. 1, Adj Summary NC worksheet.

Q. DOES THE COMMERCIAL GROUP HAVE CONCERNS WITH THE RELIABILITY OF THE INFORMATION PRESENTED IN THE BREAKOUT?

A. Yes. In the same discovery response, DEP provided the unit costs for SGS-TOU (labeled "MGS-TOU"). An examination of the SGS-TOU unit costs and billing determinants, particularly when compared to the unit costs and billing determinants of the remainder of MGS subclasses and other non-lighting commercial and industrial classes, reveals potential issues in the underlying SGS-TOU data. This is particularly apparent in the amount of kWh energy sales attributed to the SGS-TOU subclass, which is reported as 2,807,099,681 kWh, even though the amount of kWh used to calculate actual SGS-TOU rates is 8,402,221,509. *See* DEP Response to Commercial Group Data Request No. 1, Item 1-7, SGS-TOU worksheet.

Q. PLEASE EXPLAIN.

A. As shown in Table 2 below, I calculated estimated annual load factors for each non-lighting commercial and industrial class presented in DEP's unit cost results using the summer coincident peak kW and adjusted kWh sales billing determinants provided by the Company.[3]

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[3] The caveat being that the class non-coincident peak ("NCP") may be higher than the summer coincident peak.

Table 2. Estimated Load Factors for Non-Lighting Commercial and Industrial Classes, DEP Cost of Service Study.

Class/Subclass	Adjusted kWh Sales	Average Demand (kW)	Summer CP kW	Estimated Load Factor
	(1)	(2) (1) / 8,760	(3)	(4) (2) / (3)
SGS-TOU	**2,807,099,681**	**320,445**	**1,472,290**	**22%**
Remaining MGS	**8,371,865,197**	**955,692**	**626,965**	**152%**
SGS	1,950,982,004	160,062	454,333	49%
SGSCLR	31,614,397	3,609	3,739	97%
LGS Only	1,141,204,433	130,274	177,592	73%
LGT – non-curtailable	1,598,681,135	182,498	219,783	83%
RTP	5,717,905,454	652,729	807,110	81%

Source: DEP Response to Commercial Group Data Request No. 1, Item 1-4, Unit Costs 12-31-2018 worksheet

The estimated load factor of 22 percent for SGS-TOU stands out on its own, as in my experience this is far lower than the class load factors for major commercial and industrial rate schedules used by relatively high load factor customers such as members of the Commercial Group. However, the estimated load factor of 22 percent also stands out when compared to the estimated load factor of the remaining MGS subclasses, which is 152 percent (as a reference point, a load that runs constantly at its peak demand year round has a load factor of 100 percent, so a load factor of 152 percent is not technically feasible.) Finally, when benchmarked against the other classes included in the table, where estimated load factors range from 49 percent to 97 percent, the estimated load factor of 22 percent for SGS-TOU appears problematically low.

Q. WHY WOULD THE ESTIMATED LOAD FACTOR OF 22 PERCENT BE PROBELMATIC?

A. The estimated load factor of 22 percent suggests that the adjusted kWh sales allocated to SGS-TOU are too low, which is borne out by the rate design data for SGS-TOU provided by the Company. This issue clearly affects the unit costs reported by the Company for SGS-TOU and creates uncertainty as to the reliability of the cost of service study outputs.

Q. WHAT IS THE SGS-TOU UNIT COST FOR ENERGY PER THE COMPANY'S COST OF SERVICE STUDY RESULTS?

A. The Company's unit cost for energy for SGS-TOU is 11.44 c/kWh, compared to 1.31 c/kWh for the remainder of MGS. The other commercial and industrial schedules have energy unit costs ranging from 3.00 c/kWh to 3.97 c/kWh. *See* DEP Response to Commercial Group Data Request No. 1, Item 1-4, Unit Costs 12-31-2018 worksheet.

Q. DOES IT APPEAR THAT DEP'S UNIT COST RESULTS SUFFER FROM A TRANSPOSITION OF THE AJUSTED KWH SALES FOR MGS TO SGS-TOU AND FOR SGS-TOU TO MGS?

A. Yes. I checked the usages for SGS-TOU and the remainder of MGS from the cost of service study against DEP's rate design schedules and it appears that the two values were transposed. Using the kWh usages from DEP's rate design schedules results in energy unit costs of approximately 3.82 c/kWh for SGS-TOU and 3.92 c/kWh for the remainder of MGS. *See* Chriss Exhibit 6. More broadly, however, DEP needs to re-run the whole cost of service study using the corrected data to better ensure the reliability of the cost of service study results as a whole.

Q. WHAT REVENUE ALLOCATION METHODOLOGY DOES THE COMPANY PROPOSE?

A. My understanding is that DEP proposes to allocate revenue on the basis of rate base, with the goal of moving each class's deficiency or surplus to a band of +/- 10 percent if possible. *See* Direct Testimony of Michael J. Pirro, page 11, line 12 to line 15.

Q. DOES THE COMPANY'S PROPOSAL MOVE EACH CUSTOMER CLASS CLOSER TO COST-BASED LEVELS?

A. Generally, yes, as shown in Table 3 below:

Table 3. Unitized Rates of Return, Present and Proposed Rates.

Customer Class	UROR, Present	UROR, Proposed
RES	0.83	0.94
SGS	0.77	0.92
SGSCLR	0.48	0.83
MGS	1.21	1.07
LGS	1.04	1.01
SI	2.48	1.49
TSS	0.71	0.91
ALS (+ SLS for Existing)	2.65	2.14
SLS		0.88
SFL	2.57	1.52
Total Company	**1.00**	**1.00**

Source: Pirro Exhibit 4, Page 1

Q. DOES DEP'S PROPOSED REVENUE ALLOCATION TREAT ALL MGS SUBCLASSES SIMILARLY?

A. No, as shown in Table 4 below:

Table 4. DEP Proposed Base Rate Increases, Medium General Service Subclasses.

MGS Subclass	Proposed Base Rate Increase
MGS	10.9
SGS-TOU	12.0
CH-TOUE	10.9
GS-TES	10.9
APH-TES	10.3
CSE	12.5
CSG	10.8
Medium General Service Total	**11.6**
Source: Pirro Exhibit 2, Page 1	

Q. WHAT IS THE COMMERCIAL GROUP'S REVENUE ALLOCATION RECOMMENDATION TO THE COMMISSION AT THE COMPANY'S PROPOSED REVENUE REQUIREMENT?

A. The Commercial Group does not oppose the Company's proposed revenue allocation to the major customer classes. However, due to the concerns regarding the kWh usage data used for SGS-TOU and the remainder of the MGS subclasses in DEP's cost of service study, the Commission should require the percentage base rate increase for each subclass equal the overall increase for MGS.

Q. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION IF IT DETERMINES THAT A LOWER REVENUE REQUIREMENT IS APPROPRIATE?

A. If the Commission determines that the appropriate revenue requirement is less than that proposed by the Company, the Commission should (a) use the reduction in revenue requirement to move each customer class closer to its respective cost of service while ensuring that all classes see a reduction from DEP's initially proposed increases and (b) require the percentage base rate increase for each subclass equal the overall increase for MGS.

SGS-TOU Rate Design

Q. WHAT IS YOUR UNDERSTANDING OF THE COMPANY'S PROPOSAL FOR SGS-TOU RATE DESIGN?

A. My understanding is that the Company proposes the following for SGS-TOU rate design:

1) Leave the customer charge unchanged at $35.50/month;
2) Maintain the current seasonal and TOU price relationships;
3) Adjust the on-peak and off-peak kWh energy and demand rates by the same percentage; and
4) Increase the off-peak excess demand charge. *See* Direct Testimony of Michael J. Pirro, page 20, line 2 to line 16.

Q. DOES THE COMMERCIAL GROUP HAVE CONCERNS WITH THE COMPANY'S RATE DESIGN PROPOSAL SGS-TOU?

A. Yes. The Commercial Group's concerns with the rate design proposals for SGS-TOU are that SGS-TOU rates do not reflect the underlying cost of serving those classes and as a result shift cost responsibility within the rate classes in that they charge customers for demand-related (i.e., fixed) costs through energy (i.e., variable) charges.

Q. WHAT IS YOUR UNDERSTANDING OF THE COST OF SERVICE STUDY RESULTS FOR SGS-TOU?

A. My understanding is that DEP incurs three types of costs to serve SGS-TOU customers: Customer, Demand, and Energy. Demand costs are fixed costs incurred by the Company to size the system such that it can meet the peak kW demands imposed by customers and do not change with changes in how many kWh of energy are consumed by customers. Customer costs are also fixed costs, which are incurred based on the number of customers served by the Company, and do not vary by the size of each customer or how much energy the customers consume. Energy costs are variable costs incurred by the Company in relation to the amount of energy consumed by customers.

Q. WHAT PERCENT OF THE COSTS INCURRED TO SERVE SGS-TOU CUSTOMERS ARE DEMAND-RELATED?

A. Per DEP's cost of service study, approximately 49.1 percent of the costs incurred by the Company to serve SGS-TOU customers are demand-related while 49.2 percent are energy related and 1.7 percent are customer-related. *See* Chriss Exhibit 7.

Q. DOES DEP PROPOSE TO RECOVER SGS-TOU REVENUE REQUIREMENTS IN A MANNER THAT REFLECTS THE UNDERLYING COST TO SERVE THE SUBCLASS?

A. No. DEP proposes to recover the majority of SGS-TOU revenue requirements through the energy charge. As shown in Table 5 below, an examination of the proposed total and base rate revenues by charge for SGS-TOU shows a significant mismatch between functional revenues from DEP's cost of service study and how DEP proposes to recover those revenues.

Table 5. Functional Revenue per DEP's Cost of Service Study vs. Proposed Revenue Recovery.

Function	Functional Revenue as a % of Cost	Charge Revenue as % of Proposed Total Revenues	Charge Revenue as % of Proposed Base Rate Revenues
Customer	1.7%	1.2%	1.4%
Energy	49.2%	70.0%	69.0%
Demand	49.1%	28.8%	29.6%
Total	**100%**	**100%**	**100%**

Source: Chriss Exhibit 7.

As shown in the Table, DEP proposes to recover 69 percent of base rate revenues and 70 percent of total SGS-TOU revenues through the energy charges, as opposed to implementing a design based on the Company's cost of service results. The Company's proposed SGS-TOU rate design also under-recovers demand costs through the demand charges, with just under 30 percent of revenues proposed to be recovered through demand charges versus a cost-based level of 49 percent.

Q. IS THE RECOVERY OF DEMAND-RELATED COSTS THROUGH AN ENERGY CHARGE CONSISTENT WITH THE COMPANY'S CLASSIFICATION AND ALLOCATION OF DEMAND-RELATED COSTS?

A. No. In its class cost of service study, the Company does not classify or allocate any of its demand-related costs on an energy basis. Rather, these costs are incurred, and therefore classified, based on customer demand or number of customers. Costs should be recovered in a manner which reflects how they are incurred. As such, recovering demand-related costs through an energy charge violates cost causation principles.

Q. DOES THE RECOVERY OF DEMAND-RELATED COSTS THROUGH AN ENERGY CHARGE DISADVANTAGE HIGHER LOAD FACTOR CUSTOMERS?

A. Yes. The shift in demand-related costs from per kW demand charges to per kWh energy charges results in a shift in demand cost responsibility from lower load factor customers to higher load factor customers. This results in a misallocation of cost responsibility as higher load factor customers overpay for the demand-related costs incurred by the Company to serve them. In other words, higher load factor customers are paying for a portion of the demand-related costs that are incurred to serve the lower load factor customers simply because of the manner in which the Company collects those costs in rates.

Q. WOULD THE PROPER COLLECTION OF DEMAND-RELATED COSTS THROUGH A DEMAND CHARGE PROVIDE BENEFITS TO THE COMPANY?

A. Yes. By collecting a large percentage of a class revenue requirement through energy charges, the Company subjects itself to under and overcollection of its revenue requirement due to fluctuations in customer usage. As such, issues such as weather and the economy will have a greater impact on the utility versus a rate design in which an appropriate amount of revenue requirement is collected through the demand charge.

Q. WHAT IS THE COMMERCIAL GROUP'S RECOMMENDATION TO THE COMMISSION ON THIS ISSUE?

A. For the purposes of this docket, the Commercial Group recommends the following for SGS-TOU rate design:

1) The Commercial Group does not oppose the Company's proposed SGS-TOU customer charge or an increase in the off-peak excess demand charge to align that charge with distribution unit cost;
2) The Commercial Group does not oppose the Company's proposal to maintain the time-of-use and seasonal relationships between the on-peak and off-peak energy charges or the proposal to maintain the seasonal relationship between the on-peak demand charges; and
3) The Commission should require any remaining increase to the SGS-TOU subclass to be allocated only to the on-peak demand charges in a manner that maintains the seasonal relationships between those charges.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Appendix A

Steve W. Chriss
Walmart Inc.
Business Address: 2608 SE J Street, Bentonville, AR, 72716-5530

EXPERIENCE

July 2007 – Present
Walmart Inc., Bentonville, AR
Director, Energy Services (October 2018 – Present)
Director, Energy and Strategy Analysis (October 2016 – October 2018)
Senior Manager, Energy Regulatory Analysis (June 2011 – October 2016)
Manager, State Rate Proceedings (July 2007 – June 2011)

June 2003 – July 2007
Public Utility Commission of Oregon, Salem, OR
Senior Utility Analyst (February 2006 – July 2007)
Economist (June 2003 – February 2006)

January 2003 - May 2003
North Harris College, Houston, TX
Adjunct Instructor, Microeconomics

June 2001 - March 2003
Econ One Research, Inc., Houston, TX
Senior Analyst (October 2002 – March 2003)
Analyst (June 2001 – October 2002)

EDUCATION

2001	**Louisiana State University**	M.S., Agricultural Economics
1997-1998	**University of Florida**	Graduate Coursework, Agricultural Education and Communication
1997	**Texas A&M University**	B.S., Agricultural Development B.S., Horticulture

PRESENT MEMBERSHIPS

Arizona Independent Scheduling Administrators Association, Board
Arizonans for Electric Choice & Competition, Chairman
Edison Electric Institute National Key Accounts Program, Customer Advisory Group
Florida Advisory Council for Climate and Energy
Renewable Energy Buyers Alliance, Advisory Board

PAST MEMBERSHIPS

Southwest Power Pool, Corporate Governance Committee, 2019

TESTIMONY BEFORE REGULATORY COMMISSIONS

2020

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

Texas Docket No. 49831: Application of Southwestern Public Service Company for Authority to Change Rates.

2019

Missouri Case No. ER-2019-0335: In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariffs to Decrease its Revenues for Electric Service.

Michigan Case No. U-20561: In the Matter of the Application of DTE Electric Company for Authority to Increase its Rates, Amend its Rate Schedules and Rules Governing the Distribution and Supply of Electric Energy, and for Miscellaneous Accounting Authority.

Indiana Cause No. 45253: Petition of Duke Energy Indiana, LLC Pursuant to Ind. Code §§ 8-1-2-42.7 and 8-1-2-61, For (1) Authority to Modify its Rates and Charges for Electric Utility Service Through a Step-In of New Rates and Charges Using a Forecasted Test Period; (2) Approval of New Schedules of Rates and Charges, General Rules and Regulations, and Riders; (3) Approval of a Federal Mandate Certificate Under Ind. Code § 8-1-8.4-1; (4) Approval of Revised Electric Depreciation Rates Applicable to its Electric Plant in Service; (5) Approval of Necessary and Appropriate Accounting Deferral Relief; and (6) Approval of a Revenue Decoupling Mechanism for Certain Customer Classes.

Arizona Docket No. E-01933A-19-0228: In the Matter of the Application of Tucson Electric Power Company for the Establishment of Just and Reasonable Rates and Charges Designed to Realize a Reasonable Rate of Return on the Fair Value of the Properties of Tucson Electric Power Company Devoted to its Operations Throughout the State of Arizona and for Related Approvals.

Georgia Docket No. 42516: In Re: Georgia Power's 2019 Rate Case.

Colorado Proceeding No. 19AL-0268E: Re: In the Matter of Advice No. 1797-Electric of Public Service Company of Colorado to Revise its Colorado P.U.C. No. 8-Electric Tariff to Implement Rate Changes Effective on Thirty Days' Notice.

New York Case No. 19-E-0378: Proceeding on the Motion of the Commission as to the Rates, Charges, Rules, and Regulations of New York State Electric & Gas Corporation for Electric Service.

New York Case No. 19-E-0380: Proceeding on the Motion of the Commission as to the Rates, Charges, Rules, and Regulations of Rochester Gas & Electric Corporation for Electric Service.

Maryland Case No. 9610: In the Matter of the Application of Baltimore Gas and Electric Company for Adjustments to its Electric and Gas Base Rates.

Nevada Docket No. 19-06002: In the Matter of the Application by Sierra Pacific Power Company, D/B/A NV Energy, Filed Pursuant to NRS 704.110(3) and NRS 704.110(4), Addressing its Annual Revenue Requirement for General Rates Charged to All Classes of Electric Customers.

Florida Docket No. 20190061-EI: In Re: Petition of Florida Power & Light Company for Approval of FPL SolarTogether Program and Tariff.

Wisconsin Docket No. 6690-UR-126: Application of Wisconsin Public Service Corporation for Authority to Adjust Electric and Natural Gas Rates – Test Year 2020.

Wisconsin Docket No. 5-UR-109: Joint Application of Wisconsin Electric Power Company and Wisconsin Gas LLC for Authority to Adjust Electric, Natural Gas, and Steam Rates – Test Year 2020.

New Mexico Case No. 19-00158-UT: In the Matter of the Application of Public Service Company of New Mexico for Approval of PNM Solar Direct Voluntary Renewable Energy Program, Power Purchase Agreement, and Advice Notice Nos. 560 and 561.
Indiana Cause No. 45235: Petition of Indiana Michigan Power Company, and Indiana Corporation, for Authority to Increase its Rates and Charges for Electric Utility Service through a Phase In Rate Adjustment; and for Approval of Related Relief Including: (1) Revised Depreciation Rates; (2) Accounting Relief; (3) Inclusion in Rate Base of Qualified Pollution Control Property and Clean Energy Project; (4) Enhancements to the Dry Sorbent Injection System; (5) Advanced Metering Infrastructure; (6) Rate Adjustment Mechanism Proposals; and (7) New Schedules of Rates, Rules and Regulations.

Iowa Docket No. RPU-2019-0001: In Re: Interstate Power and Light Company.

Texas Docket No. 49494: Application of AEP Texas Inc. for Authority to Change Rates.

Arkansas Docket No. 19-008-U: In the Matter of the Application of Southwestern Electric Power Company for Approval of a General Change in Rates and Tariffs.

Virginia Case No. PUR-2019-00050: Application of Virginia Electric and Power Company for Determination of the Fair Rate of Return on Common Equity Pursuant to § 56-585.1:1 of the Code of Virginia.

Indiana Docket No. 45159: Petition of Northern Indiana Public Service Company LLC Pursuant to Indiana Code §§ 8-1-2-42.7, 8-1-2-61 and Indiana Code §§ 1-2.5-6 for (1) Authority to Modify its Rates and Charges for Electric Utility Service Through a Phase In of Rates; (2) Approval of New Schedules of Rates and Charges, General Rules and Regulations, and Riders; (3) Approval of Revised Common and Electric Depreciation Rates Applicable to its Electric Plant in Service; (4) Approval of Necessary and Appropriate Accounting Relief; and (5) Approval of a New Service Structure for Industrial Rates.

Texas Docket No. 49421: Application of Centerpoint Energy Houston Electric, LLC for Authority to Change Rates.

Nevada Docket No. 18-11015: Re: Application of Nevada Power Company d/b/a NV Energy, Filed Under Advice No. 491, to Implement NV Greenenergy 2.0 Rider Schedule No. NGR 2.0 to Allow Eligible Commercial Bundled Service Customers to Voluntarily Contract with the Utility to Increase Their Use of Reliance on Renewable Energy at Current Market-Based Fixed Prices.

Nevada Docket No. 18-11016: Re: Application of Sierra Pacific Power Company d/b/a NV Energy, Filed Under Advice No. 614-E, to Implement NV Greenenergy 2.0 Rider Schedule No. NGR 2.0 to Allow Eligible Commercial Bundled Service Customers to Voluntarily Contract with the Utility to Increase Their Use of Reliance on Renewable Energy at Current Market-Based Fixed Prices.

Georgia Docket No. 42310: In Re: Georgia Power Company's 2019 Integrated Resource Plan and Application for Certification of Capacity From Plant Scherer Unit 3 and Plant Goat Rock Units 9-12 and Application for Decertification of Plant Hammond Units 1-4, Plant Mcintosh Unit 1, Plant Langdale Units 5-6, Plant Riverview Units 1-2, and Plant Estatoah Unit 1.

Wyoming Docket Nos. 20003-177-ET-18: In the Matter of the Application of Cheyenne Light, Fuel and Power Company D/B/A Black Hills Energy For Approval to Implement a Renewable Ready Service Tariff.

South Carolina Docket No. 2018-318-E: In the Matter of the Application of Duke Energy Progress, LLC For Adjustments in Electric Rate Schedules and Tariffs.

Montana Docket No. D2018.2.12: Application for Authority to Increase Retail Electric Utility Service Rates and for Approval of Electric Service Schedules and Rules and Allocated Cost of Service and Rate Design.

Louisiana Docket No. U-35019: In Re: Application of Entergy Louisiana, LLC for Authorization to Make Available Experimental Renewable Option and Rate Schedule ERO.

Arkansas Docket No. 18-037-TF: In the Matter of the Petition of Entergy Arkansas, Inc. For Its Solar Energy Purchase Option.

2018

South Carolina Docket No. 2017-370-E: Joint Application and Petition of South Carolina Electric & Gas Company and Dominion Energy, Inc., for Review and Approval of a Proposed Business Combination Between SCANA Corporation and Dominion Energy, Inc., as may be Required, and for a Prudency Determination Regarding the Abandonment of the V.C. Summer Units 2 & 3 Project and Associated Customer Benefits and Cost Recovery Plans.

Kansas Docket No. 18-KCPE-480-RTS: In the Matter of the Application of Kansas City Power & Light Company to Make Certain Changes in its Charges for Electric Service.

Virginia Case No. PUR-2017-00173: Petition of Wal-Mart Stores East, LP and Sam's East, Inc. for Permission to Aggregate or Combine Demands of Two or More Individual Nonresidential Retail Customers of Electric Energy Pursuant to § 56-577 A 4 of the Code of Virginia.

Virginia Case No. PUR-2017-00174: Petition of Wal-Mart Stores East, LP and Sam's East, Inc. for Permission to Aggregate or Combine Demands of Two or More Individual Nonresidential Retail Customers of Electric Energy Pursuant to § 56-577 A 4 of the Code of Virginia.

Oregon Docket No. UM 1953: In the Matter of Portland General Electric Company, Investigation into Proposed Green Tariff.

Virginia Case No. PUR-2017-00179: Application of Appalachian Power Company for Approval of an 100% Renewable Energy Rider Pursuant to § 56-577.A.5 of the Code of Virginia.

Missouri Docket No. ER-2018-0145: In the Matter of Kansas City Power & Light Company's Request for Authority to Implement a General Rate Increase for Electric Service.

Missouri Docket No. ER-2018-0146: In the Matter of KCP&L Greater Missouri Operations Company's Request for Authority to Implement a General Rate Increase for Electric Service.

Kansas Docket No. 18-WSEE-328-RTS: In the Matter of the Joint Application of Westar Energy, Inc. and Kansas Gas and Electric Company for Approval to Make Certain Changes in their Charges for Electric Service.

Oregon Docket No. UE 335: In the Matter of Portland General Electric Company, Request for a General Rate Revision.

North Dakota Case No. PU-17-398: In the Matter of the Application of Otter Tail Power Company for Authority to Increase Rates for Electric Utility Service in North Dakota.

Virginia Case No. PUR-2017-00179: Application of Appalachian Power Company for Approval of an 100 Percent Renewable Energy Rider Pursuant to § 56-577 A 5 of the Code of Virginia.

Missouri Case No. ET-2018-0063: In the Matter of the Application of Union Electric Company d/b/a Ameren Missouri for Approval of 2017 Green Tariff.

New Mexico Case No. 17-00255-UT: In the Matter of Southwestern Public Service Company's Application for Revision of its Retail Rates Under Advice Notice No. 272.

Virginia Case No. PUR-2017-00157: Application of Virginia Electric and Power Company for Approval of 100 Percent Renewable Energy Tariffs for Residential and Non-Residential Customers.

Kansas Docket No. 18-KCPE-095-MER: In the Matter of the Application of Great Plains Energy Incorporated, Kansas City Power & Light Company, and Westar Energy, Inc. for Approval of the Merger of Westar Energy, Inc. and Great Plains Energy Incorporated.

North Carolina Docket No. E-7, Sub 1146: In the Matter of the Application of Duke Energy Carolinas, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina.

Louisiana Docket No. U-34619: In Re: Application for Expedited Certification and Approval of the Acquisition of Certain Renewable Resources and the Construction of a Generation Tie Pursuant to the 1983 and/or/1994 General Orders.

Missouri Case No. EM-2018-0012: In the Matter of the Application of Great Plains Energy Incorporated for Approval of its Merger with Westar Energy, Inc.

2017

Arkansas Docket No. 17-038-U: In the Matter of the Application of Southwestern Electric Power Company for Approval to Acquire a Wind Generating Facility and to Construct a Dedicated Generation Tie Line.

Texas Docket No. 47461: Application of Southwestern Electric Power Company for Certificate of Convenience and Necessity Authorization and Related Relief for the Wind Catcher Energy Connection Project.

Oklahoma Cause No. PUD 201700267: Application of Public Service Company of Oklahoma for Approval of the Cost Recovery of the Wind Catcher Energy Connection Project; A Determination There is Need for the Project; Approval for Future Inclusion in Base Rates Cost Recovery of Prudent Costs Incurred by PSO for the Project; Approval of a Temporary Cost Recovery Rider; Approval of Certain Accounting Procedures Regarding Federal Production Tax Credits; Waiver of OAC 165:35-38-5(E); And Such Other Relief the Commission Deems PSO is Entitled.

Nevada Docket No. 17-06003: In the Matter of the Application of Nevada Power Company, d/b/a NV Energy, Filed Pursuant to NRS 704.110(3) and (4), Addressing Its Annual Revenue Requirement for General Rates Charged to All Classes of Customers.

North Carolina Docket No. E-2, Sub 1142: In the Matter of the Application of Duke Energy Progress, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina.

Oklahoma Cause No. PUD 201700151: Application of Public Service Company of Oklahoma, an Oklahoma Corporation, for an Adjustment in its Rates and Charges and the Electric Service Rules, Regulations and Conditions of Service for Electric Service in the State of Oklahoma.

Kentucky Case No. 2017-00179: Electronic Application of Kentucky Power Company for (1) a General Adjustment of its Rates for Electric Service; (2) an Order Approving its 2017

Environmental Compliance Plan; (3) an Order Approving its Tariffs and Riders; (4) an Order Approving Accounting Practices to Establish Regulatory Assets and Liabilities; and (5) an Order Granting All Other Requested Relief.

New York Case No. 17-E-0238: Proceeding on Motion of the Commission as to the Rates, Charges, Rules, and Regulations of Niagara Mohawk Power Corporation for Electric and Gas Service.

Virginia Case No. PUR-2017-00060: Application of Virginia Electric and Power Company for Approval of 100 Percent Renewable Energy Tariffs Pursuant to §§ 56-577 A 5 and 56-234 of the Code of Virginia.

New Jersey Docket No. ER17030308: In the Matter of the Petition of Atlantic City Electric Company for Approval of Amendments to its Tariff to Provide for an Increase in Rates and Charges for Electric Service Pursuant to N.J.S.A. 48:2-21 and N.J.S.A. 48:2-21.1, for Approval of a Grid Resiliency Initiative and Cost Recovery Related Thereto, and for Other Appropriate Relief.

Texas Docket No. 46831: Application of El Paso Electric Company to Change Rates.

Oregon Docket No. UE 319: In the Matter of Portland General Electric Company, Request for a General Rate Revision.

New Mexico Case No. 16-00276-UT: In the Matter of the Application of Public Service Company of New Mexico for Revision of its Retail Electric Rates Pursuant to Advice No. 533.

Minnesota Docket No. E015/GR-16-664: In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota.

Ohio Case No. 16-1852-EL-SSO: In the Matter of the Application of Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to §4928.143, Ohio Rev. Code, In the Form of an Electric Security Plan.

Texas Docket No. 46449: Application of Southwestern Electric Power Company for Authority to Change Rates.

Arkansas Docket No. 16-052-U: In the Matter of the Application of Oklahoma Gas and Electric Company for Approval of a General Change in Rates, Charges, and Tariffs.

Missouri Case No. EA-2016-0358: In the Matter of the Application of Grain Belt Express Clean Line LLC for a Certificate of Convenience and Necessity Authorizing it to Construct, Own, Operate, Control, Manage and Maintain a High Voltage, Direct Current Transmission Line and an Associated Converter Station Providing an Interconnection on the Maywood-Montgomery 345 kV Transmission Line.

Florida Docket No. 160186-Ei: In Re: Petition for Increase in Rates by Gulf Power Company.

2016
Missouri Case No. ER-2016-0179: In the Matter of Union Electric Company d/b/a Ameren Missouri Tariffs to Increase its Revenues for Electric Service.

Kansas Docket No. 16-KCPE-593-ACQ: In the Matter of the Joint Application of Great Plains Energy Incorporated, Kansas City Power & Light Company, and Westar Energy, Inc. for Approval of the Acquisition of Westar Energy, Inc. by Great Plains Energy Incorporated.

Missouri Case No. EA-2016-0208: In the Matter of the Application of Union Electric Company d/b/a Ameren Missouri for Permission and Approval and a Certificate of Public Convenience and Necessity Authorizing it to Offer a Pilot Distributed Solar Program and File Associated Tariff.

Utah Docket No. 16-035-T09: In the Matter of Rocky Mountain Power's Proposed Electric Service Schedule No. 34, Renewable Energy Tariff.

Pennsylvania Public Utility Commission Docket No. R-2016-2537359: Pennsylvania Public Utility Commission v. West Penn Power Company.

Pennsylvania Public Utility Commission Docket No. R-2016-2537352: Pennsylvania Public Utility Commission v. Pennsylvania Electric Company.

Pennsylvania Public Utility Commission Docket No. R-2016-2537355: Pennsylvania Public Utility Commission v. Pennsylvania Power Company.

Pennsylvania Public Utility Commission Docket No. R-2016-2537349: Pennsylvania Public Utility Commission v. Metropolitan Edison Company.

Michigan Case No. U-17990: In the Matter of the Application of Consumers Energy Company for Authority to Increase its Rates for the Generation and Distribution of Electricity and for Other Relief.

Florida Docket No. 160021-EI: In Re: Petition for Rate Increase by Florida Power & Light Company.

Minnesota Docket No. E-002/GR-15-816: In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota.

Colorado Public Utilities Commission Docket No. 16AL-0048E: Re: In the Matter of Advice Letter No. 1712-Electric Filed by Public Service Company of Colorado to Replace Colorado PUC No.7-Electric Tariff with Colorado PUC No. 8-Electric Tariff.

Colorado Public Utilities Commission Docket No. 16A-0055E: Re: In the Matter of the Application of Public Service Company of Colorado for Approval of its Solar*Connect Program.

Missouri Public Service Commission Case No. ER-2016-0023: In the Matter of the Empire District Electric Company of Joplin, Missouri for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Missouri Service Area of the Company.

Georgia Public Service Commission Docket No. 40161: In Re: Georgia Power Company's 2016 Integrated Resource Plan and Application for Decertification of Plant Mitchell Units 3, 4A and 4B, Plant Kraft Unit 1 CT, and Intercession City CT.

Oklahoma Corporation Commission Cause No. PUD 201500273: In the Matter of Oklahoma Gas and Electric Company for an Order of the Commission Authorizing Applicant to Modify its Rates, Charges, and Tariffs for Retail Electric Service in Oklahoma.

New Mexico Case No. 15-00261-UT: In the Matter of the Application of Public Service Company of New Mexico for Revision of its Retail Electric Rates Pursuant to Advice Notice No. 513.

2015

Indiana Utility Regulatory Commission Cause No. 44688: Petition of Northern Indiana Public Service Company for Authority to Modify its Rates and Charges for Electric Utility Service and for Approval of: (1) Changes to its Electric Service Tariff Including a New Schedule of Rates and

Charges and Changes to the General Rules and Regulations and Certain Riders; (2) Revised Depreciation Accrual Rates; (3) Inclusion in its Basic Rates and Charges of the Costs Associated with Certain Previously Approved Qualified Pollution Control Property, Clean Coal Technology, Clean Energy Projects and Federally Mandated Compliance Projects; and (4) Accounting Relief to Allow NIPSCO to Defer, as a Regulatory Asset or Liability, Certain Costs for Recovery in a Future Proceeding.

Public Utility Commission of Texas Docket No. 44941: Application of El Paso Electric Company to Change Rates.

Arizona Corporation Commission Docket No. E-04204A-15-0142: In the matter of the Application of UNS Electric, Inc. for the Establishment of Just and Reasonable Rates and Charges Designed to Realized a Reasonable Rate of Return on the Fair Value of the Properties of UNS Electric, Inc. Devoted to its Operations Throughout the State of Arizona, and for Related Approvals.

Rhode Island Public Utilities Commission Docket No. 4568: In Re: National Grid's Rate Design Plan.

Oklahoma Corporation Commission Cause No. PUD 201500208: Application of Public Service Company of Oklahoma, an Oklahoma Corporation, for an Adjustment in its Rates and Charges and the Electric Service Rules, Regulations and Conditions of Service for Electric Service in the State of Oklahoma.

Public Service Commission of Wisconsin Docket No. 4220-UR-121: Application of Northern States Power Company, A Wisconsin Corporation, for Authority to Adjust Electric and Natural Gas Rates.

Arkansas Public Service Commission Docket No. 15-015-U: In the Matter of the Application of Entergy Arkansas, Inc. for Approval of Changes in Rates for Retail Electric Service.

New York Public Service Commission Case No. 15-E-0283: Proceeding on Motion of the Commission as to the Rates, Charges, Rules, and Regulations of New York State Electric & Gas Corporation for Electric Service.

New York Public Service Commission Case No. 15-G-0284: Proceeding on Motion of the Commission as to the Rates, Charges, Rules, and Regulations of New York State Electric & Gas Corporation for Gas Service.

New York Public Service Commission Case No. 15-E-0285: Proceeding on Motion of the Commission as to the Rates, Charges, Rules, and Regulations of Rochester Gas & Electric Corporation for Electric Service.

New York Public Service Commission Case No. 15-G-0286: Proceeding on Motion of the Commission as to the Rates, Charges, Rules, and Regulations of Rochester Gas & Electric Corporation for Gas Service.

Public Utilities Commission of Ohio Case No. 14-1693-EL-RDR: In the Matter of the Application Seeking Approval of Ohio Power Company's Proposal to Enter Into an Affiliate Power Purchase Agreement for Inclusion in the Power Purchase Agreement Rider.

Public Service Commission of Wisconsin Docket No. 6690-UR-124: Application of Wisconsin Public Service Corporation for Authority to Adjust Electric and Natural Gas Rates.

Arkansas Public Service Commission Docket No. 15-034-U: In the Matter of an Interim Rate Schedule of Oklahoma Gas and Electric Company Imposing a Surcharge to Recover All Investments and Expenses Incurred Through Compliance with Legislative or Administrative Rules, Regulations, or Requirements Relating to the Public Health, Safety or the Environment Under the Federal Clean Air Act for Certain of its Existing Generation Facilities.

Kansas Corporation Commission Docket No. 15-WSEE-115-RTS: In the Matter of the Application of Westar Energy, Inc. and Kansas Gas and Electric Company to Make Certain Changes in their Charges for Electric Service.

Michigan Public Service Commission Case No. U-17767: In the Matter of the Application of DTE Electric Company for Authority to Increase its Rates, Amend its Rate Schedules and Rules Governing the Distribution and Supply of Electric Energy, and for Miscellaneous Accounting Authority.

Public Utility Commission of Texas Docket No. 43695: Application of Southwestern Public Service Company for Authority to Change Rates.

Kansas Corporation Commission Docket No. 15-KCPE-116-RTS: In the Matter of the Application of Kansas City Power & Light Company to Make Certain Changes in its Charges for Electric Service.

Michigan Case No. U-17735: In the Matter of the Application of the Consumers Energy Company for Authority to Increase its Rates for the Generation and Distribution of Electricity and for Other Relief.

Kentucky Public Service Commission Case No. 2014-00396: Application of Kentucky Power Company for a General Adjustment of its Rates for Electric Service; (2) an Order Approving its 2014 Environmental Compliance Plan; (3) an Order Approving its Tariffs and Riders; and (4) an Order Granting All Other Required Approvals and Relief.

Kentucky Public Service Commission Case No. 2014-00371: In the Matter of the Application of Kentucky Utilities Company for an Adjustment of its Electric Rates.

Kentucky Public Service Commission Case No. 2014-00372: In the Matter of the Application of Louisville Gas and Electric Company for an Adjustment of its Electric and Gas Rates.

2014
Ohio Public Utilities Commission Case No. 14-1297-EL-SSO: In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company and the Toledo Edison Company for Authority to Provide for a Standard Service Offer Pursuant to R.C. 4928.143 in the Form of an Electric Security Plan.

West Virginia Case No. 14-1152-E-42T: Appalachian Power Company and Wheeling Power Company, Both d/b/a American Electric Power, Joint Application for Rate Increases and Changes in Tariff Provisions.

Oklahoma Corporation Commission Cause No. PUD 201400229: In the Matter of the Application of Oklahoma Gas and Electric Company for Commission Authorization of a Plan to Comply with the Federal Clean Air Act and Cost Recovery; and for Approval of the Mustang Modernization Plan.

Missouri Public Service Commission Case No. ER-2014-0258: In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariff to Increase its Revenues for Electric Service.

Pennsylvania Public Utility Commission Docket No. R-2014-2428742: Pennsylvania Public Utility Commission v. West Penn Power Company.

Pennsylvania Public Utility Commission Docket No. R-2014-2428743: Pennsylvania Public Utility Commission v. Pennsylvania Electric Company.

Pennsylvania Public Utility Commission Docket No. R-2014-2428744: Pennsylvania Public Utility Commission v. Pennsylvania Power Company.

Pennsylvania Public Utility Commission Docket No. R-2014-2428745: Pennsylvania Public Utility Commission v. Metropolitan Edison Company.

Washington Utilities and Transportation Commission Docket No. UE-141368: In the Matter of the Petition of Puget Sound Energy to Update Methodologies Used to Allocate Electric Cost of Service and For Electric Rate Design Purposes.

Washington Utilities and Transportation Commission Docket No. UE-140762: 2014 Pacific Power & Light Company General Rate Case.

West Virginia Public Service Commission Case No. 14-0702-E-42T: Monongahela Power Company and the Potomac Edison Company Rule 42T Tariff Filing to Increase Rates and Charges.

Ohio Public Utilities Commission Case No. 14-841-EL-SSO: In the Matter of the Application of Duke Energy Ohio for Authority to Establish a Standard Service Offer Pursuant to Section 4928.143, Revised Code, in the Form of Case No. 14-841-EL-SSO an Electric Security Plan, Accounting Modifications and Tariffs for Generation Service.

Colorado Public Utilities Commission Docket No. 14AL-0660E: Re: In the Matter of the Advice Letter No. 1672-Electric Filed by Public Service Company of Colorado to Revise its Colorado PUC No. 7-Electric Tariff to Implement a General Rate Schedule Adjustment and Other Rate Changes Effective July 18, 2014.

Maryland Case No. 9355: In the Matter of the Application of Baltimore Gas and Electric Company for Authority to Increase Existing Rates and Charges for Electric and Gas Service.

Mississippi Public Service Commission Docket No. 2014-UN-132: In Re: Notice of Intent of Entergy Mississippi, Inc. to Modernize Rates to Support Economic Development, Power Procurement, and Continued Investment.

Nevada Public Utilities Commission Docket No. 14-05004: Application of Nevada Power Company d/b/a NV Energy for Authority to Increase its Annual Revenue Requirement for General Rates Charged to All Classes of Electric Customers and for Relief Properly Related Thereto.

Utah Public Service Commission Docket No. 14-035-T02: In the Matter of Rocky Mountain Power's Proposed Electric Service Schedule No. 32, Service From Renewable Energy Facilities.

Florida Public Service Commission Docket No. 140002-EG: In Re: Energy Conservation Cost Recovery Clause.

Public Service Commission of Wisconsin Docket No. 6690-UR-123: Application of Wisconsin Public Service Corporation for Authority to Adjust Electric and Natural Gas Rates.

Connecticut Docket No. 14-05-06: Application of the Connecticut Light and Power Company to Amend its Rate Schedules.

Virginia Corporation Commission Case No. PUE-2014-00026: Application of Appalachian Power Company for a 2014 Biennial Review for the Provision of Generation, Distribution and Transmission Services Pursuant to § 56-585.1 A of the Code of Virginia.

Virginia Corporation Commission Case No. PUE-2014-00033: Application of Virginia Electric and Power Company to Revise its Fuel Factor Pursuant to Va. Code § 56-249.6.

Arizona Corporation Commission Docket No. E-01345A-11-0224 (Four Corners Phase): In the Matter of Arizona Public Service Company for a Hearing to Determine the Fair Value of Utility Property of the Company for Ratemaking Purposes, to Fix and Just and Reasonable Rate of Return Thereon, to Approve Rate Schedules Designed to Develop Such Return.

Minnesota Public Utilities Commission Docket No. E-002/GR-13-868: In the Matter of the Application of Northern States Power Company, for Authority to Increase Rates for Electric Service in Minnesota.

Utah Public Service Commission Docket No. 13-035-184: In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations.

Missouri Public Service Commission Case No. EC-2014-0224: In the Matter of Noranda Aluminum, Inc.'s Request for Revisions to Union Electric Company d/b/a Ameren Missouri's Large Transmission Service Tariff to Decrease its Rate for Electric Service.

Oklahoma Corporation Commission Cause No. PUD 201300217: Application of Public Service Company of Oklahoma to be in Compliance with Order No. 591185 Issued in Cause No. PUD 201100106 Which Requires a Base Rate Case to be Filed by PSO and the Resulting Adjustment in its Rates and Charges and Terms and Conditions of Service for Electric Service in the State of Oklahoma.

Public Utilities Commission of Ohio Case No. 13-2386-EL-SSO: In the Matter of the Application of Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to §4928.143, Ohio Rev. Code, in the Form of an Electric Security Plan.

2013
Oklahoma Corporation Commission Cause No. PUD 201300201: Application of Public Service Company of Oklahoma for Commission Authorization of a Standby and Supplemental Service Rate Schedule.

Georgia Public Service Commission Docket No. 36989: Georgia Power's 2013 Rate Case.

Florida Public Service Commission Docket No. 130140-EI: Petition for Rate Increase by Gulf Power Company.

Public Utility Commission of Oregon Docket No. UE 267: In the Matter of PACIFICORP, dba PACIFIC POWER, Transition Adjustment, Five-Year Cost of Service Opt-Out.

Illinois Commerce Commission Docket No. 13-0387: Commonwealth Edison Company Tariff Filing to Present the Illinois Commerce Commission with an Opportunity to Consider Revenue Neutral Tariff Changes Related to Rate Design Authorized by Subsection 16-108.5 of the Public Utilities Act.

Iowa Utilities Board Docket No. RPU-2013-0004: In Re: MidAmerican Energy Company.

South Dakota Public Utilities Commission Docket No. EL12-061: In the Matter of the Application of Black Hills Power, Inc. for Authority to Increase its Electric Rates. (filed with confidential stipulation)

Kansas Corporation Commission Docket No. 13-WSEE-629-RTS: In the Matter of the Applications of Westar Energy, Inc. and Kansas Gas and Electric Company for Approval to Make Certain Changes in their Charges for Electric Service.

Public Utility Commission of Oregon Docket No. UE 263: In the Matter of PACIFICORP, dba PACIFIC POWER, Request for a General Rate Revision.

Arkansas Public Service Commission Docket No. 13-028-U: In the Matter of the Application of Entergy Arkansas, Inc. for Approval of Changes in Rates for Retail Electric Service.

Virginia State Corporation Commission Docket No. PUE-2013-00020: Application of Virginia Electric and Power Company for a 2013 Biennial Review of the Rates, Terms, and Conditions for the Provision of Generation, Distribution, and Transmission Services Pursuant to § 56-585.1 A of the Code of Virginia.

Florida Public Service Commission Docket No. 130040-EI: Petition for Rate Increase by Tampa Electric Company.

South Carolina Public Service Commission Docket No. 2013-59-E: Application of Duke Energy Carolinas, LLC, for Authority to Adjust and Increase Its Electric Rates and Charges.

Public Utility Commission of Oregon Docket No. UE 262: In the Matter of PORTLAND GENERAL ELECTRIC COMPANY, Request for a General Rate Revision.

New Jersey Board of Public Utilities Docket No. ER12111052: In the Matter of the Verified Petition of Jersey Central Power & Light Company For Review and Approval of Increases in and Other Adjustments to Its Rates and Charges For Electric Service, and For Approval of Other Proposed Tariff Revisions in Connection Therewith; and for Approval of an Accelerated Reliability Enhancement Program ("2012 Base Rate Filing")

North Carolina Utilities Commission Docket No. E-7, Sub 1026: In the Matter of the Application of Duke Energy Carolinas, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina.

Public Utility Commission of Oregon Docket No. UE 264: PACIFICORP, dba PACIFIC POWER, 2014 Transition Adjustment Mechanism.

Public Utilities Commission of California Docket No. 12-12-002: Application of Pacific Gas and Electric Company for 2013 Rate Design Window Proceeding.

Public Utilities Commission of Ohio Docket Nos. 12-426-EL-SSO, 12-427-EL-ATA, 12-428-EL-AAM, 12-429-EL-WVR, and 12-672-EL-RDR: In the Matter of the Application of the Dayton Power and Light Company Approval of its Market Offer.

Minnesota Public Utilities Commission Docket No. E-002/GR-12-961: In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in Minnesota.

North Carolina Utilities Commission Docket E-2, Sub 1023: In the Matter of Application of Progress Energy Carolinas, Inc. For Adjustment of Rates and Charges Applicable to Electric Service in North Carolina.

2012

Public Utility Commission of Texas Docket No. 40443: Application of Southwestern Electric Power Company for Authority to Change Rates and Reconcile Fuel Costs.

South Carolina Public Service Commission Docket No. 2012-218-E: Application of South Carolina Electric & Gas Company for Increases and Adjustments in Electric Rate Schedules and Tariffs and Request for Mid-Period Reduction in Base Rates for Fuel.

Kansas Corporation Commission Docket No. 12-KCPE-764-RTS: In the Matter of the Application of Kansas City Power & Light Company to Make Certain Changes in its Charges for Electric Service.

Kansas Corporation Commission Docket No. 12-GIMX-337-GIV: In the Matter of a General Investigation of Energy-Efficiency Policies for Utility Sponsored Energy Efficiency Programs.

Florida Public Service Commission Docket No. 120015-EI: In Re: Petition for Rate Increase by Florida Power & Light Company.

California Public Utilities Commission Docket No. A.11-10-002: Application of San Diego Gas & Electric Company (U 902 E) for Authority to Update Marginal Costs, Cost Allocation, and Electric Rate Design.

Utah Public Service Commission Docket No. 11-035-200: In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations.

Virginia State Corporation Commission Case No. PUE-2012-00051: Application of Appalachian Power Company to Revise its Fuel Factor Pursuant to § 56-249.6 of the Code of Virginia.

Public Utilities Commission of Ohio Case Nos. 11-346-EL-SSO, 11-348-EL-SSO, 11-349-EL-AAM, and 11-350-EL-AAM: In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to Section 4928.143, Revised Code, in the Form on an Electric Security Plan and In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Approval of Certain Accounting Authority.

New Jersey Board of Public Utilities Docket No. ER11080469: In the Matter of the Petition of Atlantic City Electric for Approval of Amendments to Its Tariff to Provide for an Increase in Rates and Charges for Electric Service Pursuant to N.J.S.A. 48:2-21 and N.J.S.A. 48:2-21.1 and For Other Appropriate Relief.

Public Utility Commission of Texas Docket No. 39896: Application of Entergy Texas, Inc. for Authority to Change Rates and Reconcile Fuel Costs.

Missouri Public Service Commission Case No. EO-2012-0009:In the Matter of KCP&L Greater Missouri Operations Notice of Intent to File an Application for Authority to Establish a Demand-Side Programs Investment Mechanism.

Colorado Public Utilities Commission Docket No. 11AL-947E: In the Matter of Advice Letter No. 1597-Electric Filed by Public Service Company of Colorado to Revise its Colorado PUC No. 7-Electric Tariff to Implement a General Rate Schedule Adjustment and Other Changes Effective December 23, 2011.

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Public Utility Commission of Texas Docket No. 38951: Application of Entergy Texas, Inc. for Approval of Competitive Generation Service tariff (Issues Severed from Docket No. 37744).

California Public Utilities Commission Docket No. A.11-06-007: Southern California Edison's General Rate Case, Phase 2.

2011

Arizona Corporation Commission Docket No. E-01345A-11-0224: In the Matter of Arizona Public Service Company for a Hearing to Determine the Fair Value of Utility Property of the Company for Ratemaking Purposes, to Fix and Just and Reasonable Rate of Return Thereon, to Approve Rate Schedules Designed to Develop Such Return.

Oklahoma Corporation Commission Cause No. PUD 201100087: In the Matter of the Application of Oklahoma Gas and Electric Company for an Order of the Commission Authorizing Applicant to Modify its Rates, Charges, and Tariffs for Retail Electric Service in Oklahoma.

South Carolina Public Service Commission Docket No. 2011-271-E: Application of Duke Energy Carolinas, LLC for Authority to Adjust and Increase its Electric Rates and Charges.

Pennsylvania Public Utility Commission Docket No. P-2011-2256365: Petition of PPL Electric Utilities Corporation for Approval to Implement Reconciliation Rider for Default Supply Service.

North Carolina Utilities Commission Docket No. E-7, Sub 989: In the Matter of Application of Duke Energy Carolinas, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina.

Florida Public Service Commission Docket No. 110138: In Re: Petition for Increase in Rates by Gulf Power Company.

Public Utilities Commission of Nevada Docket No. 11-06006: In the Matter of the Application of Nevada Power Company, filed pursuant to NRS 704.110(3) for authority to increase its annual revenue requirement for general rates charged to all classes of customers to recover the costs of constructing the Harry Allen Combined Cycle plant and other generating, transmission, and distribution plant additions, to reflect changes in the cost of capital, depreciation rates and cost of service, and for relief properly related thereto.

North Carolina Utilities Commission Docket Nos. E-2, Sub 998 and E-7, Sub 986: In the Matter of the Application of Duke Energy Corporation and Progress Energy, Inc., to Engage in a Business Combination Transaction and to Address Regulatory Conditions and Codes of Conduct.

Public Utilities Commission of Ohio Case Nos. 11-346-EL-SSO, 11-348-EL-SSO, 11-349-EL-AAM, and 11-350-EL-AAM: In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to Section 4928.143, Revised Code, in the Form on an Electric Security Plan and In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Approval of Certain Accounting Authority.

Virginia State Corporation Commission Case No. PUE-2011-00037: In the Matter of Appalachian Power Company for a 2011 Biennial Review of the Rates, Terms, and Conditions for the Provision of Generation, Distribution, and Transmission Services Pursuant to § 56-585.1 A of the Code of Virginia.

Illinois Commerce Commission Docket No. 11-0279 and 11-0282 (cons.): Ameren Illinois Company Proposed General Increase in Electric Delivery Service and Ameren Illinois Company Proposed General Increase in Gas Delivery Service.

Virginia State Corporation Commission Case No. PUE-2011-00045: Application of Virginia Electric and Power Company to Revise its Fuel Factor Pursuant to § 56-249.6 of the Code of Virginia.

Utah Public Service Commission Docket No. 10-035-124: In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations.

Maryland Public Utilities Commission Case No. 9249: In the Matter of the Application of Delmarva Power & Light for an Increase in its Retail Rates for the Distribution of Electric Energy.

Minnesota Public Utilities Commission Docket No. E002/GR-10-971: In the Matter of the Application of Northern States Power Company d/b/a Xcel Energy for Authority to Increase Rates for Electric Service in Minnesota.

Michigan Public Service Commission Case No. U-16472: In the Matter of the Detroit Edison Company for Authority to Increase its Rates, Amend its Rate Schedules and Rules Governing the Distribution and Supply of Electric Energy, and for Miscellaneous Accounting Authority.

2010

Public Utilities Commission of Ohio Docket No. 10-2586-EL-SSO: In the Matter of the Application of Duke Energy Ohio for Approval of a Market Rate Offer to Conduct a Competitive Bidding Process for Standard Service Offer Electric Generation Supply, Accounting Modifications, and Tariffs for Generation Service.

Colorado Public Utilities Commission Docket No. 10A-554EG: In the Matter of the Application of Public Service Company of Colorado for Approval of a Number of Strategic Issues Relating to its DSM Plan, Including Long-Term Electric Energy Savings Goals, and Incentives.

Public Service Commission of West Virginia Case No. 10-0699-E-42T: Appalachian Power Company and Wheeling Power Company Rule 42T Application to Increase Electric Rates.

Oklahoma Corporation Commission Cause No. PUD 201000050: Application of Public Service Company of Oklahoma, an Oklahoma Corporation, for an Adjustment in its Rates and Charges and Terms and Conditions of Service for Electric Service in the State of Oklahoma.

Georgia Public Service Commission Docket No. 31958-U: In Re: Georgia Power Company's 2010 Rate Case.

Washington Utilities and Transportation Commission Docket No. UE-100749: 2010 Pacific Power & Light Company General Rate Case.

Colorado Public Utilities Commission Docket No. 10M-254E: In the Matter of Commission Consideration of Black Hills Energy's Plan in Compliance with House Bill 10-1365, "Clean Air-Clean Jobs Act."

Colorado Public Utilities Commission Docket No. 10M-245E: In the Matter of Commission Consideration of Public Service Company of Colorado Plan in Compliance with House Bill 10-1365, "Clean Air-Clean Jobs Act."

Public Service Commission of Utah Docket No. 09-035-15 *Phase II*: In the Matter of the Application of Rocky Mountain Power for Approval of its Proposed Energy Cost Adjustment Mechanism.

Public Utility Commission of Oregon Docket No. UE 217: In the Matter of PACIFICORP, dba PACIFIC POWER Request for a General Rate Revision.

Mississippi Public Service Commission Docket No. 2010-AD-57: In Re: Proposal of the Mississippi Public Service Commission to Possibly Amend Certain Rules of Practice and Procedure.

Indiana Utility Regulatory Commission Cause No. 43374: Verified Petition of Duke Energy Indiana, Inc. Requesting the Indiana Utility Regulatory Commission to Approve an Alternative Regulatory Plan Pursuant to Ind. Code § 8-1-2.5-1, *ET SEQ*., for the Offering of Energy Efficiency Conservation, Demand Response, and Demand-Side Management Programs and Associated Rate Treatment Including Incentives Pursuant to a Revised Standard Contract Rider No. 66 in Accordance with Ind. Code §§ 8-1-2.5-1 *ET SEQ*. and 8-1-2-42 (a); Authority to Defer Program Costs Associated with its Energy Efficiency Portfolio of Programs; Authority to Implement New and Enhanced Energy Efficiency Programs, Including the Powershare® Program in its Energy Efficiency Portfolio of Programs; and Approval of a Modification of the Fuel Adjustment Clause Earnings and Expense Tests.

Public Utility Commission of Texas Docket No. 37744: Application of Entergy Texas, Inc. for Authority to Change Rates and to Reconcile Fuel Costs.

South Carolina Public Service Commission Docket No. 2009-489-E: Application of South Carolina Electric & Gas Company for Adjustments and Increases in Electric Rate Schedules and Tariffs.

Kentucky Public Service Commission Case No. 2009-00459: In the Matter of General Adjustments in Electric Rates of Kentucky Power Company.

Virginia State Corporation Commission Case No. PUE-2009-00125: For acquisition of natural gas facilities Pursuant to § 56-265.4:5 B of the Virginia Code.

Arkansas Public Service Commission Docket No. 10-010-U: In the Matter of a Notice of Inquiry Into Energy Efficiency.

Connecticut Department of Public Utility Control Docket No. 09-12-05: Application of the Connecticut Light and Power Company to Amend its Rate Schedules.

Arkansas Public Service Commission Docket No. 09-084-U: In the Matter of the Application of Entergy Arkansas, Inc. For Approval of Changes in Rates for Retail Electric Service.

Missouri Public Service Commission Docket No. ER-2010-0036: In the Matter of Union Electric Company d/b/a AmerenUE for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Company's Missouri Service Area.

Public Service Commission of Delaware Docket No. 09-414: In the Matter of the Application of Delmarva Power & Light Company for an Increase in Electric Base Rates and Miscellaneous Tariff Charges.

2009

Virginia State Corporation Commission Case No. PUE-2009-00030: In the Matter of Appalachian Power Company for a Statutory Review of the Rates, Terms, and Conditions for the Provision of Generation, Distribution, and Transmission Services Pursuant to § 56-585.1 A of the Code of Virginia.

Public Service Commission of Utah Docket No. 09-035-15 *Phase I*: In the Matter of the Application of Rocky Mountain Power for Approval of its Proposed Energy Cost Adjustment Mechanism.

Public Service Commission of Utah Docket No. 09-035-23: In the Matter of the Application of Rocky Mountain Power for Authority To Increase its Retail Electric Utility Service Rates in Utah and for Approval of Its Proposed Electric Service Schedules and Electric Service Regulations.

Colorado Public Utilities Commission Docket No. 09AL-299E: Re: The Tariff Sheets Filed by Public Service Company of Colorado with Advice Letter No. 1535 – Electric.

Arkansas Public Service Commission Docket No. 09-008-U: In the Matter of the Application of Southwestern Electric Power Company for Approval of a General Change in Rates and Tariffs.

Oklahoma Corporation Commission Docket No. PUD 200800398: In the Matter of the Application of Oklahoma Gas and Electric Company for an Order of the Commission Authorizing Applicant to Modify its Rates, Charges, and Tariffs for Retail Electric Service in Oklahoma.

Public Utilities Commission of Nevada Docket No. 08-12002: In the Matter of the Application by Nevada Power Company d/b/a NV Energy, filed pursuant to NRS §704.110(3) and NRS §704.110(4) for authority to increase its annual revenue requirement for general rates charged to all classes of customers, begin to recover the costs of acquiring the Bighorn Power Plant, constructing the Clark Peakers, Environmental Retrofits and other generating, transmission and distribution plant additions, to reflect changes in cost of service and for relief properly related thereto.

New Mexico Public Regulation Commission Case No. 08-00024-UT: In the Matter of a Rulemaking to Revise NMPRC Rule 17.7.2 NMAC to Implement the Efficient Use of Energy Act.

Indiana Utility Regulatory Commission Cause No. 43580: Investigation by the Indiana Utility Regulatory Commission, of Smart Grid Investments and Smart Grid Information Issues Contained in 111(d) of the Public Utility Regulatory Policies Act of 1978 (16 U.S.C. § 2621(d)), as Amended by the Energy Independence and Security Act of 2007.

Louisiana Public Service Commission Docket No. U-30192 *Phase II (February 2009)*: Ex Parte, Application of Entergy Louisiana, LLC for Approval to Repower Little Gypsy Unit 3 Electric Generating Facility and for Authority to Commence Construction and for Certain Cost Protection and Cost Recovery.

South Carolina Public Service Commission Docket No. 2008-251-E: In the Matter of Progress Energy Carolinas, Inc.'s Application For the Establishment of Procedures to Encourage Investment in Energy Efficient Technologies; Energy Conservation Programs; And Incentives and Cost Recovery for Such Programs.

2008

Colorado Public Utilities Commission Docket No. 08A-366EG: In the Matter of the Application of Public Service Company of Colorado for approval of its electric and natural gas demand-side management (DSM) plan for calendar years 2009 and 2010 and to change its electric and gas DSM cost adjustment rates effective January 1, 2009, and for related waivers and authorizations.

Public Service Commission of Utah Docket No. 07-035-93: In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations, Consisting of a General Rate Increase of Approximately $161.2 Million Per Year, and for Approval of a New Large Load Surcharge.

Indiana Utility Regulatory Commission Cause No. 43374: Petition of Duke Energy Indiana, Inc. Requesting the Indiana Utility Regulatory Commission Approve an Alternative Regulatory Plan for the Offering of Energy Efficiency, Conservation, Demand Response, and Demand-Side Management.

Public Utilities Commission of Nevada Docket No. 07-12001: In the Matter of the Application of Sierra Pacific Power Company for authority to increase its general rates charged to all classes of electric customers to reflect an increase in annual revenue requirement and for relief properly related thereto.

Louisiana Public Service Commission Docket No. U-30192 *Phase II*: Ex Parte, Application of Entergy Louisiana, LLC for Approval to Repower Little Gypsy Unit 3 Electric Generating Facility and for Authority to Commence Construction and for Certain Cost Protection and Cost Recovery.

Colorado Public Utilities Commission Docket No. 07A-420E: In the Matter of the Application of Public Service Company of Colorado For Authority to Implement and Enhanced Demand Side Management Cost Adjustment Mechanism to Include Current Cost Recovery and Incentives.

2007
Louisiana Public Service Commission Docket No. U-30192: Ex Parte, Application of Entergy Louisiana, LLC for Approval to Repower Little Gypsy Unit 3 Electric Generating Facility and for Authority to Commence Construction and for Certain Cost Protection and Cost Recovery.

Public Utility Commission of Oregon Docket No. UG 173: In the Matter of PUBLIC UTILITY COMMISSION OF OREGON Staff Request to Open an Investigation into the Earnings of Cascade Natural Gas.

2006
Public Utility Commission of Oregon Docket No. UE 180/UE 181/UE 184: In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Request for a General Rate Revision.

Public Utility Commission of Oregon Docket No. UE 179: In the Matter of PACIFICORP, dba PACIFIC POWER AND LIGHT COMPANY Request for a general rate increase in the company's Oregon annual revenues.

Public Utility Commission of Oregon Docket No. UM 1129 *Phase II*: Investigation Related to Electric Utility Purchases From Qualifying Facilities.

2005
Public Utility Commission of Oregon Docket No. UM 1129 *Phase I Compliance*: Investigation Related to Electric Utility Purchases From Qualifying Facilities.

Public Utility Commission of Oregon Docket No. UX 29: In the Matter of QWEST CORPORATION Petition to Exempt from Regulation Qwest's Switched Business Services.

2004
Public Utility Commission of Oregon Docket No. UM 1129 *Phase I*: Investigation Related to Electric Utility Purchases From Qualifying Facilities.

TESTIMONY BEFORE LEGISLATIVE BODIES
2020
Regarding Missouri Senate Joint Resolution 34: Written testimony submitted to the Missouri Senate Transportation, Infrastructure and Public Safety Committee, January 30, 2020.

2019
Regarding North Carolina Senate Bill 559: Written testimony submitted to the North Carolina Committee on Agriculture/Environment/Natural Resources, April 17, 2019.

Regarding Missouri Senate Joint Resolution 25: Written testimony submitted to the Missouri Senate Committee on Judiciary, March 28, 2019.

Regarding South Carolina House Bill 3659: Written testimony submitted to the South Carolina Senate Committee on Judiciary, March 14, 2019.

Regarding Kansas Senate Bill 69: Written testimony submitted to the Kansas Committee on Utilities, February 19, 2019.

2018
Regarding Missouri Senate Bill 564: Testimony before the Missouri Senate Committee on Commerce, Consumer Protection, Energy and the Environment, January 10, 2018.

2017
Regarding Missouri Senate Bill 190: Testimony before the Missouri Senate Committee on Commerce, Consumer Protection, Energy and the Environment, January 25, 2017.

2016
Regarding Missouri House Bill 1726: Testimony before the Missouri House Energy and Environment Committee, April 26, 2016.

2014
Regarding Kansas House Bill 2460: Testimony Before the Kansas House Standing Committee on Utilities and Telecommunications, February 12, 2014.

2012
Regarding Missouri House Bill 1488: Testimony Before the Missouri House Committee on Utilities, February 7, 2012.

2011
Regarding Missouri Senate Bills 50, 321, 359, and 406: Testimony Before the Missouri Senate Veterans' Affairs, Emerging Issues, Pensions, and Urban Affairs Committee, March 9, 2011.

AFFIDAVITS
2015
Supreme Court of Illinois, Docket No. 118129, Commonwealth Edison Company et al., respondents, v. Illinois Commerce Commission et al. (Illinois Competitive Energy Association et al., petitioners). Leave to appeal, Appellate Court, First District.

2011
Colorado Public Utilities Commission Docket No. 11M-951E: In the Matter of the Petition of Public Service Company of Colorado Pursuant to C.R.S. § 40-6-111(1)(d) for Interim Rate Relief Effective on or before January 21, 2012.

ENERGY INDUSTRY PUBLICATIONS AND PRESENTATIONS
Panelist, Renewable Energy Options for Large Utility Customers, NARUC Center for Partnership & Innovation Webinar Series, January 16, 2020.

Panelist, Pathways to Integrating Customer Clean Energy Demand in Utility Planning, REBA: Market Innovation webinar, January 13, 2020.

Panelist, Should Full Electrification of Energy Systems be Our Goal? If it's No Longer Business as Usual, What Does That Mean for Consumers?, National Association of State Utility Consumer Advocates 2019 Annual Meeting, San Antonio, Texas, November 18, 2019.

Panelist, Fleet Electrification, Federal Utility Partnership Working Group Seminar, Washington, DC, November 8, 2019.

Panelist, Tackling the Challenges of Extreme Weather, Edison Electric Institute Fall National Key Accounts Workshop, Las Vegas, Nevada, October 8, 2019.

Panelist, Fleet Electrification: Tackling the Challenges and Seizing the Opportunities for Electric Trucks, Powering the People 2019, Washington, D.C., September 24, 2019.

Panelist, From the Consumer Perspective, Mid-American Regulatory Conference 2019 Annual Meeting, Des Moines, Iowa, August 13, 2019.

Panelist, Redefining Resiliency: Emerging Technologies Benefiting Customers and the Grid, EPRI 2019 Summer Seminar, Chicago, Illinois, August 12, 2019.

Panelist, Energy Policies for Economic Growth, 2019 Energy Policy Summit, NCSL Legislative Summit, Nashville, Tennessee, August 5, 2019.

Panelist, Gateway to Energy Empowerment for Customers, Illumination Energy Summit, Columbus, Ohio, May 15, 2019.

Panelist, Advancing Clean Energy Solutions Through Stakeholder Collaborations, 2019 State Energy Conference of North Carolina, Raleigh, North Carolina, May 1, 2019.

Panelist, Fleet Electrification: Getting Ready for the Transition, Edison Electric Institute Spring National Key Accounts Workshop, Seattle, Washington, April 8, 2019.

Panelist, Where the Fleet Meets the Pavement, Which Way to Electrification of the U.S. Transportation System?, Washington, D.C., April 4, 2019.

Panelist, Improving Renewable Energy Offerings: What Have We Learned?, Advanced Energy Economy Webinar, March 26, 2019.

Speaker, National Governors Association Southeast Regional Transportation Electrification Workshop, Nashville, Tennessee, March 11, 2019.

Speaker, Walmart Spotlight: A Day in the Life of a National Energy Manager, Touchstone Energy Cooperatives Net Conference 2019, San Diego, California, February 12, 2019.

Panelist, National Accounts: The Struggle is Real, American Public Power Association Customer Connections Conference, Orlando, Florida, November 6, 2018.

Panelist, Getting in Front of Customers Getting Behind the Meter Solutions, American Public Power Association Customer Connections Conference, Orlando, Florida, November 6, 2018.

Panelist, Sustainable Fleets: The Road Ahead for Electrifying Fleet Operations, EEI National Key Accounts 2018 Fall Workshop, San Antonio, Texas, October 23, 2018.

Panelist, Meeting Corporate Clean Energy Requirements in Virginia, Renewable Energy Buyers Alliance Summit, Oakland, California, October 15, 2018.

Panelist, What Are the Anticipated Impacts on Pricing and Reliability in the Changing Markets?, Southwest Energy Conference, Phoenix, Arizona, September 21, 2018.

Speaker, Walmart's Project Gigaton – Driving Renewable Energy Sourcing in the Supply Chain, Smart Energy Decisions Webcast Series, July 11, 2018.

Panelist, Customizing Energy Solutions, Edison Electric Institute Annual Convention, San Diego, California, June 7, 2018.

Powering Ohio Report Release, Columbus, Ohio, May 29, 2018.

Panelist, The Past, Present, and Future of Renewable Energy: What Role Will PURPA, Mandates, and Collaboration Play as Renewables Become a Larger Part of Our Energy Mix?, 36th National Regulatory Conference, Williamsburg, Virginia, May 17, 2018.

Panelist, Sustainability Milestone Deep Dive Session, Walmart Global Sustainability Leaders Summit, Bentonville, Arkansas, April 18, 2018.

Panelist, The Customer's Voice, Tennessee Valley Authority Distribution Marketplace Forum, Murfreesboro, Tennessee, April 3, 2018.

Panelist, Getting to Yes with Large Customers to Meet Sustainability Goals, The Edison Foundation Institute for Electric Innovation Powering the People, March 7, 2018.

Panelist, The Corporate Quest for Renewables, 2018 NARUC Winter Policy Summit, Washington, D.C., February 13, 2018.

Panelist, Solar and Renewables, Touchstone Energy Cooperatives NET Conference 2018, St. Petersburg, Florida, February 6, 2018.

Panelist, Missouri Public Service Commission November 20, 2017 Workshop in File No. EW-2017-0245.

Panelist, Energy and Climate Change, 2017-18 Arkansas Law Review Symposium: Environmental Sustainability and Private Governance, Fayetteville, Arkansas, October 27, 2017.

Panelist, Customer – Electric Company – Regulator Panel, Edison Electric Institute Fall National Key Accounts Workshop, National Harbor, Maryland, October 12, 2017.

Panelist, What Do C&I Buyers Want, Solar Power International, Las Vegas, Nevada, September 12, 2017.

Panelist, Partnerships for a Sustainable Future, American Public Power Association National Conference, Orlando, Florida, June 20, 2017.

Panelist, Corporate Renewable Energy Buyers in the Southeast, SEARUC 2017, Greensboro, Georgia, June 12, 2017.

Panelist, Transitioning Away from Traditional Utilities, Utah Association of Energy Users Annual Conference, Salt Lake City, Utah, May 18, 2017.

Panelist, Regulatory Approaches for Integrating and Facilitating DERs, New Mexico State University Center for Public Utilities Advisory Council Current Issues 2017, Santa Fe, New Mexico, April 25, 2017.

Presenter, Advancing Renewables in the Midwest, Columbia, Missouri, April 24, 2017.

Panelist, Leveraging New Energy Technologies to Improve Service and Reliability, Edison Electric Institute Spring National Key Accounts Workshop, Phoenix, Arizona, April 11, 2017.

Panelist, Private Sector Demand for Renewable Power, Vanderbilt Law School, Nashville, Tennessee, April 4, 2017.

Panelist, Expanding Solar Market Opportunities, 2017 Solar Power Colorado, Denver, Colorado, March 15, 2017.

Panelist, Renewables: Are Business Models Keeping Up?, Touchstone Energy Cooperatives NET Conference 2017, San Diego, California, January 30, 2017.

Panelist, The Business Case for Clean Energy, Minnesota Conservative Energy Forum, St. Paul, Minnesota, October 26, 2016.

Panelist, M-RETS Stakeholder Summit, Minneapolis, Minnesota, October 5, 2016.

Panelist, 40th Governor's Conference on Energy & the Environment, Kentucky Energy and Environment Cabinet, Lexington, Kentucky, September 21, 2016.

Panelist, Trends in Customer Expectations, Wisconsin Public Utility Institute, Madison, Wisconsin, September 6, 2016.

Panelist, The Governor's Utah Energy Development Summit 2015, May 21, 2015.

Mock Trial Expert Witness, The Energy Bar Association State Commission Practice and Regulation Committee and Young Lawyers Committee and Environment, Energy and Natural Resources Section of the D.C. Bar, Mastering Your First (or Next) State Public Utility Commission Hearing, February 13, 2014.

Panelist, Customer Panel, Virginia State Bar 29th National Regulatory Conference, Williamsburg, Virginia, May 19, 2011.

Chriss, S. (2006). "Regulatory Incentives and Natural Gas Purchasing – Lessons from the Oregon Natural Gas Procurement Study." Presented at the 19th Annual Western Conference, Center for Research in Regulated Industries Advanced Workshop in Regulation and Competition, Monterey, California, June 29, 2006.

Chriss, S. (2005). "Public Utility Commission of Oregon Natural Gas Procurement Study." Public Utility Commission of Oregon, Salem, OR. Report published in June, 2005. Presented to the Public Utility Commission of Oregon at a special public meeting on August 1, 2005.

Chriss, S. and M. Radler (2003). "Report from Houston: Conference on Energy Deregulation and Restructuring." USAEE Dialogue, Vol. 11, No. 1, March, 2003.

Chriss, S., M. Dwyer, and B. Pulliam (2002). "Impacts of Lifting the Ban on ANS Exports on West Coast Crude Oil Prices: A Reconsideration of the Evidence." Presented at the 22nd USAEE/IAEE North American Conference, Vancouver, BC, Canada, October 6-8, 2002.
Contributed to chapter on power marketing: "Power System Operations and Electricity Markets," Fred I. Denny and David E. Dismukes, authors. Published by CRC Press, June 2002.

Contributed to "Moving to the Front Lines: The Economic Impact of the Independent Power Plant Development in Louisiana," David E. Dismukes, author. Published by the Louisiana State University Center for Energy Studies, October 2001.

Dismukes, D.E., D.V. Mesyanzhinov, E.A. Downer, S. Chriss, and J.M. Burke (2001). "Alaska Natural Gas In-State Demand Study." Anchorage: Alaska Department of Natural Resources.

COMMISSIONER CLODFELTER: All right. Now, is anyone going to tell me my list was even more deficient than I suspected?

(No response.)

COMMISSIONER CLODFELTER: Okay, then. Mr. Page, thank you for your indulgence.

MR. PAGE: You're welcome, Commissioner Clodfelter, and thank you for the very efficient use of everybody's time.

COMMISSIONER CLODFELTER: Well, I hope you'll make equally efficient use with it.

MR. PAGE: I certainly intend to.

COMMISSIONER CLODFELTER: Okay. The case is with you, Mr. Page, for the Carolina Utility Customers Association.

MR. PAGE: Thank you, sir. Mr. O'Donnell, are you with us?

MR. O'DONNELL: Yes, I am here.

MR. PAGE: There you are. Great. Mr. O'Donnell, this actually marks your third appearance in this case, does it not? The previous two there had come during the consolidated phase?

COMMISSIONER CLODFELTER: Mr. Page, hold on second. Let's get Mr. O'Donnell sworn, okay?

MR. PAGE: That would be good.

Whereupon,

KEVIN W. O'DONNELL,

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

COMMISSIONER CLODFELTER: Okay.
Mr. Page, back on to his third appearance.

MR. PAGE: All right. Thank you,
Commissioner Clodfelter.

DIRECT EXAMINATION BY MR. PAGE:

Q. Was I correct in the earlier statement, Mr. O'Donnell, that you previously had testified on the portions of your testimony that encompass the cost of service issues and the grid modernization or GIP issues?

A. Yes, that's correct.

Q. And the purpose of your appearance today is to present the other areas of your prefiled testimony which encompass the issues involving coal ash and cost of service rate design; is that correct?

A. Yes, that is.

Q. And your testimony in this case, which was filed on or about April 13th of this year, consists, does it not, of 120 pages of written question and answer narrative together with an Appendix A and 10 exhibits entitled KWO-1 through KWO-10?

A. That's correct.

Q. Are there any additions, or corrections, or modifications that need to be made at this time either to your prefiled testimony, or the appendix, or any of the exhibits?

A. No.

Q. If I were to ask you the same questions today that appear in your prefiled testimony, would your answers today be the same?

A. Yes, they would.

MR. PAGE: Commissioner Clodfelter, we request that Mr. O'Donnell's prefiled testimony be copied into the record at this time and his appendix and exhibits marked as they were identified when prefiled.

COMMISSIONER CLODFELTER: Hearing no objection -- any objection?

(No response.)

COMMISSIONER CLODFELTER: If not, it will be so ordered.

(KWO-1 through KWO-10 and Appendix A were identified as they were marked when prefiled.)

(Whereupon, the prefiled direct testimony and Appendix A of Kevin W. O'Donnell was copied into the record as if given orally from the stand.)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS FOR THE RECORD.

A. My name is Kevin W. O'Donnell. I am President of Nova Energy Consultants, Inc. My business address is 1350 SE Maynard Rd., Suite 101, Cary, North Carolina 27511.

Q. ON WHOSE BEHALF ARE YOU PRESENTING TESTIMONY IN THIS PROCEEDING?

A. I am testifying on behalf of the Carolina Utility Customers Association (CUCA). A number of CUCA members take retail electric service from the applicant, Duke Energy Progress (DEP, Duke, or Company), and the outcome of this proceeding will have a direct bearing on these CUCA members.

Q. WERE YOUR TESTIMONY AND EXHIBITS PREPARED BY YOU OR UNDER YOUR DIRECT SUPERVISION AND CONTROL?

A. Yes, they were.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND RELEVANT EMPLOYMENT EXPERIENCE.

A. I have a Bachelor of Science in Civil Engineering from North Carolina State University and a Master of Business Administration from the Florida State University. I earned the designation of Chartered Financial Analyst ("CFA") in 1988.

I have worked in utility regulation since September 1984, when I joined the Public Staff of the North Carolina Utilities Commission ("NCUC"). I left the NCUC Public Staff in 1991 and have worked continuously since then in utility consulting: first with Booth & Associates, Inc. as a financial analyst and then as

Director of Retail Rates for the North Carolina Electric Membership Corporation from 1994 to 1995, and since then as principal for my own consulting firm.

I have been admitted as an expert witness on rate of return, cost of capital, capital structure, cost of service, rate design, and other regulatory issues in general rate cases, fuel cost proceedings, and other proceedings before the following regulatory bodies: the North Carolina Utilities Commission; the South Carolina Public Service Commission; the Wisconsin Public Service Commission; the Maryland Public Service Commission; the Virginia State Corporation Commission; the Minnesota Public Service Commission; the New Jersey Board of Public Utilities; the Colorado Public Utilities Commission; the District of Columbia Public Service Commission; the Indiana Utility Regulatory Commission; and the Florida Public Service Commission.

In 1996, I testified before the U.S. House of Representatives' Committee on Commerce and Subcommittee on Energy and Power, concerning competition within the electric utility industry. Additional details regarding my education and work experience are set forth in **Appendix A** of this testimony.

II. PURPOSE OF TESTIMONY

Q. PLEASE DESCRIBE THE SCOPE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony in this proceeding is to present my findings and recommendations to the Commission as to the following issues:

- the trend in DEP industrial rates in North Carolina and the associated impact on the state's economy;
- DEP's proposed grid investment plan;
- the appropriate amount of coal ash expense to be included in DEP's rates and the manner in which these costs should be allocated;
- a review of the DEP real-time pricing (RTP) rates; and
- the proper return on equity (ROE) and capital structure upon which DEP rates should be based; and
- the cost allocation of DEP's generating fleet.

III. SUMMARY/RECOMMENDATIONS

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS IN THIS CASE.

A. My findings are as follows:

- DEP's manufacturing rates are rising faster than the southeastern and national averages and, given the stated rate increases on the horizon, Duke will be above the national average, thereby costing North Carolina its competitive edge in areas served by the Company;
- DEP's proposed grid expenditures are too expensive and lack customer support;
- Many of the DEP's proposed grid projects lack basic evidence, such as cost benefit analyses (CBAs), showing the projects are cost beneficial and, therefore, should be disallowed;
- The Commission should only allow recovery of grid update projects in situations where DEP does not produce reliability improvements as defined by a set reliability standards such as SAIDI and SAIFI;
- The Commission should disallow the incremental costs associated with Coal Ash Management Act (CAMA) versus the federal Coal Combustion Residual (CCR) rule;
- DEP should recover its coal ash costs in a manner consistent with the allocation of fuel in its most recent fuel case;
- DEP's hourly pricing rates should be capped at the lower of DEP's costs or the market cost; and
- DEP's return on equity (ROE) should be set at 8.75% with a capital structure of 50% common equity and 50% long-term debt;
- The overall rate of return DEP should be allowed in this case is 6.46% and
- DEP's fixed generation costs should be allocated on a peak basis so as to be consistent with the manner in which the generation was built.

IV. RATE HIKE IMPACTS TO MANUFACTURERS

Q. WHAT IS THE TOTAL RATE HIKE REQUESTED BY DUKE ENERGY PROGRESS IN THIS RATE CASE?

A. According to Revised Pirro Exhibit No. 2 (Revised), the Company is seeking a total increase of $601.4 million that amounts to an overall increase of 18.6%.[1] However, this stated increase does not tell the entire story as the Company is also seeking to return to customers consumer money associated with the return of excess deferred income taxes (EDIT). As a result of the return of the EDIT, as well as the addition of the REPS and other clauses, the net increase is $480 million which equates to a net 12.6% overall increase.

Q. PLEASE EXPLAIN EXCESS DEFERRED INCOME TAXES (EDIT).

A. Excess deferred income taxes (EDIT) are taxes that consumers have paid to the utility in prior years that were planned to be paid by the utility in future years. Excess deferred taxes are, essentially, a product of the tax difference between accelerated depreciation and straight-line depreciation. In ratemaking, taxes are calculated using straight-line depreciation. However, in reality, the utility uses accelerated depreciation to calculate its taxes and, therefore, pays lower taxes than is the case with straight-line depreciation used for ratemaking purposes. As an asset ages, the taxes that the Company collected but did not pay to the governments are eventually paid so that the net result, over time, is the consumer pays the tax owed by the utility.

When the federal government reduced taxes from 35% to 21% in 2017, EDITs were created on Duke's books. As a result, in the current case, the EDIT funds need to be returned to their rightful owners – the North Carolina retail consumers of DEP.

[1] Pirro Exhibit No. 2, Pg. 2

Q. HOW IS THE FLOWBACK OF EDIT TO CONSUMERS AFFECTING THIS RATE CASE?

A. The rate increases sought by DEP in this rate case are significantly lower when the return of customer money, as represented by the EDIT, is considered. **Table 1** below shows the impact the EDIT has on the Duke requested rate hikes in this case.

Table 1: EDIT Impact on Requested DEP Rate Increases

Rate Class	Rate Hike Pre-EDIT and Riders [2]	Rate Hike Post-EDIT and Riders [3]
Residential	21.2%	14.6%
Small General Service	21.1%	14.1%
Medium Gen. Service	14.8%	9.9%
Large General Service	15.2%	9.9%
Overall	**18.6%**	**12.6%**

Q. PLEASE EXPLAIN THE IMPORTANCE OF ENERGY COSTS TO LARGE MANUFACTURING OPERATIONS.

A. Manufacturers are in a constant battle to compete. The competition is international, domestic, and amongst sister plants of the same manufacturer. If the cost to manufacture a particular product is less expensive in another state or country, the manufacturer has a duty to its customers and stockholders to move the manufacturing to the area of least cost. Sometimes the movements result in permanent plant shutdowns and mass layoffs. Other times, the movements result in line reductions such that the current plant temporarily ceases operation. There

[2] Id, Pg. 1-2

[3] Id

are several risks associated with unnecessarily high electric costs for manufacturers. These include temporary or permanent plant closures and lost expansion opportunities which could have resulted in job growth, load growth and other ancillary economic benefits. The current COVID-19 pandemic has exposed weaknesses in US manufacturing and supply chains that will likely be corrected in the near future. NC stands to benefit from this "*re-homing*" of manufacturing due to our large pharmaceutical presence in the RTP area. However, if NC's electric rates continue to rise, the State will miss out on the coming wave of industrial expansion and "*re-homing*" opportunities.

An example of a temporary shutdown is a NC plant that produces an identical product as, for example, a sister plant in Georgia. Manufacturers planning their daily production schedules can look at NC prices on a day ahead hourly basis and compare those prices to the Georgia hourly prices. If RTP prices are too high in NC, these plants don't operate. Instead, the manufacturer will allocate the related production to its Georgia plant.

In many circumstances, the NC hourly electric prices are higher than the Georgia prices and the NC plant does not operate a certain line on those days. In such a case, the NC utility loses a potential sale, but the loss is not reported in the press such as the reporting of a permanent plant closing. However, over time, the daily losses of load add up and jobs are eventually lost.

Q. ARE YOU SAYING THAT ELECTRIC COSTS ARE THE ONLY REASON MANUFACTURERS CHOOSE TO LOCATE/OPERATE IN A PARTICULAR STATE?

A. No. Manufacturers locate and operate in certain areas for a myriad of different reasons. The cost of electricity is one concern for manufacturers, but that concern is magnified when the state being examined is out-of-line relative to competing states. Energy intensive industries such as steel, air products, auto manufacturers, and paper companies are particularly sensitive to cost imbalances in the electric industry.

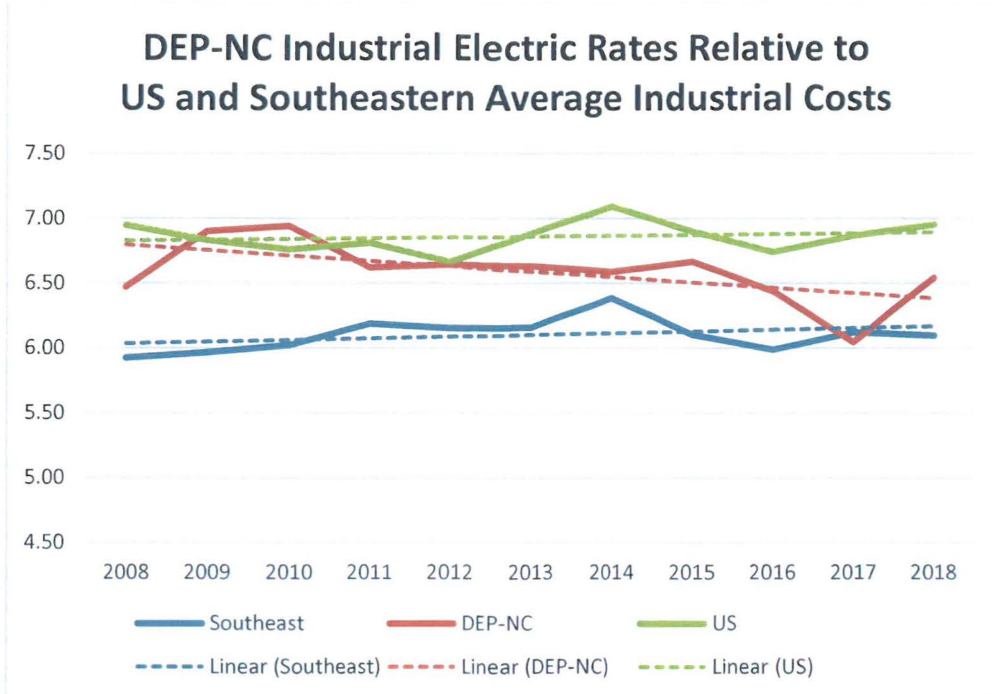
Q. ARE THERE ENERGY MANAGEMENT OPPORTUNITIES THAT EXIST IN DEREGULATED STATES THAT DO NOT EXIST IN REGULATED STATES?

A. Yes. Manufacturers in deregulated states can often hedge their power costs, particularly those tied to natural gas as the fuel input, with forward and futures contracts that offsets risk of price increases. In a fully regulated state, such as North Carolina, such risk mitigation measures are not fully available since there is not a liquid market to offset the combination of nuclear, coal, and natural gas generation such as the portfolio of DEP. As a result, manufacturers that are risk-averse have an extra incentive to locate in a deregulated state as opposed to here in North Carolina.

Q. HOW HAVE THE DEP NORTH CAROLINA AVERAGE INDUSTRIAL COSTS COMPARED TO INDUSTRIAL COSTS IN OTHER SOUTHEASTERN STATES?

A. **Chart 1** below shows DEP North Carolina average industrial costs relative to average industrial costs in South Carolina, Alabama, and Georgia. DEP's average industrial costs are above other southeastern states and, with coal ash expenses and grid transition costs on the horizon, electric costs in the DEP territory could very well be above, perhaps well above, the national average.

Chart 1: DEP-NC Electric Ind. Costs in Comparison to the National Average



Source*: Raw data obtained from the US Energy Information Administration*

The jump in the DEP costs from 2017 to 2018 is an ominous sign as the current rate case and all the anticipated future DEP rate cases may, sadly, bring the DEP costs well above the national average.

Q. WHY DO YOU BELIEVE THE DEP COST MAY SOON RISE ABOVE THE NATIONAL AVERAGE?

A. Duke's executives have a fiduciary duty to maximize earnings for their stockholders. No one can begrudge the executives for their efforts. However, in my view, their plans to push grid modifications while at the same time recover coal ash costs and coal-to-gas conversions is a trifecta of rate hikes that will cause significant pain to manufacturers at a time when costs throughout the country are moderating due to the proliferation of new natural gas generation and the incredibly low cost of natural gas.

Duke executives' goals to increase rates to drive earnings is also short-sighted in that the apparent belief amongst these executives is that customers will not react to price hikes through a decrease in demand for the products. The constant request for higher and higher rates will, eventually, wear out energy-intensive industry that will choose other locations with which to locate their facilities. With a decreasing base of customers, the rate increases sought by Duke will be spread over fewer customers. As large customers leave Duke's system, not only does this reduce the customer base, it increases the stranded costs which must be born by the remaining customers which, in turn, creates more rate increases. Some have characterized this cycle as a utility death spiral.

Q. WHY SHOULD THIS COMMISSION BE CONCERNED ABOUT DEP'S NORTH CAROLINA ELECTRIC COSTS RELATIVE TO THE NATIONAL AVERAGE?

A. Historically, states in the southeastern United States have held a competitive advantage in electric costs over other states across the country. The above chart shows that costs for DEP North Carolina were trending downward relative to national costs but, in 2017 and 2018, began to reverse that rate separation and close the gap with the national average. Such a situation does not bode well for the long-term prognosis of the state's manufacturing industry, which depends on reasonably and competitively priced electric power. Given Duke management's very public decision to drive earnings through massive grid investments, the North Carolina Utilities Commission is faced with a dilemma of allowing utility earnings to grow at the expense of the state's manufacturing industry – an industry that has long been vital to North Carolina's overall competitiveness.

Q. PLEASE EXPLAIN THE IMPORTANCE OF MANUFACTURING IN NORTH CAROLINA.

A. According to facts from the National Association of Manufacturing (NAM), manufacturing in North Carolina is a huge component of the state's economy.

Below are facts from the National Association of Manufacturers (NAM) showing the critical nature of the manufacturing industry in North Carolina:

- Manufacturing was responsible for $103.59 billion of the State's economic output in 2018; [4]
- Manufacturing accounts for 18.31% of the total of the State's output; [5]
- 474,000 North Carolinians work in manufacturing, thereby representing 10.56% of the total workforce of the state; [6]
- Average wages paid to manufacturing employees in NC was $70,702.[7]

Let me be clear – Duke's decision to implement massive rate hikes in the coming years to pay for coal ash and grid investments is a very real and present danger to manufacturing in our state. These rate hikes are very clear warning signs to today's manufacturers and should also be an unmistaken sign of a problem for our state leaders. Duke's plans for massive spending is putting jobs and the State's budget at risk. Duke must control its costs and reign in spending. If it does not, Duke will put this Commission in a very difficult bind of approving massive rate hikes to pay for the utility's spending habits or risking losing thousands of manufacturing jobs in the state, and also putting a massive hole in the state budget due to lost tax revenues.

Q. WHY IS DEP LOSING ITS ENERGY COST ADVANTAGE RELATIVE TO THE NATIONAL AVERAGE?

A. North Carolina operates a monopoly utility system in which customers have no choice but to buy power supplies from the utility that owns the franchise rights to

4 https://www.nam.org/state-manufacturing-data/2019-north-carolina-manufacturing-facts/

5 id

6 id

7 id

serve them. As a result, the real customers of the electric utilities that operate in North Carolina are, in a manner of speaking, the state regulators and not the bill-paying customers. Consequently, the dynamic that exists in regulation is almost completely divorced from the market forces and competition.

Q. IS ANY PART OF THE NORTH CAROLINA ELECTRIC MARKET CURRENTLY DEREGULATED?

A. Yes. Wholesale (i.e. sales for resale) electric sales were deregulated through the Energy Policy Act (EPACT) of 1992. Since that time, wholesale competition has existed in some form in North Carolina. However, competition from wholesale electric sales has not been vibrant, although recent activities have shown that such wholesale activity is picking up in the state. As an example, NTE Energy recently opened a plant in Kings Mountain, North Carolina that serves **many** municipal and university electric systems in both South Carolina and North Carolina.

Southern Power, a division of the Southern Company, also owns several unregulated electricity generating facilities located throughout the southeast. Southern serves a very large electric cooperative located in Duke's service territory in North Carolina.

Q. DO CUSTOMERS IN DEREGULATED WHOLESALE POWER MARKETS ALWAYS PLACE PRICE AT THE TOP OF THE LIST WHEN DECIDING UPON A NEW POWER SUPPLY ARRANGEMENT?

A. No. I have completed approximately 30 wholesale power transactions on behalf of clients in South Carolina and North Carolina. While price is, without a doubt, incredibly important, price certainty, credit quality, the trustworthiness of company representatives, and economic development assistance, also all play important roles in choosing a power supplier in an open market. With price certainty, businesses can better manage their future costs, which can help attract additional businesses to North Carolina.

One inherent disadvantage that incumbent utilities have in competing in the open wholesale markets is that the regulatory business model incentivizes utilities to build plant, such as generation, distribution, and transmission plant, as a means to drive earnings. Competitive suppliers, on the other hand, maximize profits by running lean operations and controlling their costs.

The best way to sum up my work in both the deregulated wholesale power markets and the regulated retail markets is that, in the deregulated wholesale power markets, I have the ability to CUT rates for my clients. Whereas in the regulated retail markets, I can only work to minimize the monopoly utility's requested rate increases, such as Duke in this case.

Q. ARE YOU RECOMMENDING THIS COMMISSION MOVE TO DEREGULATE THE ELECTRIC UTILITY INDUSTRY IN NORTH CAROLINA?

A. Not at this time, as I realize the current proceeding is not a referendum on deregulation. However, as noted in **Table 1** above, DEP's NET rate hike equates to 14.6% for a residential consumer, 14.1% for Small General Service consumers, 9.9% for Medium General Service consumers, and 9.9% for Large General Service consumers. Such rate hikes are hard for individuals and manufacturers to absorb. Unfortunately, as rates rise to accommodate Duke executives' plans to drive earnings, the electric cost competitive advantage in North Carolina will continue to erode and become an increasingly serious liability to the State. In time, consumers are going to demand customer choice and, when they do, the price hikes Duke is now seeking will likely make it difficult to maintain its customer base amidst competition thereby potentially eroding its own future profitability.

1. Duke's Planned Grid "*Updates*"

Q. PLEASE EXPLAIN THE CURRENT STATE OF GRID MODERNIZATION EFFORTS ACROSS THE UNITED STATES.

A. In the second quarter of 2019, 44 states, the District of Columbia, and Puerto Rico took actions related to grid modernization.[8] Most of these actions involved energy storage deployment, data access policies, distribution system planning, utility business model reforms, and integrated resource planning.[9]

Q. IS THERE AN INCENTIVE FOR UTILITIES TO CONSTRUCT PLANT AND INVEST IN GRID MODERNIZATION ASSETS?

A. Absolutely. A regulated utility with a captive set of customers is incentivized to build plant and "*modernize*" grid infrastructure, putting those costs in rate base where they can recover its full investment and earn a rate of return on that investment. In essence, a utility can drive earnings by constantly investing in plant and equipment. The "*gatekeeper*" in preventing a utility from over-investing to the detriment of ratepayers is the state regulator, which is tasked with weighing the interests of both the utility, DEP in this case, and DEP's captive consumers.

Q. PLEASE EXPLAIN HOW ENERGY CONSUMPTION TRENDS RELATE TO GRID MODERNIZATION EFFORTS.

A. As has been well-documented in the media, electricity consumption is stagnant across the United States.[10] Utility sales growth around the United States is flat-

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[8] The 50 States of Grid Modernization: U.S. Grid Modernization Activity Continues to Climb in the Second Quarter of 2019, NC Clean Energy Technology Center press release, July 31, 2019

9 Id

10 *See e.g.*, *Most Utilities Executives Agree Risk of Consumers Going Largely Off-Grid Will Increase Significantly in Next Two Years, According to Research from Accenture*, BUSINESSWIRE (Feb. 5, 2019, 7:59 AM EST), https://www.businesswire.com/news/home/20190205005078/en/Utilities-Executives-Agree-Risk-Consumers-Largely-Off-Grid; Justin Fox, *Americans Keep Using Less Electricity*, BLOOMBERG OPINION (Mar. 1, 2018, 7:00 AM EST), https://www.bloomberg.com/opinion/articles/2018-03-01/americans-electricity-use-just-keeps-falling; Dave Flessner, *TVA Plots New Future With Stagnant or Declining Demand for Power*, CHATTANOOGA TIMES FREE PRESS (Feb. 11, 2018),

to-barely growing. In past years, a utility could meet its earnings goal by simply investing in generation plant. However, with flat load growth, there is less of a need for new generation resources. As a result, utilities are looking to other means to grow earnings to satisfy investors. One area in which utilities are looking to invest is in grid modernization plans, such as the plan that DEP is proposing in this case.

On Nov. 8, 2017, Bloomberg chronicled the growing calls around the country by utilities for "*grid modernization*" when it published an article entitled "*No Sales Growth? No Problem! Utilities See Money in Grid Repairs*". The article succinctly captures the grid "*modernization/transformation*" efforts in the following statement:

> "*Utilities make money by investing in wires, poles, substations and power plants and getting a guaranteed return by their regulators on those investments. But as demand for electricity has flat-lined for nearly a decade, companies are finding it harder to justify just building more stuff for growth. So now, they're talking about making the grids they do operate more efficient and flexible, which also happens to cost money.*"[11]

As the article states, these grid modernization plans can provide benefits to customers, but they also provide utilities an opportunity to make a return on their investments.

https://www.timesfreepress.com/news/business/aroundregion/story/2018/feb/11/tvplots-new-future/463259/;

11 Mark Chediak, *No Sales Growth? No Problem! Utilities See Money in Grid Repairs*, BLOOMBERG, (Nov. 8, 2017, 4:21 PM EST, updated Nov. 8, 2017, 6:01 AM EST), https://www.bloomberg.com/news/articles/2017-11-07/-grid-mod-the-new-mantra-as-utilities-counter-stagnant-sales

Q. HOW IS THE TASK OF UTILITY REGULATION CHANGING WITH GRID MODERNIZATION EFFORTS PROPOSED BY UTILITIES?

A. Historically, a utility simply needed to build a plant and operate that plant to meet the requirements for inclusion in rate base, and therefore, rate recovery. Typically, utility regulators could easily predict and quantify the benefits and costs of the generation source. For example, if an individual knew the cost of a combined cycle gas plant, the output capacity rating, the price of natural gas delivered to the plant, and the heat rate of the plant, it would only be the matter of a calculation to calculate the all-in cost of the natural gas plant. Today, however, utility regulators are being asked to take a leap of faith in assuming that the promised benefits of grid modernization/transformation actually come to fruition. Utility regulators are being presented plans by utilities in which the utility is seeking to invest in relatively high-tech equipment <u>with the hope/goal of reducing outages and saving consumers money</u>. Unlike in times past when there was little question as to the performance of new plant being brought into rate base, current grid modification plans are contingent upon improvements of reliability indices, such as SAIDI and SAIFI, as well as other measures. As a result, there are no guarantees of performance in these grid investments, and indeed, DEP is offering no such performance guarantees to this Commission in the present filing.

Q. PLEASE EXPLAIN DEP'S GRID MODERNIZATION REQUEST IN THE CURRENT CASE?

A. Duke has made a very public announcement that it intends to "*invest*" $13 billion to "*modernize*" the electric infrastructure in the Carolinas over a period of 10 years. Duke NC President Stephen De May states the need for grid modernization in the following statement from his pre-filed testimony in the Duke Energy Carolinas rate case:

> "*Today, the need for consistent, reliable service isn't just the expectation of industry and manufacturing, but extends into every home and business—even at a time when that reliability is challenged by the increasing frequency of severe weather events*

> *and the threat of physical and cyber-attack. Customers today want a new and better experience, driven by information about how they consume energy and by tools that help them manage their consumption.*"[12]

Mr. DeMay's statement from the DEC case is incomplete, at best. I will not debate that customers want a "*new and better*" experience. However, there are limits on how much customers are willing to pay for this "*new and better*" experience. Duke knows there are limits and they have far exceeded those limits. As I will demonstrate later, Duke's plans to raise rates over 50% to residential consumers does NOT have the public support that Mr. DeMay wants this Commission to believe.

Q. IS THERE A DIFFERENCE IN THE TOTAL REVENUE FORECAST OF DUKE'S PROPOSED GRID MOD EFFORTS IN THIS CASE VERSUS ITS PREVIOUS REQUESTS?

A. No. Based on recent media reports, it is clear that Duke still anticipates spending $13 billion in grid investments in the Carolinas. On January 22, 2019, the *Charlotte Business Journal* published an article that stated, in part:

> "*Duke says the overall scale of the $13 billion, 10-year program is still "directionally correct.""* [13]

In Duke's 2018 Q4 earnings call with analysts, Duke CEO Lynn Good admitted that Duke was going to push its earnings driver regardless of the forum. Below is part of the transcript from the Q4 earnings call that took place on February 14, 2019:

[12] Prefiled Direct Testimony of Stephone DeMay, NCUC Docket No. E-7, Sub 1214, Pg. 5.

[13] Charlotte Business Journal, Jan., 22, 2019

Shar Pourreza -- *Guggenheim Securities LLC -- Analyst*

"*Okay, so that's in there. Okay and then Lynn I know you're working through a legislation around sort of grid mod and how to sort of think about potentially getting a rider mechanism, but assuming legislation doesn't sort of time the well (sic) the way you're anticipating, you guys are going to be in for serial filings on an annual basis. So, how should we sort of think about the spending of that profile, assuming that you don't get legislation, maybe the commission approves trackers, but if you don't and you're going to be in rate cases, do you see sort of -- any sort of downside to that grid mod spend?*"

Lynn J. Good -- *Chairman, President and Chief Executive Officer*

"*You know, Shar, <u>I think the capital we've put in front of you is capital that we would spend under the rate case scenario as well. So, we have contemplated both scenarios in our long-term guidance.</u> <u>So I don't see a lot of downside to grid spend as a result of what you're describing.</u>*" (*underline added) [14]

Based on the comments above, Duke still has every intention of spending large amounts of money and seeking cost recovery from captive ratepayers. Since the Company was not successful in obtaining legislation for a rate rider or a multi-year rate plan, DEP is, herein, taking the first of many steps for cost recovery in multiple rate cases. Hence, at the end of the day, the Company is still seeking massive rate hikes over 10 years. Company executives simply re-packaged the old "*Power Forward*" proposal and put a different bow on it.

The Company's proposal for grid updates is a Trojan horse. The Company wants the Commission to believe that it has learned its lesson from its failures for a grid rider and a multi-year rate plan and that it has scaled back its grid investment plans that would hike rates over 50% for consumers. Consumers are wary of Duke's real intention in this process and regulators should be concerned as well.

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[14] https://www.duke-energy.com/_/media/pdfs/our-company/investors/news-and-events/2018/4qresults/4q-18-edited-transcript.pdf?la=en

$13 billion is a massive amount of money for Duke consumers in the Carolinas to absorb. Executives are so focused on driving earnings through grid investments that they are not considering how these cost increases will negatively impact the North Carolina economy OR how consumers may respond.

Q. HOW DO YOU KNOW THAT COMPANY EXECUTIVES HAVE NOT FOCUSED ON HOW RATE INCREASES WILL IMPACT THE STATE'S ECONOMY?

A. I asked that exact question and received the following response in a data request response from DEP:

> **Request:**
>
> 16. Has DEP done any study to investigate how the proposed rate increase in this case will impact the economy of the DEP service territory? If so, please provide that study.
>
> **Response:**
> No. [15]

Q. ARE YOU SAYING THAT NO GRID INVESTMENT IS NEEDED?

A. No. I realize that some investment in the grid is warranted. However, the amount that Duke is requesting across the Carolinas is huge and the associated rate hikes are simply job killers. In addition, while the public, in general, supports some form of grid investment, Duke's own internal polling shows that customers do not support the massive rate hikes Duke has in its plans.[16]

[15] CUCA Data Request No. 1-17 and associated response from DEP

[16] DEC Response to CUCA RTP 1-4 Electric Grid Assessment, Final Report, July 6, 2015.

Q. DO YOU HAVE AN ESTIMATE OF THE RATE INCREASES THE COMPANY MAY, ULTIMATELY, ASK THE NORTH CAROLINA CONSUMERS TO PAY FOR ITS GRID INVESTMENTS?

A. Yes. I have presented these figures in previous testimony to this Commission, as well as to the South Carolina Public Service Commission. Duke has, in the past, attempted to refute these figures as just "*estimates*", but – to my knowledge – the Company has never submitted testimony in any public setting with a full set of cost estimates for the next 10 years.

Now, to be fair, Duke has shortened their plans down to 3-year increments, but – as stated above – the Company's CEO still intends to spend an estimated $13 billion on grid mod to drive earnings for her employer.

Q. PLEASE STATE HOW YOU CAME INTO DUKE'S ESTIMATED COST INCREASES ASSOCIATED WITH ITS GRID MOD PLANS?

A. On Feb. 10, 2017, Ms. Kendal Bowman of Duke Energy made a presentation to the North Carolina Legislative Working Group and provided the **annual** rate increases expected by Duke over the next 10 years to pay for its proposed "*investment*" in grid modernization. **Table 2** below provides these **annual rate hikes** as stated by Ms. Bowman on Feb. 10, 2017:

Table 2: Duke Energy Rate Increases for Grid Modernization

Customer Class	Utility	
	DEC	DEP
Residential	4.31%	4.05%
Commercial	1.18%	3.45%
Industrial	2.65%	0.86%

***Source**: Ms. Kendal Bowman at NC Leg. Working Group on Feb. 10, 2017*

As noted above from an article published by the *Charlotte Business Journal* on January 22, 2018, these anticipated Duke rate hikes are "*directionally correct.*" In other words, the Duke rate hikes are going to be substantial and painful for Duke consumers and hard on the NC economy.

Q. CAN YOU PUT THE RATE INCREASES FROM TABLE 3 INTO BETTER PERSPECTIVE IN TERMS OF THE ACTUAL COSTS TO NORTH CAROLINA CONSUMERS?

A. Yes, the above-stated rate impacts are best put into context by translating these annual rate hikes into a cumulative rate increase over 10 years. **Table 3** below provides the cumulative rate hike percentages expected to be requested by Duke for the grid updates.

Table 3: Cumulative Rate Increase for Duke's Proposed Grid Investments

Customer Class	Utility	
	DEC	DEP
Residential	52.50%	48.74%
Commercial	12.45%	40.38%
Industrial	29.89%	8.94%

Source: *Pg. 12 of Duke presentation of 2-10-17 calls for 10-year grid program*

The above percentage rate change increases can be further granulated into annual cost increases for Duke customers over the life of Duke's proposed 10-year roll-out of its grid update plans. **Table 4** below provides the cumulative cost increases associated strictly with Duke's grid updates.

Table 4: Per Customer Cost for Duke Grid Updates

$13 Billion Spend		
Customer Class	Utility	
	DEC	DEP
Residential	$3,777	$3,726
Commercial	$174,982	$613,056
Industrial	$11,993,265	$4,194,747

For residential consumers, the above table assumes a consumption of 1,100 kWh's per month using the average 2017 DEP residential cost in North Carolina as reported by the EIA. For commercial consumers, the table was constructed using a 500-kW load with a 70% load factor and a corresponding 2017 EIA average cost. Lastly, the industrial values were calculated using a 20 MW load, an 85% load factor, and cost data as reported by EIA.

The above-stated cost increases are massive. Residential consumers are looking at cost increases of close to $4,000. Commercial consumers are looking at cost increases over $600,000. Industrial consumers are faced with cost increases of close to $5 million. For industrial consumers, a $5 million cost increase over 10 years represents a single year payroll for approximately 62 individuals earning an average of $80,000 per year. <u>There can be no doubt that the cost—and jobs—impact on the North Carolina economy will be incredibly painful.</u>

Q. HOW DO YOU BELIEVE CONSUMERS WILL REACT TO THESE RATE HIKES BY DUKE?

A. Customers of all sizes may soon seek to take themselves off the Duke grid. Residential customers are already looking very strongly at solar panels. When combined with newer, stronger, and longer lasting batteries, it is possible for residential consumers to disconnect from Duke at some point in the near future.

Likewise, manufacturers with operations in other states will close the North Carolina plants and move to lower cost states OR they may even install their own generation resources as higher rates cause this to be an increasingly cost-effective solution.

As I noted previously, Duke is currently too focused on its own short-term profitability which will erode the competitiveness of its rates and thus erode NC's competitiveness in attracting new industry and jobs.

Q. HAS DUKE COMPLETED ANY MARKETING SURVEYS TO ASSESS HOW MUCH CUSTOMERS ARE WILLING TO PAY FOR DUKE'S PROPOSED GRID MODERNIZATION?

A. Not lately. In the current case, I asked if Duke had completed any such customer surveys and received the following response.

<u>Request:</u>

1-8. Has DEP done any study or customer survey to examine how its customer opinions about rate increases associated with grid modernization investments?

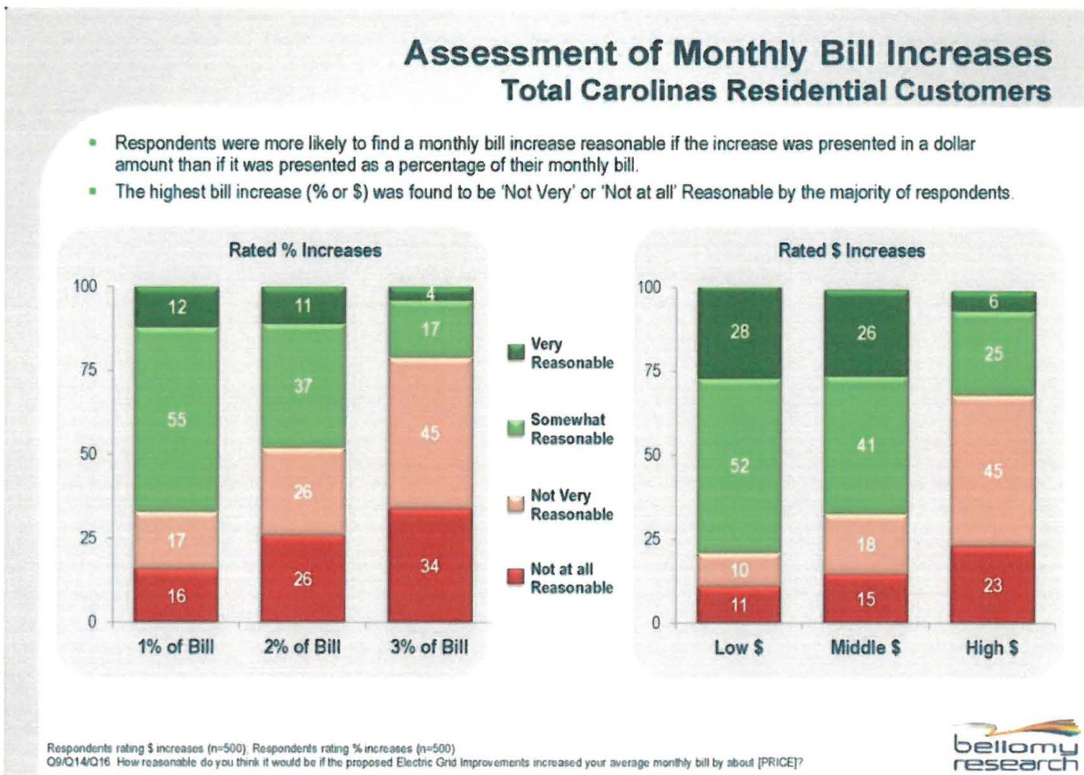
<u>Response:</u>

While not surveys, the Company has conducted several workshops and webinars with customer groups and interested parties regarding its Grid Improvement Plan. Details and reports from those events are included in Witness Oliver's direct testimony in Exhibits 11, 13, and 16.

In Duke's 2017 rate case, I also asked the Company if it completed a customer survey on its grid investment plans. The response I received in the 2017 rate case was different from its most recent response. Specifically, in DEP's response in the 2017 rate case, the Company admitted that, way back in 2015, customers were opposed to the massive rate hikes proposed to pay for its grid investments.

On July 6, 2015, Bellomy Research presented the findings of its marketing survey regarding Duke's "*Electric Grid Improvements*".[17] While most individuals indicated they were in favor of an improved grid, the data below shows that consumers have their limit. Specifically, the data below shows that 79% polled found Duke's grid improvements were "*not very reasonable*" or "*not at all reasonable*" when the cost increase was 3% per month. See **Chart 2** below for the results of the survey.

Chart 2: Duke Customer Survey



If 79% of respondents feel that 3% is too much to pay for the grid updates, common sense dictates an overwhelming percentage of consumers would be opposed to a 12.6% NET rate hike from Duke as noted in **Table 2** above or, even

[17] NCUC Docket No. E-7, Sub 1146, O'Donnell pre-filed testimony, Pg. 15.

worse, the 52.5% rate hike as calculated by the material presented by Ms. Bowman before the North Carolina General Assembly in 2017.

Mr. DeMay may be right that customers want a "*new and better*" experience from their electric provider, but the chart above tells the rest of the story. As noted above, customers are tiring of Duke's rate hikes and may soon be looking for alternatives.

Q. IS THE ABOVE INFORMATION THE SAME MATERIAL YOU PRESENTED IN THE 2017 DEP RATE CASE?

A. Yes.

Q. WHY DO YOU FEEL IT IS IMPORTANT FOR THE COMMISSION TO SEE THIS INFORMATION AGAIN?

A. First, there are several new members on the Commission that have not, heretofore, seen this material.

Second, the above survey is from the general public and is not an "*industry insider*" workgroup informal poll as DEP has indicated in the above data request response.

Third, it is common sense that no one likes rate hikes. However, the magnitude of the rate hikes for the grid mod planned by Duke is stunning and, potentially, crippling to the NC economy. I feel the Commission should be aware of these significant rate hikes so that it can see the long-term impact Duke's plans will have on the public and the state.

Finally, Duke's media blitz "*Building a Smarter Energy Future*" would be much more informative if the general public were told in those advertisements how much their bills were going to be increased in order to pay for DEP's planned investments.

Q. DOES DUKE CURRENTLY RECOVER THE COST FOR MAINTAINING AND IMPROVING RELIABILITY?

A. Yes, Duke currently collects in its rates charges to support the maintenance of the bulk electric system. Unfortunately, it appears that consumers are not getting a good bargain on the grid investments for which we are already paying Duke. On February 1, 2019, *The Wall Street Journal* reported that Duke was fined $10 million by the North American Electric Reliability Council (NERC) for safety and reliability violations. The article was entitled "*Duke Energy Broke Rules Designed to Keep Electric Grid Safe*". The first two sentences of the article state as follows:

> "*Duke Energy Corp. DUK +0.52% faces a record $10 million fine from federal authorities for serious and pervasive violations of rules designed to keep the nation's electric system safe from physical and cyber attacks, according to people familiar with the matter.*
>
> *Some violations lasted for years; others apparently are continuing, according to the people and newly released documents in a federal regulatory filing.*"

The article goes on to state:

> "*It (Duke) committed 127 violations of safety rules, federal investigators said, which "posed a serious risk to the security and reliability" of the eastern interconnection, the web of electric utilities east of the Rocky Mountains that furnishes electricity to most Americans.*"

In regard to foreign entities possibly infiltrating the Duke system, the *Wall Street Journal* states:

> "*The revelation of the extensive cybersecurity breakdown at a major utility comes as federal authorities are increasingly vocal about efforts by foreign actors, including those in Russia, to hack into U.S. utilities.*"

Q. IS THE DECISION BY DUKE MANAGEMENT TO FOCUS ON GRID EXPANSION UNIQUE TO DUKE OR IS IT AN INDUSTRY TREND?

A. Grid "*modernization*" efforts are an industry trend. Electric utility load growth is much flatter than in previous years and the resulting lack of sales has caused utilities across the country to search for new ways to drive earnings. On Nov. 8, 2017, <u>Bloomberg</u> published an article entitled "*No Sales Growth? No Problem! Utilities See Money in Grid Repairs*". The article succinctly captures the grid "*modernization*" efforts in the following statement:

> "*Utilities make money by investing in wires, poles, substations and power plants and getting a guaranteed return by their regulators on those investments. But as demand for electricity has flat-lined for nearly a decade, companies are finding it harder to justify just building more stuff for growth. So now, they're talking about making the grids they do operate more efficient and flexible, which also happens to cost money.*"[18]

So, in essence, Duke management has realized that, to continue to grow earnings, it has to stop focusing on building new generation plants and, instead, build something else. In this case, the "*something else*" is grid "*modernization*" plant. The core questions for this Commission are whether Duke's massive grid efforts are needed, and if so, are they beneficial from a cost perspective and also representative of prudent expenditures for North Carolina consumers.

Manufacturers, in particular, stand to be hurt by these Duke grid updates as they will simply be forced to absorb these massive rate increases.

[18] Bloomberg, Nov. 8, 2017, "No Sales Growth? No Problem! Utilities See Money in Grid Repairs"

Q. ARE ALL "GRID MODERNIZATION PLANS" THE SAME AROUND THE COUNTRY?

A. No. In February 2019, the NC Clean Energy Technology Center issued its 2018 report entitled the "*50 States of Grid Modernization*" and made the following statement as to grid modernization.

> "*Grid modernization is a broad term, lacking a universally accepted definition.*"

I agree with this statement from the NC Clean Energy Technology Center. Indeed, Duke's own programs filed in this case show that the term "*grid modernization*" has different meanings among industry observers. Some grid plans are called Grid Transformation Plans (GTPs)[19], while others are known as Grid Investment Modernization (GRIM); still others are known as Power Forward.

Naming issues aside, the actual details of grid modernization also vary tremendously among utilities nationwide. Some utilities are focusing on relatively high-tech programs, such as self-healing grids, whereas others are working to provide more grid hardening, while mixing in some technology innovation. Based on my review of DEP's application in this case, I believe the Company fits into this last category in that it is currently focusing on grid hardening and a relatively small amount of technology advancements.

Q. PLEASE DESCRIBE SOME OF THE ELECTRIC GRID TECHNOLOGY ADVANCEMENTS BEING CONSIDERED AROUND THE UNITED STATES.

A. Below is a non-exhaustive list of various grid modernization efforts seen around the country and a synopsis of the program:

[19] Dominion Virginia Power before the Virginia State Corporation Commission, Docket No. PUE-2019-00038

- Battery storage – batteries are being considered for use in areas of frequent voltage drops in an effort to maintain frequency levels.

- Advanced Metering Infrastructure (AMI) – two-way meters are allowing the implementation of customer communication/interaction and the adoption of new rate designs.

- Integrated Volt-VAR Control (IVVC) – system that manages voltage along the entire distribution circuit.

- Self-Healing Grid – the use of bi-directional data and power flows to allow a system to isolate a problem on the electrical grid and contain or fix that problem before it spreads to other areas of the electric system.

- Cyber Security – added layers of software security to thwart efforts by outside entities seeking to do harm to the electrical grid.

Q. IS DEP SEEKING TO EMPLOY THESE TYPES OF TECHNOLOGIES AS PART OF ITS 2020-2022 FILING IN THIS CASE?

A. Yes, according to Oliver Exhibit 10, Pg. 3 of the Company's filing in this case, DEP is seeking to implement many of these same technologies. Its capital spend request in this case is as shown in **Table 5** below.

Q. WHY DID YOU MARK SOME OF THE CAPITAL EXPENDITURE REQUEST ITEMS WITHIN TABLE 5 IN YELLOW?

A. The items in yellow are the only items which the Company claims are cost justified through a cost-benefit analyses (CBA). As can be seen in the chart, the Company has only justified 70.3% of its CapEx Plans over the next three years.

Table 5: DEP Grid CapEx Plans

Project	Annual Costs		
	2020	2021	2022
Self-Optimizing Grid	$61,528	$86,057	$154,752
IVVC	$0	$5,000	$5,000
Transmission H&R	$8,934	$9,569	$12,785
Undergrounding	$8,628	$19,524	$26,550
Energy Storage	$8,122	$24,122	$40,261
Distribution Transformer Retrofit	$30,105	$42,053	$37,568
Long Duration Int/High Impact Sites	$6,881	$4,978	$3,912
T-Transformer Bank Replacement	$25,019	$38,514	$19,217
Oil Breaker Replacements	$19,654	$20,051	$44,925
Enterprise Communications	$25,807	$32,282	$49,965
Distribution Automation	$16,322	$32,881	$29,696
Transmission System Intelligence	$6,829	$11,311	$5,559
Enterprise Applications	$1,361	$3,211	$6,232
Integrated Systems Operations Planning	$1,830	$233	$431
DER Dispatch Tool	$1,118	$1,307	$490
Electric Transportation	$12,623	$12,623	$0
Power Electronics for Volts/VAR Control	$36	$532	$532
Physical & Cyber Control	$13,683	$23,965	$31,024
Annual Totals	**$248,480**	**$368,213**	**$468,899**
Cost Justified per DEP	$168,871	$249,868	$344,970
% Justified Annually	68.0%	67.9%	73.6%
Total CapEx Req by DEP	$1,085,592		
Total CapEx Cost Justified	$763,709		
% Justified over 3 years	70.3%		

Note: *The items highlighted in yellow in above table have accompanying cost-benefit analyses.*

Q. WHY DID DUKE NOT PROVIDE A CBA FOR ALL THE PROJECTS FOR WHICH IT IS SEEKING APPROVAL IN THIS CASE?

A. In his pre-filed testimony, Company Witness Oliver stated that Duke provided CBAs only for projects for which CBAs were "*appropriate*."[20] In the footnote for that statement, Mr. Oliver says:

> *"Some programs/projects cannot be effectively measured by detailed performance metrics and targets. For example, computer hardware and software that enables grid assets to communicate with each other either works or does not work, and measures taken to prevent substations from flooding in major storms either keep water out or do not keep water out."* [21]

Q. DO YOU AGREE WITH MR. OLIVER'S CLAIM THAT THE VALUE OF SOME PROJECTS CANNOT BE MEASURED IN A CBA?

A. No, I do not. Mr. Oliver's footnote above seems like common sense, but it omits the reality that the installation of all such equipment can be measured in terms of costs and benefits. For example, Mr. Oliver claims that hardware and software either work or they don't work. What Mr. Oliver fails to acknowledge is there are costs associated with hardware and software that don't work. Such costs can be quantified in terms of outages, lost work hours, lost productivity, etc. Just because an item appears to be difficult to quantify does not excuse the analyst from working hard to proffer a cost estimate and a benefit analysis.

Similarly, there are costs associated with a flooded substation in a major storm. There are restoration costs and customer loss values associated with an outage. Again, just because it is hard to quantify such costs does not mean that the analyst should not try to come up with a value and provide the evidence upon which they calculated their cost estimate.

[20] Oliver pre-filed testimony, Pg. 38
[21] Id

Lastly, to the extent that a project, say enterprise communications, must be undertaken before another project, say self-healing grid, can be placed in operation, the cost of that project (i.e. enterprise communication) should be considered as part of the final project (i.e. self-healing grid). Excluding the cost of the independent project, such as the enterprise communication portion presented within the example referenced above, will skew the results of the CBA and not provide the Commission an accurate view of the real costs of the projects.

If independent project assets will be used in multiple grid projects, the cost of the assets associated with the independent project (i.e. such as enterprise communication) should be apportioned across the various projects.

Q. HAVE YOU REVIEWED DEP'S COST-BENEFIT ANALYSES FOR THOSE ITEMS WHICH IT DID OFFER SUCH CALCULATIONS?

A. Yes.

Q. DO YOU AGREE WITH THE METHODS WHICH MR. OLIVER FOLLOWED IN PERFORMING HIS CBAs?

A. Mr. Oliver followed what I would consider to be a standard CBA. However, where I differ with Mr. Oliver is that it does not appear he tested his assumptions with a sensitivity analysis. In my view, Mr. Oliver should have tested his forecasted reliability values and the cost inputs to the CBA model by assuming a +/- 25% variation in the benefits and costs. He could then have presented his findings as part of the results in this case so as to give the Commission a full range of results that were possible.

Q. HOW DO YOU SUGGEST THE COMMISSION DEAL WITH DEP'S APPLICATION FOR COST RECOVERY OF GRID MODERNIZATION ASSETS?

A. I have two recommendations.

First, to the extent that DEP did not provide a CBA for a specific project, that requested project should be denied. If the project that is denied was critical to the CBA of a project which DEP has deemed to be economically feasible, both projects should be denied. The reason is that DEP would not have performed the CBA in a proper manner if it did not include ALL costs associated with a specific project. As a result, the Commission would not have all necessary information on which to make a judgement as to the appropriateness of a particular grid investment.

If the Commission rejects a grid investment project, I recommend that DEP be allowed to re-file its grid plan without prejudice and be required to include ALL costs in the plan AND to apply a contingency factor of +/- 25% on various inputs into the model.

As stated above, just because performing a CBA might be difficult, that does not excuse the Company and its analysts from working to prepare and present such a detailed CBA. Given that the Company's request in this case amounts to an investment of almost $1.1 billion and represents such a massive rate hike to consumers, the Company should have presented a complete CBA for each project to this Commission and intervenors.

Second, I recommend the Commission make cost recovery of the grid modernization assets contingent upon DEP providing evidence that it is meeting its reliability targets through an increase in its SAIDI and SAIFI metrics. Specifically, each-and-every year, the Company is granted cost recovery if–and-only-if the reliability targets are reached. Duke needs to be held accountable for its promises to consumers. Granting cost recovery before obtaining evidence that the plant constructed by Duke will work as advertised is putting consumers at extreme risk.

Q. DO YOU KNOW OF ANY OTHER STATE REGULATORY AGENCY THAT HAS APPROVED AN ASSET BEING PLACED IN RATES CONTINGENT UPON THE UTILITY MEETING A PERFORMANCE TARGET?

A. Yes. The State Corporation Commission of Virginia recently required Dominion Energy Virginia (DEV) to attain a minimum capacity factor in order to have a solar generation asset added to rate base.

In Case No. PUR-2018-00101, which was filed on July 24, 2018, DEV requested approval to construct and operate two large solar facilities. The facilities were the "Colonial Trail West Solar Facility", an approximately 142 MW facility located in Surry County, and the "Spring Grove 1 Solar Facility", an approximately 98 MW AC facility also located in Surry County.

In its testimony, the Company stated that it expected the solar plants to achieve a capacity factor of 28% and its economic feasibility models were based on such a high capacity factor.[22] The Commission stated the following in regard to the 28% capacity factor:

> "*The actual performance in Virginia of solar generating resources has demonstrated actual capacity factors significantly below 28%, actually below 20%. To the extent the actual performance of the Projects falls below 28%, the cost to customers goes up, and the NPV becomes negative for customers below 25%.*"[23]

The Commission went on to require a 25% minimum annual capacity factor. In its order the Commission stated its reasons for this minimum capacity factor as follows:

22 Final Order in Case No. PUR-2018-00101, Pg. 15

23 Id, Pg. 15

> *"Based on the instant record, the Commission finds that a performance guarantee is appropriate and necessary to address the risk of rising and excessive costs to customers attendant to the proposed Projects. As discussed below, however, we further find that Dominion's proffered performance guarantee is insufficient for this purpose.*
>
> *<u>Performance Guarantee</u>*
> *The Commission finds that the Projects, as proposed in the Petition, are not "required by the public convenience and necessity" under Code § 56-580 D due to the performance and financial risks that would be placed on Dominion's customers. Dominion's cost analyses are based on a 28% solar capacity factor. The capacity factor at which customers essentially break even is 25%. Based on the record herein, we do not find that it is reasonable for customers to bear the risks, for the life of the Projects, that either of these assumed capacity factors will be met. The actual performance of solar generating resources in Virginia has been below 20%, and the Company's existing US-2 solar facilities have underperformed with capacity factors as low as 16%."*

My recommendation in this DEP grid investment request case is the same line of reasoning the Virginia SCC followed in the above-stated solar cases. Consumers should not bear the performance risk of DEP's assumptions. DEP should bear that risk as it will earn healthy returns if/when the assets are placed into service and achieve the reliability factors upon which the CBA model is built.

Q. **IS DUKE WILLING TO GUARANTEE CONSUMERS WILL REALIZE A REDUCTION IN OUTAGES FROM ITS REQUESTED GRID INVESTMENT STRATEGY?**

A. No. I asked DEP if it could offer any such guarantees from its grid investments and the Company answered no. Below are a series of questions posed to DEP and its responses:

<u>CUCA 2-8 Request:</u>

8. Will DEP provide any guarantee as to the achievable SAIDI/SAIFI ratios on which it has based its cost benefit analyses as presented in this case?

<u>Response:</u>
DEP has not based its cost benefit analyses in this case on "achievable SAIDI/SAIFI ratios." Instead, each cost benefit analysis contains reliability benefits for only the specific work.

<u>CUCA 2-9 Request:</u>

9. Will DEP be agreeable to make cost recovery of its grid mod investments contingent upon achievable reliability targets as represented by SAIDI and SAIFI?

<u>Response:</u>
No. See response to 8.

Q. HOW DO YOU RESPOND TO DUKE'S UNWILLINGNESS TO ACCEPT RESPONSIBILITY FOR THE PERFORMANCE OF ITS GRID INVESTMENTS.

A. As explained above, the "*old*" utility model is that the utility builds plant and equipment for which it seeks rate recovery. It is presumed that this plant and equipment will operate as planned. However, with these grid modifications, DEP wants unfettered rate recovery without even a review of the ability of the assets to work as promised. In essence Duke is seeking to shift the entire risk of the plant assets to consumers without any corresponding reduction in the return the utility is seeking from captive consumers. Duke's position in this case is unacceptable and should be rejected.

Duke's request in this case is akin to an auto manufacturer selling a car to a consumer without any assurance it will even operate. No one would buy a car without even a basic warranty. Consumers need such a warranty and should not be asked to spend a single dime until we receive such assurances from Duke. If Duke does not want to be held to a set SAIDI/SAIFI reliability standard, it should offer up some other standard on which its performance can be judged. The "*trust me*" mantra from DEP management is not acceptable as there are billions of dollars at stake in this proceeding and future proceedings.

Q. DID THE VIRGINIA STATE COMMERCE COMMISSION ADDRESS ANY CONCERN ABOUT THE SHIFTING OF RISK IN THE ABOVE-STATED SOLAR CASE?

A. In its final order in Docket No. PUR-2018-00101, the Virginia State Commerce Commission stated:

> *"Dominion's cost analyses are based on a 28% solar capacity factor. The capacity factor at which customers essentially breakeven is 25%. Based on the record herein, we do not find that it is reasonable for customers to bear the risks, for the life of the Projects, that either of these assumed capacity factors will be met. The actual performance of solar generating resources in Virginia has been below 20%, and the Company's existing US-2 solar facilities have underperformed with capacity factors as low as 16%."* [24]

Q. HAS DUKE HELD OPEN WORKSHOPS REGARDING ITS GRID MODERNIZATION INVESTMENTS?

A. Yes, but the <u>general public</u> has not been engaged in this process. The workshops have all involved industry insiders that understood, to a degree, the grid investment process. My attendance at the workshop at the NC State University Faculty Club in 2018 left me with the following major question:

How much is all this investment going to cost consumers?

[24] Virginia State Commerce Commission, Case No. PUR-2018-00101, Final Order, Jan. 24, 2019, Pg. 16-17

As noted previously, Duke has a current marketing campaign dubbed, "*Building a Smarter Energy Future*", but the Company has been silent in this media blitz as to the true cost of the grid investments to the consumer. If Duke were being totally transparent in this process, it would state to the consumer that it plans to raise rates upwards of 50% for the grid updates such that the typical homeowner would pay about $4,000 over the next 10 years for the Company's "*Smarter Energy Future*".

Q. HOW IS RAPIDLY CHANGING TECHNOLOGY IMPACTING THE NEED TO UPDATE THE DUKE GRID?

A. As noted above, Duke has not changed its long-term plan of spending up to $13 billion on its electric grid. This amount of spending translates into approximately $4,000 to the typical residential consumer that will still be subjected to outages. An alternative to spending $4,000 for these grid updates would be home batteries, which continue to fall in price. As an example, a 5-kW Tesla Powerwall currently costs $8,000 installed.[25] It is illogical to spend $4,000 with Duke and still endure outages when the consumer could spend $8,000 and be assured of almost no interruptions (and Duke would not be charging a rate of return on the battery, since it would be owned by the customer).

As technology continues to evolve, solutions like the one outlined above will continue to present themselves such that the massive Duke grid investment might be outdated and worthless as compared to alternatives.

Q. HAS ANY OTHER NEARBY STATE REGULATORY AGENCY RECENTLY RULED ON A GRID TRANSFORMATION REQUEST FROM A UTILITY THAT SERVES ITS STATE?

A. Yes. On March 26, 2020, the Virginia State Commerce Commission (Virginia SCC) ruled on Dominion Virginia Power's (DVP) request pursuant to § 56-585.1

[25] https://www.energysage.com/solar/solar-energy-storage/tesla-powerwall-home-battery/

A 6 ("Section A 6") of the Code of Virginia ("Code") for permission to invest close to $1 billion in grid transformation projects. The Virginia SCC **denied** about 75% of Dominion's request in the case. Below is the specific language used by the SCC in its denial of the DVP request:

> *"Through this Final Order we address the Company's request for approval of additional investments over the first three years of its ten-year Plan, referred to as Phase M. Today we approve costs of approximately $212 million and additional related costs involving cyber security, stakeholder engagement and customer education, and telecommunications, but deny approval of the remaining elements contained in Dominion's Petition and Plan,1°1 This results in the denial of approximately $626 million in proposed costs that would be borne by customers in their monthly bills. We recognize the importance of the Plan's overall objectives. We have approved those elements in which the heavy costs to customers have been adequately justified by the overall benefits to customers, and we have denied approval to those elements whose heavy costs were not justified by the overall benefits to customers, As required by the statute, we have considered whether Dominion's "plan for such projects, and the projected costs associated therewith, are reasonable and prudent."[102] Accordingly, in exercising the Commission's discretion thereunder, we have denied those projects for which we have found that the plan, or the projected costs, are not reasonable and prudent."* [26]

Virginia denying DVP's request for grid transformation projects sends a clear signal to all utilities that such projects must be undertaken to benefit consumers and not just to drive utility earnings.

V. COAL ASH COSTS

Q. MR. O'DONNELL, PLEASE EXPLAIN THE BACKGROUND THAT HAS LED DEP TO REQUEST RECOVERY OF $200 MILLION OF COAL ASH COSTS IN THIS CASE.

A. On February 2, 2014, DEC spilled a large amount of coal ash in the Dan River.

[26] Virginia State Corporation Commission, Docket No. PUR-2019-00154, Final Order, p. 25-26.

This spill made the national press. The Dan River spill will be cleaned up with Duke stockholder funds. Information exposed in the Duke federal plea deal, which is described below, revealed that on two separate occasions, Duke engineers at the Dan River plant requested an immaterial amount of budget funding to pay for video equipment to scope the pipe that later failed. Duke engineers were denied the request. [27]

In September 2014, in response to the Dan River spill, the North Carolina Legislature passed the Coal Ash Management Act (CAMA), requiring the closure of existing coal ash ponds as well as conversion from wet ash to dry ash handling. CAMA was the first such coal ash management law in the United States. This initial legislation required basins at four Duke plants to be closed by 2019.

On December 19, 2014, the EPA issued the Coal Combustion Residual (CCR) Order that provided minimum national criteria for CCR landfills, CCR surface impoundments, and lateral expansion of coal-fired units. The CCR federal rule was designated as "*self-implementing*," meaning that Duke was not under any requirement to act UNLESS it was sued by a state or other entity and loses that lawsuit.

On May 14, 2015, DEC, Duke Energy Progress (DEP), and Duke Energy Business Services pled guilty to nine violations of the Clean Water Act; as a result, Duke was fined $102 million by the federal courts.[28] Below are some of the issues to which Duke admitted guilt:

- From at least January 1, 2012, Duke Energy Carolinas and Duke Energy Business services failed to properly maintain and inspect the two storm

[27] 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

[28] United States DE Ct. of Justice press release, May 14, 2015, 1

water pipes underneath the primary coal ash basins at the Dan River Steam Station in Eden, North Carolina. On February 2, 2014, one of those pipes failed, resulting in the discharge of approximately 27 million gallons of coal ash wastewater and between 30,000 and 39,000 tons of coal ash into the Dan River.[29]

- Duke Energy Progress and Duke Energy Business Services also failed to maintain the riser structures in two of the coal ash basins at the Cape Fear Steam Electric Plant, resulting in the unauthorized discharges of leaking coal ash wastewater into the Cape Fear River.[30]
- Additionally, Duke Energy Carolinas (DEC) and Duke Energy Progress' (DEP) coal combustion facilities throughout North Carolina allowed unauthorized discharges of pollutants from coal ash basins via "*seeps*" into waters adjacent to the United States.[31]
- The Defendants' conduct violated the Federal Water Control Act (commonly referred to as the "Clean Water Act," or "CWA"). 33.U.S.C. 1251.[32]

Below is what an official with the United States Environmental Protection Agency said about Duke officials and coal ash:

> ""*Duke management failed in their responsibility to the people of North Carolina. Their criminal negligence is what caused this disaster," said Cynthia Giles, assistant administrator for enforcement for the U.S. Environmental Protection Agency.*"[33]

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[29] 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, 2

[30] Id at 3

[31] Id at 3

[32] Id at 4

[33] **http://www.wral.com/duke-energy-pleads-guilty-to-environmental-charges-linked-to-coal-ash-spill-leaks/14645414/)**

Q. CAN YOU PROVIDE ANY EVIDENCE THAT THE NORTH CAROLINA CAMA LEGISLATION WAS PROMPTED BY THE DAN RIVER SPILL?

A. Yes. An early version of the CAMA legislation, dated May 14, 2014, that was working its way through the NC General Assembly stated as follows:

"*Whereas, the issue of coal ash storage has not been adequately addressed in North Carolina for more than six decades; and*

Whereas, on February 2, 2014, an estimated 39,000 tons of coal ash was released into the Dan River following the failure of a stormwater pipe under a utility coal ash impoundment pond in Eden, North Carolina; and

Whereas, the Department of Environment and Natural Resources ("Department") finds that coal combustion products have settled into the sediment of the river bottom and will require an extensive clean-up plan to complete remediation; and

Whereas, the Department is in the process of reassessing previous efforts at achieving compliance at coal ash facilities and developing short term and long term policies in light of the Dan River spill, violations discovered in light of increased inspections of coal combustion products disposal facilities and anticipated new federal regulations on coal combustion products; and

Whereas, it is the intent of the Department to ensure that spills of wastewater are reported to the Department in a defined and adequate time frame; and
Whereas, it is the intent of the Department to protect surface water and groundwater resources for their best usage; and

Whereas, it is the intent of the Department to ensure that all unpermitted wastewater discharges are eliminated or addressed in an environmentally responsible manner; and

Whereas, it is the intent of the Department to equally subject all dams under jurisdiction of G.S. 143-215.23 to the requirements of statute and administrative code; and

Whereas, it is the intent of the Department for the owners of all dams under jurisdiction of G.S. 143-215.23 deemed intermediate and high hazard by the Department to prepare at their own cost documents that describe full and adequate response to emergency *situations at their dams and to submit those documents to the Department; and*

Whereas, it is the intent of the Department to ensure that emergency situations at dams are reported to the Department in a defined and adequate time frame; and

Whereas, the it is the intent of the Department to increase oversight of dam structure integrity to protect the health and safety of the public; and

Whereas, state law exempts coal combustion products removed from impoundments from being defined as a solid waste; and

Whereas, the Department finds that consistent environmental standards should apply to coal combustion products removed from impoundments for management or disposal and coal combustion products managed or disposed of as a solid waste; and

Whereas, the Department finds the federal Environmental Protection Agency is under consent decree to complete new regulations by December 31 2014 for coal combustion products that are proposed to bring consistency to requirements for large fills such as structural fills and landfills; and

Whereas, the Department finds that conversion and closure of coal ash storage ponds is necessary for protection of the health and safety of the public."[34]

In addition to the above quotes from this early version of CAMA, North Carolina legislators went on the record to state that the Dan River spill prompted CAMA. Evidence for this statement can be found in a WRAL.com article that demonstrates CAMA was a direct result of the Dan River spill. As the article states:

"According to one of Duke Energy's top leaders, North Carolina's 2014 coal ash legislation didn't necessarily result from a company ash spill in the Dan River.

[34] https://www.ncleg.gov/Sessions/2013/Bills/Senate/PDF/S729v1.pdf

Federal coal ash rules were already being drafted at the time, and it's possible, Duke state President David Fountain testified Monday during a rate increase hearing, that the North Carolina General Assembly would have passed its law anyway.

Twice, Sierra Club attorney Matthew Quinn asked Fountain whether the law was motivated, or partially motivated, by a spill that turned parts of the river gray.

"I really can't admit that," Fountain replied.

State Rep. Pricey Harrison, D-Guilford, who saw her push for coal ash regulations gain traction only after the spill, scoffed at this Monday evening. When the bill passed in 2014, Senate negotiator Tom Apodaca specifically said that, "When I saw the Dan River thing, I said, 'We've got to do something.'" State Rep. Chuck McGrady, R-Henderson, who negotiated the bill for the House, told the Associated Press that, "unfortunately, sometimes we wait until we have a really big problem before we address it.

It makes sense for (Fountain) to say that, but he is flat wrong," Harrison said Monday."[35]

Q. IS CAMA MORE OR LESS STRINGENT THAN THE FEDERAL COAL COMBUSTION RESIDUAL (CCR) RULE?

A. Duke has publicly admitted that CAMA is more stringent than CCR. In the May 24, 2016 edition of Utility Dive, Mr. Mark McEntire, Director of Environmental Policy at Duke, is quoted as saying:

""*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*.""

[35] http://www.wral.com/seeking-rate-increase-duke-energy-dodges-link-between-coal-ash-spill-and-coal-ash-bill/17145054/

The Utility Dive article went on to state:

> *"McIntire noted the CCR rule doesn't stipulate closure of coal ash ponds, nor contemplate a method by which they can be closed — it simply sets minimum requirements for coal ash waste disposal.*
>
> *The CAMA, however, directs state environmental regulators to set timelines for closing the coal ash facilities."*

Q. HOW DO UTILITIES RECOGNIZE IMPENDING FINANCIAL LIABILITIES SUCH AS COAL ASH EXPENSES?

A. Utilities will book expenses as asset retirement obligations (AROs) in recognition of future liabilities.

Q. HAVE YOU ANALYZED AROs RELATED TO COAL ASH FOR DEP AND COMPARED THAT ARO TO OTHER UTILITIES?

A. Yes. Using data obtained from *SNL Financial*, I extracted AROs on the books of utilities from across the country and ranked the utilities by AROs from largest to smallest. **Table 6** provides the utilities in the US with the highest AROs.

Table 6: Total AROs

Ranking	Company Name	Asset Retirement Obligations (ARO) ($) 2018Y	
1	Georgia Power Company	$	5,829,413
2	Duke Energy Progress, LLC	$	4,819,760
3	Duke Energy Carolinas, LLC	$	3,948,779
4	Alabama Power Company	$	3,210,340
5	DTE Electric Company	$	2,271,437
6	Florida Power & Light Company	$	2,130,520
7	Indiana Michigan Power Company	$	1,681,320
8	Virginia Electric and Power Company	$	1,445,698
9	Entergy Arkansas, LLC	$	1,048,428
10	Arizona Public Service Company	$	726,545
11	Duke Energy Indiana, LLC	$	721,716
12	Duke Energy Florida, LLC	$	591,138
13	Evergy Metro, Inc.	$	261,038
14	PacifiCorp	$	227,372
15	Evergy Kansas South, Inc.	$	217,485
16	Kentucky Utilities Company	$	199,408
17	Portland General Electric Company	$	197,326
18	Gulf Power Company	$	169,061
19	Mississippi Power Company	$	160,285
20	Public Service Company of New Mexico	$	157,814
21	Indianapolis Power & Light Company	$	129,451
22	Southwestern Electric Power Company	$	126,331
23	Commonwealth Edison Company	$	120,661
24	Appalachian Power Company	$	116,077
25	El Paso Electric Company	$	101,108
26	ALLETE (Minnesota Power)	$	96,901
27	Oklahoma Gas and Electric Company	$	83,942
28	Nevada Power Company	$	82,610
29	Tucson Electric Power Company	$	70,694
30	Tampa Electric Company	$	63,982
31	Westar Energy (KPL)	$	63,612
32	NSTAR Electric Company	$	63,400
33	Monongahela Power Company	$	46,889
34	Public Service Company of Oklahoma	$	46,858
35	Kentucky Power Company	$	41,681
36	Potomac Electric Power Company	$	37,192
37	Connecticut Light and Power Company	$	33,499
38	CenterPoint Energy Houston Electric, LLC	$	33,483

The AROs booked by DEC and DEP indicate that, in comparison to utilities across the United States, these Duke subsidiaries are carrying a sizable future liability.

Q. DO YOU AGREE WITH DUKE'S POSITION THAT CONSUMERS SHOULD PAY ALL THE COSTS OF CLEANUP?

A. No. Duke management made specific decisions that resulted in the coal ash spill in North Carolina that, in turn, led to the creation of the Coal Ash Management Act (CAMA).

Q. HAVE THERE BEEN ANY LEGAL ACTIONS TAKEN ON THE COAL ASH ORDER SINCE THE COMMISSION'S FINAL ORDER IN THE 2017 CASE?

A. Yes, the NC Attorney General and the Public Staff have both filed appeals to the NC Supreme Court. If the NC Supreme Court agrees with the Attorney General and the Public Staff that errors were made in the Commission's final order, the case will be remanded back to the Commission. If that occurs, the 2017 case may be re-opened for interpretation by this Commission again.

Q. HAS ANY OTHER STATE REGULATORY BODY RULED ON THE ISSUE OF DUKE'S COAL ASH REMEDIATION COSTS?

A. Yes. The South Carolina Public Service Commission (SC PSC) ruled that consumers should only pay for the federal CCR costs and not the incremental cost of the CAMA legislation.

Q. DID THE SC PSC FIND THAT THE CAMA LEGISLATION IS MORE STRINGENT THAN THE FEDERAL CCR?

A. Yes. In its final order in the case, the SC PSC stated:

> "*...this Commission has received evidence that confirms that North Carolina's CAMA is much more stringent and results in costs in excess of those that would be incurred absent CAMA.*"

Q. ARE THERE PENDING LEGAL ACTIONS IN THE 2019 DEP RATE CASE IN SC?

A. Yes. Duke has appealed the final order from the SC PSC so, like the case in NC, the issue may return to the SC Commission for further review.

Q. PLEASE STATE THE DIFFERENCES BETWEEN THE NORTH CAROLINA CAMA AND THE FEDERAL CCR.

A. Below is a list of the differences between CAMA and CCR as it relates to cost recovery in the current case:

1. Closure Methods – CCR allows for cap-in-place closure as compared to CAMA which allows only "*low risk*" basins to be closed by cap in place;
2. Closure Mandates – CCR requires closure if basins cannot meet various safety and reliability requirements as compared to CAMA that is based solely on priority designation;
3. Closure Timing – the CCR closure timing runs from 5 years to 15.5 years as compared to CAMA that has closure timelines of 5, 10, and 15 years;
4. Inactive Sites – CCR does not apply to inactive sites whereas CAMA does;
5. Benefication – CCR does not require benefication as compared to CAMA that does require benefication at 3 sites.

Q. **IS THE CCR APPLICABLE TO PLANTS WHERE THE COAL ASH SITE IS NO LONGER OPEN?**

A. If a surface impoundment is closed and no longer receiving coal ash, it is not subject to the CCR rule.[36]

Q. **WOULD A SITE THAT IS NO LONGER RECEIVING COAL ASH BE SUBJECTED TO CAMA?**

A. Yes.

Q. **BASED ON THIS CLOSURE RULE, DO YOU BELIEVE DEP SHOULD RECEIVE COMPLETE RECOVERY OF ITS REQUESTED COAL ASH EXPENSES?**

A. No. My recommendation is that DEP not be allowed to recover coal ash expenses associated with any plant that is not subjected to CCR, but is subjected to CAMA. To the extent that any site is no longer receiving coal ash, I don't believe its remediation costs should be paid for by ratepayers in this case or any future cases.

Q. **FOR THE COSTS THAT THIS COMMISSION DEEMS SHOULD BE PAID BY CONSUMERS, HOW DO YOU RECOMMEND THOSE COAL ASH COSTS BE ALLLOCATED?**

A. My recommendation is the allocation of coal ash should follow the allocation of fuel costs approved in DEP's last fuel case. If the allocation is a fixed % change across all customer classes, my recommendation is that coal ash costs be assigned to all customer classes based on a fixed equal % share.

[36] https://www.epa.gov/sites/production/files/2014-12/documents/factsheet_ccrfinal_2.pdf

Q. WHY DO YOU BELIEVE SUCH AN EQUAL % CHANGE IN COAL ASH COSTS IS EQUITABLE?

A. For the past several years, the Commission has approved fuel changes based on an equal % change for all customer classes. In times of fuel cost increases, this allocation methodology benefitted large consumers. In time of fuel cost decreases, such an allocation methodology benefitted small consumers. What has been deemed to be appropriate for fuel cases for many years should also be appropriate for the allocation of coal ash costs.

VI. DEP MANUFACTURING RATE CONCERNS

1. Hourly Pricing Rates

Q. DOES DUKE OFFER A REAL-TIME HOURLY PRICE RATE?

A. Yes, it does.

Q. DO DEP INDUSTRIAL CONSUMERS TAKE ADVANTAGE OF THE HOURLY PRICING RATE OFFERED BY DEP?

A. Yes, but in the past two years, I have heard consistent concerns from manufacturers regarding the excessive costs of Duke's hourly prices in relation to prices found in other parts of the country and, in particular, with another southeastern competitor, Georgia.

Q. PLEASE EXPLAIN THE CONCERN ABOUT DUKE'S HOURLY PRICES RELATIVE TO PRICES IN OTHER PARTS OF THE COUNTRY.

A. Duke operates a closed system as it relates to its hourly prices to consumers. The price offered to consumers on an hourly basis is the DEP marginal cost for its generation. However, at the same time that DEP is selling marginal cost power to its RTP customers, the Company is also operating in the competitive wholesale power market where opportunity purchases and sales are being made. There may be times throughout the year when DEP's marginal cost of power offered to its manufacturing customers is greater than the price the Company could pay for that same power in the open wholesale market. Unfortunately, since Duke operates a closed system and prices its RTP costs at its own marginal costs, manufacturers are paying higher costs than necessary. On the same front, by failing to take advantage of lower cost power on the wholesale market, Duke is also needlessly running its higher cost generating plants, leading to higher fuel costs for all consumers.

Q. IS THIS ARGUMENT THE SAME AS THE ONE YOU PRESENTED IN DEP'S LAST RATE CASE IN SOUTH CAROLINA?

A. Yes, it is.

Q. WHY ARE YOU PRESENTING THIS ARGUMENT AGAIN IN THIS CASE?

A. Because DEP has not made any effort to address its hourly pricing issues with large manufacturers. My concern is that manufacturers need every option available to them to help mitigate the massive rate increases Duke has in-store for them through grid transformation and coal ash clean up. Duke should be working hard to help manufacturers develop rate alternatives.

Manufacturers in NC need DEP to become more competitive. This issue is one that does not cost DEP any funds and, therefore, should be of no contention to the utility. If DEP is indifferent and it saves manufacturers in higher power bills, I see no reason why DEP should not be ordered to set the RTP rates at the lower of the Company's marginal cost or the price as set by the open wholesale power market, as adjusted for transmission costs and line losses for moving the power to the DEP service territory.

Q. DO YOU HAVE ANY RECOMMENDATION FOR DEP IN AMENDING ITS RTP RATE SCHEDULE IN THIS PROCEEDING?

A. Yes. DEP's hourly pricing should be set at the lower of DEP's marginal cost or the price set by the open wholesale power market adjusted for transmission costs and line losses.

The above recommendation to improve the DEP hourly pricing rates is, but one way that Duke can improve its relationship with its business customers.

VII. COST OF CAPITAL

A. Review of Company's Requested ROE

Q. WHAT ROE DID DEP ASK THE COMMISSION TO GRANT IT IN THIS PROCEEDING?

A. According to Company Witness Hevert, the ROE that should be afforded the Company in this proceeding is 10.50%.

Q. DO YOU AGREE WITH DEP'S REQUESTED ROE?

A. No. I disagree with DEP's requested ROE. The requested ROE is excessive and unwarranted given the current financial market conditions; it simply does not comport with the current economic reality facing investor-owned utilities. Moreover, the models and inputs used by Company Witness Hevert to determine DEP's cost of equity are biased, in nearly every sense, to artificially inflate his ROE results.

Q. PLEASE EXPLAIN ON WHAT VARIABLE MR. HEVERT'S DCF ANALYSIS IS BIASED.

A. In his DCF analysis, Mr. Hevert uses only forecasted earnings growth rates. As discussed in my testimony herein, there is ample financial literature demonstrating the errors that accompany the exclusive use of forecasted earnings growth rates. Mr. Hevert made no adjustments to account for the upward nature of analyst forecast estimates.

As I note in my ROE analysis below, it is immensely important that the analyst present as much relevant information as possible to utility regulators so they can make informed decisions. Historical information, as well as information on dividend growth, earnings growth, and book value growth, are critical pieces of information omitted by Mr. Hevert, whose forecasted earnings-only analysis is very limited and restricted. I believe a more complete and robust analysis is required in every cost of equity analysis.

Q. HOW DO YOU RESPOND TO MR. HEVERT'S COMMENTS DISAVOWING HIS DCF RESULTS?

A. On Pg. 5-6 of his direct testimony, Mr. Hevert provides reasons why he recommends the Commission give less weight to his DCF results than the results of other models. Specifically, Mr. Hevert states:

> "*In developing my recommendation, I recognized that the low end of the range of results (set by the low end of the range of Constant Growth DCF model results) is not likely to be a reasonable estimate of the Company's Cost of Equity. In large measure, that is the case because those results are far removed from the returns recently authorized in other jurisdictions and fail to adequately reflect evolving capital market conditions. Because Risk Premium-based methods directly reflect measures of capital market risk, they are more likely than other approaches (such as the Constant Growth DCF method) to provide reliable estimates of the Cost of Equity during periods of market instability.*"[37]

37 Hevert pre-filed direct, Pg. 5-6.

The statement sounds simple, but – in reality – it is misleading. The DCF model is used to estimate the current market ROE of investors. Stock prices go up and stock prices go down. As such, the current return changes each and every day as investors bid the stock price up and down to account for perceived levels of risk changes. However, Mr. Hevert wants this Commission to believe that ROEs are static and do not change in response to high stock prices. The following quote is from Pg. 29 of Mr. Hevert's direct testimony in the general rate case of Pepco before the District of Columbia Public Service Commission:

> "*In one sense, relatively low dividend yields should be associated with relatively high growth rates. That is, low dividend yields are the result of relatively high stock prices which, in turn, should be associated with relatively high growth rates. If those relationships do not hold, the model's results should be viewed with some caution.*"[38]

The above statement inappropriately implies that returns are static. They are not. As this Commission is aware, the stock market hit record highs earlier this year, only to fall dramatically in the wake of the coronavirus situation. As such, investors are paying more and more for a given level of income. When a situation occurs that causes equity prices to rise and fall, it is a mathematical certainty that the current return is going to change as well. This is a concept that Mr. Hevert's testimony fails to acknowledge. Indeed, Mr. Hevert's implication that model results should not be given as much credence when they produce lower returns as a result of higher stock prices simply fails the common sense test and does nothing but provide a misleading analysis to support Mr. Hevert's irrational proposal for a higher ROE than even his own DCF analysis produces.

38 Exhibit Pepco (G) (Hevert) at 29:14-18.

Q. CAN YOU PROVIDE AN EXAMPLE OF INCREASING MARKET PRICES DRIVING DOWN THE CURRENT RETURN OF ANY STOCK INVESTMENT?

A. Yes. Suppose a stock that paid $1.00 in dividends was projected to increase the dividend by 4% per year into the indefinite future, and the current stock price was $20 per share. In this scenario, the DCF formula would be:

$$ROE = ((D_0 * (1+g))/P_0)) + G$$

Where D_0 is the current dividend paid
G is the growth in the dividend; and
P_0 is the current price.

Which translates into the following:
ROE = (($1.0*(1+.04))/$20) + 4%
ROE = 9.2%

Now, if the market bids up the price of the stock to $25, the formula and result is as follows:

ROE = (($1.0*(1+.04))/$25) + 4%
ROE = 8.2%

The above example shows that, contrary to Mr. Hevert's argument, the market is NOT static and, by mathematical definition, higher stock prices in the face of unchanging dividend growth forecasts translates into lower ROEs. Mr. Hevert's arguments are simply an effort to mislead the Commission into believing that market returns do not change. Such a position is simply wrong from a basic mathematical standpoint and financial position, as well as from a simple common-sense position.

Today, in the midst of the COVID-19 pandemic and market downfall, it will be highly interesting to see how Mr. Hevert adjusts his ROE recommendation in this case. I will not be surprised to now see Mr. Hevert backtrack on his earlier assertions that the DCF was not reliable and, instead, now tout the virtues of the model.

The fundamental problem with Mr. Hevert's analysis is that his models don't produce the results he wants for his utility clients. Mr. Hevert has been claiming for over three years that interest rates will rise and utility stock prices will fall.[39] Up until the current market downfall due to the COVID-19 pandemic, Mr. Hevert has been flat wrong in his prognostications. Even today, he is only half-correct. Interest rates have fallen, but so have utility stock prices. Regardless, Mr. Hevert's analyses are constantly changing in an attempt to present unrealistic returns for his utility clients.

There is no problem with the DCF model. It is working exactly as it should in today's market in that as prices move upward, returns go down, and vice versa. Such is a basic mathematical reality, as noted above, that Mr. Hevert fails to appreciate.

Q. WHAT IS THE RANGE OF RESULT FOR MR. HEVERT'S DCF ANALYSIS?

A. **Table 1a** of Mr. Hevert's pre-filed direct testimony on Pg. 12 shows mean DCF results of 8.78% to 8.97%. The midpoint of this range of 8.84%. Despite the

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[39] *See, e.g.*, Pre-filed testimony of Robert Hevert before the NC Utilities Commission in Docket No. E-7, Sub 1146, Pg. 82 (June 1, 2017) (stating that investors clearly expect interest rates to rise in the near- and long-term).

results of his own DCF analysis, Mr. Hevert recommends a significantly higher ROE of 10.5% in this proceeding.

Q. HOW IS MR. HEVERT'S CAPM ANLYSIS BIASED UPWARD?

A. The risk premiums used by Mr. Hevert in his analysis are grossly in excess of forecasts cited by market professionals. Specifically, as shown in **Exhibit RBH-4**, of Mr. Hevert's testimony,[40] his risk premium range of 12.04% to 12.19% are contingent upon Mr. Hevert's overall market forecast of 14.48% to 14.62% return on the market.[41]

Mr. Hevert's **Chart 17**, which is found on Pg. 99 of his pre-filed testimony, shows that Mr. Hevert's market premiums tend to increase when interest rates decrease.[42] In this case, Mr. Hevert is using a market risk premium of 12.04% to 12.19% at a time when 30-year Treasury bonds are yielding less than 2.0%[43]. However, when one looks at Mr. Hevert's **Chart 16**, the risk premium for 30-year U.S. Treasury bonds yielding 2% is approximately 8%, not the 12.04% to 12.19% as claimed by Mr. Hevert. In fact, a risk premium of anything over 8% is not even found on Mr. Hevert's **Chart 16**, thereby showing Mr. Hevert's own data proves his methods are biased to generate a high ROE for his utility clients.

Q. WHAT EXPECTED MARKET RETURN DOES MR. HEVERT USE IN THE CAPM ANALYSIS HE EMPLOYS IN THIS CASE?

A. In his direct testimony in this case, Mr. Hevert uses expected market return estimates of 14.48% to 14.62% return on the market.[44] As I will demonstrate in

[40] Exhibit RBH-4

[41] Exhibit RBH-2

[42] Hevert prefiled direct, Pg. 95

[43] *See* U.S. Department of Energy, Daily Treasury Yield Curve Rates, available at https://www.treasury.gov/resource-center/data-chart-center/interest-rates/Pages/TextView.aspx?data=yield .

[44] Hevert prefiled direct testimony, Exhibit RBH-2, Pg. 1, 8

this testimony, market professionals are expecting total returns of approximately half of Mr. Hevert's outrageous forecast of 14.48% to 14.62%.

Q. HOW DOES THIS MARKET FORECAST OF 14.48% TO 14.62% COMPARE WITH HISTORICAL RETURNS?

A. Historically, as noted previously, the market returns have averaged 10.0% (geometric mean) to 12.0% (arithmetic mean), both of which are well below the bottom end of Mr. Hevert's forecast. I urge the Commission to consider whether Mr. Hevert's market return forecast of nearly 15% makes sense in today's marketplace.

Q. HOW IS MR. HEVERT'S RISK PREMIUM ANALYSIS BIASED UPWARDS FOR HIS UTILITY CLIENTS?

A. The same errors cited above in regard to market forecasts and risk premium embedded in Mr. Hevert's CAPM have flowed through to his Risk Premium analysis. Specifically, the risk premiums espoused by Mr. Hevert are nonsensical and have no fundamental basis in reality. As I demonstrated above, one need only to look at Mr. Hevert's **Chart 17** to see that the risk premiums he suggests in this case do not match the risk premiums as found in his own chart.

Q. HAS ANY NEARBY STATE REGULATORY BODY RECENTLY RECOGNIZED OBVIOUS FLAWS EXHIBITED IN MR. HEVERT'S TESTIMONY?

A. Yes. Mr. Hevert filed testimony on behalf of Dominion Virginia Power at the Virginia State Corporation Commission ("Virginia SCC") in Case No. PUR-2017-00038. Mr. Hevert's recommendation was that Dominion Virginia Power ("DVP") should be granted a 10.50% ROE which, ironically, is the same ROE he is recommending in this case. The Virginia SCC weighed the evidence and instead granted DVP a 9.20% ROE. The Virginia SCC found the following:

1. Mr. Hevert's proposed cost of equity of 10.25% to 10.75% did not represent the actual cost of equity in the marketplace nor a reasonable ROE for DVP;[45]
2. Mr. Hevert's recommended ROE of 10.50% was not supported by reasonable growth rates, DCF methods or risk premium analyses;[46]
3. Mr. Hevert's application of the CAPM was flawed and his application of the Bond Yield Plus Risk Premium model contained similar flaws as his CAPM analysis;[47] and
4. Mr. Hevert's claim of Dominion deserving a 10.50% ROE due to certain business risk was summarily rejected because the majority of DVP's future CapEx could be recovered through automatic revenue adjustment clauses.[48]

Q. ARE YOU AWARE OF ANY REGULATORY BODY THAT HAS RECENTLY AUTHORIZED A ROE OF LESS THAN 9.0%?

A. Yes. For one, on May 28, 2019, the Public Utility Commission of South Dakota authorized an 8.75% ROE for Otter Tail Power in Docket No. EL 18-021.

Q. WHO WAS THE RATE OF RETURN WITNESS FOR OTTER TAIL POWER IN THAT RATE CASE AND WHAT WAS HIS/HER RECOMMENDATION?

A. Mr. Robert Hevert was the witness for Otter Tail Power in the South Dakota proceeding. Mr. Hevert's recommendation in the South Dakota case was 10.30%.

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45 *Application of Virginia Electric and Power Company For the Determination of the Fair Rate of Return on Common Equity to be Applied to its Rate Adjustment Clauses*, Case No. PUR-2017-00038, Final Order, 4 (Nov. 29, 2017).

46 *Id.*

47 *Id.* at 5.

48 *Id.* at 6.

Q. ARE YOU AWARE OF ANY STATE REGULATORY BODY IN THE SOUTHEAST THAT HAS RECENTLY ENTERED AN ORDER IN WHICH MR. HEVERT HAS BEEN THE WITNESS FOR THE PETITIONING UTILITY? IF SO, WHAT WAS THE ALLOWED ROE SET BY THAT REGUALTORY BODY?

A. Yes. Mr. Hevert testified in both of the Duke Energy subsidiary rate cases heard in South Carolina. Mr. Hevert recommended a 10.75% ROE in both cases. However, on May 1, 2019, the South Carolina Public Service Commission ("SCPSC") authorized Duke Energy Progress to earn a 9.50% ROE.

B. O'Donnell Cost of Capital Analysis

1. Economic and Regulatory Policy Guidelines for a Fair Rate of Return

Q. PLEASE EXPLAIN THE CONCEPT OF RISK AND RETURN AND HOW THAT RELATIONSHIP IMPACTS THE COST OF CAPITAL IN UTILITY RATEMAKING.

A. In order for a utility, such as DEP, to provide safe, reliable, and adequate service, it must invest in capital equipment to meet the needs of the citizens and businesses located in its service area. To raise the funds needed for the investments, DEP must ask investors to either invest in the Company by purchasing equity in a company, or to loan it funds by purchasing debt from the Company. Investors will only buy equity in a Company or loan it money if the promised returns for those invested or borrowed funds are commensurate with the level of risk of the Company. As one might expect, the riskier the business, the higher the return investors expect from that investment. Correspondingly, the lower the risk, the lower the cost of capital.

Q. IS THE OPERATION OF A REGULATED UTILITY CONSIDERED TO BE LOW-RISK, MEDIUM RISK, OR HIGH RISK?

A. Operating a regulated utility with a defined service territory is considered a low-risk business in that it has a monopoly of such service within its territory and that it can ask for higher rates when it needs or wants more revenue to meet the Company's defined needs in its service territory.

Q. IS THERE A WAY TO MEASURE THE RISK OF A UTILITY VERSUS ANOTHER COMPANY OPERATING IN COMPETITIVE MARKETS?

A. Yes. As will be discussed later in this testimony, beta represents a measure of risk of owning a company relative to the total overall market. Specifically, beta is a measurement of the volatility of one investment relative to the overall volatility in the entire equity market. The overall market has a beta of 1.0. A company with low risk, as measured in volatility, has a beta of less than 1.0, whereas a company with high risk has a beta of greater than 1.0. The concept of beta is a well-known financial tool used in risk assessment and the CAPM for many decades.

Q. WHAT IS THE BETA OF DEP?

A. DEP does not have a beta as it is owned by Duke Energy Corp., which is a utility holding company. Duke Energy Corp., however, has a beta of 0.45,[49] thereby showing it is far less risky than the overall market.

Q. HOW DOES THIS LOW-RISK UTILITY OPERATION TRANSLATE INTO THE EXPECTED RETURN FROM INVESTORS?

A. Investors in a low-risk utility operation should receive a return commensurate with that risk. Specifically, investors in a low-risk utility venture expect returns lower than more risky entities, represented by the total investment opportunities in the marketplace.

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[49] *Value Line* Investment Survey: 2/14/2020

Q. DOES THE FACT THAT A UTILITY IS REGULATED POSE ANY RISK TO A UTILITY?

A. No. Despite the fact that regulation involves requirements, such as reporting, and an obligation to serve, a regulated utility has less risk overall. The fact that the utility has the protection of regulation, including the opportunity to recover its cost of service and earn a fair return, is a risk-reducing component of operating a utility business.

Q. PLEASE BRIEFLY DESCRIBE THE ECONOMIC AND REGULATORY POLICY CONSIDERATIONS YOU HAVE TAKEN INTO ACCOUNT IN DEVELOPING YOUR RECOMMENDATION CONCERNING THE FAIR RATE OF RETURN THAT UTILITY COMPANIES SHOULD HAVE AN OPPORTUNITY TO EARN.

A. The theory of utility regulation assumes that public utilities perform functions that are natural monopolies. Historically, it was believed or assumed that it was more efficient for a single firm to provide a particular utility service than multiple firms. Even though deregulation for the procurement of natural gas and generation of electric power and energy is spreading, delivery of these products to end-use customers is still a monopoly business and will, for the foreseeable future, be regulated. On this basis, state legislatures or Commissions establish exclusive franchised territories to public utilities or determine territorial boundaries where disputes arise, in order for these utilities to provide services more efficiently and at the lowest reasonable cost. In exchange for the protection within its monopoly service area, the utility is obligated to provide adequate, universal service at fair, regulated rates.

Q. WHAT CONSTITUTES A JUST AND REASONABLE RATE OF RETURN?

A. The generally accepted answer is that a prudently managed electric utility should be allowed to recover the reasonable and prudent costs of providing utility service and the opportunity to earn a fair rate of return on invested capital. This just and reasonable rate of return on capital should allow the utility, under prudent management, to provide adequate service and attract capital to meet future expansion needs in its service area. Since public utilities are capital-intensive businesses, the cost of capital is a crucial issue for utility companies, their customers, and regulators. If the allowed rate of return is set too high, then consumers are burdened with excessive costs, current investors receive a windfall, and the utility has an incentive to overinvest. If the return is set too low, adequate service is jeopardized because the utility will not be able to raise new investment or working capital on reasonable terms. Since every equity investor faces a risk-return tradeoff, the issue of risk is an important element in determining the fair rate of return for a utility.

Q. PLEASE SUMMARIZE THE LEGAL STANDARDS FOR DETERMINING A UTILITY RATE OF RETURN.

A. Although I am not a lawyer, based on my experience, I have come to understand certain basic legal tenets regarding rate of return determinations. Regulatory law and policy recognize that utilities compete with other firms in the market for investor capital. The United States Supreme Court set the guidelines for a fair rate of return in two often-cited seminal cases: *Bluefield Water Works and Improvement Co. v. Public Service Comm'n.* 262 U.S. 679, 692; (1923) ("*Bluefield*") and the *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944) ("*Hope Natural Gas*").

In the *Bluefield* case, the Supreme Court stated:

> "*A public utility is entitled to such rates as will permit it to earn a return upon the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit, and*

enable it to raise the money necessary for the proper discharge of its public duties."[50]

In the above finding, the Court found that utilities are entitled to earn a return on investment similar to companies of comparable risks and that the corresponding return should be sufficient enough to support credit activities and to raise funds to carry out its mission. In *Hope Natural Gas*, the U.S. Supreme Court also recognized that utilities compete with other firms in the market for investor capital.

Q. PLEASE EXPLAIN THE SIGNIFICANCE OF THE HOPE NATURAL GAS CASE AS IT APPLIES TO THE CURRENT RATEMAKING PURPOSES?

A. Over the years, this case has provided legal and policy guidance concerning the return which public utilities should be allowed to earn. In *Hope Natural Gas*, the U.S. Supreme Court stated that the return to equity owners (or shareholders) of a regulated public utility should be "*commensurate*" to returns on investments in *other* enterprises whose "*risks correspond*" to those of the utility being examined:

"[T]he 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 credit and attract capital."[51]

The *Hope Natural Gas* case is still the primary guideline for utility ratemaking. Specifically, the guideline set by the Supreme Court is to ensure that the returns set by regulatory bodies are commensurate with risks of investments that have similar risks.

[50] *Bluefield*, 262 U.S. at 692.

[51] *Hope Natural Gas*, 320 U.S. at 603.

Q. HAS THE HOPE/BLUEFIELD STANDARD BEEN ADOPTED BY THE COMMISSION?

A. Yes. This Commission has emphasized that a rate of return on common equity must fall within the range of reasonableness under the Commission's statutory authority to set just, reasonable, and nondiscriminatory rates.[52] The Commission has previously approved standards such as these described by the D.C. Court of Appeals, as follows:

> *"The Commission, not this court, has the responsibility for establishing rate designs and for setting specific utility rates . . . . Rate design principles and specific rates approved by the Commission, however, must be "reasonable, just, and nondiscriminatory." . . . This statutory authority is deliberately broad and gives the Commission authority to formulate its own standards and to exercise its ratemaking function free from judicial interference, provided the rates fall within a zone of reasonableness which assures that the Commission is safeguarding the public interest that is, the interests of both investors and consumers . . . . From the investor standpoint, courts have defined the lower boundary of this zone of reasonableness as "one which is not confiscatory in the constitutional sense." . . . From the consumer standpoint, the upper boundary cannot be so high that the rate would be classified as "exorbitant." "*[53]

Q. DO YOU HAVE ANY OTHER COMMENTS REGARDING THE LEGAL PRECEDENT DESCRIBED IN THIS TESTIMONY?

A. Yes. I want to reiterate and make clear that I am a financial analyst and not an attorney. As such, all descriptions of relevant law included in this testimony are my personal interpretations and I am not offering legal advice.

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52 *See Formal Case No. 1139*, Order No. 18846¶ 276, July 25, 2017 at Pg. 87; *Formal Case No. 1093*, Order No. 17132 ¶ 40, May 15, 2013, at Pg. 16.

53 *See, e.g.*, In the Matter of the Application of Potomac Electric Power Co. for Authority to Increase Existing Retail Rates and Charges for Electric Distribution Service, Formal Case No. 1139, Opinion and Order No. 18846 (Jul. 25, 2017) at P 276, citing *Metropolitan Board of Trade v. Pub. Serv. Comm'n of the District of Columbia*, 432 A.2d 343, 350 (D.C. 1981).

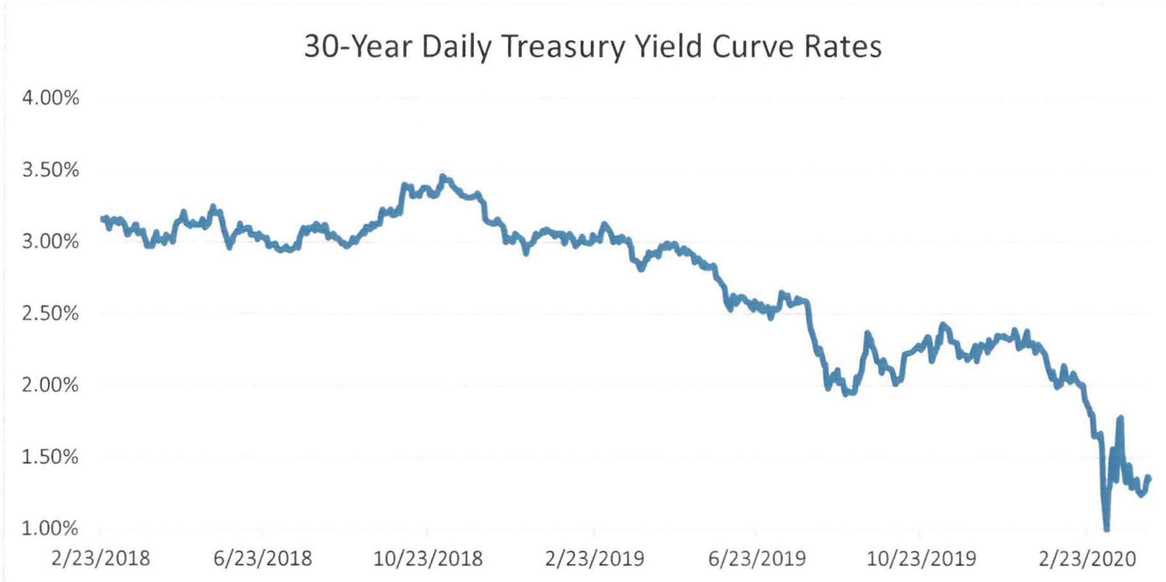
2. Current State of the Financial Markets

Q. HOW HAS THE DEBT MARKET FOR DEP CHANGED SINCE THE COMPANY'S LAST RATE CASE?

A. The Company's last rate case began in 2017 and a final order was issued for this case on February 23, 2018. Long-term interest rates have fallen since the Company's last rate case.[54] In **Chart 4** below, I have provided the change in the 30-year U.S. Treasury bonds subsequent to February 23, 2018. On that date, the yield on 30-year U.S. Treasury bonds was 3.16%. As of March 13, 2020, the yield on 30-year U.S. Treasury bonds was 1.56%, which equates to a 160-basis point decrease in the yield on 30-year U.S. Treasury bonds. Additionally, the yield on the 30-year U.S. Treasury bonds on April 9, 2020 (i.e. the most recent date with data as of the date that the data was pulled on April 10, 2020) was 1.35%, equating to a 181-basis point decrease in the yield on the 30-year U.S. Treasury bons. As such, this drop in interest rates implies the cost of capital has fallen significantly since DEP's last rate case, thereby indicating the Company's cost of capital is lower throughout 2020 than it was at the time of the prior rate case.

[54] S&P Global, Rate Case History, available at snl.com (data retrieved March 16, 2020).

Chart 4: Yield on 30-Year U.S. Treasury Bonds[55]



Q. HAS THE FEDERAL RESERVE RECENTLY LOWERED INTEREST RATES?

A. Yes, on September 18, 2019, the Federal Reserve decreased the Federal Funds target range to 1.75% from 2.0%.[56] On October 30, 2019, the Federal Reserve lowered the target federal funds rate to 1.5% from 1.75%.[57] In its mid-December meeting, the Federal Reserve chose not to change interest rates.[58] Subsequently, on March 3, 2020, the Federal Reserve decreased the Federal Funds rates 50 basis points to a targeted range of between 1% and 1.25% in response to recent market

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55 U.S. Department of Treasure, *Daily Treasury Yield Curve Rates*, available at https://www.treasury.gov/resource-center/data-chart-center/interest-rates/Pages/TextView.aspx?data=yield (2018, 2019, and 2020 data retrieved April 10, 2020).

56 *See* Board of Governors of the Federal Reserve System, *Federal Reserve Issues FOMC Statement* (Sept. 18, 2019), available at: https://www.federalreserve.gov/newsevents/pressreleases/monetary20190918a.htm.

57 *See* Board of Governors of the Federal Reserve System, *Federal Reserve Issues FOMC Statement* (Oct. 30, 2019), available at: https://www.federalreserve.gov/newsevents/pressreleases/monetary20191030a.htm.

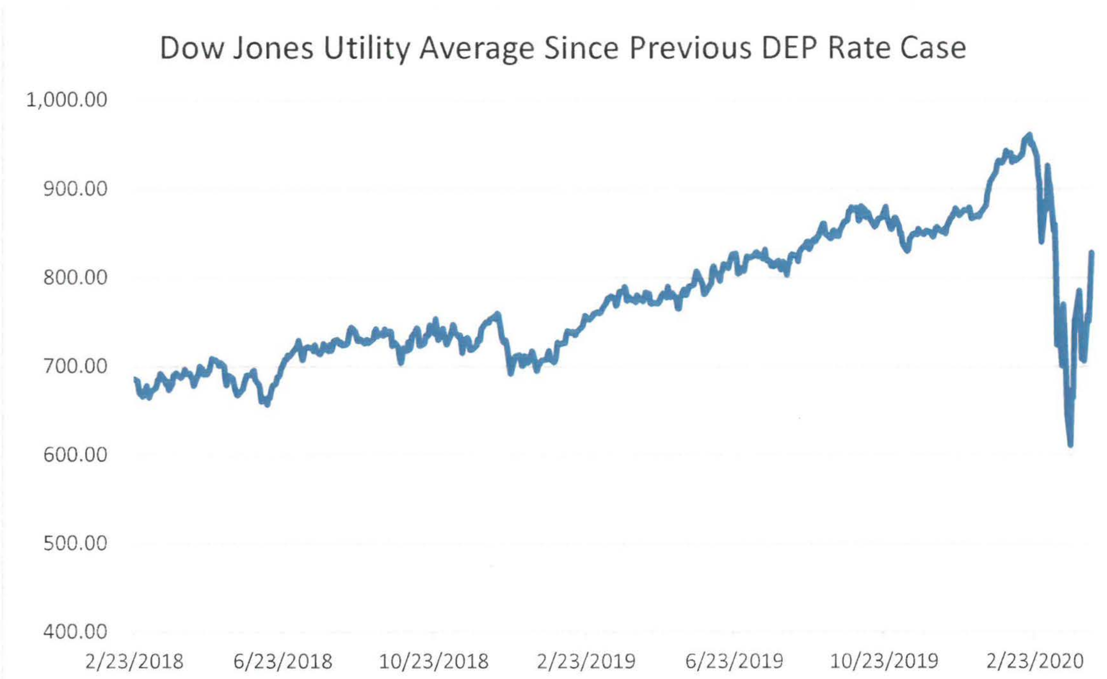
58 *See* Board of Governors of the Federal Reserve System, *Federal Reserve Issues FOMC Statement* (Dec. 11, 2019), available at: https://www.federalreserve.gov/newsevents/pressreleases/monetary20191211a.htm.

conditions.[59] On March 16, 2020, the Federal Reserve cut interest rates to near 0% in a reaction to the coronavirus pandemic.[60]

Q. HOW HAS THE STOCK MARKET FOR UTILITIES CHANGED SINCE THE COMPANY'S LAST RATE CASE?

A. Until the recent coronavirus scare, the stock market had been incredibly strong and constantly setting new highs. However, since the severity of the coronavirus situation became clear, the market fell dramatically. The only "*constant*" in the market of-late is an increase in volatility for all investors. **Chart 5** below shows the dramatic changes in the utility equity market since the Company's last rate case in 2018.

Chart 5: Dow Jones Utility Average Since Last DEP Rate Case[61]



59 https://www.cnbc.com/2020/03/03/heres-what-this-surprise-fed-rate-cut-means-for-you.html
60 https://www.cnn.com/2020/03/15/economy/federal-reserve/index.html
61 Yahoo Finance, https://finance.yahoo.com/quote/%5EDJU/history?p=%5EDJU (data retrieved April 10, 2020).

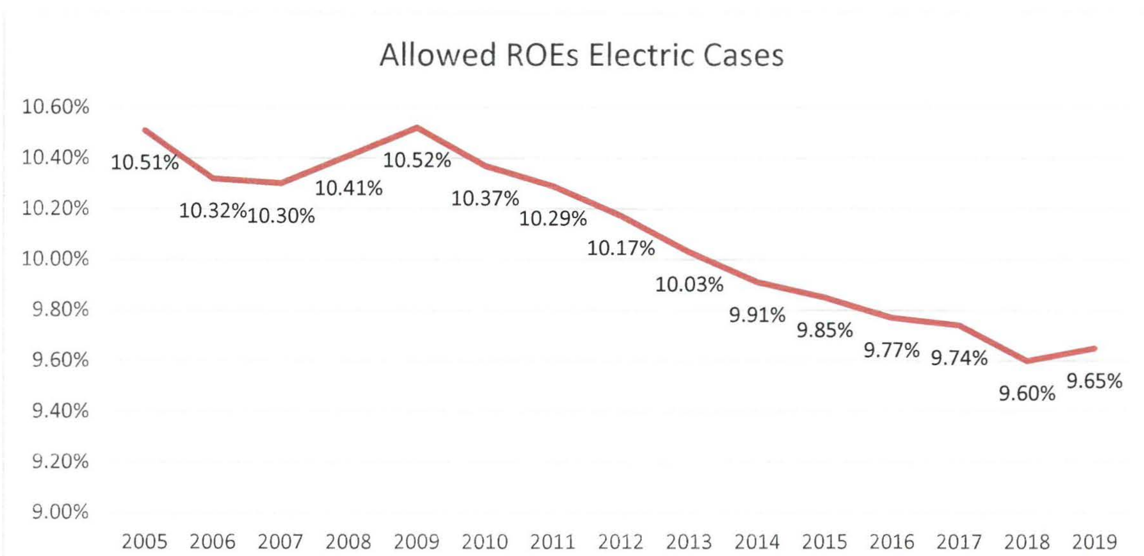
Q. WHEN WAS THE LAST ELECTRIC RATE CASE HEARD BY THIS COMMISSION AND WHAT ROE CAME FROM THAT CASE?

A. On Sept. 17, 2019, the Public Staff and Dominion North Carolina Power filed a joint settlement agreement whereby the parties agreed to a 9.75% ROE. Since the final order in that case, the market had soared, only to fall precipitously in the wake of the impact from the coronavirus / COVID-19 pandemic.

Q. HOW DOES THE COMPANY'S REQUEST IN THIS CASE COMPARE TO THE OVERALL TREND IN ALLOWED ROEs?

A. As this Commission is likely aware, regulated ROEs have trended down over the past 15 years. In **Chart 7** below, I have provided a chart that shows the ROEs allowed for electric utilities by state regulators across the United States from 2005 through 2019.

Chart 7: Allowed ROEs 2005 – 2019[62]



62 S&P Global Market Intelligence, Rate Case History; Date Range: 15 Years; Service Type: Electric; Chart Items: Common Equity to Total Capital, Return on Equity (Retrieved March 16, 2020) (source for raw data)

As for the most recent year, 2019, the overall allowed ROE for electric utilities was 9.65%,[63] which included a recent ruling from the nearby Virginia State Corporation Commission which authorized a 9.20% ROE for Dominion Virginia Power.

3. Development of DEP's Proxy Group

Q. COULD YOU PERFORM A COST OF EQUITY ANALYSIS DIRECTLY ON DEP?

A. No. DEP is a wholly-owned subsidiary of Duke Energy Corp. Since DEP's stock is not publicly traded, I could not develop a cost of equity specifically for DEP. For that reason, I developed a proxy group of companies to assess the risk and corresponding return for DEP.

Q. PLEASE EXPLAIN HOW YOU DEVELOPED A PROXY GROUP FOR DEP.

A. I used the following parameters for developing a proxy group of similarly situated companies to DEP from which to derive a just and reasonable ROE:

1. All companies must be followed by the *Value Line* Investment Survey ("*Value Line*") as an electric utility;
2. All companies must derive at least 50% of their 2018 revenues from regulated utilities;
3. All companies have an investment grade credit rating;
4. No company can be in the midst of merger or acquisition discussions;
5. All companies must have at least 5 years of historical data; and
6. All companies must have paid a dividend each quarter in the past year.

63 S&P Global Market Intelligence, Rate Case History; Date Range: 15 Years; Service Type: Electric; Chart Items: Common Equity to Total Capital, Return on Equity (Retrieved March 16, 2020) (source for raw data)

Q. PLEASE EXPLAIN THE REASONING FOR THE FIRST PARAMETER IN THE CREATION OF YOUR COMPARABLE GROUP.

A. The *Value Line Investment Survey* is, in my opinion, the most trusted and referenced financial information publication in today's marketplace. *Value Line* provides a tremendous amount of information, both on a historical basis and on a forecasted basis. I focused solely on electric utilities as followed by *Value Line.* In today's world of large utility holding companies, it is virtually impossible to find a comparable group of large utilities that are well followed by the investment community that contain only electric utilities.

Q. PLEASE EXPLAIN THE REASONING FOR THE SECOND PARAMETER.

A. The second parameter requires that the utility obtain at least 50% of its revenues from regulated operations. Again, in today's world of utility holding companies, many companies have unregulated generation affiliates or other such subsidiaries, which is why this screen is important. I used a threshold of 50% revenues to screen just for regulated utility operations in order to ensure the level of risk for the comparable group was consistent with low-risk utility operations.

Q. PLEASE EXPLAIN THE REASONING FOR THE THIRD PARAMETER.

A. The third parameter includes companies with only investment grade credit ratings to ensure that no companies that are currently in, or close to, bankruptcy would be included in the group. The reason for the exclusion of companies in bankruptcy is that bankruptcy adds an element of risk that is counter to the low-risk nature of a utility, such as DEP. Companies that continue to operate in bankruptcy proceedings are, generally, much riskier than those that are not in bankruptcy.

Q. PLEASE EXPLAIN THE REASONING FOR THE FOURTH PARAMETER.

A. For the fourth parameter, I excluded companies that are in the midst of merger or acquisition discussions as stock prices for those utilities often operate based on immediate financial gain instead of long-term operating abilities. This has the effect of distorting the DCF returns as short-term capital gains becomes part of the pricing process.

Q. PLEASE EXPLAIN THE REASONING FOR THE FIFTH PARAMETER.

A. I believe investors' confidence is strengthened with historical information from which they can gather and assess trends. When a company does not have such history, I don't feel it is truly comparable to a company, such as Pepco, that does have such a long track record.

Q. PLEASE EXPLAIN YOUR SIXTH PARAMETER

A. Finally, I required all companies in my proxy group to have consistently paid dividends over the past year, with no cuts. The reason for this parameter is to ensure the utility's stock price is reacting to long-term operating characteristics and not in reaction to short-term dividend payments.

Q. DOES DEP MEET ALL THE PARAMETERS AS SET FORTH IN YOUR COMPARABLE GROUP GUIDELINES?

A. DEP does not meet all of the above-stated guidelines because it is a wholly owned subsidiary of Duke Energy Corp. However, these guidelines do reflect the relatively low-risk nature of utility operating companies and are, therefore, comparable to DEP in their operating natures.

Q. DID YOU PERFORM A COST OF EQUITY ANALYSIS ON ANY OTHER PROXY GROUP INTRODUCED IN THIS CASE?

A. Yes, I also used the Hevert proxy group in my cost of equity analysis in this case. Specifically, I subjected the Hevert proxy group to my cost of capital analysis in the same manner as I did with the O'Donnell proxy group.

Q. IS DEP PART OF MR. HEVERT'S COMPARABLE GROUP?

A. No, for the reasons stated above, DEP is not part of Mr. Hevert's comparable group in that it is a subsidiary of Duke Energy and does not have publicly traded stock.

Q. WHY DID YOU ALSO ANALYZE THE HEVERT PROXY GROUP AS PART OF YOUR COST OF CAPITAL ANALYSIS IN THIS CASE?

A. I analyzed the Hevert proxy group to provide the Commission with as much information as possible on which to make its decision. The addition of the Hevert proxy group to my analysis also provides a benchmark on which to check the O'Donnell proxy group and assists in providing a complete and robust analysis.

4. Cost of Common Equity

Q. PLEASE EXPLAIN HOW THE ISSUE OF DETERMINING AN APPROPRIATE RETURN ON A UTILITY'S COMMON EQUITY INVESTMENT FITS INTO A REGULATORY AUTHORITY'S DETERMINATION OF JUST AND REASONABLE RATES FOR THE UTILITY.

A. In North Carolina, as in virtually all regulatory jurisdictions, a utility's rates generally must be "*just and reasonable.*" Thus, regulation recognizes that utilities are entitled to an opportunity to recover the reasonable and prudent costs of providing service, and the opportunity to earn a fair rate of return on the capital invested in the utility's facilities, such as electric distribution equipment, buildings, vehicles, and similar long-lived capital assets.

Q. HOW DOES THE MANNER IN WHICH UTILITIES OBTAIN CAPITAL FUNDING RELATE TO THE COMMISSION'S DETERMINATION OF THE APPROPRIATE COST OF CAPITAL FOR A SPECIFIC UTILITY?

A. Utilities obtain capital funding through a combination of borrowing (i.e. debt financing) and issuing stock (i.e. equity financing). The allowed ROE is the amount that is determined to be just and reasonable for the utility's common stockholders to earn on the capital that they invest in the utility when they buy its stock when balanced against the interests of ratepayers to avoid overpaying to allow the company with access to capital. If the regulatory authority sets the ROE too low, the stockholders will not have the opportunity to earn a fair return and this may either cause existing shareholders to sell their shares or deter new investors from buying shares. If, on the other hand, the regulatory authority sets the ROE too high, the ratepayers will pay too much. Because ratepayers cannot choose a different utility due to the monopolistic service territory restrictions, countervailing competitive market forces are absent and the resulting rates will be unjust and unreasonable to the ratepayer.

Q. HOW IS THE ESTIMATED SHARE PRICE USED IN DETERMINING THE LEVEL OF A UTILITY'S ALLOWED EARNINGS?

A. A cost of capital model, such as the DCF, uses current stock price values to determine the return that investors expect from that stock. The relationship between stock prices and returns are inversely related in that when stock prices go up, the expected returns go down. The opposite is also true in that, when stock prices go down, the expected returns go up. As a result, utility stock prices have a direct and immediate bearing on the return allowed by state regulators.

Q. HOW DO REGULATORY AUTHORITIES GO ABOUT DETERMINING A JUST AND REASONABLE RATE OF RETURN ON EQUITY FOR A UTILITY COMPANY?

A. Regulatory commissions and boards, as well as financial industry analysts, institutional investors, and individual investors, use different analytical models and methodologies to estimate/calculate reasonable rates of return on equity, including the DCF model and the Capital Asset Pricing Model ("CAPM").

Q. CAN YOU EXPLAIN WHY REGULATORY AUTHORITIES AND FINANCIAL ANALYSTS NEED TO USE SUCH METHODOLOGIES TO DERIVE A COMPANY'S ESTIMATED RATE OF RETURN ON EQUITY?

A. Yes. There is no direct, observable way to determine the rate of return required by equity investors in any company or group of companies. Investors must make do with indications from market data and analysts' predictions to estimate the appropriate price of a share.

Q. PLEASE EXPLAIN WHY YOU BELIEVE THE DCF MODEL IS SUPERIOR TO OTHER APPROACHES.

A. The DCF is a pure investor-driven model that incorporates current investor expectations based on daily and ongoing market prices. When a situation develops in a company that affects its earnings and/or perceived risk level, the price of the stock adjusts immediately. Since the stock price is a major component in the DCF model, the change in risk level and/or earnings expectations is captured in the investor return requirement with either an upward or downward movement to account for the change in the company.

This stands in stark contrast to book-based methodologies that are based on earned returns from book equity, not market equity. In these models, there is no direct and immediate stockholder input and thus, has no bearing on stockholder expectations.

a. Discounted Cash Flow Model

Q. PLEASE EXPLAIN THE DISCOUNTED CASH FLOW MODEL.

A. The DCF method is a widely used method for estimating an investor's required return on a firm's common equity. In my thirty-four years of experience, first with the Public Staff of the North Carolina Utilities Commission and later as a consultant, I have seen the DCF method used much more often than any other method for estimating the appropriate return on common equity. Consumer advocate witnesses, utility witnesses, and other intervenor witnesses have used the DCF method, as do many regulators, including the Federal Energy Regulatory Commission, either by itself or in conjunction with other methods such as the CAPM, in their analyses.

The DCF method is based on the concept that the price which the investor is willing to pay for a stock is the discounted present value (*i.e.*, its present worth) of what the investor expects to receive in the future as a result of purchasing that stock. This return to the investor is in the form of future dividends and price appreciation. However, price appreciation is only realized when the investor sells the stock, and a subsequent purchaser presumably is also focused on dividend growth following his or her purchase of the stock. Mathematically, the relationship is:

Let D = dividends per share in the initial future period

g = expected growth rate in dividends

k = cost of equity capital

P = price of asset (or present value of a future stream of dividends)

$$\text{then } P = \frac{D}{(1+k)} + \frac{D(1+g)}{(1+k)^2} + \frac{D(1+g)}{(1+k)^3} + \ldots\ldots + \frac{D(1+g)}{(1+k)^t}$$

This equation represents the amount (P) an investor will be willing to pay *today* for a share of common equity with a given dividend stream over (t) periods.

Reducing the formula to an infinite geometric series, we have:

$$P = \frac{D}{k-g}$$

Solving for k yields:

$$k = \frac{D}{P} + G$$

Q. MR. O'DONNELL, DO INVESTORS IN UTILITY COMMON STOCKS REALLY USE THE CONSTANT GROWTH DCF MODEL IN MAKING INVESTMENT DECISIONS?

A. Yes, I believe that to be so. There are three primary reasons for my conclusion. First, there is extensive literature that supports the fact that, while so-called "*irrational*" behavior in the short term may affect (and has affected) share prices, over the long term a company's financial fundamentals drive the market.[64] Second, analysts give great weight to earnings, dividend, and book value growth in formulating their recommendations to clients. Finally, even a casual search on the internet produces hundreds of pages discussing the definition of the DCF methodology and how to apply it for investment decisions, from which I infer that general investor interest in DCF analysis is significant and widespread.

Thus, in today's investment environment, a stock investor will likely calculate (or seek a calculation of) the amount of funds they will receive relative to the initial investment, which is defined as the current dividend yield, as well as the amount of funds that the investor can expect in the future from the growth in the dividend.

The combination of the current dividend yield and the future growth in dividends is central to the basic tenet of the DCF model.

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64 *See, e.g.*, Koller, T. et al., *Valuation: Measuring and Managing the Value of Companies*, 4th Edition, McKinsey & Company (2010) ("Provided that a company's share price eventually returns to its intrinsic value in the long run, managers would benefit from using a discounted-cash-flow approach for strategic decisions. What should matter is the long-term behavior of the share price of a company, not whether it is undervalued by 5 or 10 percent at any given time."); see also Goedhart, M. et al., *Do fundamentals—or emotions—drive the stock market?*, McKinsey & Company, (March 2005), available at: **http://www.mckinsey.com/business-functions/strategy-and-corporate-finance/our-insights/do-fundamentalsor-emotionsdrive-the-stock-market;** Weisenthal, J., *And Now We Know For Sure What's Really Been Driving The Market The Last Few Years...*, Business Insider (Aug. 15, 2012), available at: **http://www.businessinsider.com/what-drives-the-stock-market-2012-8.**

Q. IS THE DCF FORMULA EASY TO UNDERSTAND?

A. Yes. While the DCF formula stated above may appear complicated, it is intuitively a very simple model to understand. To determine the total rate of return one expects from investing in a particular equity security, the investor adds the dividend yield, which they expect to receive in the future, to the expected growth in dividends over time. If the regulatory authority sets the rate at a level consistent with the foundational principles established in *Hope Natural Gas* and *Bluefield*, the utility will be able to attract capital, without forcing the utility's customers to pay more than necessary to attract needed capital.

Q. CAN YOU GIVE AN EXAMPLE?

A. Yes. If investors expect a current dividend yield of 5%, and also expect that dividends will grow at 4% for a particular utility, then the Constant Growth DCF model indicates that investors would buy the utility's common stock if it provided a return on equity of 9%.

Q. WHAT DIVIDEND YIELD DO YOU THINK IS APPROPRIATE FOR USE IN THE DCF MODEL?

A. Because the DCF formula relies upon the expected dividend yield in deriving investor expectations, I have calculated the appropriate dividend yield by averaging the dividend yield expected over the next 12 months for each proxy company, as reported by the *Value Line Investment Survey*. For purposes of my calculation, I relied on the values reported for the period of January 17, 2020 through April 10, 2020 by *Value Line*. In order to study the short-term as well as long-term movements in expected dividend yields, I incorporated the 13-week, 4-week, and 1-week average dividend yields expected over the next 12 months as reported by *Value Line* for each of the proxy groups. My results appear in **Exhibit KWO-1**, showing an average range of 3.2% to 3.7% across all study periods for the O'Donnell proxy group. **Exhibit KWO-6** shows a range of 3.1% to 3.6% across the same study period range (i.e. 13-week, 4-week, and 1-week) for the Hevert proxy group.

It is important to note that my calculations as described above provide the forecasted annualized dividend yields, exactly as prescribed by the DCF model. The *Value Line* forecasted dividend yield represents the *Value Line* expected dividend to-be paid over the next 12 months divided by the current price.[65]

Q HOW DID YOU DEVELOP THE SPECIFIC DIVIDEND YIELD RANGES DISCUSSED ABOVE?

A. Each week, *Value Line* issues a Summary and Index report that provides the estimated yield over the next 12 months, as noted above, for the stocks it follows. To develop the market expectation of the dividend yield over the next year, I averaged these weekly expected yield values over three time periods: 13-weeks; 4 weeks; and 1-week. This range of time periods captures investor sentiment over a long-time period (13-weeks), a middle time period (4-weeks), and the most recent time period (1-week).

Q. HOW DID YOU DERIVE THE EXPECTED GROWTH RATE FOR YOUR DCF ANALYSIS?

A. I used five different methods in determining the growth in dividends that investors expect. These five methods, in my opinion, give a wide range of investor expectations based on historical data and forecasted projections. Therefore, I believe that these methods most accurately reflect the market's understanding of the underlying securities. Specifically, these five methods examine earnings, dividends, and book value growth over a 5-year and 10-year period, as well as several forecasts of earnings, dividends, and book value. Such a holistic approach to Company financial details provides the Commission with the best perspective of investment opportunities.[66] These five methods provide me a solid reference

65 *Value Line*, *Glossary* (last viewed, March 16, 2020) available at: **https://www.valueline.com/Glossary/GlossaryDisplay.aspx?taxonomyid=4294967301.**

66 In contrast, DEP witness Hevert offers testimony attempting to limit the Commission's review to only forecasted earnings growth rates.

of investor expectations in regard to future dividend growth expectations that are the second element in the DCF model.

Q. PLEASE DESCRIBE THE FIRST METHOD YOU USED TO DETERMINE GROWTH RATE.

A. The first method I used was an analysis commonly referred to as the "*plowback ratio*" method. If a company is earning a rate of return (*r*) on its common equity, and it retains a percentage of these earnings (*b*), then each year the earnings per share (EPS) are expected to increase by the product (*br*) of its EPS in the previous year. Therefore, *br* is a good measure of growth in dividends per share. For example, if a company earns 10% on its equity and retains 50% (the other 50% being paid out in dividends), then the expected growth rate in earnings and dividends is 5% (50% of 10%). To calculate a plowback for the proxy group, I used the following formula:

$$g = \frac{br(2017) + br(2018) + br(2019/2019E) + br(2022E\text{-}2025E\ Avg)}{4}$$

The 2022E to 2025E referenced above represents the average plowback estimate over the time period from 2022E through 2024E or 2023E through 2025E, depending on the company within the comparable proxy group. This is due to the fact that *Value Line* has published actual 2019 plowback ratios for certain of the companies in my comparable proxy group, while still holding estimated 2019E plowback ratios for certain of the other companies included in my comparable proxy group. As such, for any company included in my comparable proxy group with actual 2019 plowback ratios, the forecasted plowback ratio range is for the time period from 2023E-2025E, and for any company for which *Value Line* still includes 2019E estimated plowback ratios as of the date of this testimony, the forecasted plowback ratio range is for the time period from 2022E-2024E. While the estimated time periods referenced previously incorporates an estimate period of 3 years for each company included within the comparable proxy group subjected to my analysis, the above-stated formula provides a single average estimate for this three-year time period that is incorporated with the plowback tables presented within **Exhibit KWO-2** for each company within my comparable proxy group. The formula presented above therefore uses the plowback values from **Exhibit KWO-2** for at least two historical years, as well as the expected plowback ratio for at least 3 future estimated years. The plowback estimates for all companies in the proxy group can be obtained from *The Value Line Investment Survey* under the title "*percent retained to common equity.*"

A key component in the DCF Method is the expected growth in dividends. In analyzing the proper dividend growth rate to use in the DCF Method, the analyst must consider how dividends are created. Over the long term, dividends cannot be paid out without a corporation having sufficient earnings to pay for the dividends. Put another way, over the long-term, dividends cannot consistently outpace earnings as, if they do, the corporation cannot sustain the dividend payments. As a result, earnings growth is a key element in analyzing what if any growth can be expected in dividends. Similarly, what remains in a corporation after it pays its dividend is reinvested, or "*plowed back,*" into a corporation in order to generate future growth. As a result, book value growth is another element that, in my opinion, must be considered in analyzing a corporation's expected dividend growth.

Q. PLEASE DESCRIBE THE SECOND METHOD YOU USED TO DETERMINE GROWTH RATE.

A. To analyze the expected growth in dividends, I believe the analyst should first examine the historical record of past earnings, dividends, and book value. Hence, the second method I used to estimate the expected growth rate was to analyze the historical 10-year and 5-year historical compound annual rates of change for earnings per share ("EPS"), dividends per share ("DPS"), and book value per share ("BPS") as reported by *Value Line* for each of the relevant corporations.

Value Line is the most recognized investment publication in the industry and, as such, is used by professional money managers, financial analysts, and individual investors worldwide. A prudent investor tries to examine all aspects of an enterprise's performance when making a capital investment decision. As such, it is only practical to examine historical growth rates for the corporation for which the analysis is being performed. The historical growth rates for the O'Donnell comparable proxy group can be seen in **Exhibit KWO-1** and in **Exhibit KWO-6** for the Hevert comparable group. Additionally, the results of the O'Donnell DCF analysis derived partially from these historical growth rates can be found in **Exhibit KWO-4**.

I do note that certain analysts do not present historical growth rates in their DCF analyses. I believe analysts that do not present such available data fail to completely inform the respective regulatory bodies of the full extent of information on which investors base their expectations.

Q. PLEASE DESCRIBE THE THIRD METHOD YOU USED TO DETERMINE GROWTH RATE.

A. The third method I used was to rely upon the *Value Line* forecasted compound annual rates of change for earnings per share, dividends per share, and book value per share.

Q. PLEASE DESCRIBE THE FOURTH METHOD YOU USED TO DETERMINE GROWTH RATE.

A. The fourth method I used relied upon the forecasted rate of change for earnings per share as recorded by *Center for Financial Research* ("*CFRA*"), a publication of S&P Global Market Intelligence.

Q. PLEASE DESCRIBE THE FIFTH METHOD YOU USED TO DETERMINE GROWTH RATE.

A. The last method was another forecasted earnings growth rate as reported by the *Charles Schwab & Co.* (i.e. *Schwab*). This forecasted rate of change is not a forecast supplied by *Charles Schwab & Co.*, but is, instead, a compilation of forecasts by industry analysts.

The data behind my constant growth DCF analysis can be seen in **Exhibit KWO-1** for the O'Donnell comparable proxy group, and the results can be found within **Exhibit KWO-4**.

Q. WHAT ARE THE DIVIDEND YIELD RANGES FROM THE DCF ANALYSIS FOR THE O'DONNELL PROXY GROUP?

A. As shown on **Exhibit KWO-1** and **Exhibit KWO-4**, the expected dividend yield over the next 12 months as derived by for the average over the three timeframes discussed above (i.e. 13-weeks. 4-weeks, and 1-week) range from 3.2% – 3.7%. For the Hevert comparable group as shown in **Exhibit KWO-6** and **Exhibit KWO-9**, the expected dividend yield over the same time periods was 3.1% – 3.6%.

Q. WHAT ARE THE GROWTH RATE RANGES FROM THE DCF ANALYSIS FOR THE O'DONNELL PROXY GROUP?

A. In terms of the growth rates, the O'Donnell comparable proxy group has grown at a solid and steady pace. Over the past 10-years, the proxy group shows a range of growth rates from 3.7% (i.e. *Value Line* 5-year earnings per share EPS) to 6.1% (i.e. *Value Line* 5-year dividends per share DPS). The forecasted growth rates for the proxy group per *Value Line* are higher than its historical growth rates for EPS and BPS, and slightly lower than the historical growth rates for DPS. Additionally, of all of the forecasted growth rates presented on **Exhibit KWO-1** (i.e. *Value Line* Forecasted EPS, DPS and BPS / *CFRA* Forecasted EPS / *Schwab* Forecasted EPS), growth rates fall within the range of 4.5% (*Schwab* Forecasted EPS) to

5.7% (*CFRA* Forecasted EPS). Also, the plowback growth rate average for the comparable group is 3.7%. Refer to **Exhibit KWO-1** for all of these figures.

As for the proper dividend growth rate to employ for the comparable group in the DCF analysis, it is appropriate to examine the recent history of earnings and dividend growth to assess and provide the best estimate of the dividend growth that investors expect in the future. An examination of the 10-year and 5-year historical growth rates for the proxy group shows that dividends have been growing slightly faster than earnings. Dividends cannot, however, sustain a higher growth rate than earnings over the long-term as, eventually, there will not be sufficient earnings to pay dividends. The market expects this situation to begin to self-correct in the future with these rates drawing closer together in the Forecasted numbers, as the *Value Line* forecasted earnings and dividends for the group are 5.4% and 5.5%, respectively.

Based on these results, I believe the proper growth rate range to use in the DCF model for the comparable group is 4.0% to 6.0%. The low-end (4.0%) of this range is slightly above the low point of the historical range of results for the O'Donnell proxy group (3.7% *Value Line* 5-year EPS for Historical) and slightly below the low point of the forecasted range of results for the O'Donnell proxy group (4.5% for *Schwab* forecasted EPS). The high end (6.0%) of the range is relatively aligned with the high point of the O'Donnell proxy group's historical range of results (6.1% *Value Line* 5-year DPS), as well as the high point of the O'Donnell proxy group's forecasted range of results (5.7% for *CFRA* forecasted EPS). These figures are found within **Exhibit KWO-1** and **Exhibit KWO-4**.

Q. WHAT ARE THE GROWTH RATE RANGES FROM THE DCF ANALYSIS FOR THE HEVERT PROXY GROUP?

A. Over the past 10-years, the Hevert proxy group has grown in the range of approximately 4.5% (*Value Line* 10-year book value per share BPS) to 6.3%

(*Value Line* 5-year DPS). The forecasted growth rates for the Hevert proxy group are comparable to the historical growth rates and are in the range of 4.7% (*Value Line* Forecasted BPS) to 5.7% (*Value Line* Forecasted DPS). The plowback growth rate average for the Hevert comparable group is 3.5%.

Based on these results, I also believe that the proper growth rate range to use in the DCF model for the Hevert comparable group is also 4.0% to 6.0%. The low-end (4.0%) of this range is slightly below the low point for the historical range of results (4.5% for 10-year *Value Line* BPS) and slightly below the low point for the forecasted range of results (4.7% for *Value Line* Forecasted BPS). The high end (6.0%) of the range is slightly below the high point for the historical range of results (6.3% for 5-year *Value Line* DPS) and slightly below the high point for the forecasted range of results (6.1% for *CFRA* Forecasted EPS). These figures are found within **Exhibit KWO-6** and **Exhibit KWO-9**.

Q. IN LIGHT OF ACADEMIC LITERATURE THAT QUESTIONS THE ACCURACY OF ANALYST FORECASTS, HAVE YOU TAILORED THE IMPLEMENTATION OF THE DCF METHODOLOGY?

A. In the June/July 1999 edition of the *Journal of Business Finance and Accounting*, Richard D.F. Harris authored a study entitled "*The Accuracy, Bias and Efficiency of Analysts' Long Run Earnings Growth Forecasts*." His conclusions regarding analyst forecasts were, in part, as follows:

1. The accuracy of forecasts was extremely low;
2. Analyst forecasts are overly optimistic; and

3. Forecasts by analysts are inefficient.[67]

In November 2003, Louis K. C. Chan, Jason Karceski and Josef Lakonishok published an article entitled "*Analysts' Conflict of Interest and Biases in Earnings Forecasts*" in the *Journal of Finance*. The conclusion of the paper stated:

> "*...it is commonly suggested that one group of informed participants, security analysts, may have some ability to predict growth. The dispersion in analysts' forecasts indicates their willingness to distinguish boldly between high- and low-growth prospects. IBES long-term growth estimates are associated with realized growth in the immediate short-term future. Over long horizons, however, there is little forecastability in earnings, and analysts' estimates tend to be overly optimistic.*"[68]

In 2010, Marc H. Goedhart, Rishi Raj, and Abhishek Saxena wrote "*Equity analysts: Still too bullish*" that was published in *McKinsey on Finance*. The article stated:

> "*No executive would dispute that analysts' forecasts serve as an important benchmark of the current and future health of companies. To better understand their accuracy, we undertook research nearly a decade ago that produced sobering results. Analysts, we found, were typically overoptimistic, slow to revise their forecasts to reflect new economic conditions, and prone to making increasingly inaccurate forecasts when economic growth declined.*"[69]

In June 2007, in the *Journal of Accounting Research*, Peter D. Easton and Gregory A. Sommers wrote a paper entitled "*Effect of Analysts' Optimism on Estimates of the Expected Rate of Return Implied by Earnings Forecasts*".

> "*We show that, on average, the difference between the estimate of the expected rate of return based on analysts' earnings forecasts and the estimate based on current earnings realizations is 2.84%. When estimates of the expected rate of return in the extant*

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67 *The Accuracy, Bias, and Efficiency of Analysts' Long Run Earnings Growth Forecasts*, Journal of Business Finance & Accounting, at 751 (June/July 1999).

68 Chan, L. et al., *The Level and Persistence of Growth Rates*, Journal of Finance, at 683 (2003).

69 *Equity Analysts, Still Too Bullish*, McKinsey on Finance, at 14 (Spring 2010).

literature are adjusted to remove the effect of optimistic bias in analysts' forecasts, the equally weighted estimate of the equity risk premium appears to be close to zero."[70]

As can be seen in these academic articles and contrary to the statement as provided by Mr. Hevert, the concept that analysts provide accurate expectations for investors is still a highly debated topic.

To mitigate the problems as cited above, I have presented EPS, DPS, and BPS figures to the Commission and systematically explained my rationale for arriving at the above stated growth rates. I believe it is incumbent upon every analyst presenting testimony in this case to present such a robust analysis to the Commission. Presenting only part of the data, such as only forecasted growth rates, makes one question why an analyst would leave out such critical pieces of information.

Q. SHOULD ONLY EARNINGS GROWTH RATES IN THE DCF METHODOLOGY BE USED?

A. No. Since the DCF formula is dependent on future dividend growth, it would be inaccurate to use only earnings growth rates in the DCF. Doing so produces unrealistically high ROE numbers that cannot be sustained in real life.

Q. WHAT IS THE DCF RANGE THAT YOUR ANALYSES PRODUCED?

A. Combining the O'Donnell proxy group's dividend yield of 3.2% to 3.7% over the three periods (i.e. 13 weeks, 4 weeks, 1 week) with the growth rate range of 4.0% to 6.0% produces a DCF range of 7.2% - 9.7%. As such, the chosen estimate range approximates 7% - 10%. Additionally, refer to **Exhibit KWO-4**, which presents the following DCF Calculations, (1) the Dividend Yield Averages for the 13-

70 *Effect of Analysts' Optimism on Estimates of the Expected Rate of Return Implied by Earnings Forecasts*, Journal of Accounting Research, at 1012 (December 2007).

weeks / 4-weeks / 1-week periods plus the Forecasted and Historical Growth Rate Averages, and (2) the Dividend Yield Averages for the 13-weeks / 4-weeks / 1-week periods plus the Plowback Ratios. These DCF calculations result in ranges found within **Exhibit KWO-4** that are presented as support behind the chosen DCF estimate range of 7.0% - 10.0%.

In repeating the same process for the Hevert proxy group, the group's 3.1% to 3.6% dividend yield for all three periods (i.e. 13 weeks, 4 weeks, 1 week) is combined with the same 4.0% to 6.0% growth rate range found appropriate in the O'Donnell group to arrive at a comparable DCF estimate for the Hevert group as that of the O'Donnell group: 7.1% to 9.6% (i.e. approximately 7.0% to 10.0%).

Due to the similar results of both groups, I view this as further validation for my recommendation as I believe the proper DCF range is 7.0% to 10.0%.

b Capital Asset Pricing Model

Q. PLEASE EXPLAIN THE CAPITAL ASSET PRICING MODEL.

A. The CAPM is a risk premium model that determines a firm's ROE relative to the overall market return on equity. The formula for the CAPM is as follows:

ROE = Rf + Beta [E(RM) – Rf]; where:

ROE is the return on equity;

Rf is the risk-free rate;

Beta is the risk of the studied company relative to the overall market; and

E(RM) is the expected return on the market.

To be specific, the CAPM is a measure of firm-specific risk, known as unsystematic risk and measured by beta, as well as overall market risk, otherwise known as systematic risk and measured by the expected return on the market.

The CAPM calculates ROE based on a company's risk and can be restated as follows:

ROE = Rf + (Beta * Risk Premium)

Where Risk Premium represents the adjusted company-specific risk of the company.

Q. HOW IS THE RISK-FREE RATE MEASURED?

A. The risk-free rate is designated as the yield on United States government bonds because the risk of default is seen as highly unlikely (i.e. "*risk-free*"). Utility witnesses and consumer witnesses regularly use United States government bond yields as the risk-free rate in the CAPM. However, what is often debated in the risk-free portion of the CAPM is the term of those bonds. In my analysis for this case, I have developed risk premiums relative to the 30-year U.S. Treasury bonds as this time period is the longest available in the marketplace, thereby affording consumers the longest protection at the risk-free rate. Notably, this is also the proxy used by the Federal Energy Regulatory Commission to determine the risk-free rate in the CAPM.[71] **Chart 4**, which I provided earlier in this testimony, provides the yield on 30-year U.S. Treasury bonds over the past year.

Q. IS THE CURRENT LEVEL OF INTEREST RATES EXPECTED TO CHANGE MATERIALLY IN THE FORESEEABLE FUTURE?

A. No. Economic forecasters, as well as the Federal Reserve, all believe that the current interest rate environment is expected to remain relatively stable for many years to come. In fact, in June 16, 2016, Bloomberg published an article entitled

71 *Ass'n of Bus. Advocating Tariff Equity, et al. v. Midcontinent Indep. Sys. Operator, Inc., et al.*, Opinion No. 569, 169 FERC ¶ 61,129, at P 238 (2019) ("FERC Opinion No. 569").

"*Yellen Says Forces Holding Down Rates May Be Long Lasting*." The key takeaway from the article is the following statement:

> "*In a press conference after the Fed held policy steady, Yellen spoke of a sense that rates may be depressed by "factors that are not going to be rapidly disappearing, but will be part of the new normal.*""[72]

I recognize this statement from Chairperson Yellen is over 3 years old, but what the chairperson said in 2016 still rings true today. The Federal Reserve cut rates in 2019 and then, in its December meeting, announced plans to keep interest rates at current levels throughout 2020.[73] Then on March 3, 2020, the Federal Reserve decreased the Federal Funds rates 50 basis points to a targeted range of between 1% and 1.25% in response to recent market conditions.[74] On March 16, 2020, the Federal Reserve dropped interest rates to 0%.

Mr. Hevert, on the other hand, has been predicting interest rates to rise for several years. As an example, in 2017, Mr. Hevert provided testimony in the general rate case of Duke Energy Progress before the North Carolina Utilities Commission in which he analyzed the interest rate prospects at that time and stated the following:

> "*Q. WHAT DO YOU CONCLUDE FROM THOSE ANALYSES?*
>
> *A. First, it is clear that interest rates have increased from the low levels experienced in early 2016. Second, it is clear that market-based data indicate investors' expectations of rising interest rates in the near- and longer-term.*

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72 Miller, R., *Yellen Says Forces Holding Down Rates May Be Long Lasting*, Bloomberg (June 15, 2016), available at: **https://www.bloomberg.com/news/articles/2016-06-15/yellen-seems-to-sign-on-to-summers-view-of-lingering-low-rates.**

73 Rugaber, C., *Federal Reserve leaves interest rates unchanged and foresees no moves in 2020*, PBS News Hour (Dec. 11, 2019), available at: https://www.pbs.org/newshour/economy/federal-reserve-leaves-interest-rates-unchanged-and-foresees-no-moves-in-2020.

74 https://www.cnbc.com/2020/03/03/heres-what-this-surprise-fed-rate-cut-means-for-you.html

> *The observation that interest rates have increased indicates that the financial community sees the strong prospect of increased growth throughout the economy. As that occurs, and as interest rates continue to rise, it would be reasonable to expect lower utility valuations, higher dividend yields and higher growth rates. In the context of the Discounted Cash Flow model, those variables would combine to indicate increases in the Cost of Equity.*[75]" (*underline added for emphasis)

As I have demonstrated above, interest rates have continued to trend at lower levels, and utility stock prices have also skyrocketed, subsequent to Mr. Hevert's testimony in 2017 up until the recent coronavirus pandemic & its related impacts to the markets. Put simply, Mr. Hevert's forecast regarding interest rates and utility stock prices was wrong.

Q. HOW IS BETA MEASURED IN THE CAPM?

A. Beta is a statistical calculation of a company's stock price movement relative to the overall stock movement. A company whose stock price is less volatile than the overall market will have a beta less than 1.0. A company whose stock price is more volatile than the overall market will have a beta more than 1.0. Since utilities are generally conservative equity investments, utility betas are almost always less than 1.0.

Q. WHAT IS THE CURRENT MARKET RISK PREMIUM APPROPRIATE FOR USE IN THE CAPM?

A. The development of the current market risk premium is, undoubtedly, the most controversial aspect of the CAPM calculations. I believe one measure to analyze current premiums is to look at historical risk premiums. To gauge the historical

75 *Application of Duke Energy Progress, LLC For Adjustment of Rates and Charges Applicable to Electric Service in North Carolina*, NCUC Docket No. E-2, Sub 1142, Direct Testimony of Robert Hevert, at Pg. 82 (June 1, 2017).

risk premium, I turned to the Ibbotson database published by Morningstar. The long-term geometric and arithmetic returns for both equities and fixed income securities and the resulting risk premiums are shown below in **Table 7** as follows:

Table 7: Equity Risk Premium Calculations[76]

Asset Class	Geometric Mean	Arithmetic Mean
Large Company Stocks	10.0%	11.9%
Long-Term Govt. Bonds	5.9%	6.3%
Resulting Risk Premium	**4.1%**	**5.6%**

Q. WHAT MARKET RETURNS ARE WELL-KNOWN PROFESSIONAL INVESTORS EXPECTING FOR THE FORESEEABLE FUTURE?

A. On January 16, 2020, Morningstar.com published an article entitled "*Experts Forecast Long-Term Stock and Bond Returns: 2019 Edition.*"[77] By future returns, these market experts are discussing total market returns, and not just the equity risk premium. Below are some of the market return forecasts from this article:

<u>BlackRock Investment Institute</u>

6.1% nominal (not inflation adjusted) return for US large caps over the next decade, 6.5% for European equities, and 7.5% for emerging markets equities.

76 Ibbotson® SBBI®, *2019 Classic Yearbook: Stocks, Bonds, Bills, and Inflation, 1926-2018*, at **Table 7**.

77 Benz, C., *Experts Forecast Long-Term Stock and Bond Returns: 2020 Edition*, Morningstar (Jan. 16, 2020), available at: https://www.morningstar.com/articles/962169/experts-forecast-long-term-stock-and-bond-returns-2020-edition.

Grantham, Mayo, & van Otterloo ("GMO")

-4.4% real (inflation adjusted) returns for US large caps over the next 7 years.

JP Morgan Asset Management

5.6% nominal return for US equities over a 10-15 year horizon.

Morningstar Investment Management

1.7% 10-year nominal returns for US stocks.

Research Affiliates

0.3% real (inflation adjusted) returns for US large caps furring the next 10 years.

Vanguard

Nominal equity market returns of 3.5% to 5.5% during the next decade.

The above-stated equity returns display a very large range. On the low side is GMO, which forecasts that US large caps will, after inflation, lose 4.4% of asset value annually over the next seven years. On the more positive side is BlackRock Investment that expects a nominal (before inflation adjustment) of 6.1% per year. Of the above-stated returns, Vanguard, JP Morgan, and BlackRock all forecast nominal (not inflation adjusted) returns in the range of 3.5% to 6.5%. A mid-range estimate is 4% to 6% for the group.

In 2018, Duke University finance professors published their annual equity risk premium estimates that stated the expected average risk premium exhibited by a survey of U.S. Chief Financial Officers around the country is 4.42%.[78] The article states as follows:

> "*During the past 18 years, we have collected almost 25,000 responses to the survey. Panel A of Table 1 presents the date that*

78 Graham, J. & Harvey, C., *The Equity Risk Premium in 2018*, Duke University, at 3-4 (March 28, 2018).

> *the survey window opened, the number of responses for each survey, the 10-year Treasury bond rate, as well as the average and median expected excess returns. There is relatively little time variation in the risk premium. This is confirmed in Fig. 1a, which displays the historical risk premiums contained in Table 1.* ***The current premium, 4.42%, is above the historical average of 3.64%****. The December 2017 survey shows that the expected annual S&P 500 return is 6.79% (=4.42%+2.37%) which is slightly below the overall average of 7.11%. The total return forecasts are presented in Fig. 1b.2."*[79]

Q. WHAT IS YOUR CONCLUSION AS TO THE ESTIMATED EQUITY RISK PREMIUM FOR USE IN THE CAPM?

A. Using historical data, such as the data noted above in **Table 7**, as well as ex ante (forecasts) data, the evidence suggests the equity risk premium is clearly within the range of 4% to 6%.

Q. HOW DID YOU DETERMINE THE BETA YOU USED IN THE CAPM?

A. I used the *Value Line* derived beta that I found in the most recent *Value Line* editions[80] for each company in the proxy group.

Q. WHAT WERE YOUR CAPM RESULTS?

A. The actual calculations for the CAPM can be seen in **Exhibit KWO-5** for the O'Donnell comparable group and in **Exhibit KWO-10** for the Hevert comparable group. Over the time period from the date of the Commission's final order in DEP's last rate case (i.e. February 23, 2018) to the date that the data was pulled (i.e. April 10, 2020), the yield on 30-year U.S. Treasury bonds (Rf) ranged from a minimum of 0.99% to a maximum 3.46%. Additionally, the average beta for the O'Donnell proxy group is 0.55, which was calculated by averaging the beta

79 *Id.*

80 *The Value Line Investment Survey,* Value Line (Jan 24, 2020); *The Value Line Investment Survey,* Value Line (Feb. 14, 2020); *The Value Line Investment Survey,* Value Line (March 13, 2020).

reported by Value Line for all companies in the group. I then multiplied this average beta of 0.55 by the risk premium range of 4.0% to 6.0% to produce a beta-adjusted risk premium of 2.20% to 3.30%. The 30-year US Treasury yield (Rf) range of 0.99% to 3.46% over the period outlined above is next added to the beta-adjusted risk premium range of 2.20% to 3.30% to arrive at the proxy group CAPM result range of 3.17% to 6.74% ROE for the O'Donnell comparable group **(Exhibit KWO-5)**.

I followed the same process for the Hevert comparable group, which has an average beta of 0.54, to arrive at a nearly identical CAPM range of 3.15% to 6.69% **(Exhibit KWO-10)**.

Based on this range of results for the CAPM, I find the proper ROE derived from the CAPM is in the range of 5.0% to 7.0%. The low-end (5.0%) of this range is 183 basis points higher than the low-end of the O'Donnell comparable proxy group CAPM results using the 4.0% of the equity risk premium. The high end (7.0%) of the range is 26 basis points higher than the high end of the O'Donnell comparable proxy group CAPM results using the 6.0% equity risk premium.

Q. WHAT CONCLUSIONS DO YOU DRAW FROM YOUR CAPM ANALYSIS?

A. Although I derive DEP's ROE from my DCF analysis, the CAPM results offered here present a critical check on those results. CAPM has been relied on heavily by both the financial and regulatory communities and should serve as the principal alternative to confirm the veracity of the DCF results.

c. Comparable Earnings Analysis

Q. PLEASE EXPLAIN THE COMPARABLE EARNINGS (CE) ANALYSIS AND HOW YOU PERFORMED THIS ANALYSIS.

A. The Comparable Earnings (CE) analysis is a process whereby companies that are deemed similar in risk are compared to assess a relative valuation. In this process, the analyst simply examines details of companies within its comparable group and within its industry to assess a relative return for the examined company.

In the CE analysis I performed in this case, I examined the allowed actual earned returns on book value, not market value. As a result, the earned returns I examined were higher than what investors are actually requiring in today's marketplace.

Q. PLEASE EXPLAIN THE DIFFERENCE BETWEEN MARKET VALUE AND BOOK VALUE.

A. Market values reflect the actual price that investors are willing to pay for a share of a company's stock. Book value, on the other hand, is the actual net assets of a company divided by the number of shares outstanding.

Q. HOW DOES THE MARKET VALUE OF UTILITIES, IN GENERAL, COMPARE TO BOOK VALUE?

A. The market value of utilities is currently about 1.5X to 2.0X that of the book value of utilities. As an example, the book value of Duke Energy Corp. at year-end 2019 was, according to *Value Line*, estimated to be $61.21. However, its market price as of December 31, 2019 was $91.21, thereby representing a market-to-book (M/B) ratio of 1.49X.

As noted in the above example with Duke Energy Corp, a return on book value will be far greater than a return on market value as the denominator in a return on book value (*see* e.g. $61.21 above) is less than the dominator in a return on market value (*see* e.g. $91.21 above). Hence, when the book value is less than the market value and the net income is the same under both scenarios, it is a mathematical fact that the return on book value will be greater than the return on market value.

The above example illustrates why I believe the stated returns on book value, such as provided by *Value Line*, should be used only as a guide to the DCF market-required estimates. Simply put, analysts can mistakenly and/or improperly equate the two returns (return on book value and return on market value) and cause confusion for regulators.

Q. PLEASE EXPLAIN HOW YOU PERFORMED THE COMPARABLE EARNINGS ANALYSIS.

A. **Exhibit KWO-3** presents a list of the earned returns on equity of the O'Donnell comparable group over the period of 2017 through 2025E. **Exhibit KWO-8** presents the earned returns on equity of the Hevert comparable group over the same time period. I picked this range to provide the Commission with two years of historical returns and five years of forecasted returns. As can be seen in this exhibit, the average earned returns on equity for the proxy group ranges from 9.5% to 10.3% for the O'Donnell proxy group. For the Hevert proxy group, the range is from 9.5% to 10.3%.

Q. DO YOU HAVE ANOTHER COMPARABLE EARNINGS ANALYSIS TO PRESENT IN THIS CASE?

A. Yes. I also examined ROEs granted by state regulators across the country.
It is important to understand what state regulatory commissions across the country are allowing for earned ROEs. Allowed ROEs are widely known and discussed in the financial community and investors take these regulatory decisions into account when they set prices in the open market for which they are willing to purchase the stock of a regulated utility.

As this Commission is likely aware, regulated ROEs have trended down over the past 15 years. In **Chart 7** above, I provided a chart that shows the allowed ROEs for electric utilities by state regulators across the United States from 2005 through 2019. The average allowed ROE for 2019 was 9.65%.

Q. ARE YOU AWARE OF A STATE REGULATORY BODY THAT HAS RECENTLY ISSUED AN ORDER FOR A DUKE ENERGY SUBSIDIARY, IN WHICH MR. HEVERT HAS BEEN THE WITNESS? IF SO, WHAT WAS THE ALLOWED ROE SET BY THAT REGUALTORY BODY?

A. Yes. Mr. Hevert testified in the Duke Energy subsidiary rate cases (Duke Energy Carolinas and Duke Energy Progress) heard in South Carolina. Mr. Hevert recommended a 10.75% ROE in both cases. On May 1, 2019, the SCPSC authorized a 9.50% ROE for Duke Energy Carolinas.[81] On May 8, 2019, the SCPSC authorized Duke Energy Progress the opportunity to earn a 9.50% ROE.[82]

Q. ARE YOU AWARE OF ANY REGULATORY BODY THAT HAS RECENTLY AUTHORIZED A ROE OF LESS THAN 9.50%?

A. Yes. On May 28, 2019, the Public Utility Commission of South Dakota authorized an 8.75% ROE for Otter Tail Power in Docket No. EL 18-021.

Q. WHO WAS THE ROR WITNESS FOR OTTER TAIL POWER IN THAT RATE CASE AND WHAT WAS THEIR RECOMMENDATION?

A. Mr. Robert Hevert was the witness for Otter Tail Power in the South Dakota proceeding. Mr. Hevert's recommendation in the South Dakota case was 10.3%, slightly less than the 10.5% ROE he is recommending in the current proceeding.

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81 Snl.com

82 *Id.*

Q. WHAT CONCLUSIONS DO YOU DRAW FROM THE COMPARABLE EARNINGS ANALYSIS?

A. Regulators across the United States have continued to recognize the decrease in capital cost and, as shown in **Chart 4** above, steadily reduced the allowed returns of utilities over the past 15 years.

Based on the above-stated findings, I believe the proper ROE using a comparable earnings analysis is in the range of 9.25% to 10.25%. The lower end of this range recognizes the unmistakable downward trend of the average ROE allowed by state regulators for electric utilities dating back to 2005. The high end of the range recognizes high forecasted earned returns on equity for the O'Donnell and Hevert comparable groups in the 2022E-2025E timeframe.

d. Return on Equity Summary

Q. MR. O'DONNELL, PLEASE SUMMARIZE THE RESULTS OF YOUR ROE ANALYSIS IN THIS CASE.

A. **Table 8** below lists the results of my DCF analysis and CAPM analysis.

Table 8: ROE Method Results

	ROE Results		
Method	Low	High	Midpoint
DCF	7.0%	10.0%	8.50%
CAPM	5.0%	7.0%	6.50%
Comparable Earnings	9.25%	10.25%	9.75%

Q. DO YOU THINK THAT THE MIDPOINT OF YOUR DCF ANALYSIS WOULD PROVIDE THE COMPANY WITH A FAIR RETURN?

A. I believe the midpoint of the DCF analysis is an accurate portrayal of market conditions and my CAPM analysis provides further support for an ROE at the midpoint of my DCF analysis, if not lower. However, I am also mindful of current allowed returns from around the country. Given that the allowed returns from other jurisdictions are above the 8.50% midpoint of the DCF range, I believe choosing a return in the upper end of the DCF range is more appropriate for use in this case.

Q. WHAT IS YOUR RETURN ON EQUITY RECOMMENDATION IN THIS PROCEEDING?

A. My recommendation in this case is for the Commission to grant DEP a return on equity of 8.75%. This 8.75% ROE is above the midpoint of the DCF range, well above the CAPM results, and below the comparable earnings results.

Q. WOULD YOU PLEASE PROVIDE THE REASONS FOR YOUR RECOMMENDATION?

A. As the Commission is aware, interest rates remain quite low relative to historic levels. Individuals seeking an income stream see utility dividends as good alternatives at the present time with the lack of adequate fixed income (bond) opportunities. This "*chase for yield*" is part of the reason that the Dow Jones Utility Average, until the recent coronavirus scare, has nearly doubled since 2013.

When stock prices increase, dividend yields decrease even though the dollar amount of the dividend remains the same or even increases. Hence, during the bull run over the past 10 years, the increase in utility stock prices has driven dividend yields of utility stocks downward. Thus, we cannot ignore the current low cost of capital environment. If a utility's rates are set too high, the economy in its service territory will suffer and stockholders will receive a windfall at the expense of captive ratepayers.

Although the midpoint of my DCF analysis is 8.50%, I am recommending an 8.75% ROE in recognition of the higher allowed ROEs from across the country.

C. Capital Structure

Q. WHAT IS A CAPITAL STRUCTURE AND HOW WILL IT IMPACT THE REVENUES THAT DEP OR ANY OTHER UTILITY IS SEEKING IN A RATE CASE?

A. The term "*capital structure*" refers to the relative percentage of debt, equity, and other financial components that are used to finance a company's investments. For simplicity, there are three financing methods. The <u>first</u> method is to finance an investment with common equity, which essentially represents ownership in a company and its investments. Returns on common equity, which in part take the form of dividends to stockholders, are not tax deductible which, on a pre-tax basis alone, makes this form of financing about 28% more expensive than debt financing. The second form of corporate financing is preferred stock, which is normally used to a much smaller degree in capital structures. Dividend payments associated with preferred stock are not tax deductible.

Corporate debt is the third major form of financing used in the corporate world. There are two basic types of corporate debt: long-term and short-term. Long-term debt is generally understood to be debt that matures in a period of more than one year. Short-term debt is debt that matures in a year or less. Both long-term debt and short-term debt represent liabilities on the company's books that must be repaid prior to any common stockholders or preferred stockholders receiving a return on their investment.

Q. HOW IS A UTILITY'S TOTAL RETURN CALCULATED?

A. A utility's total return is developed by multiplying the component percentages of its capital structure represented by the percentage ratios of the various forms of capital financing relative to the total financing on the company's books by the cost rates associated with each form of capital and then totaling the results over all of the capital components. When these percentage ratios are applied to various cost rates, a total after-tax rate of return is developed. Because the utility must pay dividends associated with common equity and preferred stock with after-tax funds, the post-tax returns are then converted to pre-tax returns by grossing up the common equity and preferred stock dividends for taxes. The final pre-tax return is then multiplied by the Company's rate base in order to develop the amount of money that customers must pay to the utility for return on investment and tax payments associated with that investment. This return, or profit, is awarded in addition to the utility being allowed to recover its reasonable level of annual operating expenses.

Q. HOW DOES CAPITAL STRUCTURE IMPACT THIS CALCULATION?

A. Costs to consumers are greater when the utility finances a higher proportion of its rate base investment with common equity and preferred stock versus long-term debt. Long-term debt, which is first in line for repayment, imposes a contractual obligation to make fixed payments on a pre-established schedule, as opposed to common equity where no similar obligations exist. Thus, long-term debt is a less risky investment warranting a lower cost.

Q. WHY SHOULD THIS COMMISSION BE CONCERNED ABOUT HOW DEP FINANCES ITS RATE BASE INVESTMENT?

A. There are two reasons that the Commission should be concerned about how DEP finances its rate base investment. First, DEP's cost of common equity is higher than the cost of long-term debt, meaning that an equity percentage above an optimal level will translate into higher costs to DEP's customers without any corresponding improvement in quality of service. Long-term debt is a financial promise made by the company and is carried as a liability on the company's books. Common stock is ownership in the company. Due to the nature of this investment, common stockholders require higher rates of return to compensate them for the extra risk involved in owning part of the company versus having a more senior claim against the company's assets.

The second reason the Commission should be concerned about DEP's capital structure is due to the tax treatment of debt versus common equity. Public corporations, such as DEP, can deduct payments associated with debt financing. Corporations are not, however, allowed to deduct common stock dividend payments for tax purposes. All dividend payments must be made with after-tax funds, which are more expensive than pre-tax funds. Because the regulatory process allows utilities to recover reasonable and prudent expenses, including taxes, rates must be set so that the utility is able to pay all its taxes and has enough left over to pay its common stock dividend. If a utility is allowed to use a capital structure for ratemaking purposes that is top-heavy in common stock, customers will be forced to pay the associated income tax burden, resulting in unjust, unreasonable, and unnecessarily high rates. Setting rates through the use of capital structure that is top-heavy in common equity violates the fundamental principles of utility regulation that rates must be just and reasonable and only high enough to support the utility's provision of safe, adequate, and reliable service at a fair price.

Q. HOW IS SETTING A CAPITAL STRUCTURE FOR A RATE-REGULATED ELECTRIC UTILITY COMPANY DIFFERENT THAN SETTING A CAPITAL STRUCTURE FOR A NON-REGULATED COMPANY THAT OPERATES IN A COMPETITIVE ENVIRONMENT?

A. Unregulated companies in competitive markets must carefully weigh the risk of using lower cost debt that can be used to leverage profits versus the use of the more expensive common equity that dilutes profits. Such a capital sourcing decision is based, in large part, on the competitive nature of the business in which the entity operates.

In the case of a rate-regulated electric utility with a licensed service territory that has little-to-no competition in its service territory, there is a strong incentive for the company to use common equity to build assets that can be placed in rate base. The utility is guaranteed the opportunity to earn its allowed rate of return on plant investment and, as such, can maximize profits by building plant and receiving favorable regulatory treatment from state regulators. In essence, normal competitive markets serve to lower capital costs through efficient capital cost decisions whereas electric utility rate regulation can act as an incentive for excessive or unnecessary plant investment.

Q. PLEASE EXPLAIN HOW ONGOING CONSTRUCTION NEEDS ARE IMPACTING UTILITIES AND THEIR CUSTOMERS.

A. Utilities finance construction with three primary sources of capital: retained earnings; common equity issuances; and long-term debt issuances. Financing construction with retained earnings is preferable to the utility because using funds from ongoing operations does not dilute common equity (as would an equity issuance) and does not add debt leverage to the utility's balance sheet. However, in most cases, financing a large asset with only retained earnings may not be possible due to sheer size of the plant investment. As a result, utilities undergoing large construction projects often issue common equity or long-term debt to finance these projects.

Selecting the ratio of equity to debt is important. Entities in more competitive markets have a profit motive that provides an incentive for such entities to select the most efficient capitalization ratio. However, electric utilities operating in exclusive, rate-regulated service territories have an incentive to maximize the amount of common equity in their capital structure so as to increase rates and, correspondingly, the utility profit. Rate-regulated electric utilities should only be allowed to recover in rates a revenue requirement derived from a capitalization ratio that allows the utility to provide reliable service at the least cost. Finding the right balance between debt and equity is critical.

Q. PLEASE EXPLAIN THE RAMIFICATIONS OF RATES BEING SET AT AN UNBALANCED DEBT/EQUITY LEVEL.

A. If a utility issues too much common equity and not enough debt for a certain project, the ratepayers pay higher rates to support a capital structure that is neither prudent nor reasonable. It is also important to recognize how rate levels affect economic development. The reality in today's economy is that economic development occurs in places where costs are lower. A utility with high rates will, all else being equal, cause its service territory to lose out on economic development opportunities.

If, on the other hand, the utility incurs too much debt, the utility's capitalization ratio presents excess financial risk to the capital markets, thereby driving up the costs required by the markets to compensate them for the added risk. In this case, the consumer would also lose because the cost it must pay the utility for accessing the capital markets is higher than it would pay using a less debt-leveraged capital structure.

One role of regulation is to balance the needs of the capital markets, including utility stockholders, with the needs of ratepayers. Too much equity or too much debt can harm both the stockholders of the corporation as well as the consuming public. Careful study of the risks and costs of various capitalization ratios is important.

Q. HAVE YOU REVIEWED THE CAPITAL STRUCTURE REQUESTED BY THE COMPANY IN THIS PROCEEDING?

A. Yes, I have.

Q. WHAT CAPITAL STRUCTURE IS DEP SEEKING IN THIS CASE?

A. According to Smith Exhibit 4 the Company is seeking the following capital structure:

Table 9: DEP's Requested Capital Structure[83]

Component	Capital Structure Ratio (%)
Long-Term Debt	47.0%
Common Equity	53.0%
Total Capitalization	**100.0%**

Q. DO YOU FEEL THIS CAPITAL STRUCTURE IS APPROPRIATE FOR RATEMAKING PURPOSES IN THIS CASE?

A. No, I do not.

83 Duke Witness Smith Testimony, Exhibit 4

Q. PLEASE EXPLAIN WHY YOU BELIEVE THE REQUESTED CAPITAL STRUCTURE IS INAPPROPRIATE FOR USE IN SETTING RATES IN THIS PROCEEDING.

A. The above-requested capital structure is the Company's capital structure as of Dec. 31, 2018, but it is actually a reflection of the amount of equity financing that DEP's owner, Duke Energy Corp, wishes to infuse into the utility relative to the amount of debt DEP issues. As a result, the actual capital structure of a utility operating company, such as DEP, does not reflect market forces, but, instead, represents a decision by its parent holding company as to the capital structure on which it wishes rates to be determined.

Due to the decision-making ability of Duke Energy to set an equity ratio for DEP without the influence of market forces, I believe the Commission should examine similarly-situated utility holding companies and equity ratios set by utility regulators across the country to ascertain a more market-driven capital structure that is best used in setting rates.

Q. WHAT IS THE AVERAGE COMMON EQUITY RATIO OF THE COMPANIES IN YOUR TWO PROXY GROUPs?

A. **Table 10** below shows the average common equity ratio of each company in the proxy group which I developed.

Table 10: O'Donnell Proxy Group Equity Ratio[84]

Company	2018 Ratio
American Electric Power Co Inc	46.8%
ALLETE Inc	60.1%
Alliant Energy Corp	46.6%
Ameren Corp	48.8%
CMS Energy Corp	30.7%
Consolidated Edison Inc	48.9%
Dominion Resources Inc	39.2%
Duke Energy Corp	46.2%
Edison International	38.3%
Entergy Corp	35.9%
Eversource Energy	46.9%
Hawaiian Electric Industries Inc	51.7%
IDACORP Inc	56.4%
MGE Energy Inc	62.3%
NextEra Energy Inc	56.0%
Northwestern	47.8%
OGE Energy Corp	58.0%
Otter Tail	55.3%
Pinnacle West Capital Corp	53.0%
PNM Resources Inc	38.6%
Portland General	53.5%
Public Service Enterprise Group Inc	52.2%

84 *The Value Line Investment Survey*, Value Line (January 24, 2020); *The Value Line Investment Survey*, Value Line (February 14, 2020); *The Value Line Investment Survey*, Value Line (March 13, 2020).

Sempra Energy	38.4%
Southern Co (The)	37.6%
WEC Energy Group Inc	49.4%
Xcel Energy Inc	43.6%
AVERAGE	**47.8%**

Table 11 provides the common equity ratios of the Hevert comparable group.

Table 11: Hevert Proxy Group Equity Ratio[85]

Company	**2018 Ratio**
American Electric Power Co Inc	46.8%
ALLETE Inc	60.1%
Alliant Energy Corp	46.6%
Ameren Corp	48.8%
Avangrid	73.8%
CMS Energy Corp	30.7%
DTE Energy Co	45.8%
Evergy Corp.	60.0%
Hawaiian Electric Industries Inc	51.7%
NextEra Energy Inc	56.0%
Northwestern Corp	47.8%
OGE Energy Corp	58.0%
Otter Tail Corp	55.3%
Pinnacle West Capital Corp	53.0%
PNM Resources Inc	38.6%
Portland General Electric Co	53.5%
Southern Co (The)	37.6%
WEC Energy Group Inc	49.4%
Xcel Energy Inc	43.6%
AVERAGE	**50.4%**

85 *The Value Line Investment Survey*, Value Line (January 24, 2020); *The Value Line Investment Survey*, Value Line (February 14, 2020); *The Value Line Investment Survey*, Value Line (March 13, 2020).

As can be seen in the table above, the average common equity ratio in the two proxy groups is 47.8% and 50.4%, both of which are below the requested equity ratio in this case of 53.0%.

Q. WHAT IS THE AVERAGE COMMON EQUITY RATIO GRANTED BY UTIILTY REGULATORS ACROSS THE UNITED STATES IN 2019?

A. The average common equity ratio granted by regulators in 2019 to electric utilities was 49.94%.[86]

Q. WHAT COMMON EQUITY RATIO HAVE STATE REGULATORS ACROSS THE UNITED STATES GRANTED TO ELECTRIC UTILITIES OVER THE PAST 15 YEARS?

A. State regulators have been quite consistent in their rulings in electric utility cases over the past 15 years. From 2005 through 2019, state regulators from across the country allowed common equity ratios in the range of roughly 47% to 51%.[87] The average common equity ratio for each year over the past 15 years can be seen in **Chart 8** below.

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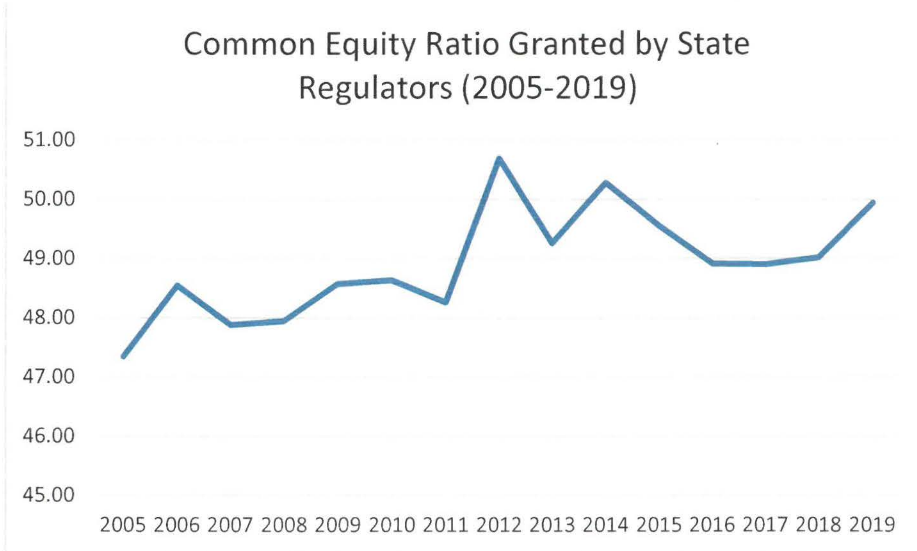
[86] S&P Global Market Intelligence, Rate Case History; Date Range: 15 Years; Service Type: Electric; Chart Items: Common Equity to Total Capital, Return on Equity (Retrieved March 16, 2020) (source for raw data)

[87] *Id.*

Chart 8: Common Equity Ratio Granted by State Regulators (2005-2019)



The data for **Chart 8** is found in **Table 12** below.

Table 12: Common Equity Ratios[88]

Year	Common Equity (%) to Total Capital
2005	47.34%
2006	48.54%
2007	47.88%
2008	47.94%
2009	48.57%
2010	48.63%
2011	48.26%
2012	50.69%
2013	49.25%
2014	50.28%
2015	49.54%
2016	48.91%
2017	48.90%
2018	49.02%
2019	49.94%
Average	**48.91%**

88 *Id.*

The average common equity ratio from 2005 through 2019 was slightly below 50%, at 48.91%.

Q. PLEASE SUMMARIZE YOUR FINDINGS IN REGARD TO THE REQUESTED EQUITY RATO IN THIS CASE RELATIVE TO THE EQUITY RATIO OF OTHER ELECTRIC UTILITIES.

A. **Table 13** below provides a summary of how DEP's request in this case compares to the following equity ratios: the equity ratio requested by the Company, the equity ratio of the two proxy groups, and the average allowed equity ratio by state regulators across the country in 2019.

Table 13: Common Equity Comparison

DEP Request	53.00%
O'Donnell Proxy Group Average	48.30%
Hevert Proxy Group Average	50.40%
2019 Average Reg Eq Ratio	49.94%

Q. GIVEN THE ABOVE, DO YOU BELIEVE THAT THE CAPITAL STRUCTURE BEING PROPOSED BY DEP IN THIS CASE IS APPROPRIATE FOR RATEMAKING PURPOSES?

A. No, the Company's request in this case is higher than any of the standards as I have noted above. Specifically, the requested equity ratio of 53.0% is:

- Higher than the O'Donnell proxy group's equity ratio;
- Higher than the Hevert proxy group's equity ratio;
- Higher than the average allowed equity ratio from state regulators across the United States in 2019;

- Higher than the allowed equity ratio of 52.0% from the 2017 DEP rate case.

Based on these comparisons, I believe the proper capital structure the Commission should employ in this proceeding should consist of 50% common equity and 50% long-term debt. My recommended capital structure for DEP is found below in **Table 14.**

Table 14: O'Donnell Recommended Capital Structure

Component	Capital Structure Ratio (%)	Cost Rate (%)
Long-Term Debt	50.00%	4.15%
Common Equity	50.00%	---
Total Capitalization	**100.00%**	

VIII. OVERALL RATE OF RETURN

Q. WHAT IS YOUR OVERALL RECOMMENDED RATE OF RETURN IN THIS PROCEEDING?

A. The overall rate of return I am recommending is 6.46% and can be seen in the table below.

Table 15: Recommended Overall Rate of Return

Component	Capital Structure Ratio (%)	Cost Rate (%)	Wgtd. Cost Rate (%)
Long-Term Debt	50.00%	4.15%	2.08%
Common Equity	50.00%	8.75%	4.38%
Total Capitalization	**100.00%**		**6.46%**

IX. DEP COST OF SERVICE STUDY

Q. DO YOU HAVE ANY COMMENTS IN REGARD TO DEP'S COST OF SERVICE STUDY?

A. The Company filed two cost of service studies. The primary difference between the two studies was in the manner that generation assets were allocated. The summer/winter peak and average (SWPA) model allocates fixed plant investment by the average of 50% of the customer class ratio at the time of the system peak and 50% of the ratio of energy consumption throughout the year. The next method employed by the Company was the summer coincident peak (SCP), whereby the generation assets were allocated based entirely on the ratio of the customer class demand at the time of the summer peak.

Q. WHICH OF THESE TWO METHODS DO YOU BELIEVE PROPERLY REFLECTS THE MANNER IN WHICH DEP BUILT ITS GENERATION FLEET?

A. DEP built its generation fleet to meet peak demand. As a result, I believe the proper allocation methodology to use in this case is the SCP methodology.

To-date, I have completed approximately 30 wholesale power projects for municipal utilities and university utilities throughout the Carolinas. In the wholesale markets, fixed costs are always billed on demand and variable costs are billed on energy. I have heard that regulation should mimic markets. If that is the case, fixed costs, such as generation, should be allocated on peak and not any mix of demand (capacity) and energy.

Lastly, as I have noted several times above, Duke's plans for multiple rate hikes in the coming years will put a very heavy strain on manufacturers located throughout the Carolinas. If manufacturing leaves our state because of high costs, residential and commercial consumers will see a permanent rate hike that may dwarf the rate hike difference between allocating generation assets by SWPA vs. SCP. I suggest the Commission take the long view on this allocation issue.

X. RECOMMENDATIONS AND CONCLUSION

Q. PLEASE SUMMARIZE THE RESULTS OF YOUR ANALYSIS IN THIS CASE.

A. I began my analysis in this case by examining the DEP rates relative to utilities across the United States and, in particular, the southeast. My analysis concludes: (1) DEP's industrial rates are losing its competitive position and will soon be above the national average if the Commission approves of DEP's long-term plan of multiple rate cases over the next 10 years; and (2) Duke's management has put the Commission in an unenviable position of having to choose between the utility's desire to drive earnings versus the future of manufacturing in North Carolina.

On the issue of grid investment expenses, the evidence shows Duke's consumers are simply not willing to pay for massive rate hikes to enjoy a very modest potential increase in system reliability, and Duke is unwilling to guarantee any such improvement in reliability. My recommendation is the Commission deny Duke's planned grid updates for which they cannot/will not provide a cost benefit analysis (CBA). Without such an analysis, the Company has provided no evidence in the record to show that its investment, and corresponding rate hikes, are warranted. For those projects which DEP did provide a CBA, I recommend the

Commission order Duke to perform a sensitivity analysis on each project so it can assess the level of reasonableness of the DEP inputs. I further recommend that cost recovery for each grid modernization project be conditioned upon DEP achieving a set standard of reliability estimates that prove the value of the grid "*modernization*" efforts as promised by DEP in this proceeding.

With regard to coal ash, I have provided evidence in this proceeding that the Dan River spill caused the passage of the Coal Ash Management Act (CAMA) in North Carolina. After the coal ash spill, the federal government investigated the actions of Duke Energy at its coal ash ponds and subsequently charged the Company with nine violations of the Clean Water Act. Duke and the federal government reached a plea deal where Duke admitted guilt and was fined $102 million.

North Carolina consumers should only pay for coal ash costs that are the result of prudent operations. Duke's admission of guilt to imprudent operation of its coal ash ponds resulted in the passage of CAMA. My analysis attempted to determine a dividing line between Company actions before-and-after CAMA. The fact that Duke's mismanagement of coal ash resulted in the passage of CAMA should require that Duke's shareholders, not ratepayers, bear any cost burdens that exceed CCR requirements to meet the requirements of CAMA.

My recommendation is the Commission disallow all coal ash remediation costs for sites that are no longer accepting coal ash. Doing so will prevent consumers from paying at least a part of the incrementally more expensive costs associated with CAMA as opposed to the federal CCR costs.

In terms of allocating coal ash costs, my recommendation is the Commission be consistent in the manner of allocating coal costs as it is with allocating fuel costs. Specifically, I recommend that the Commission use the same cost allocation method approved by the Commission in the last fuel case, which is the equal percentage change for all customer classes,[89] for the allocation of the coal ash costs in this case and in future cases.

As for the allocation of fixed generation costs, my recommendation is the Commission allocate such costs based on peak.

The Commission should order DEP to change its hourly pricing rates to guarantee that manufacturers in DEP's service territory are receiving the lower cost power available, either from DEP, itself, or from the marketplace.

In terms of the proper rate of return on which the Commission should set rates, I recommend the ROE be set at 8.75%, the capital structure be set at 50% common equity and 50% long-term debt, and the overall rate of return be set at 6.46%.

Q. DOES THIS CONCLUDE YOUR PREPARED DIRECT TESTIMONY?

A. Yes.

[89] Find of Fact No. 32, Pg. 36, Final Order in Docket No. E-2, Sub 1204

Appendix A

Kevin W. O'Donnell, CFA

Nova Energy Consultants, Inc. (Nova)

1350-101 SE Maynard Rd.
Cary, NC
919-461-0270
919-461-0570 (fax)
kodonnell@novaenergyconsultants.com

Kevin W. O'Donnell, is the founder of Nova Energy Consultants, Inc. in Cary, NC. Mr. O'Donnell's academic credentials include a B.S. in Civil Engineering - Construction Option from North Carolina State University as well as a MBA in Finance from Florida State University. Mr. O'Donnell is also a Chartered Financial Analyst (CFA).

Mr. O'Donnell has over thirty-four years of experience working in the electric, natural gas, and water/sewer industries. He is very active in municipal power projects and has assisted numerous southeastern U.S. municipalities cut their wholesale cost of power by as much as 67%. On Dec. 12, 1998, ***The Wilson Daily Times*** made the following statement about O'Donnell.

> **Although we were skeptical of O'Donnell's efforts at first, he has shown that he can deliver on promises to cut electrical rates.**

Through 2018, Mr. O'Donnell has completed close to 30 wholesale power projects for municipal and university-owned electric systems throughout North and South Carolina. In May of 1996 Mr. O'Donnell testified before the U.S. House of Representatives, Committee on Commerce, Subcommittee on Energy and Power regarding the restructuring of the electric utility industry.

Mr. O'Donnell has appeared as an expert witness in over 110 regulatory proceedings before the North Carolina Utilities Commission, the South Carolina Public Service Commission, the Virginia Corporation Commission, the Minnesota Public Service Commission, the New Jersey Board of Public Utilities, the Colorado Public Service Commission, Public Service Commission of the District of Columbia, the Maryland Public Service Commission, the Public Utility Commission of Texas, the Indiana Utility Regulatory Commission, the Wisconsin Public Service Commission, the Pennsylvania Public Service Commission, the Oklahoma State Corporation Commission, the California Public Utilities Commission, and the Florida Public Service Commission. His area of expertise has included rate design, cost of service, rate of return, capital structure, creditworthiness issues, fuel adjustments, merger transactions, holding company applications, as well as numerous other accounting, financial, and utility rate-related issues.

Mr. O'Donnell is the author of the following two articles: "Aggregating Municipal Loads: The Future is Today" which was published in the Oct. 1, 1995 edition of *Public Utilities Fortnightly;* and "Worth the Wait, But Still at Risk" which was published in the May 1, 2000 edition of *Public Utilities Fortnightly.* Mr. O'Donnell is also the co-author of "Small Towns, Big Rate Cuts" which was published in the January, 1997 edition of *Energy Buyers Guide.* All of these articles discuss how rural electric systems can use the wholesale power markets to procure wholesale power supplies.

Regulatory Cases of Kevin W. O'Donnell, CFA
Nova Energy Consultants, Inc.

Year	Name of Applicant	State Jusrisdiction	Docket No.	Client/ Employer	Case Issues
1985	Public Service Company of NC	NC	G-5, Sub 200	Public Staff of NCUC	Return on equity, capital structure
1985	Piedmont Natural Gas Company	NC	G-9, Sub 251	Public Staff of NCUC	Return on equity, capital structure
1986	General Telephone of the South	NC	P-19, Sub 207	Public Staff of NCUC	Return on equity, capital structure
1987	Public Service Company of NC	NC	G-5, Sub 207	Public Staff of NCUC	Return on equity, capital structure
1988	Piedmont Natural Gas Company	NC	G-9, Sub 278	Public Staff of NCUC	Return on equity, capital structure
1989	Public Service Company of NC	NC	G-5, Sub 246	Public Staff of NCUC	Return on equity, capital structure
1990	North Carolina Power	NC	E-22, Sub 314	Public Staff of NCUC	Return on equity, capital structure
1991	Duke Energy	NC	E-7, Sub 487	Public Staff of NCUC	Return on equity, capital structure
1992	North Carolina Natural Gas	NC	G-21, Sub 306	Public Staff of NCUC	Natural gas expansion fund
1992	North Carolina Natural Gas	NC	G-21, Sub 307	Public Staff of NCUC	Natural gas expansion fund
1995	Penn & Southern Gas Company	NC	G-3, Sub 186	Public Staff of NCUC	Return on equity, capital structure
1995	North Carolina Natural Gas	NC	G-21, Sub 334	Carolina Utility Customers Assoc.	Return on equity, capital structure, rate design, cost of service
1995	Carolina Power & Light Company	NC	E-2, Sub 680	Carolina Utility Customers Assoc.	Fuel adjustment proceeding
1995	Duke Power	NC	E-7, Sub 559	Carolina Utility Customers Assoc.	Fuel adjustment proceeding
1996	Piedmont Natural Gas Company	NC	G-9, Sub 378	Carolina Utility Customers Assoc.	Return on equity, capital structure, rate design, cost of service
1996	Piedmont Natural Gas Company	NC	G-9, Sub 382	Carolina Utility Customers Assoc.	Return on equity, capital structure, rate design, cost of service
1996	Public Service Company of NC	NC	G-5, Sub 356	Carolina Utility Customers Assoc.	Return on equity, capital structure, rate design, cost of service
1996	Cardinal Extension Company	NC	G-39, Sub 0	Carolina Utility Customers Assoc.	Capital structure, cost of capital
1997	Public Service Company of NC	NC	G-5, Sub 327	Carolina Utility Customers Assoc.	Return on equity, capital structure, rate design, cost of service
1998	Public Service Company of NC	NC	G-5, Sub 386	Carolina Utility Customers Assoc.	Return on equity, capital structure, rate design, cost of service
1998	Public Service Company of NC	NC	G-5, Sub 386	Carolina Utility Customers Assoc.	Natural gas transporation rates
1999	Public Service Company of NC/SCANA Corp	NC	G-5, Sub 400	Carolina Utility Customers Assoc.	Merger case
1999	Public Service Company of NC/SCANA Corp	NC	G-43	Carolina Utility Customers Assoc.	Merger Case
1999	Carolina Power & Light Company	NC	E-2, Sub 753	Carolina Utility Customers Assoc.	Holding company application
1999	Carolina Power & Light Company	NC	G-21, Sub 387	Carolina Utility Customers Assoc.	Holding company application
1999	Carolina Power & Light Company	NC	P-708, Sub 5	Carolina Utility Customers Assoc.	Holding company application
2000	Piedmont Natural Gas Company	NC	G-9, Sub 428	Carolina Utility Customers Assoc.	Return on equity, capital structure, rate design, cost of service
2000	NUI Corporation	NC	G-3, Sub 224	Carolina Utility Customers Assoc.	Holding company application
2000	NUI Corporation/Virginia Gas Company	NC	G-3, Sub 232	Carolina Utility Customers Assoc.	Merger application
2001	Duke Power	NC	E-7, Sub 685	Carolina Utility Customers Assoc.	Emission allowances and environmental compliance costs
2001	NUI Corporation	NC	G-3, Sub 235	Carolina Utility Customers Assoc.	Tariff change request.
2001	Carolina Power & Light Company/Progress E	NC	E-2, Sub 778	Carolina Utility Customers Assoc.	Asset transfer case
2001	Duke Power	NC	E-7, Sub 694	Carolina Utility Customers Assoc.	Restructuring application
2002	Piedmont Natural Gas Company	NC	G-9, Sub 461	Carolina Utility Customers Assoc.	Return on equity, capital structure, rate design, cost of service
2002	Cardinal Pipeline Company	NC	G-39, Sub 4	Carolina Utility Customers Assoc.	Cost of capital, capital structure
2002	South Carolina Public Service Commission	SC	2002-63-G	South Carolina Energy Users Committee	Rate of return, accounting, rate design, cost of service
2003	Piedmont Natural Gas/North Carolina Natura	NC	G-9, Sub 470	Carolina Utility Customers Assoc.	Merger application
2003	Piedmont Natural Gas/North Carolina Natura	NC	G-9, Sub 430	Carolina Utility Customers Assoc.	Merger application
2003	Piedmont Natural Gas/North Carolina Natura	NC	E-2, Sub 825	Carolina Utility Customers Assoc.	Merger application
2003	Carolina Power & Light Company	NC	E-2, Sub 833	Carolina Utility Customers Assoc.	Fuel case
2004	South Carolina Electric & Gas	SC	2004-178-E	South Carolina Energy Users Committee	Return on equity, capital structure, rate design, cost of service
2005	Carolina Power & Light Company	NC	E-2, Sub 868	Carolina Utility Customers Assoc.	Fuel case
2005	Piedmont Natural Gas Company	NC	G-9, Sub 499	Carolina Utility Customers Assoc.	Return on equity, capital structure, rate design, cost of service
2005	South Carolina Electric & Gas	SC	2005-2-E	South Carolina Energy Users Committee	Fuel application
2005	Carolina Power & Light Company	SC	2006-1-E	South Carolina Energy Users Committee	Fuel application
2006	IRP in North Carolina	NC	E-100, Sub 103	Carolina Utility Customers Assoc.	Submitted rebuttal testimony in investigation of IRP in NC.
2006	Piedmont Natural Gas Company	NC	G-9, Sub 519	Carolina Utility Customers Assoc.	Creditworthiness issue
2006	Public Service Company of NC	NC	G-5, Sub 481	Carolina Utility Customers Assoc.	Return on equity, capital structure, rate design, cost of service
2006	Duke Power	NC	E-7, 751	Carolina Utility Customers Assoc.	App to share net revenues from certain wholesale pwr trans

Regulatory Cases of Kevin W. O'Donnell, CFA
Nova Energy Consultants, Inc.

Year	Name of Applicant	State Jusrisdiction	Docket No.	Client/ Employer	Case Issues
2006	South Carolina Electric & Gas	SC	2006-192-E	South Carolina Energy Users Committee	Fuel application
2007	Duke Power	NC	E-7, Sub 790	Carolina Utility Customers Assoc.	Application to construct generation
2007	South Carolina Electric & Gas	SC	2007-229-E	South Carolina Energy Users Committee	Rate of return, accounting, rate design, cost of service
2008	South Carolina Electric & Gas	SC	2008-196-E	South Carolina Energy Users Committee	Base load review act proceeding
2009	Western Carolina University	NC	E-35, Sub 37	Western Carolina University	Rate of return, accounting, rate design, cost of service
2009	Duke Power	NC	E-7, Sub 909	Carolina Utility Customers Assoc.	Cost of service, rate design, return on equity, capital structure
2009	South Carolina Electric & Gas	SC	2009-261-E	South Carolina Energy Users Committee	DSM/EE rate filing
2009	Duke Power	SC	2009-226-E	South Carolina Energy Users Committee	Return on equity, capital structure, rate design, cost of service
2009	Tampa Electric	FL	080317-EI	Florida Retail Federation	Return on equity, capital structure
2010	Duke Power	SC	2010-3-E	South Carolina Energy Users Committee	Fuel application - assisted in settlement
2010	South Carolina Electric & Gas	SC	2009-489-E	South Carolina Energy Users Committee	Return on equity, capital structure, rate design, cost of service
2010	Virginia Power	VA	PUE-2010-00006	Mead Westvaco	Rate design
2011	Duke Energy	SC	2011-20-E	South Carolina Energy Users Committee	Nuclear construction financing
2011	Northern States Power	MN	E002/GR-10-971	Xcel Large Industrials	Return on equity, capital structure
2011	Virginia Power	VA	PUE-2011-0027	Mead Westvaco	Capital structure, revenue requirement
2011	Duke Energy	NC	E-7, Sub 989	Carolina Utility Customers Assoc.	Accounting, cost of service, rate design, ROE, capital structure
2011	Duke Energy	SC	2011-271-E	South Carolina Energy Users Committee	Accounting, cost of service, rate design, ROE, capital structure
2011	Dominion Virginia Power	VA	PUE-2011-00073	Mead Westvaco	Rate design
2012	Town of Smithfield/Partners Equity Group	NC	ES-160, Sub 0	Partners Equity Group	Rate design, asset valuation
2012	Florida Power & Light	FL	120015-EI	Florida Office of Public Counsel	Capital structure
2012	South Carolina Electric & Gas	SC	2012-218-E	South Carolina Energy Users Committee	Accounting, cost of service, rate design, ROE, capital structure
2013	Progress Energy Carolinas	NC	E-2, Sub 1023	Carolina Utility Customers Assoc.	Accounting, cost of service, rate design, ROE, capital structure
2013	Duke Energy Carolinas	NC	E-7, Sub 1026	Carolina Utility Customers Assoc.	Rate design
2013	Jersey Central Power & Light	NJ	BPU ER12111052	Gerdau Ameristeel	Return on equity, capital structure
2013	Duke Energy Carolinas	SC	2013-59-E	South Carolina Energy Users Committee	Accounting, cost of service, rate design, ROE, capital structure
2013	Tampa Electric	FL	130040-EI	Florida Office of Public Counsel	Capital structure and financial integrity
2013	Piedmont Natural Gas	NC	G-9, Sub 631	Carolina Utility Customers Assoc.	Accounting, cost of service, rate design, ROE, capital structure
2014	Dominion Virginia Power	VA	PUE-2014-00033	Mead Westvaco	Recoverable fuel costs, hedging strategies
2014	Public Service Company of Colorado	CO	14AL-0660E	Colorado Healthcare Electric Coordinating Council	Return on equity, capital structure
2015	WEC Acquisition of Integrys	WI	9400-YO-100	Staff of Wisconsin Public Service Commission	Merger analysis
2015	Dominion Virginia Power	VA	PUE-2015-00027	Federal Executive Agencies	Return on equity
2015	South Carolina Electric & Gas	SC	2015-103-E	South Carolina Energy Users Committee	Return on equity
2015	Western Carolina University	NC	E-35, Sub 45	Western Carolina University	Accounting, cost of service, rate design, ROE, capital structure
2016	Sandpiper Energy	MD	9410	Maryland Office of People's Counsel	Return on equity, capital structure
2016	Washington Gas Light	DC	FC 1137	Washington, DC Office of People's Counsel	Return on equity, capital structure
2016	Florida Power & Light	FL	160021-EI	Florida Office of Public Counsel	Capital Structure
2016	Jersey Central Power & Light	NJ	EM15060733	NJ Division of Rate Counsel	Asset valuation
2016	Rockland Electric Company	NJ	ER16050428	NJ Division of Rate Counsel	Rate design
2016	Dominon NC Power	NC	E-22, Sub 532	Carolina Utility Customers Assoc.	Accounting, cost of service, rate design, ROE, capital structure
2017	Potomac Electric Power	DC	FC 1139	Healthcare Council of the National Capitol Area (HCNCA)	ROE and capital structure
2017	Columbia Gas of Maryland	MD	FC 9447	Maryland Office of People's Counsel	ROE and capital structure
2017	Washington Gas Light	DC	FC 1142	Washington, DC Office of People's Counsel	Merger analysis
2017	Duke Energy Progress	NC	E-2, Sub 1142	Carolina Utility Customers Assoc.	Accounting, cost of service, rate design, ROE, capital structure
2018	Public Service Electric & Gas	NJ	GR17070776	NJ Division of Rate Counsel	ROE and capital structure
2018	Duke Energy Carolinas	NC	E-7, Sub 1146	Carolina Utility Customers Assoc.	Accounting, cost of service, rate design, ROE, capital structure
2018	Elkton Gas/SJI	MD	FC 9475	Maryland Office of People's Counsel	Merger analysis
2018	Entergy Texas	TX	PUC 48371	Public Utilities Commission of Texas	ROE
2018	Duke Energy Carolinas	SC	2018-3-E	South Carolina Energy Users Committee	Fuel case

Regulatory Cases of Kevin W. O'Donnell, CFA
Nova Energy Consultants, Inc.

Year	Name of Applicant	State Jusrisdiction	Docket No.	Client/ Employer	Case Issues
2018	Elkton Gas Company	MD	FC 9488	Maryland Office of People's Counsel	Accounting, ROE, capital structure
2018	Baltimore Gas & Electric	MD	FC9484	Maryland Office of People's Counsel	ROE, capital structure
2018	South Carolina Electric & Gas	SC	2017-370-E	South Carolina Energy Users Committee	Creditworthiness issue
2018	Jersey Central Power & Light	NJ	EO18070728	NJ Division of Rate Counsel	ROE and capital structure
2019	Duke Energy Carolinas	SC	2018-319-E	South Carolina Energy Users Committee	Accounting, rate design
2019	Duke Energy Progress	SC	2018-318-E	South Carolina Energy Users Committee	Accounting, rate design
2019	Public Service Electric and Gas	NJ	EO18060629	NJ Division of Rate Counsel	ROE and capital structure
2019	Potomac Electric Power	MD	FC 9602	Maryland Office of People's Counsel	ROE, capital structure
2019	Oklahoma Gas and Electric	OK	PUD 201800140	Sierra Club	Creditworthiness issue
2019	Peoples Natural Gas	PA	R-2018-3006818	Pennsylvania Office of Consumer Advocate	ROE, capital structure
2019	UGI Natural Gas	PA	R-2018-3006814	Pennsylvania Office of Consumer Advocate	ROE, capital structure
2019	Dominion Virginia Power	VA	PUR-2019-00050	Federal Executive Agencies	Return on Equity
2019	Piedmont Natural Gas	NC	G-9, Sub 743	Carolina Utility Customers Assoc.	Accounting, cost of service, rate design, ROE
2019	Pacific Gas & Electric, Southern California Edison, San Diego Gas & Electric	CA	A-1904014, et al	Federal Executive Agencies	ROE, capital structure
2019	Duke Energy Indiana	IN	Cause 45253	Federal Executive Agencies	ROE, capital structure

Q. Mr. O'Donnell, have you also prepared and caused to be prefiled, a summary of your testimony in this case?

A. Yes, I have.

MR. PAGE: Commissioner Clodfelter, we are part of a stipulation concerning carrying over of some testimony from the previous cases. Is this a good time to bring that up, or would you like me to bring that up at some other time?

COMMISSIONER CLODFELTER: Let's do this first. Let's admit into the case his summary statement, which will be admitted unless there's an objection.

(Whereupon, the prefiled summary of testimony of Kevin W. O'Donnell was copied into the record as if given orally from the stand.)

Summary of Kevin O'Donnell

DEP General Rate Case

Docket No. E-2 Sub 1219

My summary today will focus only on my observations and recommendations in regard to coal ash and cost of service/rate design.

Coal Ash

The circumstances surrounding Duke's coal ash spill, subsequent federal prosecution, and the development of the Coal Ash Management Act (CAMA) are well known. I will not repeat that well known history in this summary.

My position on coal ash in this case is consistent with my testimony in DEC and DEP's last rate cases as well as my position in DEC and DEP's South Carolina rate cases last year. Specifically, consumers should only pay for federal CCR costs and not the incremental cost associated with CAMA. In South Carolina, the Public Service Commission stated in its final order (Docket No. 2018-318-E) that it had received evidence that confirms CAMA is more stringent than CCR. I recommend this Commission make a similar finding in this case and take corresponding action.

Cost of Service/Rate Design

In regard to cost of service, my recommendation is the Commission use the summer coincident peak (SCP) rate design as opposed to the summer winter peak and average (SWPA) methodology. In my career I have completed close to 30 wholesale power deals for university and municipal clients. In those transactions, fixed generation costs are always based on coincident peak (CP) pricing and variable costs are based on energy costs. Hence, the pricing in the competitive wholesale market mirrors the SCP cost allocation methodology. SWPA does not. To the extent that one believes regulation should assign costs to the customer(s) that causes those costs to be incurred, otherwise known as the cost causation principle, fixed generation costs should be allocated on the SCP method.

As to rate design, I made only one recommendation in this case and that is that DEP be required to set hourly pricing rates based on the lower of Duke's marginal costs OR costs found in the competitive wholesale power markets as adjusted for transmission costs and line losses. Manufacturers need every advantage possible to sustain operations in light of Duke's planned rate hikes for the future. This simple change in the hourly pricing methodology may save manufacturers on real-time pricing rates a substantial amount of operating funds.

This completes my summary.

COMMISSIONER CLODFELTER: And now you have testimony by stipulation that is to come in from the Duke Energy Carolinas case; is that correct?

MR. PAGE: Yes, sir; that is correct.

COMMISSIONER CLODFELTER: This is the appropriate point for you to move that that testimony be admitted into the record of this proceeding and copied into the transcript.

MR. PAGE: All right. The stipulation, Commissioner Clodfelter, is the joint stipulation that involves Duke Energy Progress, CIGFUR, NCSEA, the Justice Center, Housing Coalition, Natural Resources Defense Council, and several other parties, including CUCA. And our stipulation is to Mr. O'Donnell's prior testimony appears as item number 5, about the middle of page 2 of that stipulation. If possible, I would like to make one modification to that, and it deals with my apparent inability to grasp what is meant by the term "live testimony," because what I asked to have included was the same qualifying questions for Mr. O'Donnell's other testimony that I just asked him. So it would be duplicative to put those in brought over from the DEC case.

COMMISSIONER CLODFELTER: What exactly are you proposing? You're proposing to exclude the qualifying questions?

MR. PAGE: Yes. And those appear in the stipulation as transcript Volume 20, pages 19-22. I am proposing not to bring those forward.

COMMISSIONER CLODFELTER: Well, Mr. Page, for purposes of your motion and for clarity of this record, please now advise us what transcript pages and lines you are proposing to enter into this record by stipulation.

MR. PAGE: That would be transcript Volume 20, pages 156 through 164.

COMMISSIONER CLODFELTER: Okay. Hold a second, does everyone understand Mr. Page's motion? Is there any objection to that motion?

(No response.)

COMMISSIONER CLODFELTER: Mr. Page, your motion is granted.

(Whereupon, the testimony from Docket Number E-7, Sub 1214, transcript Volume 20, page 156 through page 164 were copied into the record as if given orally from the stand.)

CHAIR MITCHELL: We're getting a lot of feedback from the line this morning. I believe it's when you and Mr. O'Donnell are both unmuted. So I'd ask that you-all just keep your lines muted until you need to speak.

All right. So the witness is available for questions. The only party who has indicated cross examination or reserved cross examination time for the witness is Duke. We've heard that Duke has no questions for the witness.

Any other cross examination for the witness?

MR. JENKINS: Yes, Chair. Alan Jenkins.

CHAIR MITCHELL: All right. Mr. Jenkins, you may proceed.

MR. JENKINS: Thank you.

CROSS EXAMINATION BY MR. JENKINS:

Q. Mr. O'Donnell, Alan Jenkins for the Commercial Group. How are you today?

A. I'm good, sir; how are you?

Q. Good. There were some questions yesterday that I thought you might shed some light on. You've been involved with the OPT issues for many years, haven't you?

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A. Yes. Many is kind.
Q. Now, do you recall the process where the current OPT structure was negotiated between parties and finally approved by the Commission several cases ago?
A. I'll be honest with you, Mr. Jenkins, I don't remember the parties negotiating the OPT. I do remember it being approved. But I don't -- put it to you this way, I wasn't part of any negotiating process, or at least I can't remember it.
Q. But you gave input over the years on how to structure an OPT program; is that right?
A. Yeah, I think that's probably correct. I mean, I have definitely submitted testimony in terms of rate design and cost of service study before this Commission. Specific to OPT, I just -- I don't remember, I'm sorry.
Q. Okay. No problem. Have you heard any discussion about a potential comprehensive rate design process?
A. Yes, I have.
Q. And would you say, of all the rate schedules of DEC, that the OPT has had more review than perhaps any other?

A. I couldn't testify to that. It may make logical sense, but I really don't know the details of whatever else has been examined. I'm sorry.

Q. Fair enough. Would you expect, in the upcoming process, that your client would agree to, let's say, an SWPA class cost of service study being implemented?

A. No. Can I explain my reason why?

Q. Sure.

A. And I think this Commission knows that I've done a lot of wholesale power work in my day. I've done about 30 wholesale power deals around the Carolinas. And in the wholesale power markets, the fixed costs were always allocated on peak demand. Variable costs were always on -- excuse me, let me back up. Peak cost -- fixed costs were always priced, not allocated, but they were always priced on demand. Typically peak -- well, always peak demand. Variable costs are always priced at -- on energy. There is no allocations. They are always priced in that way.

I think, if the theory of regulation is to mimic what is available in the open comparative markets, then the price signals we ought to be sending ought to be based on peak and not summer/winter peak

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and average. And I have a tremendous amount of respect and admiration for Mr. McLawhorn, I heard his discussion yesterday. I just don't know too many, if any, industrials that have the ability to shut down their factories at time of the system peak. I mean, I just don't see it.

On top of that, on retail, you're not giving load signals. It's not like Duke sends out a load signal to everyone and says, "Hey, shut down." On the wholesale side, yeah, you know, you could do that. You could run a diesel generator in your back and clip the peak, because wholesale has coincident peak in Duke's formula regulated rates. You don't have that on the retail side.

So that's a long answer to say, Mr. Jenkins, that I do not believe that my clients would welcome a summer/winter peak and average because it is not market driven, at least not in the markets that I see -- in the competitive markets that I see here in the Carolinas.

Q. Do you have any opinion as to whether a comprehensive rate design review process, as is being discussed, would resolve all these issues ahead of the next DEC rate case?

A. I think it's going to be a tall order. From what I understand, Duke's going to be coming in for rate cases on a very frequent basis. I can understand the worthwhile -- the need for the process. I would just argue, again, that if what we're looking for is to lower rates for our respective clients, then we perhaps ought to look at market pricing, and we ought to go towards market pricing, because that's how you're going to lower rates for our clients, the consumers.

I can take you to several places in the Carolinas where market prices have lowered rates for residential customers a whole lot more than what we could be discussing in pricing reform such as the minimum system study.

Q. Thank you. And one further question.

Do you have any opinion as to whether rate design suggestions that you've made in this case or other parties have made in this case for, say, adjustments to the OPT should be postponed until there's a comprehensive rate review process done?

A. I would hope not. The arguments that I've made here in this case have been made previously and have not been addressed by Duke. So what I'm saying here is not new to Duke, they've seen it before, and we haven't received any traction on it. In terms of waiting until the next rate case, as you well know, Mr. Jenkins, and I think you pointed out yesterday regarding loss of Penneys, we have several manufacturers around the state that may not come back into play or may not come back into business. And these rate increases -- and I indicate this in my testimony, between grid mod coal ash and coal to gas, we're looking at pretty sizable rate hikes.

That's going to really harm manufacturing in North Carolina, which was the backbone of the state's economy. And it's obviously going to harm your customers as well. So I would argue that we really can't wait too much longer. A lot of our folks are not going to be coming back.

Q. Thank you.

MR. JENKINS: Nothing further.

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

(No response.)

CHAIR MITCHELL: All right. Mr. Page, any redirect for your witness?

MR. PAGE: Very shortly, Madam Chair, thank you.

REDIRECT EXAMINATION BY MR. PAGE:

Q. Mr. O'Donnell, I believe you stated in response to one of Mr. Jenkins' questions that you did hear the discussions yesterday afternoon by the Public Staff panel, including Mr. McLawhorn and Mr. Floyd; is that correct?

A. Yes, I did.

Q. And did you hear the portion where, if I understood his testimony correctly, Mr. Floyd was saying that the landscape over the last 40, 50 years in the electric business has changed, and there are all these new things coming online with diversified generation, and smart metering, and smart grids, and this, and that, and the other thing, and all of that is proposed, as I understand it, to be taken up in these new rate studies.

My question to you is, are you aware of anything in those proposed new rate studies that would change the principle that has been around since before Professor Bonbright's book that what you do in a cost of service study is you allocate costs to the group of customers who are imposing those costs on the system? Do you see that changing?

A. I would hope not, because, again, that is not reflective of what happens in competitive markets. That's not what happens outside the world of regulation.

Q. Thank you, Mr. O'Donnell. That's all I have.

CHAIR MITCHELL: All right. Questions from Commissioners, beginning with Commissioner Brown-Bland.

COMMISSIONER BROWN-BLAND: I don't have any questions.

CHAIR MITCHELL: All right. Commissioner Gray?

COMMISSIONER GRAY: No questions.

CHAIR MITCHELL: All right. Commissioner Clodfelter?

COMMISSIONER CLODFELTER: Nothing from me this morning. Thank you.

CHAIR MITCHELL: All right. Commissioner Duffley?

COMMISSIONER DUFFLEY: No questions.

CHAIR MITCHELL: Commissioner Hughes?

COMMISSIONER HUGHES: No questions.

CHAIR MITCHELL: All right. And Commissioner McKissick?

COMMISSIONER McKISSICK: No questions.

CHAIR MITCHELL: All right. Mr. O'Donnell, you are off the hook.

MR. PAGE: Madam Chair, we'd like to move that Mr. O'Donnell's appendix and exhibits be admitted into the record at this time, and that Mr. O'Donnell be excused from further participation in the Duke Carolinas case.

CHAIR MITCHELL: All right. Mr. Page, your motion is allowed.

(Exhibits KWO-1 through KWO-8 and O'Donnell Appendix A were admitted into evidence.)

CHAIR MITCHELL: Thank you for your time this morning, Mr. O'Donnell.

THE WITNESS: Thank you.

CHAIR MITCHELL: All right. Ms. Downey, we return to the Public Staff. You may call your witnesses.

MS. JOST: Good morning, this is Megan Jost with Public Staff. The Public Staff calls Bernie Garrett and Vance Moore.

CHAIR MITCHELL: All right. Good morning, Ms. Jost. And let me see if I can find the witnesses. There's Mr. Moore. Mr. Garrett, I

MR. PAGE: May I make, then, the just housekeeping question posed to Ms. Jagannathan? Based on previous conversation, Ms. Jagannathan, I understand that Duke is actually going to copy and send these pages into the court reporter; am I correct about that?

MS. JAGANNATHAN: Yes, that's my understanding, Mr. Page.

MR. PAGE: Thank you very much. And thank all for your patience. Mr. O'Donnell is ready for cross examination.

COMMISSIONER CLODFELTER: Thank you, Mr. Page.

Mr. Jenkins, I believe you are up first here.

MR. JENKINS: Thank you.

CROSS EXAMINATION BY MR. JENKINS:

Q. Good afternoon, Mr. O'Donnell.

A. Good afternoon.

Q. And my questions, since the Commercial Group also entered into that stipulation, are just concerning the DEP case.

A. Okay.

Q. Can you direct your attention to page 51 of your testimony, and the Q and A beginning at line 18.

A. All right. Let me get up there. Okay. I'm here.

Q. You make a recommendation there that coal ash cleanup costs should follow the allocation of fuel costs approved in DEP's last fuel case. I'm not sure I fully followed this recommendation, and wonder if you can give an example or flush out how this would work.

A. Okay. I'll give you a little history. I'm going to guess it was probably about 10 years ago. The Utilities Commission started to agreeing with a change in the manner that fuel costs were going to be allocated in fuel proceedings. And with commodity costs that were increasing -- and of course this is probably more than 10 years ago now, probably 12 years ago, 13 years ago -- fuel costs were increasing pretty rapidly. And the manufacturers, quite frankly, were getting a little bit hurt with the constant fuel increases. So there was an effort underway to have an equal percentage rate increase on the fuel. So instead of a flat cents-per-kilowatt hour fuel rate, it was going to be an equal percentage across all customer classes.

Well, along comes fracking and natural gas costs, and I'm assuming coal costs as well, they start plummeting. So we continue to use equal percentage when -- for, I guess, about 10 years now or so -- when it was not to the advantage of high-load factor customers, your group commercials as well as the industrials.

And so when we come to this coal ash situation, all I'm recommending is that we be consistent. And that is, if the argument is that coal ash is a byproduct of fuel, and we're using equal percentage increases on the fuel side, then we should do the same on coal ash. And, specifically, when fuel costs are increasing -- in this case coal ash costs are increasing -- equal percentage benefits industrial customers and high-load factor customers like commercials.

When fuel costs are decreasing like they have been for 10 years or so -- overall that's a broad general statement. Year to year it may go up, may go down, but ever since fracking has come along, we've seen gas costs go down pretty significantly. But in any event, when fuel costs go down, a percentage hurts industrial customers.

So all I'm asking is that we be consistent.

And with an equal percentage like this, it could benefit industrial customers as those costs increase, and high-load factor. Doesn't have to be industrial customers. High-load factor customers would benefit, and I'm just asking for some consistency.

Q. Thank you. On a similar allocation issue, you recall Public Staff witness Thomas suggested allocating 97 percent of GIP reliability cost to commercial and industrial customers?

A. Yes, I heard that.

Q. Do you have any idea the magnitude of those costs?

A. Considering that -- I know Duke will object to me saying this, but I still believe that, from everything I've seen, we're still looking at grid mod costs of $13 billion. I know it's been split off into various pieces, and we're not asking for all $13 billion now, but nowhere has it been denied that Duke is still going to seek grid mod cost of $13 billion. And, in fact, the evidence in the record that I presented indicates that Duke executive management is still looking at $13 billion of grid mod costs.

So you apply 97 percent of $13 billion to high-load factor customers and you're talking about some -- you know, some really massive rate increases. And as we saw yesterday, industrial load is decreasing in North Carolina; and, in fact, its load forecast has it decreasing. So -- and we also know that Duke's cost, at least in some corners -- some of our industrial members are telling us that they're in the top quartile of costs at their various plants.

There was an article in Charlotte Business Journal a few weeks or a few months ago about that. So if you hit commercials and industrials with 97 percent of these costs, particularly when they already have generation on site to back up their facilities when power goes out, you're going to accelerate that loss on industrial customers. And when that happens, only one thing is going to happen, and that is the rates for everyone else is going to go up. That's just a basic math fact that, when costs are going up for the utility and you're spreading it over fewer customers, rates are going to go up disproportionately to those customers who do not have the ability to move.

Q. Thank you. On the other hand, are you aware that staff witness Floyd argues against refunding excess deferred income taxes for ratepayers on a per-kWh basis?

A. I'm aware of that. I think that is a little bit inconsistent relative to the coal ash, but I recognize Mr. Floyd may have some reasons for that. I just believe it's a little bit inconsistent, because the customer class rates of return are going to be different for the residential group, the commercial, and for the industrial group.

Q. Taken together, these three allocation methods, what impact would those have on North Carolina businesses?

A. Well, it's all these items, particularly the grid mod, the coal ash, and now the IRP -- I've submitted testimony. I call it the trifecta. These three items, when you put them together, they're going to drive industry and large commercials out of the state. We are -- all you have to do is look at the numbers and we're seeing a dramatic decrease in Duke's industrial load. They are getting close to the national average now, and when you look at places like Texas that have open markets and we don't, you're going to start seeing a continued movement away from North Carolina, which is really sad.

This is my home state. This is my home. So

I take it very personally. I grew up in a textile family. Between my father and my grandfather we have 100 years in the textile mills, so it bothers me tremendously to see this. But it is a fact of life, that we are losing industrial load throughout the state of North Carolina, and that's going to continue if these electric rates continue to go where they are.

Q. Thank you, Mr. O'Donnell, nothing further.

A. Thank you.

COMMISSIONER CLODFELTER: Thank you, Mr. Jenkins. Ms. Goldstein, are you with us?

MS. GOLDSTEIN: Yes, Commissioner Clodfelter, thank you. I'm here.

COMMISSIONER CLODFELTER: Yes. I think you're next.

MS. GOLDSTEIN: Yes, sir.

CROSS EXAMINATION BY MS. GOLDSTEIN:

Q. Good afternoon, Mr. O'Donnell.

A. Good afternoon. Good afternoon.

Q. Thank you. Just a few general questions. And you just spoke of some industry laws, which is a good segue right into your testimony and the testimony of Hornwood and the relief that we're requesting.

Among other things, your testimony advocates, is it correct, for some changes in the RTP rate as administered here in North Carolina by DEP?

A. Yes. Specifically, I recommended that the RTP rate on an hourly basis be the lower of whatever Duke can generate versus open market costs. Open market costs right now, because of gas, and because of the advances in combined cycle generation, are very attractive. So -- and I see these on a monthly basis when my clients -- my wholesale clients get their monthly bills, and I see the hours that we go into the open wholesale market instead of generating at our plant that we're buying power from. So my specific recommendation, in terms of RTP, is the lower open market versus what Duke can generate.

Q. Okay. Thank you. And are you aware that there's a participation cap on RTP currently of 85 customers?

A. Several years ago I was aware of that cap. I don't know where that cap is now. I don't know how many customers are in it or anything like that, but I knew at one point in time there was a cap.

Q. Okay. Thank you. Talking about the industry laws here in North Carolina, would you say that eliminating the cap of 85 customers would help incent industry and business to stay here in the state?

A. Yes. But I think our problems go a little bit deeper than that. When I talked to some of my industrial members at CUCA, what I hear consistently is we can get lower costs in Texas; we can get lower costs in Georgia; we can get lower costs in Ohio. So why are we going to continue to invest in North Carolina.

And there are the lots of things that go into locating a plant and expanding a plant. I don't want to say electricity is the only one, that would be wrong, but it is a factor. And our costs are high relative to other states that my members of CUCA are telling me about. So I think the answer to what you're saying is yes, but we need a lot more than just access to RTP rates.

Q. Okay. Understood. Mr. O'Donnell, customers who participate in RTP and are able to curtail during the high price times, are they able to save money on their electricity costs?

A. Oh, yes. I mean, absolutely. Well, curtail or move the operations. Yeah, they reduce their outage. I mean, they switch from one product that's less energy intensive, then, yes, they can save money, absolutely.

Q. Okay. So, Mr. O'Donnell, wouldn't you say it's reasonable that, for those customers who are able to shift load and lower their electricity costs, it would enhance their ability to stay competitive with other customers who might not be able to go on to the rate because the rate is capped at 85?

A. Yes. But at the same time you've got LGS-TAU rates, for example, for industrials, that a customer can save money on that. Now, it is not -- it is not a sure thing that RTP rates always save money. I mean, you have to look at this on an annual basis, and look at your loads and look at your hourly costs, and then determine -- and then run the numbers on LGS-TAU and determine whether or not you're going to save money.

If you're operating at a time of, you know, 4:00 and a Saturday at Thursday -- excuse me, a Wednesday at 4:00 in the middle of the summer, you're going to get hurt. And sometimes customers can't cut back. If you have a special-needs customer who needs to get something done, you're going to operate through it.

So you can't always assume one versus the other. But as a general rule, yes, I will agree with you that, if a customer can take advantage of the RTP rates and they cut their load, then yes, they can save money relative to those who may not have access to the RTP.

Q. Okay. Mr. O'Donnell, isn't it true that, once the CBL has drawn the customer baseline, that if a customer is not able to shift load during those high price times, they're going to pay higher for anything used above their CBL, correct?

A. I'll be honest with you, I don't consider myself to be an expert on exactly how the CBL is determined. I know it's done on a company-by-company basis, but, you know, exactly how the Company, Duke Progress sets the CBL and whatnot, I'm not really familiar with that, because that's not a company-by-company basis.

Q. Okay. Thank you. Understood. Do you -- Mr. O'Donnell, are you aware of the comprehensive rate design study that's been discussed throughout the rate case?

A. Yes, I am.

Q. Okay. Mr. O'Donnell, do you -- in your opinion, would eliminating the cap of 85 customers for just large customers -- customers over 1000 kW, do you believe that eliminating that cap would interfere with this comprehensive rate study that's being offered?

MR. MEHTA: Objection.

Commissioner Clodfelter, all of this is basically friendly cross, and frankly, a waste of time.

COMMISSIONER CLODFELTER: Well, we won't make that judgment, Mr. Mehta, but whether or not it's friendly remains to be seen in how it all turns out. I'm going to allow Ms. Goldstein a chance to pursue the line of questioning a little further.

MS. GOLDSTEIN: Okay. Thank you, Commissioner Clodfelter.

Q. Mr. O'Donnell, are you -- do you know if Duke is offering any other additional time of use rates in this current rate case proceeding?

A. No, I'm not.

Q. Okay. And are you aware that Duke has stated that they will be studying the DEC pilot rates in conjunction with making further determination of opening up any rates in DEP?

A. I am not totally familiar with what the discussion has been in terms of what we're going to be studying down the road in the various rate designs. I have to plead ignorance to that. I'm not aware of how that's all going to shake out.

Q. Okay. Thank you.

MS. GOLDSTEIN: I no further questions for Mr. O'Donnell. Thank you.

COMMISSIONER CLODFELTER: Thank you, Ms. Goldstein. My notes do not show any further party requesting to reserve cross examination, but I'll ask at this point in time. Are there any other parties who wish to have an opportunity to cross examine Mr. O'Donnell?

MS. DOWNEY: Commissioner Clodfelter, Dianna Downey here.

COMMISSIONER CLODFELTER: Yes, Ms. Downey.

MS. DOWNEY: I have a couple of clarifying questions for Mr. O'Donnell based on some of this other cross, if that's appropriate.

COMMISSIONER CLODFELTER: You may proceed with your clarifying questions.

CROSS EXAMINATION BY MS. DOWNEY:

Q. Mr. O'Donnell, Mr. Jenkins asked you about Mr. Jeff Thomas' recommendation regarding the customer benefits presented by grid mod; do you remember that question?

A. Yes. I didn't know it came from Mr. Thomas, but I do remember the questions.

Q. I'm sorry. Mr. Jenkins.

A. Oh, no. Yes, we're on the same page.

Q. Yes. Isn't it true that what Public Staff witness recommended was that he was only pointing out that C&I customers receive 97 percent of the benefits; he didn't actually recommend allocating those -- that percentage of costs in this case, did he?

A. I'm not aware of what he specifically recommended in this case, but I stand by what I said. Allocating those costs to commercials and industrials will be very painful, whether it's in this case or whether it's in the next case accounting with the deferral.

Q. Mr. O'Donnell, are you -- I'm sorry. Mr. O'Donnell, are you aware of Public Staff witness McLawhorn's recommendation that the Public Staff -- that there be a study of the allocation of GIP costs?

A. Is that -- I'm assuming that's going to be part of the total study of rates that we're going to undertake sometime here in the next year.

Q. Mr. O'Donnell, have you reviewed -- had a chance to review the 2020 IRP filed by Duke on

September 1, 2020, in Docket E-100, Sub 165?

A. Yes.

MS. DOWNEY: Commissioner Clodfelter, I would ask the Chair to take judicial notice of that filing.

COMMISSIONER CLODFELTER: Ms. Downey, for my benefit, again, describe the particular document you want to have noticed.

MS. DOWNEY: It's the Company's IRP filed September 1, 2020, in Docket E-100, Sub 165.

COMMISSIONER CLODFELTER: That is a filing made with the Commission, and it is appropriate for judicial notice. The Commission will take judicial notice of that filing. Let me say that we will have proceedings on that filing in that docket, so we -- questions are fine so far, but let's not get too far afield into that particular docket.

MS. DOWNEY: I think that's all I need actually. Thank you.

COMMISSIONER CLODFELTER: Very good. Thank you.

Anyone else with cross examination for Mr. O'Donnell?

(No response.)

COMMISSIONER CLODFELTER: All right.

Mr. Page, any redirect?

MR. PAGE: I have just one.

REDIRECT EXAMINATION BY MR. PAGE:

Q. Mr. O'Donnell, you responded to a question, I believe, from counsel for Hornwood to the extent that you had not closely followed all of the proposals in this case for various different kinds of rate design studies to take place between now and the next rate case; is that correct?

A. Yeah, that's correct. I mean, I know we're going to be going down that road, and I know the Public Staff is involved. And I'll work closely with the Public Staff, and the Commercial Group, and anyone else that wants to get involved and make certain that we do the best we can for the benefit of all of our respective clients.

Q. So it would be safe for me to say, the fact that you have not had time to devote to these various proposals to date does not mean that you will not be actively involved with them in the future; is that correct?

A. Well, assuming that CUCA continues to employ me, then I'll be actively involved.

Q. Thank you, Mr. O'Donnell. That's all the redirect I have.

A. Thank you.

COMMISSIONER CLODFELTER: Thank you, Mr. Page.

Are there questions from Commissioners, starting with Commissioner Brown-Bland?

COMMISSIONER BROWN-BLAND: No, I don't have any questions. Thank you.

COMMISSIONER CLODFELTER: All right. Thank you. Commissioner Gray?

COMMISSIONER GRAY: No questions, thank you.

COMMISSIONER CLODFELTER: All right. Chair Mitchell?

CHAIR MITCHELL: No questions.

COMMISSIONER CLODFELTER: Commissioner Duffley?

COMMISSIONER DUFFLEY: No questions.

COMMISSIONER CLODFELTER: Commissioner Hughes?

COMMISSIONER HUGHES: No questions.

COMMISSIONER CLODFELTER: And

Commissioner McKissick?

COMMISSIONER McKISSICK: No questions.

COMMISSIONER CLODFELTER: Okay. That brings us to the point where I need to ask Mr. Page, do you have any additional motions you need to make?

MR. PAGE: Yes, Mr. Clodfelter. We would like to move the introduction of Mr. O'Donnell's Appendix A, and O'Donnell Exhibits KWO-1 through KWO-10.

COMMISSIONER CLODFELTER: Is there any objection to that motion?

(No response.)

COMMISSIONER CLODFELTER: Hearing none, motion is granted.

(KWO-1 through KWO-10 and Appendix A were admitted into evidence.)

MR. PAGE: Could we also ask that Mr. O'Donnell be dismissed?

COMMISSIONER CLODFELTER: If there's no objection, Mr. O'Donnell, you are excused.

THE WITNESS: Thank you, sir.

COMMISSIONER CLODFELTER: Thank you.

Ms. Cress, I believe you are next; am I

correct.

MS. CRESS: Thank you, Commissioner Clodfelter. That is my understanding as well.

COMMISSIONER CLODFELTER: All right. Do we have -- Mr. Phillips is with us, I see.

THE WITNESS: Yes, I am.

COMMISSIONER CLODFELTER: All right. Ms. Cress, do you have any preliminary matters you need to address before we swear in the witness?

MS. CRESS: I do, Commissioner Clodfelter. Before beginning with Mr. Phillips, I did just want to bring to the Commission's attention that CIGFUR did not file a motion to strike or make a motion to strike with respect to Public Staff witness Floyd's second supplemental testimony filed in this docket. It did not do so because the timing and circumstances in this case, as compared to the circumstances and timing of the DEC case, were different.

However, I did have some discussions with Ms. Edmondson about the opportunity to ask witness Phillips some questions that would be responsive to the testimony contained in witness

Floyd's second supplemental, as well as witness Pirro's then rebuttal testimony in response to witness Floyd's second supplemental. And it's my understanding that the Public Staff does not have any objection to that, but I did want to let you know that I have not broached that subject with any of the other parties. So I would definitely want to make sure that nobody has an objection to that before I proceed down that avenue.

COMMISSIONER CLODFELTER: All right, Ms. Cress, that's a reasonable request. And let me ask if any party wants to be heard on Ms. Cress' request that the scope of her examination of Mr. Phillips can also extend to the second supplemental testimony of Mr. Floyd, and also then the subsequent testimony put into the record by Mr. Pirro as well.

(No response.)

COMMISSIONER CLODFELTER: Ms. Cress, I think you're good to go.

MS. CRESS: Thank you, Commissioner Clodfelter. We appreciate the accommodation. I believe the witness is ready to be sworn at your pleasure, Commissioner.

COMMISSIONER CLODFELTER: Let me just ask again to be sure my notes are correct. Do we have any testimony for Mr. Phillips that we need to import from the DEC case?

MS. CRESS: We do, Commissioner Clodfelter, and I am prepared to make that motion after I ask some foundational questions.

COMMISSIONER CLODFELTER: That's great. I just wanted to make sure my notes are tracking correct. So Mr. Phillips, let's get you sworn.

Whereupon,

NICHOLAS PHILLIPS, JR.,

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

COMMISSIONER CLODFELTER: Thank you, Ms. Cress. You may proceed.

MS. CRESS: Thank you, Commissioner Clodfelter.

DIRECT EXAMINATION BY MS. CRESS:

Q. Good afternoon, Mr. Phillips.

A. Good afternoon.

Q. Would you please state your name for the record?

A. My name is Nicholas Phillips, Jr.
Q. And, Mr. Phillips, by whom are you employed?
A. I'm a managing principal at the firm of Brubaker & Associates located in the suburbs of St. Louis, Missouri.
Q. Okay. And what is your business address?
A. My business address is 16690 Swingley Road, Suite 140, Chesterfield, Missouri.
Q. Okay. And on whose behalf are you testifying in this proceeding?
A. I'm testifying on behalf of CIGFUR.
Q. Did you, on April 13, 2020, cause to be filed in this docket, prefiled direct testimony consisting of 43 pages and Appendix A, as well as five exhibits named NP Exhibits 1 through 5 to your direct testimony?
A. Yes, I did.
Q. And did you, on September 29, 2020, cause to be filed in Docket Number E-2, Sub 1219A, a summary of your prefiled direct testimony?
A. That's correct.
Q. Do you have any changes to your prefiled direct testimony that has been filed in this docket?
A. I do not.
Q. And if I were to ask you the same questions

here today, would your answers be the same?

A. Yes, they would.

MS. CRESS: Commissioner Clodfelter, at this time, CIGFUR moves that Mr. Phillips' prefiled direct testimony consisting of 43 pages, including one appendix and five exhibits, as well as Mr. Phillips' witness summary, be entered into the record in this proceeding and copied into the record at this time as if given orally from the stand; and that Mr. Phillips' exhibits attached to his prefiled direct testimony be marked for identification as Phillips Direct Exhibits 1 through 5.

COMMISSIONER CLODFELTER: All right. Hearing no objection, it will be so ordered.

(Phillips Direct Exhibits 1 through 5 were identified as they were marked when prefiled.)

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

BEFORE THE

NORTH CAROLINA UTILITIES COMMISSION

In the Matter of **Application of Duke Energy Progress, LLC For Adjustment of Rates and Charges Applicable to Electric Service in North Carolina**	**Docket No. E-2, Sub 1219**

Direct Testimony of Nicholas Phillips, Jr.

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

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

Q WHAT IS YOUR OCCUPATION?

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

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

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

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

A Yes. I have been involved in many prior proceedings before this Commission and have presented testimony in many of those proceedings, most recently in NCUC dockets G-9, Sub 743 and E-22, Sub 562. I have been involved with matters involving DEP for many years including DEP's previous base rate filing, E-2, Sub 1142, and other proceedings.

Q WHAT IS THE SUBJECT MATTER OF YOUR TESTIMONY?

A I present testimony pertaining to the appropriate cost allocation methodology for use in this proceeding and subsequent revenue distribution to the various customer classes of any increase granted by the Commission and the associated rate design. I also

[1]For the purposes of this proceeding, CIGFUR II members are: Archer Daniels Midland Company, Corning Incorporated, Elementis Chromium, Inc., Evergreen Packaging, LLC, Celanese Corporation, GE-Hitachi Nuclear Energy, Georgia-Pacific LLC, International Paper Company, Nutrien, Ltd., Praxair, Inc., Smithfield Foods, Weyerhaeuser Company.

address the Company's requested Return on Equity ("ROE"). I discuss DEP's proposed Grid Improvement Plan ("GIP") and deferral request. Lastly, I comment on DEP Rider EDIT-2.

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

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

Summary of Conclusions and Recommendations

Q WOULD YOU BRIEFLY SUMMARIZE YOUR RECOMMENDATIONS IN THIS PROCEEDING?

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

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

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

3. DEP's proposed energy charges for the Large General Service ("LGS"), and LGS Time of Use rates continue to be priced significantly higher than unit costs for energy calculated and filed by DEP. DEP's proposed rates do not reflect unit costs or the dominant winter peak demand used by DEP for planning. Therefore, any reduction to DEP's requested increase should be applied to reduce energy charges to achieve the authorized revenue level for Rate LGS.

4. DEP should allow existing RTP customers the opportunity to adjust Customer Baseline Loads ("CBL") to enhance RTP usage which benefits both customers and the system with cost based price signals.

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

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

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

Cost of Service and Rate Design Principles

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Q PLEASE DISCUSS THE STABILITY CONSIDERATION.

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

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

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

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

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

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

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

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

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

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

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

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

Appropriate Cost of Service Study and Revenue Distribution

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

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

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

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

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

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

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

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

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

Q WHICH COST OF SERVICE STUDY DO YOU RECOMMEND?

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

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

A DEP has transitioned from a summer to a winter peaking utility. According to FERC Form-1 data from 2015 through 2019, all of the last five system peaks (100%) occurred during winter months. This is shown graphically on Exhibit NP-4. Additionally, DEP indicates that it has changed from using a summer planning peak to a winter planning peak since its 2016 IRP. Specifically, DEP's 2019 IRP states:

> "DEP's IRP includes new resource additions driven by winter peak demand projections inclusive of winter reserve requirements."

DEP forecasts as peaking in the winter for the foreseeable future as shown graphically in Exhibit NP-5 for the period 2020 through 2029.

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

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

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

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

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

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

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

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

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

After lengthy discussion of the SWPA method in the DEP case, the Commission determined that a coincident peak demand allocation of production and transmission capacity costs was appropriate. This method properly allocates cost responsibility to customer classes and, if implemented properly, minimizes the need for new generating capacity consistent with DEPs load management goals.

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

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

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

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

Q IS THIS A NEW COST OF SERVICE CONCEPT?

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

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

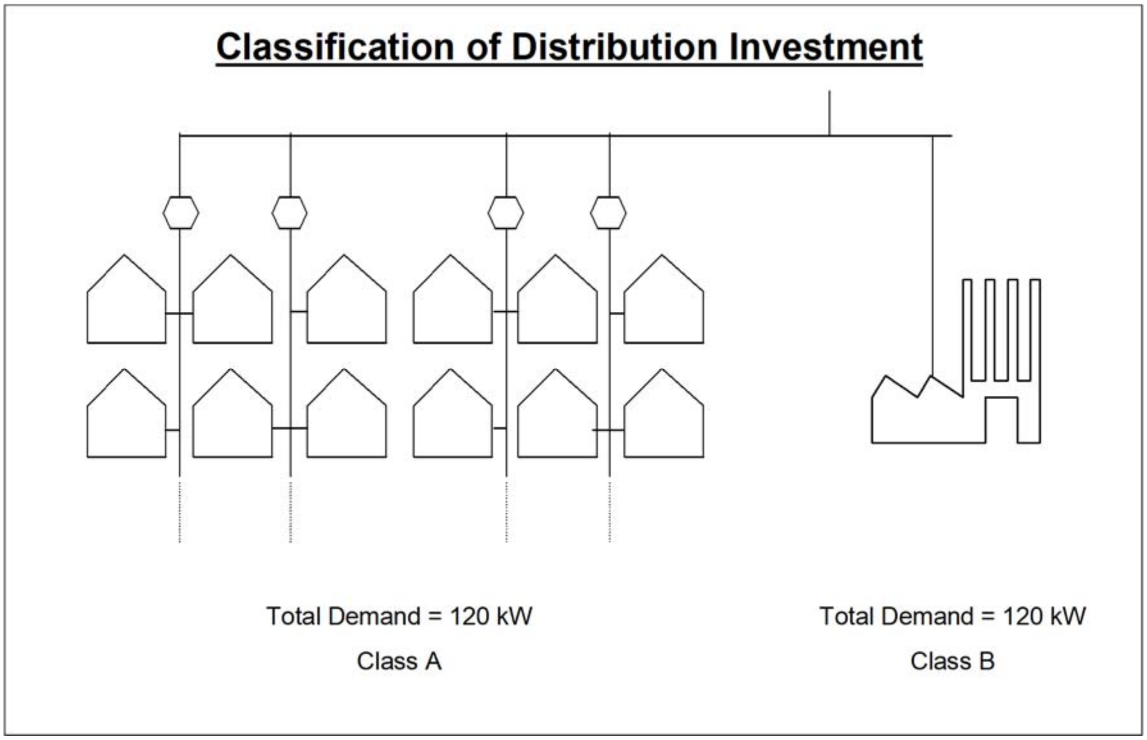
Q PLEASE ELABORATE FURTHER ON THE MDS CONCEPT AND THE DISTINCTION BETWEEN CUSTOMER-RELATED COSTS AND DEMAND-RELATED COSTS IN THE CONTEXT OF A CLASS COST OF SERVICE STUDY.

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

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

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

Figure 1



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

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

Q PLEASE EXPLAIN.

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

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

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

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

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

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

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

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

Figure 2

TABLE 6-1

CLASSIFICATION OF DISTRIBUTION PLANT[1]

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

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

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

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

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

Industrial Rate Design

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

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

Q PLEASE DESCRIBE THE LGS RATE DESIGN.

A In general, the LGS rate structure consists of a monthly Basic Facilities charge, declining block demand charges and energy charges. DEP's proposed energy charges are 6.327¢ per kWh while DEP's unit cost of LGS energy, which were contained in Item 45E of the Company's E-1 filing. DEP's proposed rates continue to contain energy charges for that exceed the unit cost of energy by more than 100%.

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

A I recommend that any approved reduction to the Company's requested revenue requirement increase for the LGS class be used to reduce DEP's proposed on-peak energy rates. As previously stated, the DEP proposed energy rates for LGS customers are more than 100% above the unit costs resulting from the Company's cost of service study and unit cost filing are 3.06¢ per kWh. The Rate LGS energy charges should be reduced to better reflect actual energy costs.

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

A Yes. It is recommended that existing RTP customers be allowed to modify their existing CBL up or down to better match current circumstances and enhance RTP usage. Hourly prices reflect actual cost by hour and are an excellent pricing mechanism that benefits both the RTP customers and the DEP system.

DEP data basically forecasts a flat or declining in industrial customers and industrial sales through 2025 while the residential and commercial sectors are growing. This cost based rate modification will help mitigate sluggish industrial sales and benefit the system.

Grid Improvement Plan

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

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

Q SHOULD THE DEFERRAL REQUEST BE APPROVED?

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

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

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

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

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

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

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

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

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

A During the period between rate cases, a utility has a strong incentive to control its costs to be more profitable to its shareholders and to diminish the need for future rate cases.

Between rate cases, a utility has a profit motivation that causes it to be diligent and efficient in managing its operations, seeking the best pricing possible for its needed facilities, equipment, etc., since it benefits directly from the cost savings. Since the GIP deferral would allow an almost guaranteed recovery of the cost of grid modernization, plus a return, DEP has a far weaker incentive to be as diligent or efficient in its procurement and operations.

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

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

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

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

Return on Equity & Capital Structure

Q IS DEP'S PROPOSED 10.30% ROE APPROPRIATE?

A No. DEP's requested ROE of 10.30% is excessive when compared with recent rate ROEs approved by commissions nationwide and the Commission's recent decisions and should be rejected. The Company's current authorized ROE is 9.9%, which was authorized in the Commission's Final Order in Docket No. E-2, Sub 1142, issued on February 23, 2018. It is important to note that, market costs of capital have not increased since DEP's last rate case. Further, the national average ROE has been below 10% for electric utilities since 2014.

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

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

TABLE 2

NCUC's Authorized ROEs

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

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

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

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

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

TABLE 3

NCUC's Approved Equity Percentage

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

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

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

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

Rider EDIT-2

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

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

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes, it does.

Qualifications of Nicholas Phillips, Jr.

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

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

Q PLEASE STATE YOUR OCCUPATION.

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

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EMPLOYMENT EXPERIENCE.

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

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

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

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

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

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

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

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

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

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

Q HAVE YOU PREVIOUSLY APPEARED BEFORE A REGULATORY COMMISSION?

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

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Summary of Direct Testimony of Nicholas Phillips, Jr.
On behalf of Carolina Industrial Group for Fair Utility Rates II
Docket No. E-2, Sub 1219

My name is Nicholas Phillips, Jr., and I am a consultant in the field of public utility regulation and a Managing Principal of Brubaker & Associates, Inc. ("Brubaker"), energy, economic, and regulatory consultants. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017. Brubaker has been in this field since 1937 and has participated in more than 1,000 proceedings in 40 states and in various provinces in Canada. We have experience with more than 350 utilities, including many electric utilities, gas pipelines, and local distribution companies. In addition to having testified before this Commission in numerous proceedings including the preceding general rate case for Duke Energy Progress, LLC ("DEP" or the "Company"), Docket No. E-2, Sub 1142, I have testified before this Commission in many electric and gas rate proceedings on virtually all aspects of ratemaking. More details supporting my qualification as an expert witness in this proceeding are provided in Appendix A to my direct testimony filed in this docket.

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

A summary of my position and recommendations included in my direct testimony[1] follows:

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

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

DEP's proposed energy charges from the Large General Service ("LGS"), and LGS Time of Use rates continue to be priced significantly higher than unit costs for energy calculated and filed by DEP. DEP's proposed rates do not reflect unit costs or the dominant winter peak demand

[1] My direct testimony in this docket was filed on April 13, 2020. After the filing of my direct testimony, CIGFUR II and DEP entered into an Agreement and Stipulation of Settlement (the "Agreement"). I support the Agreement and believe it is reasonable, in the public interest, and should be accepted and approved by the Commission. I look forward to the opportunity to provide live testimony to this effect.

used by DEP for planning. Therefore, any reduction to DEP's requested increase should be applied to reduce energy charges to achieve the authorized revenue level for Rate LGS.

DEP should allow existing RTP customers the opportunity to adjust Customer Baseline Loads ("CBL") to enhance RTP usage which benefits both customers and the system with cost based price signals.

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

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

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

This concludes my summary.

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

MS. CRESS: Thank you, Commissioner Clodfelter. And pursuant to the joint stipulation of live testimony and exhibits of certain rate design and cost allocation witnesses agreed to between several of the parties to this docket, I also move that Mr. Phillips' live testimony provided in the DEC-specific portion of this hearing in Docket Number E-7, Sub 1214, located at transcript Volume 22, pages 89 through 93, and 134 through 158, also be copied into the record in the docket at this time as if given orally from the stand.

COMMISSIONER CLODFELTER: Thank you, Ms. Cress, without objection to the motion, it will be so ordered.

(Whereupon, the testimony from Docket Number E-7, Sub 1214, Transcript Volume 22, page 89 through page 93; and Volume 22, page 134 through 158 were copied into the record as if given orally from the stand.)

CHAIR MITCHELL: Yes, Ms. Downey.

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

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

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

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

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

CHAIR MITCHELL: All right.

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

Whereupon,

NICHOLAS PHILLIPS, JR.,

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

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

MS. CRESS: Thank you, Chair Mitchell.

DIRECT EXAMINATION BY MS. CRESS:

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

A. Nicholas Phillips, Jr.

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

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

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

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

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

A. I am testifying on behalf of CIGFUR.

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

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

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

A. Yes, I did.

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

A. That's my understanding, yes.

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

A. Yes, that's correct.

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

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

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

A. I do not.

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

A. Yes, they would.

Q. Okay.

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

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

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

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

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

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

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

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they are planning to do cross where cross was previously waived, so I would just ask your permission.

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

MS. CRESS: Thank you.

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

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

A. Yes, I was.

Q. Why were you surprised?

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

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

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

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

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

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

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

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

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

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

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

A. Yes, I did.

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

A. Yes, I did.

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

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

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

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

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

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

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

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

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

Q. My apologies. Thank you.

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

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

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

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

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

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

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

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

CHAIR MITCHELL: Overruled. Proceed, Ms. Cress.

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

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

What's your reaction to that testimony?

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

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

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

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

CHAIR MITCHELL: All right. Ms. Downey.

MS. DOWNEY: I just have one set of

questions.

CROSS EXAMINATION BY MS. DOWNEY:

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

A. I will have it.

Q. I believe you just --

A. I have it.

Q. Sorry?

A. I just said I have it.

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

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

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

A. (Witness peruses document.)

I have that.

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

A. I do.

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

A. That is right.

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

A. I am generally aware of that.

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

CHAIR MITCHELL: All right. Mr. Neal?

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

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

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

CHAIR MITCHELL: You may proceed, Mr. Somers.

MR. SOMERS: Thank you.

CROSS EXAMINATION BY MR. SOMERS:

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

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

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

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

A. I do.

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

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

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

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

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

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

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

A. I say they are.

Q. Thank you. No further questions.

A. Thank you.

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

(No response.)

CHAIR MITCHELL: All right. Redirect for the witness?

(Pause.)

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

CHAIR MITCHELL: All right. Questions

from Commissioners, beginning with Brown-Bland.

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

EXAMINATION BY COMMISSIONER BROWN-BLAND:

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

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

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

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

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

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

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

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

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

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

A. Thank you.

CHAIR MITCHELL: All right. Commissioner Gray?

COMMISSIONER GRAY: No questions.

CHAIR MITCHELL: Commissioner Clodfelter?

COMMISSIONER CLODFELTER: No questions.

CHAIR MITCHELL: Okay. Commissioner Duffley?

(No response.)

CHAIR MITCHELL: Commissioner Hughes?

COMMISSIONER HUGHES: No questions.

CHAIR MITCHELL: Commissioner McKissick?

COMMISSIONER McKISSICK: No questions.

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

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

CHAIR MITCHELL: All right, Mr. Neal.

MR. NEAL: Briefly.

EXAMINATION BY MR. NEAL:

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

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

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

Q. And you would agree, though, that this

Commission has never before been confronted with the question of whether or not to use the minimum system methodology when it comes to grid modernization projects or things like the grid improvement project, specifically; isn't that right?
A. I don't think they have, but it's just enhancing distribution costs. It's the same distribution system. You have the same voltages, you have the same theory of the minimum system.
Q. I understand the theory is the same, but just to be clear, the application of that theory to something like the Company's grid improvement plan has not been a question that this Commission has answered previously; isn't that right?
A. They asked for a study to be done, and it was completed last March. Other than that, I can't give you an example on future grid costs.
Q. And you would agree that classifying FERC accounts 364 to 368 on a demand basis, another way of referring to that would be the basic customer method?
A. Yes.
Q. And you would agree that there are a number of public utilities commissions around the country that have rejected the minimum system method and have,

instead, ordered utilities to adopt the basic customer method in their cost of service studies?

A. There probably is, yes.

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

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

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

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

Q. No. Small users.

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

MR. NEAL: I have no further questions.

Thank you, Chair Mitchell.

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

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

EXAMINATION BY MS. CRESS:

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

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

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

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

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

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

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

Q. And --

A. Cost causation.

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

A. No, that's it.

Q. Okay. And CIGFUR -- excuse me.

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

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

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

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

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

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

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

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

Q. Why do you support the winter peak?

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

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

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

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

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

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

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

MS. CRESS: Thank you, Chair Mitchell.

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

MS. DOWNEY: Same objection. Same objection.

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

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

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

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

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

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

MS. CRESS: Thank you, Commissioner Clodfelter.

Q. Mr. Phillips, have you had occasion to read Mr. Floyd's second supplemental testimony filed in this case on September 16, 2020?

A. Yes, I have.

Q. And have you had occasion to read DEP witness Pirro's rebuttal testimony responding, in part, to witness Floyd's second supplemental testimony?

A. Yes, I have.

Q. Do you agree with the positions taken by Mr. Floyd in his second supplemental testimony as they relate to CIGFUR's settlement with DEP?

A. I do not. Some of the reasons are the same as given in my live testimony before, and, in addition, he -- his testimony is similar to the DEC. And I think some of that's premature, because Duke is going to propose some things in its next case, and everybody will have a chance to comment. There's nothing predetermined.

And I'm not going to repeat all that again today, but in addition, he takes issue with passing back the tax refunds, as it was done before in the Progress cases, and I don't agree with him. And I think it's a mechanism to move rates closer to costs in a way that you can do when it's a decrease instead of an increase.

Q. Okay. And did witness Pirro address some of those same positions taken in his rebuttal testimony?

A. Yes. He basically said that the industrial sector, as a whole, is paying subsidies to other classes and passing back the tax money on a uniform charge or credit per kilowatt hour is as it was done -- I had looked that up recently. I think, in November of 2018, the 100-and-something million was passed back on a uniform amount per kilowatt hour. And the Public Staff did not oppose that, and the Commission approved it, and we're basically asking for the same treatment here.

Q. And so is it fair to say that you agree with Mr. Pirro's explanation for flowing back the EDIT on a per-kilowatt-hour basis?

A. Yes, I do. I should explain Mr. Pirro's method of allocating the increase to classes is a reduction in current subsidies paid or received by 25 percent. The 25 percent is a way of moderating any rate increases to classes, but it only gets you one-fourth of the way toward cost. So the method he's -- he and CIGFUR have agreed to and the Commission has previously approved to pass back the tax credits moves a little bit farther than the 25 percent and would help get rates closer to cost.

Q. And you've already sort of alluded to this in your answers to some of my prior questions, but do you know whether the Commission has previously approved a flowback of EDIT to DEP customers on a uniform cents-per-kilowatt hour basis?

A. Yes, they have. It was, I believe, Docket E-2, Sub 1188 where they passed back more than $100 million on that method, and I think that order says it was previously done in a previous case on some state taxes in that same way.

Q. Okay. And do you know whether it was also done in Docket Number E-2, Sub 1174 and E-2, Sub 1192?

A. I believe so. I think that order I'm referring to, the Sub 1188, refers to those dockets.

Q. Is there anything about CIGFUR's settlement with DEP that precludes, prevents, or otherwise hinders Mr. Floyd's wish list for his rate design study should the Commission agree with that recommendation and direct Duke to undertake such a study?

A. Not to my knowledge. Some of the things in there that CIGFUR and Duke have agreed to do would be presented in a subsequent rate case or studied between now and the next rate case. So they would be proposed in a subsequent case, and the Public Staff and all parties can comment as they see fit. And then it's up to the Commission to approve or not approve at that time.

Q. Is there any provision in CIGFUR's settlement with DEP that, if approved by the Commission, would in any way bind the Commission to decisions -- future decisions in future rate cases related to cost allocation or rate design?

A. No. I don't know of any way two parties can enter into a settlement that binds the Commission to some finding in a future case, frankly.

Q. Is there anything, in your opinion, that is inconsistent as between CIGFUR's settlement with DEP and the Public Staff settlements with DEP?

A. I don't see any inconsistency, no. I think they're -- they help each other, frankly.

Q. And do you think that the CIGFUR settlement with DEP is beneficial to all ratepayers, should the Commission approve it?

A. In my opinion, it is, yes.

MS. CRESS: Commissioner Clodfelter, witness Phillips is now available for cross.

COMMISSIONER CLODFELTER: Thank you, Ms. Cress.

Ms. Downey, cross?

MS. DOWNEY: I just have one question -- or a couple of questions.

CROSS EXAMINATION BY MS. DOWNEY:

Q. Mr. Phillips, good afternoon.

A. Good afternoon.

Q. Mr. Phillips, do you know what the LGS class rate of return was under summer CP?

A. (Witness peruses document.)

Well, the LGS index that I have for the summer CP in the 2018 test year was 104.

Q. And that's within the plus or minus 10 percent band of reasonableness that the Commission has historically found appropriate; isn't that correct?

A. Yes, that is correct.

Q. That's all I had.

COMMISSIONER CLODFELTER: Okay, Ms. Downey.

Mr. Neal?

MR. NEAL: Thank you,

Commissioner Clodfelter.

CROSS EXAMINATION BY MR. NEAL:

Q. Good afternoon, Mr. Phillips.

A. Good afternoon.

Q. Just a couple of questions as well.

The website for Brubaker & Associates is consultbai.com; is that correct?

A. I believe so.

Q. And are you familiar generally with the contents of your company's website?

A. I -- I'm kind of embarrassed to say I don't keep up that much with the website.

Q. Would you agree that there is an "about us" tab which includes a selection for representative clients on the consultbai.com website?

A. I'll accept that. I haven't looked at it.

Q. But you wouldn't be surprised that it would list as representative clients companies such as ALCOA, Marathon Oil or Exxon Mobile, correct?

A. I wouldn't be surprised, if that's your question.

Q. And you would agree that under representative clients, there's no Brubaker & Associates clients listed who represent residential utility customers,

correct?

A. I would doubt that. I think we've done some work for Cub and we've done some work for hospitals, but I don't think specifically residential customers, as I recall.

Q. I have no further questions.

COMMISSIONER CLODFELTER: Thank you. Are there any other parties who have questions on cross examination for Mr. Phillips?

(No response.)

COMMISSIONER CLODFELTER: If there are not, Ms. Cress, do you have any redirect?

MS. CRESS: Just briefly.

REDIRECT EXAMINATION BY MS. CRESS:

Q. Mr. Phillips, I understand that you did not personally design your consulting firm's website, but can you tell us a little bit about some of your personal work as a witness.

Have you ever been retained on behalf of a consumer advocate?

A. I've been retained by the Office of Regulatory Staff, which is kind of like the Public Staff, but in South Carolina, to represent them in two different Duke cases. I, actually, when I was younger, got hired by Ellen Ruff at Duke to represent them in an arbitration case involving the cost of splits in the Catawba plant.

Q. So you have, in fact, been an expert witness for consumer advocates very much like the Public Staff's role in this case?

A. Yes. And there's been others in my firm that do return on equity and different financial studies that have been hired by public advocates. Different people from Brubaker & Associates have been hired by public advocates.

Q. So would it be fair or unfair to say that you exclusively appear on behalf of commercial or industrial interests?

A. No. As I said, there's -- sometimes there's universities. I've represented, within Indiana, of University of Notre Dame, which has gotten some high profile lately due to the Supreme Court pick and so on. But we represent universities, hospitals, and others at different times.

Q. And the South Carolina consumer advocate?

A. Office of Regulatory Staff, I think they're called.

Q. Okay. Thank you.

MS. CRESS: No further redirect.

COMMISSIONER CLODFELTER: All right. Thank you.

Questions from Commissioners, starting with Commissioner Brown-Bland.

COMMISSIONER BROWN-BLAND: Mr. Phillips, it is good to see you again, but I don't have questions for you this time.

THE WITNESS: It's good to see you again as well.

COMMISSIONER CLODFELTER: Commissioner Gray?

COMMISSIONER GRAY: No, no questions.

COMMISSIONER CLODFELTER: All right. Chair Mitchell?

CHAIR MITCHELL: No questions.

COMMISSIONER CLODFELTER: Commissioner Duffley?

COMMISSIONER DUFFLEY: No questions.

COMMISSIONER CLODFELTER: Commissioner Hughes?

COMMISSIONER HUGHES: No questions.

COMMISSIONER CLODFELTER: Commissioner McKissick?

COMMISSIONER McKISSICK: No questions.

COMMISSIONER CLODFELTER: All right. Ms. Cress, back to you with any additional motions you need to make, if there are any.

MS. CRESS: Thank you, Commissioner Clodfelter. I believe that Mr. Phillips' prefiled exhibits have already been moved and admitted into the record, but if that's not the case, then I move them in at this time.

COMMISSIONER CLODFELTER: Well, to the extent we need belt and suspenders, your motion is granted. Thank you.

(Phillips Direct Exhibits 1 through 5 were admitted into evidence.)

MS. CRESS: Thank you.

COMMISSIONER CLODFELTER: All right. Anything further? Do you want Mr. Phillips to be excused, or do we need to keep him here?

MS. CRESS: That would be -- that would be fantastic. Would the Commission entertain a motion to excuse witness Phillips?

COMMISSIONER CLODFELTER: We will entertain a motion, and unless there's an objection, we'll grant the motion. Mr. Phillips, thank you, you are excused.

THE WITNESS: Thank you, Commissioner.

COMMISSIONER CLODFELTER: Okay. Anything else from CIGFUR II?

MS. CRESS: Nothing else, Commissioner Clodfelter. Thank you.

COMMISSIONER CLODFELTER: Okay. Let's take our afternoon break here. Actually, before we start, Mr. Neal, do we need to hear any -- you would be next in order. Do we need to hear motions from you on Mr. Wallach?

MR. NEAL: Yes, Commissioner Clodfelter, if you'd like to do that now, I'm happy --

COMMISSIONER CLODFELTER: Let's go ahead and do those now before we take our afternoon break, and then we come back with Mr. Smith and witness Barnes. Okay? So, Mr. Neal, we'll call your group of parties.

MR. NEAL: Thank you, Commissioner Clodfelter.

(Exhibits JH-1 through JH-6 were moved at the consolidated hearing and admitted into evidence.)

(Whereupon, the prefiled direct

testimony of John Howat was moved at the consolidated hearing and copied into the record as if given orally from the stand.)

TABLE OF CONTENTS

EXHIBITS

I. Introduction

Q. PLEASE STATE YOUR NAME, JOB TITLE, EMPLOYER AND BUSINESS ADDRESS.

A. My name is John Howat. I am a Senior Policy Analyst at the National Consumer Law Center ("NCLC"), 7 Winthrop Square, Boston, Massachusetts 02110. The National Consumer Law Center is a non-profit law and policy advocacy organization using expertise in consumer law and energy policy to advance consumer justice, racial justice, and economic security for low-income families and individuals in the United States.

Q. PLEASE SUMMARIZE YOUR PROFESSIONAL BACKGROUND AND EXPERIENCE.

A. Over the past 20 years at NCLC, I have managed a range of regulatory, legislative, and advocacy projects across the country in support of low-income consumers' access to utility and energy-related services. I have been involved with the design and implementation of energy affordability and efficiency programs, regulatory consumer protections, transportation electrification, rate design, home energy improvement financing, issues related to metering and billing, credit scoring and reporting, and energy burden and demographic analysis.

I have worked on behalf of community-based organizations in 23 states and have worked under contract on low-income energy and utility issues with a number of federal and state agencies, including utility consumer advocates. In addition, I have presented at national conferences, including for the National

Community Action Foundation, National Association of Regulatory Utility Commissions, and National Association of State Utility Consumer Advocates.

I am the co-author of Access to Utility Service, a law and policy manual published by NCLC, and the 2016 Lawrence Berkeley National Laboratory report, "Recovery of Utility Fixed Costs: Utility, Consumer, Environmental and Economist Perspectives."[1] I am primary author of "Home Energy Costs: The New Threat to Independent Living for the Nation's Low-Income Elderly,"[2] "Tracking the Home Energy Needs of Low-Income Households through Trend Data on Arrearages and Disconnections,"[3] "Rethinking Prepaid Utility Service: Customers at Risk,"[4] and "Public Service Commission Consumer Protection Rules and Regulations: A Resource Guide."[5]

My resume is included as Exhibit JH-1.

Q. HAVE YOU TESTIFIED PREVIOUSLY BEFORE STATE PUBLIC UTILITIES COMMISSIONS?

A. I have presented testimony or comments before utility regulatory commissions in Alabama, California, Idaho, Illinois, Indiana, Louisiana, Maryland, Massachusetts, Missouri, New Mexico, Nevada, Pennsylvania, Rhode Island, South Carolina, Texas, Vermont, Washington State, and Wisconsin. I have presented testimony before the North Carolina Utilities Commission

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[1] https://emp.lbl.gov/sites/all/files/lbnl-1005742_1.pdf.
[2] Clearinghouse Review, Vol. 9 - 10, Jan - Feb 2008
[3] National Energy Assistance Directors' Association, 2004, http://www.neada.org/publications/Tracking_the_Need.pdf
[4] National Consumer Law Center, 2012, https://www.nclc.org/images/pdf/energy_utility_telecom/consumer_protection_and_regulatory_issues/report_prepaid_utility.pdf.
[5] National Energy Assistance Directors' Association, 2006, http://www.neada.org/publications/Consumer_Protection_Guide.pdf

("Commission") in Dockets No. E-2 Sub 1142, No. E-7 Sub 1146, and No. E-7 Sub 1214.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of the North Carolina Justice Center, North Carolina Housing Coalition, Natural Resources Defense Council, and Southern Alliance for Clean Energy ("Justice Center *et al.*").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to address issues related to affordability of electric service for Duke Energy Progress' ("Company's" or "DEP's") lower-income residential customers, and discuss programs and policies designed to mitigate affordability challenges faced by those customers.

I will comment on the need for low-income affordability programs, outline policy objectives and program design elements featured in effective programs, provide brief descriptions of a sampling of investor-owned utility bill affordability programs operating in the United States, and recommend that the Commission initiate a process culminating in approval of funding and implementation of enhanced low-income bill payment assistance programming and low-income residential energy-efficiency programming in the DEP service territory. Finally, I present evidence demonstrating that elevated basic customer charges disproportionately harm low-income and low-volume consumers within a rate class. I will show that on average, low-income households, households headed by those over the age of 65, and African-American-headed households use less electricity than their counterparts, and that elevated monthly fixed charges cause disproportionate harm and exacerbate pre-existing problems with electric-utility affordability and home-energy security faced by many of these households. I recommend that the Commission reject the $14.00 residential basic facilities charge ("BFC") as proposed by DEP and approve the $9.63 BFC as proposed by witness Jonathan Wallach. I will also recommend that the Commission direct DEP to expand the Helping Home Fund and consider shifting it from a shareholder- to a ratepayer-funded program.

II. Importance of Electric Utility Affordability

Q. PLEASE DESCRIBE THE CONTEXT OF YOUR DISCUSSION OF BILL AFFORDABILITY.

A. On January 22, 2020, the Commission issued an Order directing the Public Staff to file testimony regarding cost of service methodologies and ". . . affordability of electricity within (the DEP) service territory as well as programs available to DEP's customers that address affordability with particular focus on residential energy customers."[6] With this testimony, the Justice Center *et al.* provide evidence, discussion, and recommendations regarding bill affordability in response to the Commission's interest in the topic.

Q. WHAT HAS THE COMPANY STATED IN THIS CASE WITH RESPECT TO PROGRAMS TO MITIGATE PRICE IMPACTS ON CUSTOMERS WHO ARE MOST IN NEED?

A. DEP President and witness Stephen G. De May testified that "… more low-income energy assistance programs can be offered to aid customers in need of support and we have ideas for several low-income programs that we believe

[6] North Carolina Utilities Commission, Order Directing Public Staff to File Testimony, p. 2 (Jan. 22, 2020).

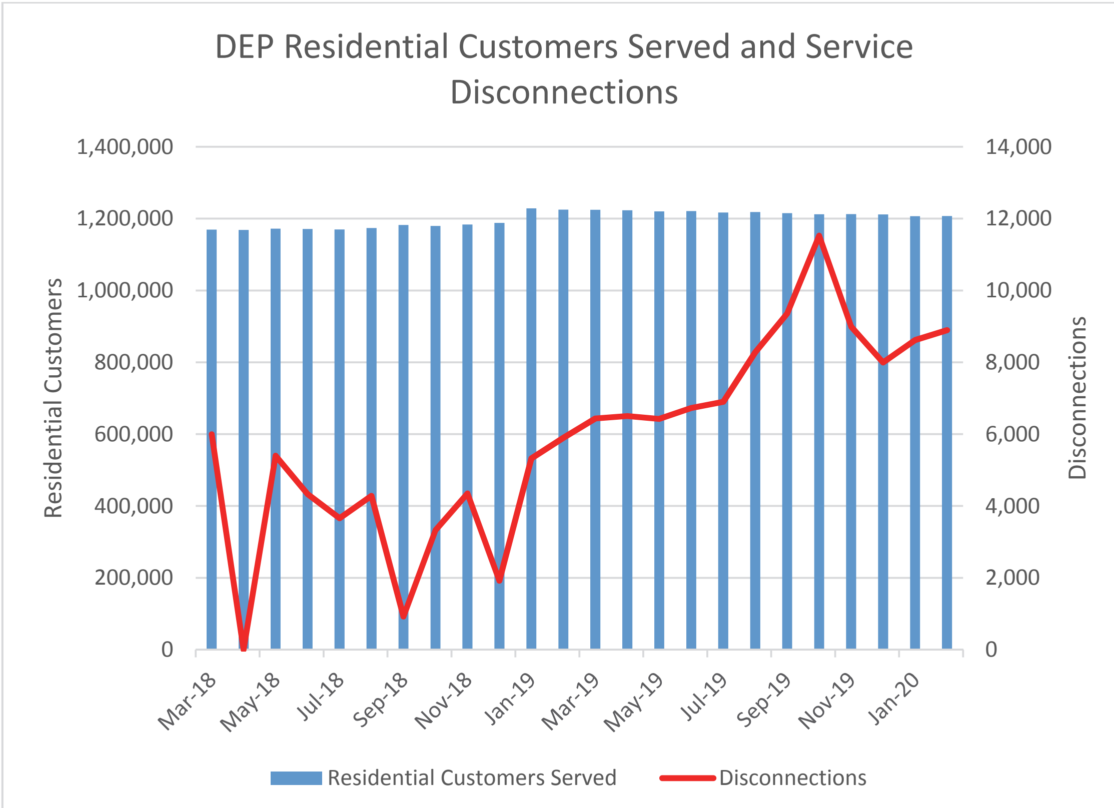
could help accomplish this goal."[7] Mr. De May also outlined existing programs intended to assist low-income customers, including the Helping Home Fund, the Energy Neighbor Fund, and energy efficiency programs, including the Neighborhood Energy Saver Program[8]

Q. PLEASE COMMENT ON MR. DE MAY'S STATEMENT REGARDING LOW-INCOME BILL AFFORDABILITY.

A. Mr. De May is to be applauded for his recognition of the need for enhanced and expanded programming to support low-income bill affordability, as is the Commission for seeking information regarding tariffed residential rates that address affordability issues. Utility bill affordability challenges faced by North Carolina low-income households, and the threats to health, safety, and home energy security posed by those challenges, are widely known and have been documented in previous proceedings before the Commission.[9]

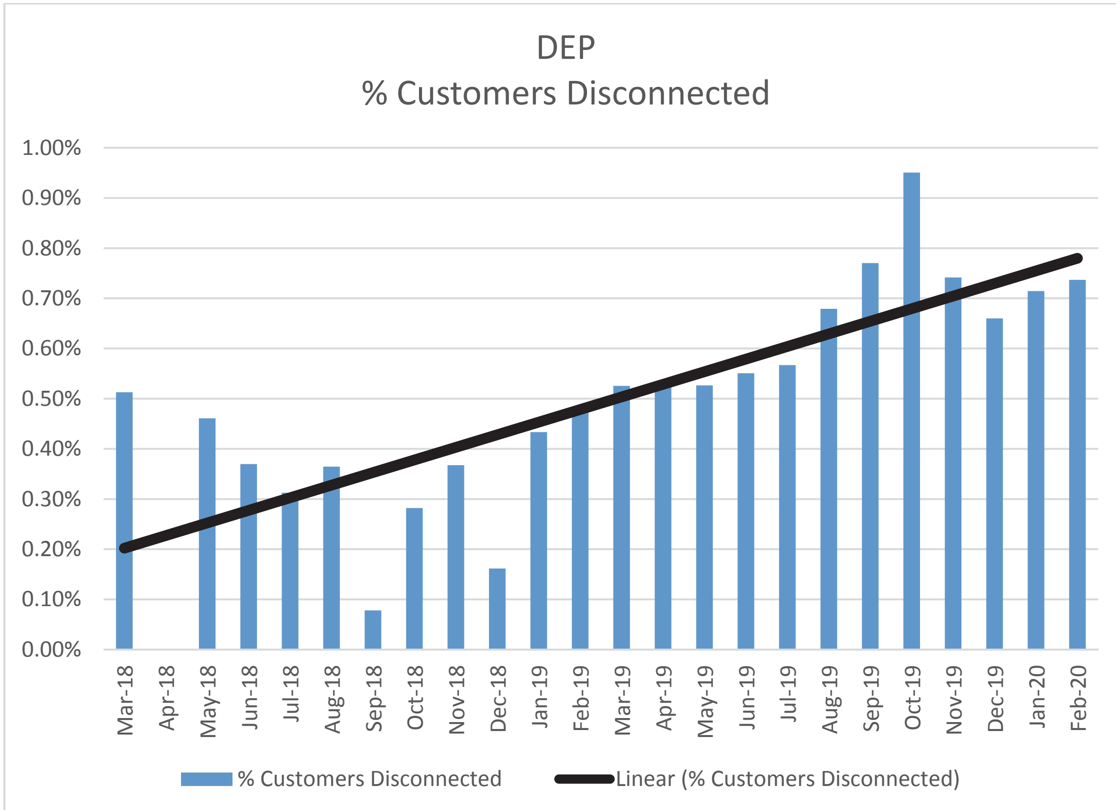
Disconnections for nonpayment are a key indicator of bill affordability challenges in a utility service territory. Increased disconnections for nonpayment in the DEP service territory between March 2018 and February 2020 offer an indication of affordability challenges faced by residential customers. Over this period, the average number of residential customers served monthly by DEP increased only slightly, while the number of monthly residential service disconnections for nonpayment rose more sharply. The chart below illustrates recent changes in residential customers served and service disconnections.[10][11]

[7] Direct Testimony of Stephen G. De May, p. 9.
[8] *Id.*, p. 8.
[9] *See*, e.g., Direct Testimony of John Howat, Docket No. E-7, Sub 1146 (Jan. 19, 2018).
[10] DEC Response to NCJC *et al.* Data Request 8-2.A, and DEC monthly filings in Docket No. M-100, Sub 61A.



Monthly residential service disconnections as a percentage of the average number of residential customers, along with a linear trend line, are reflected in the chart below.[12]

[11] The Docket Portal on the Commission's website does not include a monthly disconnections report from DEP for April, 2018. Thus, the referenced chart reflects zero disconnections for that month rather than actual disconnections.
[12] DEC Response to NCJC *et al* Data Request 8-2.A, and DEC monthly filings in Docket No. M-100, Sub 61A.



The chart above shows a troubling upward trend in the percentage of DEP's residential customers who were disconnected from service between March 2018 and February 2020, and flags electricity bill affordability challenges faced by a growing number of customers.

Additional information provided by DEP likewise demonstrates that many of the Company's customers regularly face difficulty affording their electric utility service. Each month, large numbers of DEP residential customers are charged late payment fees, or receive a disconnection notice. From March 2018 through February 2020, DEP collected a total of over $12,000,000 in late payment charges, and an average of 21.5% of all DEP residential customers were charged a late payment fee each month.[13] During that same period, an average of over 14.5% of all residential customers were sent a notice of disconnection each month.[14] Payment of late charges, receipt of disconnection notices, and involuntary loss of electricity service are often signs that residential customers are experiencing trouble affording their electric bills.

Thus, in light of the increase in involuntary loss of electric utility service, the number of DEP customers receiving service disconnection notices, and the number of customers paying late payment charges, Mr. De May's recognition of the need for enhanced bill affordability programming is well founded.

III. Bill Affordability Programming

Q. PLEASE LAY OUT POLICY OBJECTIVES AND PROGRAM DESIGN PRINCIPLES OF AN EFFECTIVE LOW-INCOME ELECTRICITY AFFORDABILITY PROGRAM.

A. Reliable electricity service is a necessity of life. Without electricity, residents cannot participate effectively in present-day society or be secure from threats to health and safety. All DEP customers, including those with low incomes, should have access to reliable and secure sources of electricity. To help ensure home energy security for low-income residents, what is needed is an electricity affordability program that:

- Serves all residential electricity customers at or below 150% of the federal poverty level eligible to participate in the Low Income Home Energy Assistance Program ("LIHEAP");
- Lowers program participants' electricity burdens to an affordable level;

[13] DEP Response to NCJC *et al.* Data Requests 8-2(A), (C), and (d), attached as Exhibit JH-2.
[14] DEP Response to NCJC *et al.* Data Requests 8-2(A) and (E), attached as Exhibit JH-2.

- Promotes regular, timely payment of electric bills by program participants;
- Comprehensively addresses payment problems associated with program participants' current and past-due bills;
- Is funded through a mechanism that is reliable while providing sufficient resources to meet policy objectives over an extended timeframe; and
- Is administered efficiently and effectively.

Q. PLEASE PROVIDE RECOMMENDATIONS REGARDING ELIGIBILITY GUIDELINES, PARTICIPATION AND ENROLLMENT.

A. Income eligibility for participation in DEP's electricity affordability program should be capped at no less than the LIHEAP income-eligibility guideline – currently 150% of the federal poverty guideline (for crisis assistance). All households receiving or eligible for benefits through the federal LIHEAP should be automatically enrolled in the electric affordability program. In the event that the electricity affordability program's participation level does not exceed any enrollment ceiling that may be established, consenting households receiving benefits from other means-tested benefit programs (e.g., SNAP, Medicaid) should also be automatically enrolled in the electricity affordability program.

Q. PLEASE PROVIDE RECOMMENDATIONS REGARDING PROGRAM BENEFITS.

A. DEP affordability program participants should receive benefits in the form of discounted electric rates or fixed credits on their electric bills. The goal of the program should be to substantially lower the electricity burden[15] of participants.

[15] The term "electricity burden" refers to the proportion of household income that is devoted to paying for residential electricity service. The terms "energy burden" and "home energy burden" refer to the proportion of income devoted to all home energy services.

To meet these objectives, I recommend that one of the following be funded and implemented:

- Percentage discount of at least 25%;
- Tiered discount setting payments at a targeted electricity burden level of approximately 5%; or
- Percentage of income payment plan ("PIPP") lowering all participants' electricity bill payments to 5% of household income.

These program types, offered in many states around the country, are described in greater detail below.

In order to promote efficient use of energy resources, monthly discounts or bill reductions may be capped at a predetermined consumption level or bill credits may be fixed. In addition, discounts are often applied to the fixed, monthly customer charge in addition to the volumetric rate. Benefit levels could be capped based on weather-normalized, average electricity consumption at the participant's residence, or among all DEP households with similar end-use needs (i.e., general appliance use only, general appliances and hot water, or general appliances, hot water and heat). However, such mechanisms should be carefully designed so that they do not result in unintended threats to health and safety.[16]

Q. PLEASE DESCRIBE YOUR RECOMMENDATIONS REGARDING INCORPORATION OF AN ARREARAGE MANAGEMENT COMPONENT INTO AN AFFORDABLE BILL PAYMENT PROGRAM.

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[16] Some high-use electricity customers may have little control over the thermal characteristics and appliances that are used in their houses or apartments. As explained below, for such energy-intensive customers, it is especially important to make comprehensive energy-efficiency services available. Other high-use customers may require electricity-driven equipment for medical purposes. In such cases, it is important that program design features do not provide customers with an incentive to under-consume in a manner that could prove harmful to health.

A. To sustain participants' affordability and home energy security, program design must be comprehensive in its approach to dealing with *both* participants' current bills and arrearage balances. Affordability objectives of energy assistance programs that discount current bills, but fail to address preprogram arrears, are undermined by the requirement that participants must add arrearage payoff to that of the current bill. In other words, incorporating arrearage management helps ensure that a portion of the household energy burden reductions that come from discounted current bills is not simply "given back" as customers pay off outstanding balances. Similarly, energy assistance programs that focus entirely on retirement of arrears but not on the affordability of current bills are unlikely to result in long-term household energy security. If current bills are not affordable, there is a strong likelihood that arrears will simply re-accrue after balances are initially retired.

In order to enhance the effectiveness of discounts on *current* bills and promote timely program participant payments going forward, I recommend that DEP implement an arrearage write-down, or management program, in conjunction with low-income rates. Effectively promoting regular bill payment entails ensuring that *total* payments are affordable. A program that is intended to promote regular, timely payments by participants through reduction of electricity burdens to an affordable level is rendered less effective by a requirement that participants pay an amount in addition to the affordable current bill. Simultaneous payment of pre-existing arrears and the discounted electric bill therefore runs counter to the policy objective of promoting regular, timely payments by program participants.

There are two basic models of low-income utility arrearage management that have been implemented in the United States. One entails the write-down of customer arrears over time after a series of timely payments on current bills. The other model entails the retirement of arrearage balances in full on a one-time basis. The one-time "forgiveness" model is administratively straightforward, but entails a large initial outlay of program cash resources. Write-downs over a period of 12 months may provide customers with an enhanced incentive to keep up with current bills (as long as they are affordable), while placing less strain on program cash flow. I recommend that the Company implement an arrearage management program that provides low-income rate participants to write down one-twelfth (1/12) of a pre-program overdue balance with each timely payment of a current bill.

Q. PLEASE DESCRIBE YOUR RECOMMENDATIONS REGARDING PROGRAM FUNDING.

A. Funding for an electricity affordability program needs to be sufficient and reliable. Program funding should be sufficient to provide meaningful energy burden reduction and energy security for electricity customers living below 150% of the federal poverty level. In addition, program administration costs of 5% to 7% of program benefits to the total program cost estimate are required.

A sustainable electricity affordability program with set benefit levels and participation rates also requires funding that is predictable and reliable. A uniform volumetric charge – approved prior to program implementation – is the optimal funding source for an effective program.

Q. PLEASE PROVIDE YOUR RECOMMENDATIONS REGARDING PROGRAM ADMINISTRATION AND IMPLEMENTATION.

A. Electricity affordability program design should foster efficient, streamlined administrative procedures. With limited program resources available, funds should be devoted to participant benefits rather than administrative costs to the greatest extent feasible. Minimizing administrative costs while delivering an effective electricity affordability program requires that certain agencies, organizations and individuals work together cooperatively and efficiently. I recommend that whenever possible, administrative structures and procedures that apply to the state's LIHEAP be "piggybacked" onto any new electricity affordability program to create administrative efficiencies.

The state's Community Action Agencies, with sufficient support from program administrative funds collected by the Company, are ideally suited to conduct program intake and outreach functions. The agencies that certify LIHEAP eligibility could then simultaneously certify low-income rate and arrearage management eligibility using the same procedures that currently apply to LIHEAP.

DEP would be responsible for collecting program-related charges, and assigning qualified customers to a tariffed, low-income rate. DEP would further be responsible for tracking arrearage write-down for each participating customer. The Company would also be responsible for regular reporting to the Commission of program activities and financial transactions. All program costs, including bill credits or discounts, approved startup and ongoing administrative expenses, and approved arrearage retirement amounts should be recoverable through volumetric charges, as described above.

Affordability rate applicants would provide documentation required for certification on an annual basis. In addition, program applicants should be referred to all appropriate energy efficiency services that may be available.

Q. WHAT ARE THE UTILITY SYSTEM COSTS OF IMPLEMENTING THE PROGRAM THAT YOU HAVE PROPOSED?

A. Most prospective low-income assistance program costs may be readily identified and quantified. Projecting the cost of implementing the affordability program requires multiplying the projected number of program participants by the sum of the value of the monthly discount (or revenue loss) per customer and the average arrearage per customer that is retired. Program administration costs must then be added to the value of discounts and retired arrearages to obtain an estimate of total program costs.

Q. WHAT ARE SOME OF THE UTILITY SYSTEM BENEFITS ASSOCIATED WITH EFFECTIVE BILL PAYMENT ASSISTANCE?

A. Quantifying the entire range of program benefits, including those associated with utility uncollectible accounts, presents a greater analytical challenge than quantifying costs. Nonetheless, quantification challenges do not appropriately lead to the conclusion that benefits simply do not exist. Rather, they suggest that decisions regarding adoption and implementation of low-income payment assistance programs should not hinge entirely on the results of overly simplified cost-benefit analysis.

That said, effective bill payment assistance programming may bring the benefit of reduced uncollectible account write-offs. Precise quantification of the bad debt mitigation impact of a low-income payment assistance program presents a considerable analytical challenge, particularly on a prospective basis. The extent to which this objective may be achieved is contingent on a number of existing conditions and key program design and implementation elements, including the following:

- A company's existing bad debt profile and the extent to which uncollectible account write-offs are currently concentrated among low-income customers;
- Income and expense circumstances of the program participants;
- Program benefit levels and reduction of participants' utility burden (i.e., reduction of the proportion of a participant's income that is devoted to utility bills);
- Outreach and targeting of "payment troubled" customers and prospective program participants;
- The extent to which the program comprehensively incorporates reduction of current bills with means of effectively managing pre-program arrears; and
- Contact and follow-up with program participants.

Q. PLEASE BRIEFLY DESCRIBE THE STRAIGHT DISCOUNT PROGRAM DESIGN MODEL.

A. A straight discount entails reducing the total utility bill by a specified percentage or dollar amount. Under this model, the discount may be achieved through a set customer charge reduction and/or a usage charge reduction. The states of California and Massachusetts have adopted straight discount rates that are available to utility customers who participate in LIHEAP. The straight discount model reduces the energy burden of participants at a relatively low administrative cost. However, this model does not differentiate the benefit level within the broad participant group. In other words, the benefit level is the same for a household living at 50% of the federal poverty level as it is for a household living at the upper limit of the income eligibility guideline.

The table below illustrates the electricity burden impacts of a 25% discount on various low-income household configurations, assuming an undiscounted annual electricity service expenditure of $1,566/year[17] and preprogram arrears of $200. For comparative purposes, the table also reflects the home electricity burdens of higher-income, nonparticipating residential customers.

Electricity Burden Impacts: 25% Discount

	Single, Minimum Wage* Worker (40 hours x 52 weeks)	2-person Household, 100% 2019 FPL	2-person Household, 150% 2019 FPL	2-Person Median Income Household	Upper-income Household ($100,000)
Annual Pretax Income	$15,080	$17,240	$25,860	$52,172	$100,000
Monthly Pretax Income	$1,257	$1,437	$2,155	$4,348	$8,333
Undiscounted Annual Current Electricity Expenditure	$1,566	$1,566	$1,566	$1,566	$1,566
Arrearage Payment ($200/4)	$1,616	$1,616	$1,616	$1,566	$1,566
Undiscounted Electricity Burden (During Arrearage Payoff)	10.7%	9.4%	6.2%	3.0%	1.6%
Discounted (25%) Electricity Expenditure	$1,175	$1,175	$1,175	$1,566	$1,566
Discounted Electricity Burden	7.8%	6.8%	4.5%	3.0%	1.6%

[17] DEP 2018 FERC Form 1, p. 304.

Q. PLEASE BRIEFLY DESCRIBE THE PERCENTAGE OF INCOME PAYMENT PLAN MODEL.

A. A percentage of income payment plan ("PIPP") entails participant customers paying a predetermined, "affordable" percentage of income for natural gas or electric service. PIPPs therefore target benefit levels to a household's particular income circumstances based on a predetermined affordability goals. However, since a separate billing and payment arrangements must be developed for each participating customer, PIPPs generally entail a somewhat higher level of administrative complexity than straight discount rates. The Colorado Public Utilities Commission recently approved a PIPP for Excel Energy customers. Illinois investor-owned utilities have also implemented a PIPP. In addition, the program model has been operative for many years in Ohio, Pennsylvania, New Jersey and Maine. A full description of the Ohio PIPP, as implemented by Duke Energy Ohio, is attached as Exhibit JH-3. The table below illustrates the electricity burden impacts of a PIPP that sets the target electricity burden level at 5% of household income, assuming an undiscounted annual electricity service expenditure of $1,566/year and preprogram arrears of $200.

Electricity Burden Impacts: PIPP Discount (5% Target Burden)

	Single, Minimum Wage* Worker (40 hours x 52 weeks)	2-person Household, 100% 2019 FPL	2-person Household, 150% 2019 FPL	2-Person Median Income Household	Upper-income Household ($100,000)
Annual Pretax Income	$15,080	$17,240	$25,860	$52,172	$100,000
Monthly Pretax Income	$1,257	$1,437	$2,155	$4,348	$8,333
Undiscounted Annual Current Electricity Expenditure	$1,566	$1,566	$1,566	$1,566	$1,566
Arrearage Payment ($200/4)	$1,616	$1,616	$1,616	$1,566	$1,566
Undiscounted Electricity Burden (During Arrearage Payoff)	10.7%	9.4%	6.2%	3.0%	1.6%
Discounted Electricity Expenditure	$754.00	$862.00	$1,293.00	$1,566	$1,566
Discounted Electricity Burden	5.0%	5.0%	5.0%	3.0%	1.6%

Q. PLEASE BRIEFLY DESCRIBE THE TIERED DISCOUNT MODEL.

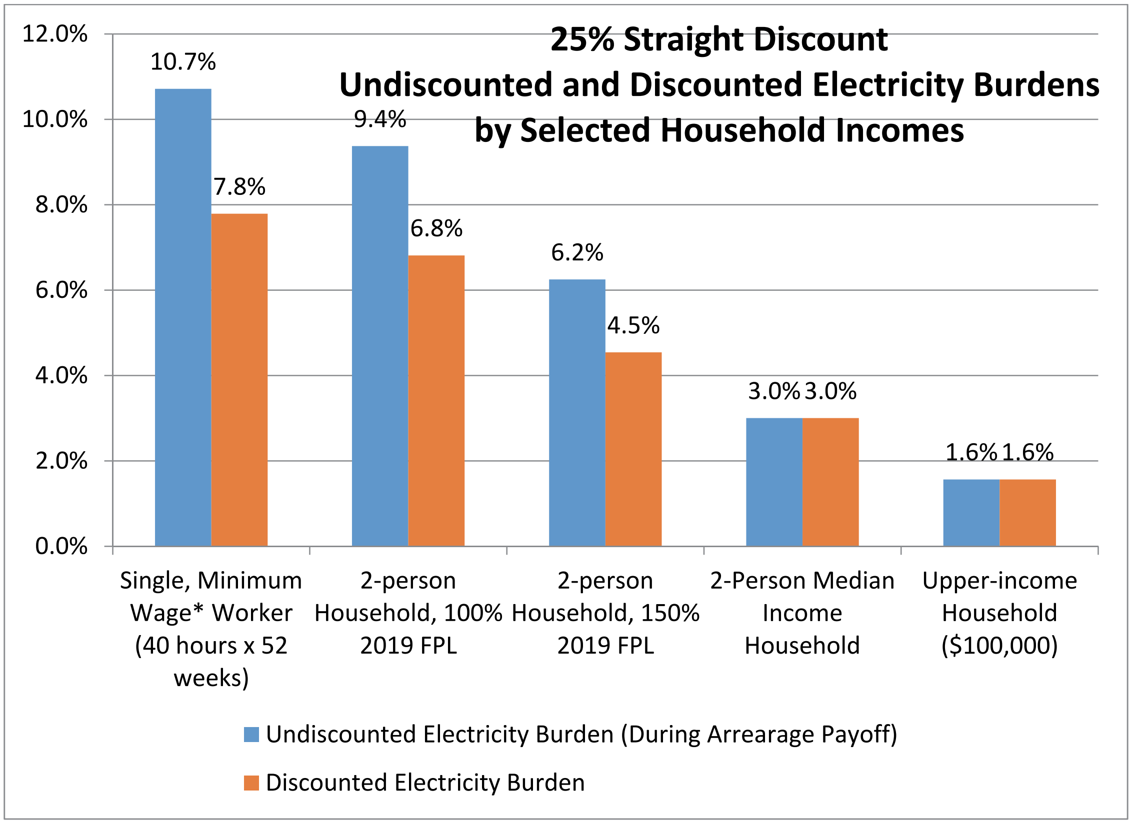
A. A tiered discount represents a hybrid of design elements of straight discount and PIPP models. In a tiered discount, the level of the discount depends on the customer's income or poverty level. Like a PIPP, the tiered discount is designed to reduce a customer's bill to an affordable level, and households in the lower income or poverty tiers receive a steeper discount than those in higher tiers. Thus, benefits are targeted according to a household's income circumstances, but the individual payment arrangements and billing typified by a PIPP are not required. A tiered discount entails somewhat higher administrative cost than a straight discount, but considerably less than a PIPP. Tiered discount programs currently operate in New Hampshire and Indiana. The table below illustrates the electricity burden impacts of a tiered discount that sets the target electricity burden level at 5% of household income, assuming an undiscounted annual electricity service expenditure of $1,566/year and preprogram arrears of $200.

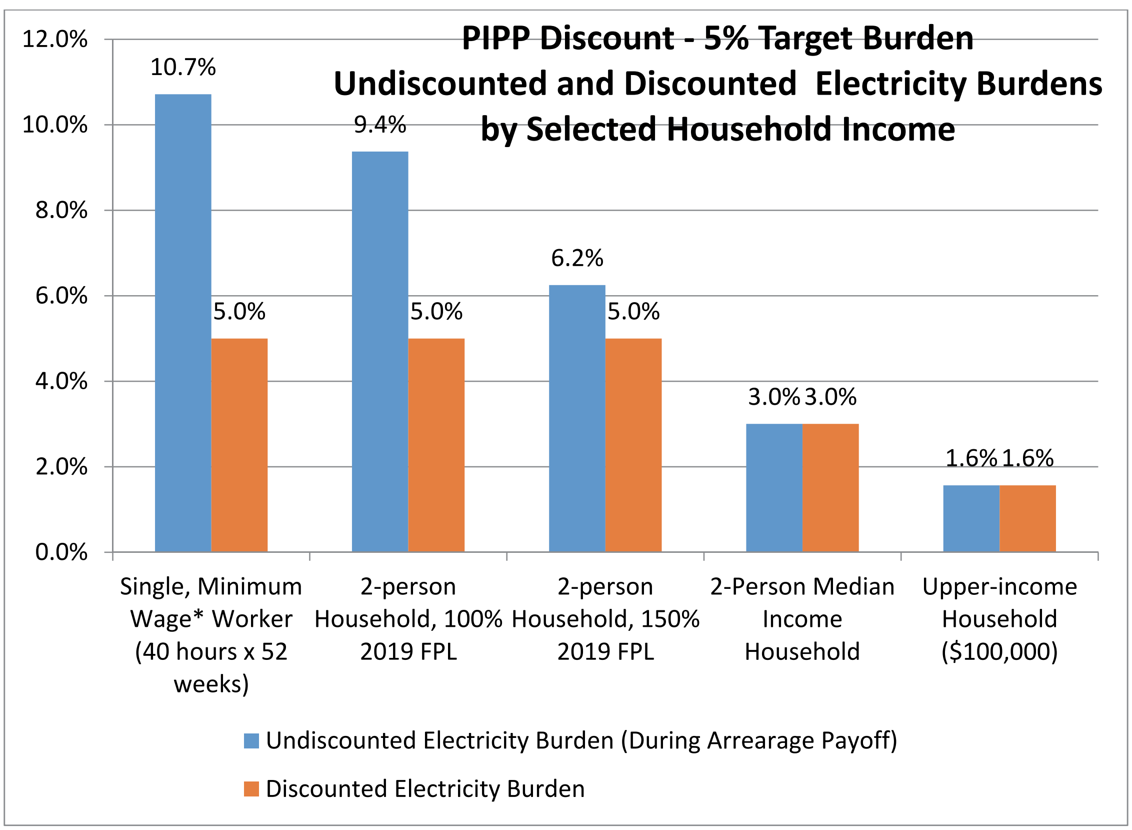
Electricity Burden Impacts: Tiered Discount (5% Target Burden)

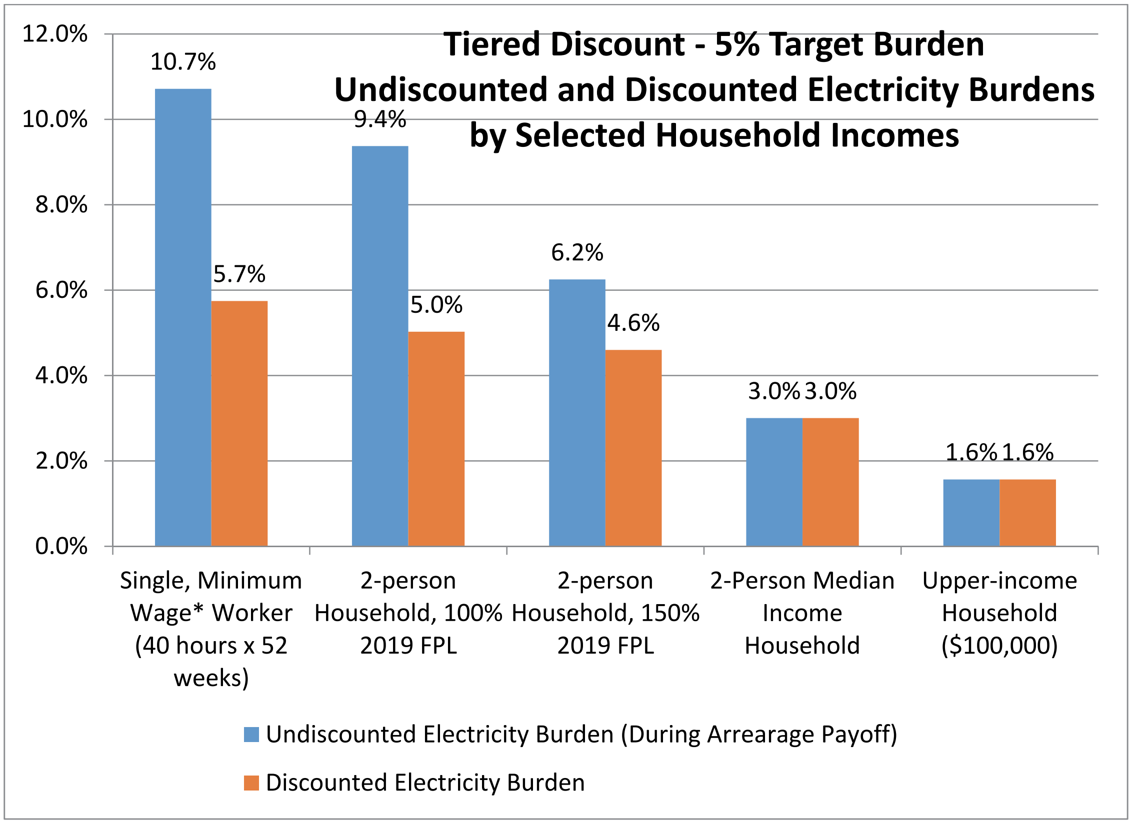
	Single, Minimum Wage* Worker (40 hours x 52 weeks)	2-person Household, 100% 2019 FPL	2-person Household, 150% 2019 FPL	2-Person Median Income Household	Upper-income Household ($100,000)
Annual Pretax Income	$15,080	$17,240	$25,860	$52,172	$100,000
Monthly Pretax Income	$1,257	$1,437	$2,155	$4,348	$8,333
Undiscounted Annual Current Electricity Expenditure	$1,566	$1,566	$1,566	$1,566	$1,566
Arrearage Payment ($200/4)	$1,616	$1,616	$1,616	$1,566	$1,566
Undiscounted Electricity Burden (During Arrearage Payoff)	10.7%	9.4%	6.2%	3.0%	1.6%
Discounted Electricity Expenditure	$866.31	$866.31	$1,189.56	$1,566	$1,566
Discounted Electricity Burden	5.7%	5.0%	4.6%	3.0%	1.6%

Q. PLEASE PROVIDE A COMPARATIVE VIEW ILLUSTRATING THE BURDEN IMPACTS OF THE PROGRAM DESIGNS THAT YOU DESCRIBED ABOVE.

A. The charts on the following page, based on current poverty guidelines and the North Carolina minimum wage, provide a comparative view of the burden impacts of three program designs.


25% Straight Discount
Undiscounted and Discounted Electricity Burdens
by Selected Household Incomes
12.0%
10.0%
8.0%
6.0%
4.0%
2.0%
0.0%
10.7%
7.8%
9.4%
6.8%
6.2%
4.5%
3.0%
3.0%
1.6%
1.6%
Single, Minimum Wage* Worker (40 hours x 52 weeks)
2-person Household, 100% 2019 FPL
2-person Household, 150% 2019 FPL
2-Person Median Income Household
Upper-income Household ($100,000)
Undiscounted Electricity Burden (During Arrearage Payoff)
Discounted Electricity Burden


PIPP Discount - 5% Target Burden
Undiscounted and Discounted Electricity Burdens
by Selected Household Income
12.0%
10.0%
8.0%
6.0%
4.0%
2.0%
0.0%
10.7%
5.0%
9.4%
5.0%
6.2%
5.0%
3.0%
3.0%
1.6%
1.6%
Single, Minimum Wage* Worker (40 hours x 52 weeks)
2-person Household, 100% 2019 FPL
2-person Household, 150% 2019 FPL
2-Person Median Income Household
Upper-income Household ($100,000)
Undiscounted Electricity Burden (During Arrearage Payoff)
Discounted Electricity Burden



The charts above show that discounted burden levels would vary somewhat between the respective design models. Assuming average usage and expenditures among all program participants, the straight discount model provides a uniform benefit to all program participants, regardless of income. The result is that participants with the lowest incomes are left with a higher post-discount burden than participants with somewhat higher incomes. However, under a PIPP or tiered discount design, steeper discounts are provided to households with the lowest incomes, resulting in burdens that are more consistent throughout the spectrum of participants' incomes. Thus, under the targeted PIPP and tiered discount models, all participants' bills are brought closer to an "affordable" level. Under a PIPP, participants' burdens are brought precisely to the target level, whereas under a tiered discount, actual burdens vary somewhat according to variation between the participant's income and the midpoint of the income tier to which the customer is assigned.

Q. WHICH OF THE DESCRIBED PROGRAM DESIGNS DO YOU RECOMMEND?

A. As noted above, the administrative cost of a PIPP is somewhat higher than that associated with a straight or tiered discount. The added administrative cost comes primarily from the need to provide each participant with an individualized bill credit. However, the benefit from targeting program resources in accordance with individual household income circumstances, in my view, warrants the added administrative cost. Further, DEP has long-standing experience in Ohio with administering such a program. This experience could be beneficial in designing and implementing a similar program structure in North Carolina. However, I ultimately concur with Mr. De May that new affordability program offerings be developed through a collaborative process between the Commission, the Public Staff, the Company, and interested stakeholders.[18] I recommend that the Commission convene such a process, that it be hosted by the Commission, and that participating parties and stakeholders be afforded the opportunity to file comments with the Commission regarding findings and recommendations of the stakeholder process.

Q. IS THERE A COMPREHENSIVE SOURCE OF INFORMATION REGARDING BILL ASSISTANCE PROGRAMS THAT HAVE BEEN IMPLEMENTED IN THE UNITED STATES?

A. Yes. The National Center for Appropriate Technology has operated the LIHEAP Clearinghouse through a contract from the United States Department of Health

[18] De May Direct Testimony, p. 10.

and Human Services, Administration for Children and Families, Office of Community Services, Division of Energy Assistance. The LIHEAP Clearinghouse maintains a number of informational resources related to LIHEAP and other energy affordability programs. Among these resources is a database of information regarding ratepayer-funded bill payment assistance and energy efficiency programs operating in the United States. The most recent update on these programs was completed by the LIHEAP Clearinghouse in 2014. Thus, some of the information provided on the Clearinghouse website is dated. However, links on the clearinghouse website[19] lead to basic information regarding dozens of affordability programs operating across the United States. A table reflecting 2014 findings is attached as Exhibit JH-4.

Q. WHAT IS THE ROLE OF ENERGY EFFICIENCY IN PROVIDING FOR ELECTRICITY BILL AFFORDABILITY AND HOME ENERGY SECURITY?

A. Comprehensive low-income energy efficiency programs provide the cornerstone of low-income home energy security. Effective low-income efficiency programs deliver detailed home energy assessments, heating and cooling system repair or replacement, cost-effective building envelope improvements, and replacement of inefficient lighting and appliances. For low-income households, these services and improvements are often delivered at no up-front or repayment cost to the participant, maximizing the energy savings cash flow benefits stemming from these measures and contributing to increased affordability of home energy services. In addition, effective, comprehensive, deep retrofit efficiency programs

[19] https://liheapch.acf.hhs.gov/Supplements/2014/supplement14.htm

improve indoor air quality while helping cash-strapped utility consumers maintain healthy indoor temperatures. When offered in conjunction with meaningful bill payment assistance, a low-income household has a much higher likelihood of retaining access to essential utility service at a more affordable cost than would be the case in the absence of such programs.

Q. HAVE DEP LOW-INCOME CUSTOMERS HAD ACCESS TO COMPREHENSIVE ENERGY EFFICIENCY PROGRAMMING AS YOU DESCRIBE ABOVE?

A. Yes. In the past, a limited number of DEP customers living at or below 200 percent of the federal poverty level had the opportunity to participate in the shareholder-supported Helping Home Fund, which provided comprehensive efficiency services at no cost to participants. In 2018, 642 customers participated in the program at a total program cost from DEP dollars of about $1.4 million, or $2,200 per participant. Because funding for this program supplements existing state and federally funded program dollars (such as the Weatherization Assistance Program), the actual amount spent on efficiency upgrades per home was likely much greater. For example, according to an evaluation of the Helping Home Fund from 2015 to 2017, on average $5,151 was spent in total per home on 3,516 homes (across both Duke Energy service territories in North Carolina).[20]

[20] Advanced Energy, Duke Energy, Lockheed Martin, and North Carolina Community Action Association, *Evaluation of Duke Energy's Helping Home Fund*, p. 2, (October 2017) (of critical importance was the added flexibility of dollars from the Company to allow the community action agencies to perform necessary health and safety repairs that were required before weatherization upgrades could be made. According to surveys completed by the service providers, 44 percent of the homes that they worked on would have otherwise been deferred were it not for the Helping Home Fund dollars), attached as Exhibit JH-5.

Unfortunately, in 2019, only 358 of DEP's customers participated in the Helping Home Fund program.[21]

Q. WHAT IS YOUR RECOMMENDATION REGARDING DEP'S LOW-INCOME ENERGY EFFICIENCY PROGRAMMING AS A MEANS OF ENHANCING AFFORDABILITY AND HOME ENERGY SECURITY?

A. As a means of mitigating any approved rate increases for low-income customers, I recommend that DEP be authorized and directed to expand an efficiency program design modeled after the Helping Home Fund. I further recommend that total funding be increased to maximize the number of low-income customers who are able to participate annually. Finally, I recommend that, to better ensure sustainability of the program, this expansion be accompanied by transitioning the program from a shareholder-funded effort to one that is ratepayer-funded.

IV. Ramifications of DEP's Residential Basic Facilities Charge For Low-Income Customer Electricity Affordability

Q. WHAT HAVE DEP AND INTERVENORS PROPOSED IN THIS PROCEEDING WITH RESPECT TO THE RESIDENTIAL BASIC FACILITIES CHARGE?

A. DEP proposes to retain the current residential basic facilities charge ("BFC") at $14 per bill.[22] However, the testimony of Justice Center *et al.* witness Jonathan Wallach, filed contemporaneously in this docket, points out that the $14 BFC proposal is based on the Company's reliance on the minimum-system analysis and inappropriate inclusion of usage-based costs in the BFC. Mr. Wallach states that the appropriate residential BFC calculation, inclusive only of customer-based costs, should be set at $9.63.[23] Mr. Wallach further states that an inappropriately

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[21] DEP Response to PS Data Request 92-4, attached as Exhibit JH-6.
[22] Direct Testimony of Michael J. Pirro, p.16.
[23] Direct Testimony of Jonathan Wallach, pp. 25-33.

high BFC results in both intra-class cross subsidization of high-volume consumers by low-volume consumers and reduction of the economic incentive to invest in energy efficiency and other usage-reduction measures.[24]

Q. WHAT ARE THE RAMIFICATIONS OF INAPPROPRIATELY HIGH FIXED CUSTOMER CHARGES FOR LOW-INCOME ELECTRICITY CONSUMERS?

A. On average, low-income, elderly, and African-American-headed households use less electricity than their counterparts. Inappropriately high fixed customer charges derived through inclusion of usage-based costs bring disproportionate economic harm to these households as they are saddled with costs that are more appropriately recovered through volumetric charges.

Q. WHAT EVIDENCE DO YOU CITE TO SUPPORT THE CONTENTION THAT LOW-INCOME HOUSEHOLDS, ELDERS, AND AFRICAN-AMERICAN-HEADED HOUSEHOLDS, ON AVERAGE, USE LESS ELECTRICITY THAN THEIR COUNTERPARTS?

A. As relayed in previous testimony before the Commission[25], results of the United States Department of Energy/Energy Information Administration Residential Energy Consumption Survey provides evidence of this usage dynamic. The table below illustrates that, on average, low-income households in North Carolina and South Carolina use 15.6% less electricity than their higher-income counterparts, elder households use 11.2% less electricity than non-elder households, and African-American households use 11.6% less than white households. This data is from 2009, the most recent year that the Residential Energy Consumption survey was conducted using a sample large enough to support results for geographic areas smaller than census divisions.

[24] *Id.*, pp. 35 – 39.
[25] Direct Testimony of John Howat, Docket No. E-7, Sub 1146 (Jan. 19, 2018).

2009 Median Household Electricity Usage by Poverty 150% Status, Elder Status, and Race of Householder – North Carolina and South Carolina

Household Income	*kWh*	*% Difference*
< or = 150% Poverty	12,105	-15.6%
> 150% Poverty	14,343	

Householder's Age	*kWh*	*% Difference*
65 or Over	12,469	-11.2%
Less than 65	14,038	

Race of Householder	*kWh*	*% Difference*
African-American	12,468	-11.6%
White	14,111	

Source: Energy Information Administration, 2009 Residential Energy Consumption Survey

Q. PLEASE DESCRIBE THE DATA SOURCES AND METHODOLOGY THAT YOU USED TO GENERATE THE TABLES AND CHARTS IN THIS SECTION.

A. I generated the tables depicting electricity usage using microdata from the 2009 Residential Energy Consumption Survey.[26] The Survey includes detailed residential energy consumption and expenditure information from 27 U.S. geographic areas referred to as "reportable domains." North Carolina and South Carolina comprise one of the reportable domains.[27] The Survey instrument includes questions regarding a broad range of demographic factors and household

[26] https://www.eia.gov/consumption/residential/data/2009/index.php?view=microdata.

[27] The Survey results cannot be sorted to provide results that apply specifically to an individual utility service territory. However, while the electricity usage among subgroups of residential consumers in the Company's service territory may vary somewhat from the two-state average usage, the relative usage patterns identified in the North Carolina and South Carolina region are highly consistent with those from other geographic regions across the United States. It is therefore reasonable to assume that the general usage patterns identified in North Carolina and South Carolina – and throughout the United States – apply to the DEP service territory.

characteristics. Using SPSS statistical software, I sorted Survey data to generate cross-tabulations of median kilowatt-hour usage by poverty status, race, and age of residents.

Results of these analyses demonstrate that in the North Carolina-South Carolina reportable domain, households headed by low-income, elderly, and African-American customers use less electricity—on average—than their wealthier, younger, and white counterparts. As indicated above, the Company's proposal, by penalizing low-volume consumers, will disproportionately harm these groups of ratepayers.

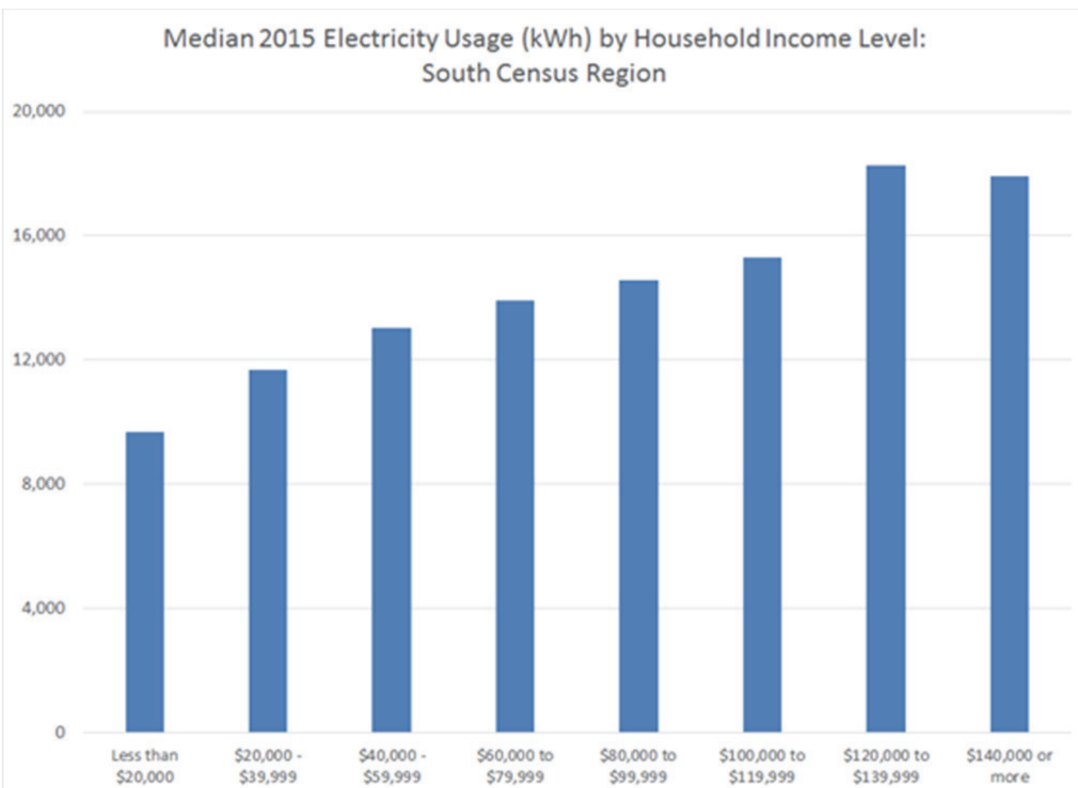
The Survey data demonstrate that in 26 of 27 regions surveyed, median average electricity consumption among households living at or below 150% of the federal poverty guidelines is less than that of higher-income households. The table below[28] reflects this consistent pattern.

[28] Tabulated by National Consumer Law Center using U.S. Energy Information Administration 2009 Residential Energy Consumption Survey.

Median 2009 Site Electricity Usage (kWh), by 150% Poverty Status				
	< or = 150% Poverty	Above 150% Poverty	All Households	% Difference
Connecticut, Maine, New Hampshire, Rhode Island, Vermont	4,708	7,468	6,961	-37.0%
Massachusetts	4,222	6,056	5,686	-30.3%
New York	4,544	5,969	5,355	-23.9%
New Jersey	4,969	7,497	7,231	-33.7%
Pennsylvania	8,402	9,690	9,306	-13.3%
Illinois	7,350	9,116	8,432	-19.4%
Indiana, Ohio	7,831	9,999	9,365	-21.7%
Michigan	7,073	8,190	7,764	-13.6%
Wisconsin	7,449	7,889	7,727	-5.6%
Iowa, Minnesota, North Dakota, South Dakota	6,241	9,285	8,940	-32.8%
Kansas, Nebraska	8,808	9,402	9,302	-6.3%
Missouri	11,705	12,232	11,991	-4.3%
Virginia	10,997	13,859	13,231	-20.7%
Delaware, District of Columbia, Maryland, West Virginia	10,381	13,063	12,848	-20.5%
Georgia	12,727	13,816	13,499	-7.9%
North Carolina, South Carolina	12,105	14,343	13,651	-15.6%
Florida	11,905	13,760	13,212	-13.5%
Alabama, Kentucky, Mississippi	11,802	15,847	14,656	-25.5%
Tennessee	12,537	14,480	13,782	-13.4%
Arkansas, Louisiana, Oklahoma	12,628	13,646	13,421	-7.5%
Texas	10,602	13,799	12,878	-23.2%
Colorado	5,216	6,516	6,231	-20.0%
Idaho, Montana, Utah, Wyoming	10,665	9,588	9,804	11.2%
Arizona	10,088	13,056	12,105	-22.7%
Nevada, New Mexico	7,637	9,434	9,164	-19.0%
California	4,739	5,939	5,628	-20.2%
Alaska, Hawaii, Oregon, Washington	10,597	10,799	10,754	-1.9%
U.S. Average	*8,432*	*10,072*	*9,687*	*-16.3%*

Q. WHY DO YOU REFER TO THE 2009 RECS RESULTS RATHER THAN THE MORE RECENT 2015 RECS?

A. After 2009, the RECS was conducted again in 2015. However, due to dramatically reduced sampling, the 2015 RECS cannot be filtered by geographic areas as small as those reflected in the 2009 RECS. In addition, the 2015 RECS did not include ratio of income to poverty flags or household income brackets that are narrow enough to allow for calculation of household income-to-poverty ratios. However, despite the lack of geographic granularity, the relationship between median electricity usage and household income identified using the 2009 RECS is confirmed in the 2015 survey. Data from the South Census Region of the RECS—the region that includes North Carolina—demonstrates that lower-income households' median electricity usage increases in each of the RECS annual household income brackets until the highest bracket of $140,000 is reached.



Source: *U.S. Energy Information Administration, Residential Energy Consumption Survey*

While the best available data shows that a majority of low-income, elderly and African-American-American households consume less home energy than their counterparts, there is considerable usage variation within these groups. For low-income households, elders, and households of color that are high-volume electricity users, it is appropriate to advance energy efficiency and bill assistance as proposed above to mitigate excessive home energy burdens rather than look to increasing or retaining high customer charges.

Q. HOW DOES A HIGH BFC AFFECT THE INCENTIVE OF LOW-INCOME HOUSEHOLDS TO PARTICIPATE IN ENERGY EFFICIENCY PROGRAMS OR INVEST IN ENERGY EFFICIENCY MEASURES?

A. An elevated BFC shifts recovery of the a the Company's revenue requirement from volumetric to unavoidable fixed charges and thereby undermines the incentive for all households, including low-income households, to participate in energy efficiency programs or independently invest in energy-efficient appliances and improvements. In short, the higher the BFC, the lower the potential financial reward from energy efficiency. This dynamic is of particular importance to low-income households for whom the economic benefits of energy efficiency often required to reduce home energy costs to an affordable level.

Q. ARE REDUCED FIXED CHARGES COMPATIBLE WITH BILL PAYMENT ASSISTANCE PROGRAMS PUCH AS A PIPP?

A. Yes. In fact, the monthly minimum charge paid by Ohio customers participating in the PIPP Plus program is $10.[29] In addition to the PIPP, Duke Energy Ohio administers a low-income residential service program under Rate RSLI available to electricity customers with income at or below 200% of the federal poverty level who do not participate in the PIPP. (Income eligibility for participation in the Ohio PIPP is capped at 150% of the federal poverty level.) The customer

[29] Ohio Public Utilities Commission, "Energy Assistance Resource Guide – 2019-2020," p. 5. (Exhibit JH-3.)

charge paid by participants in the RSLI program is set at $2 per month. The tariff sheet for Rate RSLI, provided by DEP in response to Public Staff 171-5, is attached as Exhibit JH-5. These examples demonstrate the compatibility of reduced customer charges and low-income bill affordability programs, including ones delivered by DEP's Ohio affiliate.

V. Summary of Findings and Recommendations

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS TO THE COMMISSION.

A. My recommendations to the Commission are as follows:

- A low-income percentage discount of at least 25%, a tiered discount setting payments at a targeted electricity burden level of approximately 5%, or a PIPP lowering all participants' electricity bill payments to 5% of household income should be implemented by DEP.
- DEP should be directed by the Commission to implement an arrearage management program to operate in conjunction with a current bill reduction program.
- Affordability programs should be funded through uniform, volumetric charges.
- New affordability program offerings should be developed through a collaborative process – hosted by the Commission – between the Public Staff, the Company and interested stakeholders. Participating parties should be afforded the opportunity to file comments with the Commission regarding findings and recommendations of the stakeholder process.

- DEP should expand the Helping Home Fund, or a low-income energy efficiency with a similar design. Expansion should be accompanied by transitioning the program from a shareholder-funded effort to one that is ratepayer-funded.
- The Commission should reject the BFC proposed by DEP because it inappropriately reflects usage-related costs, would result in cross-subsidies of high-volume consumers, would discourage energy efficiency, and would disproportionately harm low-income, elder, and African-American-headed households.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

MR. NEAL: Yes, this is David Neal on behalf of the Justice Center, et al., and at this time we would move that Mr. Wallach's direct testimony that was prefiled on April 13, 2020, consisting of 51 pages be copied into the record as if given orally from the stand. And that Mr. Wallach's exhibits premarked JFW-1 through JFW-9 be entered into the record at this time.

COMMISSIONER CLODFELTER: There is no objection to the motion, the motion is allowed.

(JFW-1 through JFW-9 were admitted into evidence.)

(Whereupon, the prefiled direct testimony of Jonathan F. Wallach was copied into the record as if given orally from the stand.)

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EXHIBITS

JFW-1 – Resume of Jonathan F. Wallach, Resource Insight, Inc.

JFW-2 – George J. Sterzinger, *The Customer Charge and Problems of Double Allocation of Costs*, PUBLIC UTILITIES FORTNIGHTLY 30–32 (1981).

JFW-3 – Duke Energy Progress Second Supplemental Response to NCJC Data Request 4-16, Docket No. E-2, Sub 1219, March 16, 2020.

JFW-4 – Duke Energy Indiana, LLC Response to Citizens Action Coalition Data Request 12-4, IURC Cause No. 45253, September 23, 2019.

JFW-5 – Duke Energy Progress Response to NCJC Data Request 4-5, Docket No. E-2, Sub 1219, February 10, 2020.

JFW-6 – Duke Energy Progress Revised Response to Public Staff Data Request Item No. 60-15, Docket No. E-2, Sub 1219, February 10, 2020.

JFW-7 – Citations to Marginal-Price Elasticity Studies

JFW-8 – Duke Energy Progress Response to NCJC Data Request 4-1, Docket No. E-2, Sub 1219, February 10, 2020.

JFW-9 – Letter from Paul Curl, Secretary of Washington Utilities and Transportation Commission, to Julian Ajello of the California Public Utility Commission, regarding review of the NARUC Electric Utility Cost Allocation Manual, June 11, 1992.

I. INTRODUCTION AND SUMMARY

Q: PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A: My name is Jonathan F. Wallach. I am Vice President of Resource Insight, Inc., 5 Water Street, Arlington, Massachusetts.

Q: PLEASE SUMMARIZE YOUR PROFESSIONAL EXPERIENCE.

A: I have worked as a consultant to the electric power industry since 1981. From 1981 to 1986, I was a Research Associate at Energy Systems Research Group. In 1987 and 1988, I was an independent consultant. From 1989 to 1990, I was a Senior Analyst at Komanoff Energy Associates. I have been in my current position at Resource Insight since 1990.

Over the past four decades, I have advised and testified on behalf of clients on a wide range of economic, planning, and policy issues relating to the regulation of electric utilities, including: electric-utility restructuring; wholesale-power market design and operations; transmission pricing and policy; market-price forecasting; market valuation of generating assets and purchase contracts; power-procurement strategies; risk assessment and mitigation; integrated resource planning; mergers and acquisitions; cost allocation and rate design; and energy-efficiency program design and planning.

My resume is attached as Exhibit JFW-1.

Q: HAVE YOU TESTIFIED PREVIOUSLY IN UTILITY PROCEEDINGS?

A: Yes. I have sponsored expert testimony in more than 90 state, provincial, and federal proceedings in the United States and Canada, including before this Commission in the previous general rate cases for Duke Energy Carolinas (Docket No. E-7, Sub 1146) and for Duke Energy Progress (Docket No. E-2, Sub

1142). I also testified in the most recent Duke Energy Carolinas and Duke Energy Progress rate cases in South Carolina and in the most recent Duke Energy Indiana rate case. In addition, I submitted testimony in the pending Duke Energy Carolinas general rate case (Docket No. E-7, Sub 1214). I include a detailed list of my previous testimony in Exhibit JFW-1.

Q: ON WHOSE BEHALF ARE YOU TESTIFYING?

A: I am testifying on behalf of the North Carolina Justice Center, North Carolina Housing Coalition, Natural Resources Defense Council, and Southern Alliance for Clean Energy.

Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A: On October 30, 2019, Duke Energy Progress, LLC ("DEP" or "the Company") filed an application and supporting testimony for approval of increased electric rates and charges. My testimony responds to the testimony by Company witnesses:

- Michael J. Pirro, regarding the Company's proposals to: (1) allocate among the various retail rate classes the requested base revenue increase; and (2) maintain the monthly Basic Customer Charge ("BCC") for residential customers at its current rate.[1]
- Janice Hager, regarding the Company's cost of service study ("COSS"), which served as the basis for the Company's proposals for allocating the requested base revenue increase and for setting the residential BCC.

Ms. Hager cites to a March 28, 2019 report by the Public Staff ("Public Staff MSM Report") as the basis in part for her endorsement of the Company's

[1] On March 13, 2020, DEP filed supplemental testimony by Mr. Pirro. I also respond to this supplemental testimony.

COSS.[2] My testimony therefore also addresses the findings and recommendations of this report.

Q: PLEASE SUMMARIZE YOUR FINDINGS AND CONCLUSIONS WITH REGARD TO DEP'S PROPOSAL FOR ALLOCATING THE REQUESTED BASE REVENUE INCREASE.

A: The Commission should reject the Company's proposal for allocating the requested base revenue increase. The Company's proposal relies solely on the results of a cost of service study that does not allocate costs to customer classes in a manner that reasonably reflects each class's responsibility for such costs. Specifically, the Company's COSS misallocates distribution costs by: (1) misclassifying a portion of such costs as customer-related by relying on a flawed "minimum-system" analysis to classify distribution costs; and (2) misallocating the demand-related portion of such costs by relying on an allocator that fails to account for the impact of load diversity on distribution equipment sizing and cost. Because of these two errors, the Company's COSS allocates more distribution plant costs to the residential rate classes than is appropriate under generally accepted cost-causation principles.

The Commission should therefore direct DEP to discontinue its use of the minimum-system method for classifying distribution costs in the Company's COSS. Instead, consistent with best practice, DEP should rely on the "basic customer method" for classifying such costs in its COSS. In addition, in order to reasonably account for the effect of load diversity on distribution equipment sizing and cost, demand-related distribution costs should be allocated to rate classes on the basis of each class's diversified peak demand.

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[2] *Report of the Public Staff on the Minimum System Methodology of North Carolina Electric Public Utilities*, Docket No. E-100, Sub 162 (March 28, 2019) [hereinafter "Public Staff MSM Report"].

Correcting for the misallocations in the Company's COSS would substantially reduce the allocation of the requested base revenue increase to the residential rate classes. Accordingly, a fair and reasonable approach would be to increase base revenues for the residential rate classes by the same percentage as the overall system-average increase authorized by the Commission, if any.

Q: PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS WITH REGARD TO DEP'S PROPOSAL REGARDING THE RESIDENTIAL BCC.

A: The Company has not justified its proposal to maintain the residential BCC at its current rate. As explained in more detail below, the Company's proposal runs contrary to long-standing principles for designing cost-based rates since it would allow for the continued inappropriate recovery of usage-driven costs through the fixed residential BCC. The Company's proposal to continue recovering usage-driven costs through the residential BCC would:

- Continue the current subsidization of high-usage residential customers' costs by low-usage customers.
- Dampen price signals to consumers for controlling their bills through conservation or investments in energy efficiency or distributed renewable generation.

Consequently, the Commission should reject the Company's proposal to maintain the monthly BCC for residential customers at its current rate of $14.00 per bill. Instead, I recommend that the residential BCC be reduced to $9.63, reflecting the actual cost to connect a residential customer. Consistent with long-standing cost-causation and rate-design principles, a monthly BCC of $9.63 would provide for the recovery of the cost of meters, service drops, and customer services required to connect a residential customer.

Q: PLEASE SUMMARIZE YOUR ASSESSMENT OF THE PUBLIC STAFF MSM REPORT.

A: The Public Staff MSM report fails to make the case for minimum-system classification methods. The Public Staff's endorsement of minimum-system methods rests on its unsubstantiated belief that there is a minimum portion of the cost for the distribution grid which is incurred regardless of demand. This notion of a minimum distribution cost which lies at the foundation of minimum-system methods simply does not comport with standard practice for distribution planning and spending. Utilities do not first incur "minimum" distribution-grid costs for the purposes of connecting customers at zero load and then incur additional costs to meet expected demand. Instead, utilities typically size and invest in distribution systems based on an expectation of customer demands on those systems. In other words, the notion that there is a minimum portion of a distribution grid whose costs are "caused" by (i.e., varies with) the number of customers is an unrealistic hypothetical construct. The reality is that distribution-grid costs in total are primarily driven by customer demand.

This implausibility gap between the imagined and the actual causes of investments in the distribution grid will only grow wider as DEP increases spending on its proposed Grid Improvement Plan. It is therefore long past time for North Carolina's electric utilities to discard this false notion that there is a minimum portion of distribution-grid costs. The Commission should categorically reject as contrary to the public interest the use by DEP and other electric utilities of minimum-system classification methods for either cost-allocation or rate-design purposes. Instead, DEP should be directed to follow best practice by adopting the basic customer method for classifying distribution costs in its cost of service studies. In addition, the Commission should investigate whether discretionary GIP costs, to the extent authorized, should be allocated to rate classes in the Company's COSS commensurate with the benefits to those classes from GIP spending. In this way, the Commission can ensure that distribution costs are allocated in the Company's cost of service studies and recovered through rates in a manner that is consistent with established cost-causation and economic principles.

Q: HOW IS THE REST OF YOUR TESTIMONY ORGANIZED?

A: In Section II, I describe how the Company's proposal for allocating the requested base revenue increase relies on a cost of service study that over-allocates distribution plant costs to the residential rate classes. In Section III, I propose an alternative approach for allocating any base revenue increase authorized by the Commission in order to correct for the flaws in the Company's COSS. In Section IV, I explain how DEP's proposal for the residential BCC violates long-standing principles of cost-based rate design, would continue unreasonable cross-subsidization within the residential class, and would dampen energy price signals. In Section V, I comment on the Public Staff MS Report. Finally, I reiterate my recommendations in Section VI.

II. DEP'S COSS OVER-ALLOCATES COSTS TO THE RESIDENTIAL RATE CLASSES

Q: PLEASE DESCRIBE THE COMPANY'S REQUESTED REVENUE INCREASE.

A: The Company is requesting that electric retail base rates be increased on average by 18.4% in order to recover an expected revenue deficiency of about $586.0 million in the 2018 test year.[3] Of the total $586.0 million requested base revenue

[3] Derived from data provided in Pirro Supplemental Exhibit 4, attached to *Supplemental Testimony of Michael J. Pirro for Duke Energy Progress, LLC*, Docket No. E-2, Sub 1219 (March 13, 2020). The 18.4% value represents the percentage increase over revenues under current rates exclusive of current rider revenues.

increase, DEP proposes to allocate about $340.2 million to residential customers. This amount represents a 21.2% increase over residential test-year base revenues under current rates.[4]

Q: WHAT IS THE BASIS FOR THE COMPANY'S PROPOSED ALLOCATION OF THE REQUESTED BASE REVENUE INCREASE TO THE RESIDENTIAL RATE CLASSES?

A: According to DEP witness Michael J. Pirro, the Company's COSS served as the basis for his revenue allocation proposal. Specifically, Mr. Pirro derived the proposed allocation of the base revenue deficiency to rate classes in two steps, each of which relied on the results of the Company's COSS. First, Mr. Pirro allocated the requested base revenue increase to rate classes in proportion to each class's allocation of total rate base in the Company's COSS.[5] Second, Mr. Pirro increased or decreased each class's allocation of the requested base revenue increase by 25% of the increase or decrease, respectively, in each class's revenues under current rates required to achieve the system-average rate of return under current rates.[6]

Q: WHAT IS THE PURPOSE OF A COST OF SERVICE STUDY?

A: The primary purpose of a cost of service study is to allocate a utility's total revenue requirements to rate classes in a manner that reasonably reflects each class's responsibility for such revenue requirements. In other words, the primary purpose of a cost of service study is to attribute costs to rate classes based on how those classes cause such costs to be incurred.

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[4] *Id.* The $340.2 million amount represents the total allocation to all residential rate schedules. Standard residential service is provided under Rate Schedule RES. Time-of-use residential service is provided under Rate Schedules R-TOUD and R-TOU.

[5] *Direct Testimony of Michael J. Pirro for Duke Energy Progress, LLC*, Docket No. E-2, Sub 1219, 11 (March 13, 2020) [hereinafter "Pirro Direct"].

[6] Pirro Supplemental Exhibit 4.

Q: PLEASE DESCRIBE HOW THE COMPANY'S COSS ALLOCATES TOTAL-SYSTEM RETAIL REVENUE REQUIREMENTS TO RATE CLASSES.

A: In order to allocate costs to rate classes, the COSS first separates total costs into production, transmission, distribution, and customer functions. Costs in each function are then classified as energy-, demand-, or customer-related based on whether costs are considered to be "caused" by energy sales, peak demand, or the number of customers, respectively. Finally, costs classified as either energy-, demand-, or customer-related are allocated to rate classes in proportion to each class's contribution to total-system energy sales, peak demand, or number of customers, respectively.[7]

Q: DOES THE COMPANY'S COSS REASONABLY ALLOCATE TEST-YEAR REVENUE REQUIREMENTS?

A: No. The Company's COSS does not allocate costs to rate classes in a manner that reasonably reflects each class's responsibility for such costs. In particular, the COSS misallocates distribution costs.

Q: HOW DOES THE COMPANY'S COSS MISALLOCATE DISTRIBUTION COSTS?

A: As described in detail below, the Company's COSS misallocates distribution plant costs by inappropriately classifying a portion of such costs as customer-related. The COSS then compounds this error by allocating demand-related distribution plant costs on the basis of customer maximum demand, rather than based on customer demand coincident with class peaks. Because of these two errors, the Company's COSS allocates more distribution plant costs to the

[7] *Direct Testimony of Janice Hager for Duke Energy Progress, LLC*, Docket No. E-2, Sub 1219, 5-6 (October 30, 2019) [hereinafter "Hager Direct"].

residential rate classes than is appropriate under generally accepted cost-causation principles.

A. Misclassification of Distribution Plant Costs

Q: PLEASE DESCRIBE HOW COSTS ARE CLASSIFIED IN THE COMPANY'S COSS.

A: The Company classifies the costs of meters, service drops, and customer services ("customer connection costs") as customer-related in the COSS. In addition, the Company relies on a "minimum-system" analysis to classify a portion of the costs incurred for poles, conductors, conduits, and line transformers ("distribution-grid costs") as customer-related.[8]

The remaining portion of pole, conductor, conduit, and line-transformer costs not classified as customer-related are instead classified as demand-related in the COSS, along with all production and transmission plant and fixed operations and maintenance ("O&M") costs. Finally, fuel and variable O&M costs are classified as energy-related.

Q: PLEASE DESCRIBE HOW THE COMPANY USES THE MINIMUM-SYSTEM ANALYSIS TO CLASSIFY SOME POLE, CONDUCTOR, CONDUIT, AND LINE-TRANSFORMER COSTS AS CUSTOMER-RELATED.

A: The Company's minimum-system analysis attempts to estimate the cost to install the same amount of poles, conductors, conduit, and line transformers as are currently on the distribution system, assuming that each piece of distribution equipment is sized to meet minimal load.[9] In other words, the Company's

[8] Specifically, DEP applies a minimum-system analysis to the costs recorded in FERC accounts 364 (poles, towers, and fixtures), 365 (overhead conductors and devices), 366 (underground conduit), 367 (underground conductors and devices), and 368 (line transformers).

[9] Hager Direct, 14.

minimum-system analysis attempts to estimate the cost to replicate the configuration of the existing distribution grid using "minimum-size" equipment.[10] Consequently, this type of minimum-system analysis is typically referred to as the "minimum-size" classification method.

The Company's COSS classifies the cost of this hypothetical minimum-size distribution grid as customer-related. The remaining test-year cost of the distribution grid is classified as demand-related in the COSS.

Q: DOES THE COMPANY'S MINIMUM-SYSTEM ANALYSIS PRODUCE COST CLASSIFICATIONS THAT ARE CONSISTENT WITH COST-CAUSATION PRINCIPLES?

A: No. The Company's minimum-system analysis suffers from a number of conceptual and structural flaws that result in misclassifications of distribution-grid costs. These misclassifications, in turn, lead to allocations of distribution-grid costs which are contrary to cost-causation principles. Specifically, minimum-system classifications result in an over-allocation of distribution-grid costs to the residential rate classes.

Q: WHY DOES THE COMPANY'S MINIMUM-SYSTEM ANALYSIS PRODUCE COST CLASSIFICATIONS THAT ARE INCONSISTENT WITH COST-CAUSATION PRINCIPLES?

A: The Company's minimum-system analysis is premised on the false notion that DEP incurs a "minimum" amount of distribution-grid costs to serve customers at zero load and then incurs additional costs to meet the total load of those customers. In reality, utilities typically size their distribution systems, and incur

[10] The Company's minimum-system analysis of pole costs does not assume the same number of poles as currently installed on the DEP distribution system. Instead, DEP estimates the number of minimum-size poles required to carry a mile of minimum-size conductor and then calculates the total number of minimum-size poles required based on the number of miles of overhead conductor currently installed on the DEP distribution system.

the costs to build those systems, based on an expectation regarding the total demand of all customers connected to the grid.[11] In other words, distribution-grid costs are typically driven by customer load, not by the number of customers.

Indiana Michigan Power Company offers an example of typical utility practice with respect to the sizing of distribution systems. According to testimony before the Indiana Utility Regulatory Commission, Indiana Michigan Power Company's distribution-grid costs are driven by customer demand, not by the number of customers:

> The minimum system approach of classifying a portion of the costs included in accounts 364-368 as customer related … does not recognize the Company's standard engineering practice of planning and sizing distribution facilities to meet the peak demand of the customers served by those facilities. As such, the peak demand on Company facilities, not the number of customers served by the facilities, causes the Company to incur distribution facility costs.[12]

Contrary to typical engineering and investment practice, the Company's minimum-system analysis posits an imaginary world where some portion of the Company's distribution-grid costs were incurred regardless of customer demand. In this fictional world of the minimum system analysis, spending on the imagined minimum grid is considered to be driven by number of customers and thus classified as customer-related. But in the real world, spending on the actual distribution grid is driven by customer demand and thus appropriately classified as demand-related.[13] Consequently, applying the minimum-size method to the

[11] In fact, it is unlikely that DEP would incur the cost to connect a zero- or minimal-load customer under the Company's line-extension policies and would instead require this customer to bear any such connection cost. The Company's line-extension policies and procedures are set forth in the *Line Extension Plan*, included as part of the electric tariff.

[12] *Pre-Filed Verified Rebuttal Testimony of Michael M. Spaeth*, Indiana Utility Regulatory Commission Cause No. 45235, 11-12 (September 17, 2019).

[13] This part of my testimony addresses cost allocation, not rate design. As I discus below in Section V with regard to the Public Staff's Minimum System Method Report, it would not be

Company's distribution-grid costs yields classifications that are inconsistent with cost-causation.

Q: ARE THERE OTHER ASPECTS OF THE COMPANY'S MINIMUM-SIZE APPROACH TO COST CLASSIFICATION THAT ARE INCONSISTENT WITH COST-CAUSATION PRINCIPLES?

A: Yes. Even if one accepts the false premise of a minimum distribution system, the Company's minimum-system analysis suffers from a number of structural defects which lead to classifications and allocations of distribution-grid costs that are contrary to cost-causation principles.

For one, the Company's approach erroneously assumes that the minimum system would consist of the same amount of equipment (e.g., number of transformers) as the actual system.[14] In reality, load levels help determine the amount of equipment, as well as their size. Minimum-system analyses ignore the effect of loads on the amount or type of equipment installed, classifying some costs as customer-related even though they are really driven by demand. Any such costs misclassified as customer-related will therefore be misallocated to rate classes on the basis of customer number, contrary to cost-causation principles.

For another, the Company's minimum-system analysis fails to account for the fact that even the minimum-size equipment currently installed on the system has some amount of load-carrying capability. Consequently, some portion of the cost for this minimum-size equipment should be classified as demand-related. However, under the minimum-size method, that demand-related portion of the

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appropriate to recover costs classified as demand-related in the Company's COSS in a residential demand charge.

[14] As noted above, the exception is the Company's assumption with regard to the number of minimum-size poles.

cost of the minimum-sized equipment instead would be misclassified as customer-related.

The failure to account for the load-carrying capability of minimum-size equipment distorts the allocation of distribution-grid costs in two ways. First, the load-carrying portion of minimum-grid costs are misallocated to rate classes on the basis of customer number, contrary to cost-causation principles. Second, the remaining demand-related portion of distribution-grid costs will be allocated to rate classes on the basis of each class's total demand, even though some of that demand was carried by the minimum-size portion of the distribution grid and therefore did not cause those remaining demand-related costs to be incurred. In other words, the Company's COSS will double-allocate the costs to carry a portion of a class's demand: once through the allocation of the load-carrying portion of minimum-grid costs and again through the allocation of the remaining demand-related costs on the basis of the demand carried by the minimum grid.[15]

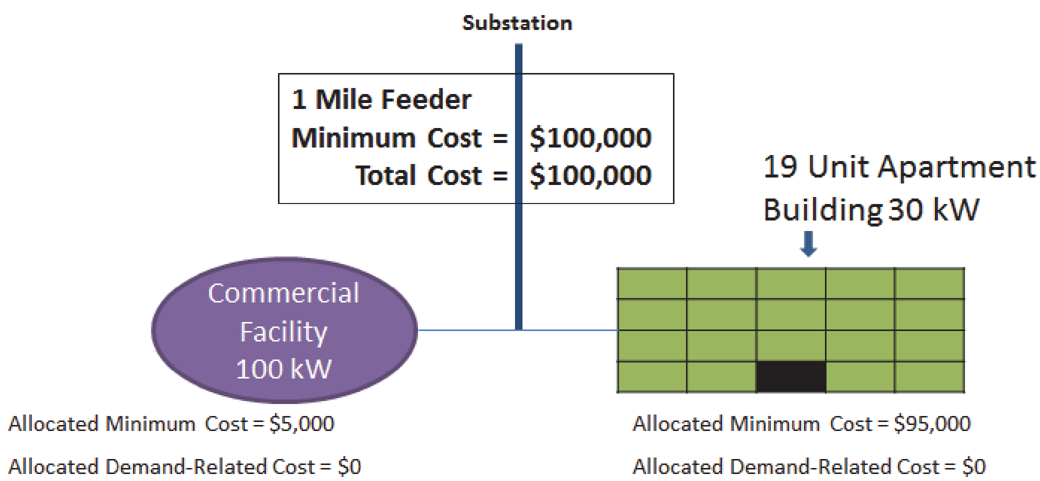
Q: PLEASE PROVIDE AN ILLUSTRATIVE EXAMPLE OF THIS DOUBLE-ALLOCATION PROBLEM.

A: Figures 1a and 1b illustrate this problem of double-allocation of demand-related costs when using the minimum-size method. Figures 1a and 1b assume a hypothetical distribution system consisting of a single one-mile feeder. In the example shown in Figure 1a, there are 20 customers served by the feeder: 19 units in an apartment building with a combined load of 30 kilowatt ("kW") and a single commercial facility with a load of 100 kW. In this example, the minimum-size feeder is assumed to be large enough to cover the combined load on the system, meaning that the minimum cost is equal to the total cost of the feeder.

[15] George J. Sterzinger, "The Customer Charge and Problems of Double Allocation of Costs," *Public Utilities Fortnightly*, (July 2, 1981). A copy of this article is attached as Exhibit JFW-2.

Consequently, under the minimum-size approach, 100% of the total cost of the feeder is inappropriately classified as customer-related and the residential class (with 19 of the 20 customer accounts served by the hypothetical distribution system) is allocated 95% of this cost, even though those 19 residential apartment dwellers are responsible for less than 25% of the load.[16]

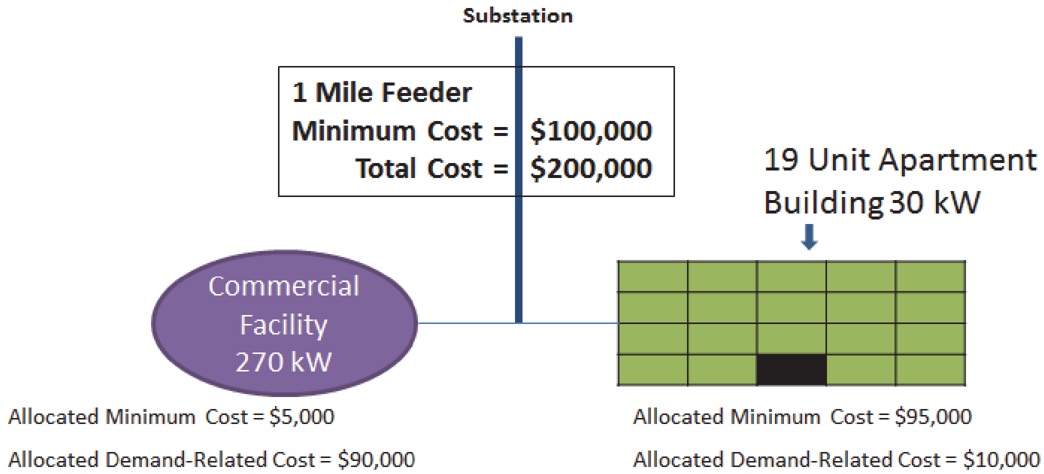
Figure 1a



The example shown in Figure 1b assumes the same number of customers as in Figure 1a. However, in this example, the commercial facility has a load of 270 kW, requiring a larger feeder. As in Figure 1a, the residential class would be allocated 95% of the minimum cost of the feeder. Unlike the case in Figure 1a, however, the residential class would also be allocated 10% of the demand-related feeder costs – those costs in excess of the cost of a minimum-size feeder – even though such costs would not have been incurred without the additional commercial load on the system. Instead, all such excess costs in this example should instead be allocated to the commercial class.

[16] As discussed above, allocating minimum-size costs on the basis of number of customer accounts is inconsistent with cost-causation.

Figure 1b



Q: IS THERE AN ALTERNATIVE METHOD USED BY UTILITIES THAT CLASSIFIES DISTRIBUTION COSTS IN ACCORDANCE WITH COST-CAUSATION PRINCIPLES?

A: Yes. Numerous utilities across the country rely on the basic customer method of cost classification to classify distribution costs in accordance with cost-causation principles. Under the basic customer method, only the costs of meters, service drops, and customer services are classified as customer-related and all other distribution costs are classified as demand-related. The Regulatory Assistance Project recently published a comprehensive study of cost-allocation methods which declares the basic customer method to be best practice.[17]

Q: WHICH UNITED STATES UTILITIES RELY ON THE BASIC CUSTOMER METHOD TO CLASSIFY DISTRIBUTION COSTS?

A: I have not done a comprehensive survey of classification methods by U.S. utilities.[18] However, I am aware of a number of utilities which rely on the basic

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[17] Jim Lazar, et. al., *Electric Cost Allocation for a New Era: A Manual*, Regulatory Assistance Project, 18 (January, 2020), available at https://www.raponline.org/knowledge-center/electric-cost-allocation-new-era/ [Hereinafter "RAP Cost Allocation Manual"].

[18] According to a study commissioned by the National Association of Regulatory Utility Commissioners, the basic customer approach is employed in more than thirty states. *See*

customer method in Arkansas, California, Colorado, District of Columbia, Illinois, Indiana, Iowa, Maryland, Massachusetts, Michigan, Oregon, South Carolina, Texas, Utah, and Washington.

Q: DOES DEP OR ITS UTILITY AFFILIATES IN OTHER JURISDICTIONS USE THE BASIC CUSTOMER METHOD TO CLASSIFY DISTRIBUTION COSTS?

A: Yes. Up until its most recent rate case, DEP in South Carolina had been relying on the basic customer method to classify distribution-grid costs as demand-related.[19] The Company's utility affiliate in Indiana likewise has been using the basic customer method to classify distribution costs for the past 25 years.

Q: HAS DEP ESTIMATED THE IMPACT OF ITS MISCLASSIFICATION OF DISTRIBUTION PLANT COSTS ON THE ALLOCATION OF THE REQUESTED BASE REVENUE INCREASE TO THE RESIDENTIAL RATE CLASSES?

A: Yes. In response to a data request, DEP modified its COSS to classify distribution plant costs based on the basic customer method rather than on the minimum-size method.[20] Specifically, DEP classified all pole, conductor, conduit, and line transformer costs as demand-related for this version of the COSS. This modified

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Frederick Weston, *Charging for Distribution Utility Services: Issues in Rate Design*, Regulatory Assistance Project, 30 (December, 2000), available at https://pubs.naruc.org/pub.cfm?id=536F0210-2354-D714-51CF-037E9E00A724.

[19] In a 1988 order granting a rate increase to DEP's predecessor, Carolina Power & Light Company ("CP&L"), the Commission rejected an intervenor's recommendation that CP&L use the minimum-system method to classify distribution costs. *See* Public Service Commission of South Carolina, *Order Granting Increase*, Order No. 88-864, Docket No. 88-11-E, 11 (August 29, 1988). The Public Service Commission explicitly declined to rule on the merits of the Company's proposal to switch from the basic customer method to the minimum-system method in the most recent DEP rate case. *See* Public Service Commission of South Carolina, *Order*, Order No. 2019-341, Docket No. 2018-318-E, p. 64 (May 21, 2019).

[20] DEP second supplemental response to NC Justice Center et al. Data Request Item No. 4-16. Attached as Exhibit JFW-3.

COSS without minimum-system classification of distribution plant costs therefore classifies only the cost of meters, service drops, and customer services as customer-related.

Correcting for the misclassification of distribution plant costs in the Company's COSS substantially reduces the allocation of 2018 test-year base revenue requirements to the residential class. As discussed above, DEP is requesting an increase in base revenues (i.e., excluding rider revenues) of 18.4% on average for all customers and proposing an increase of 21.2% for residential customers. In contrast, under Mr. Pirro's proposed approach for allocating the requested base revenue increase, residential base revenues would be increased by only 19.6% – closer to the system-average increase – if distribution plant costs were correctly classified in the Company's COSS with the basic customer method.

Q: WHAT DO YOU RECOMMEND WITH REGARD TO THE CLASSIFICATION OF DISTRIBUTION PLANT COSTS IN THE COMPANY'S COSS?

A: The classification of distribution plant costs in the Company's COSS does not reasonably reflect cost-causation. The Commission should therefore direct DEP to discontinue its use of the minimum-system method for classifying distribution plant costs in the Company's COSS. Instead, DEP should rely on the basic customer method for classifying such costs in its COSS.

B. Misallocation of Demand-Related Distribution Plant Costs

Q: HOW DOES THE COMPANY'S COSS ALLOCATE DEMAND-RELATED DISTRIBUTION PLANT COSTS?

A: As discussed above, DEP classifies a portion of distribution plant costs as customer-related based on a minimum-system analysis, allocating those costs to rate classes in the COSS based on the number of customers in each class. The remaining portion is then classified as demand-related and allocated to rate classes in the Company's COSS on the basis of what DEP refers to as "non-coincident peak" demand ("NCP"). The Company derives class NCP by summing individual customers' maximum demand during the test year. The NCP allocator derives each class's percentage share of demand-related distribution plant costs as the ratio of: (1) the class NCP for the test year; and (2) the sum of all rate classes' NCPs in the test year.[21]

Q: DOES THE NCP ALLOCATOR REASONABLY REFLECT COST-CAUSATION?

A: No. The NCP allocator does not account for the effect of load diversity on distribution equipment loading and thus does not reasonably reflect the drivers of the Company's distribution plant costs. By failing to account for load diversity, the NCP allocator likely overstates the residential rate classes' contributions to distribution costs and thus over-allocates such costs to the residential classes.

Q: HOW DOES LOAD DIVERSITY AFFECT THE SIZING OF DISTRIBUTION PLANT?

A: Residential customers reach their individual maximum demands on different days and in different hours of the day. This diversity of demand among a group of residential customers served by a piece of shared distribution equipment results in a group peak demand that is lower than the sum of customers' individual maximum demands.

I illustrate the impact of load diversity in Table 1 with an example that assumes that three residential customers take service from a single transformer. For simplicity's sake, this example further assumes that there are four hours in

[21] Hager Direct, 11.

the year and that the three residential customers have hourly demands as shown in Table 1.

Table 1: Impact of Load Diversity

	Customer #1 Demand (kW)	Customer #2 Demand (kW)	Customer #3 Demand (kW)	Total Demand (kW)	
Hour 1	3	2	1	6	
Hour 2	7	4	2	13	
Hour 3	5	6	3	14	Diversified Peak Demand
Hour 4	2	3	4	9	
Maximum	7	6	4	17	Sum of Maximum Demand

As indicated in Table 1, the sum of the individual customers' maximum demands is 17kW in this example. In contrast, the diversified peak demand on the shared transformer is only 14kW, or about 18% less than the sum of individual maximum demands, because of load diversity.

Q: DOES DEP ACCOUNT FOR LOAD DIVERSITY IN THE SIZING OF DISTRIBUTION PLANT?

A: Yes. As is typical for electric utilities, DEP sizes distribution plant to meet the diversified peak demand in total of the group served by that plant, not to meet the sum of the maximum demands of the individual customers in that group. Referring to diversified peak demand as "non-coincident peak" and the sum of maximum demands as "Individual Customer Maximum Demand (ICMD)," Duke Energy states in its response to the Public Staff in Docket No. E-100, Sub 162 that:

> Duke's position is that all customers do not impose their maximum demand on the distribution system at the same time. Rather, individual customers will use their maximum demand at different times than other customers who are served by the same distribution facilities, and as a group, will have a non-coincident peak [i.e., diversified peak] that is less than the group's ICMD. (For obvious reasons, this load diversity is higher the farther away the distribution equipment is from the customer.) Thus, Duke Energy "sizes" distribution equipment to meet this non-coincident peak [i.e., diversified peak].[22]

Q: PLEASE PROVIDE AN EXAMPLE OF HOW DEP ACCOUNTS FOR LOAD DIVERSITY WHEN SIZING DISTRIBUTION EQUIPMENT.

A: In response to discovery in an ongoing rate case in Indiana, Duke Energy Indiana provided a copy of the guidelines used to size transformers in Duke Energy's service territories in the Carolinas and the Midwest.[23] According to these guidelines, DEP sizes transformers based on an estimate of the diversified peak load of the customers sharing the transformer. As indicated in the following excerpt from the guidelines, the Company assumes that load diversity increases with the number of customers taking service from a transformer, i.e. that the ratio of load on the transformer to the sum of the individual customers maximum demand ("coincidence factor") decreases as the number of customers taking service from a transformer increases.

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[22] "Duke Energy Response to Public Staff Initial Data Request," 11-12 (emphasis added). Provided in Appendix 1 of Public Staff MSM Report.

[23] A copy of this discovery response is attached as Exhibit JFW-4.

Diversity (Coincidence Factor)

Carolinas

Customers	Heat Pump	A/C
1	1	1
2	.695	.82
3	.568	.73
4	.486	.645
5	.427	.58
6	.377	.515
7	.352	.49
8	.337	.475
9	.323	.47
10	.314	.46
11	.314	.46
12 & up	.314	.46

For example, these guidelines indicate that DEP assumes a coincidence factor of 0.486 for the purposes of sizing a transformer that will serve four residential customers with heat pumps. This means that DEP assumes that load on that transformer (i.e., diversified demand) will be less than half of the sum of the maximum demands of the four customers taking service from the transformer (i.e., non-coincident demand), because of the diversity between the individual customer demands.

Q: WHY DOES THE NCP ALLOCATOR OVER-ALLOCATE DEMAND-RELATED DISTRIBUTION PLANT COSTS TO THE RESIDENTIAL CLASS?

A: The NCP allocator over-allocates costs to the residential class because it does not account for the effect of load diversity on equipment sizing and thus on equipment cost.

Specifically, the NCP allocator does not account for the fact that distribution equipment serving many small residential customers can be smaller (and less expensive) than equipment that serves fewer large industrial customers, even when the sum of the residential maximum demands is equal to the sum of industrial maximum demands. As the number of customers served by distribution equipment increases, so too does the diversity of maximum hourly demands among those customers. And as the diversity of maximum demands increases, so too does the variance between the sum of individual customers' maximum hourly demands (i.e., group NCP) and the maximum demand for the group as a whole (i.e., group diversified demand.) By not accounting for load diversity, the NCP allocator allocates cost to classes as if the sizing and cost of distribution equipment is driven by each class's NCP rather than by the class's diversified demand on the equipment.

Q: HAS DEP ESTIMATED THE IMPACT OF ITS MISALLOCATION OF DEMAND-RELATED DISTRIBUTION PLANT COSTS ON THE ALLOCATION OF THE REQUESTED BASE REVENUE INCREASE TO THE RESIDENTIAL CLASS?

A: No. In response to a data request, DEP declined to modify its COSS to allocate demand-related distribution plant costs based on diversified peak demand rather than on non-coincident peak, stating that "the Company has not prepared the requested analysis."[24]

While DEP has refused to modify its COSS to correct for the misallocation of demand-related distribution plant costs, it's likely that such a correction would have further reduced the residential allocation of the requested base revenue increase beyond that achieved by correcting for the minimum-system misclassification of distribution plant costs discussed above. In other words, under Mr. Pirro's proposed approach for allocating the requested revenue increase, the residential base revenue increase could be equal to or even less than the 18.4% requested system-average increase if the Company's COSS were

[24] DEP response to NCJC Data Request Item No. 4-5. Attached as Exhibit JFW-5.

corrected for both the minimum-system misclassification of distribution plant costs and the NCP misallocation of the demand-related portion of such costs.

Q: HOW SHOULD DEMAND-RELATED DISTRIBUTION PLANT COSTS BE ALLOCATED?

A: As DEP acknowledges in its response to the Public Staff in Docket No. E-100, Sub 162, the Company sizes its distribution equipment based on diversified peak demand not on customer maximum demand. Thus, in order to reasonably account for the effect of load diversity on distribution equipment sizing and cost, demand-related distribution plant costs should be allocated on the basis of each class's diversified peak demand.[25] Class diversified peak demand is simply the peak hourly demand for the class as a whole.

III. <u>RESIDENTIAL BASE REVENUES SHOULD BE INCREASED BY NO MORE THAN THE APPROVED SYSTEM-AVERAGE INCREASE</u>

Q: PLEASE DESCRIBE THE COMPANY'S PROPOSAL FOR INCREASING RESIDENTIAL BASE REVENUES.

A: As discussed above in Section II, the Company is requesting that electric retail base rates be increased on average by 18.4% in order to recover an expected revenue deficiency of about $586.0 million in the 2018 test year. Of the total $586.0 million requested base revenue increase, DEP proposes to allocate about $340.2 million to residential customers. This amount represents a 21.2% increase over residential test-year revenues under current base rates.

Company witness Pirro derived the proposed allocation of the base revenue deficiency to the residential rate classes in two steps, each of which relied on the results of the Company's COSS. Under Mr. Pirro's proposed allocation method,

[25] RAP Cost Allocation Manual, 150.

the residential class is first allocated $329.2 million of the total requested $586.0 million base revenue increase based on the allocation of total rate base in the Company's COSS. The Company's COSS also indicates that residential revenues under current rates would need to be increased by an additional $44.2 million in order to achieve the system-average rate of return under current rates. Under Mr. Pirro's proposed allocation method, the residential class is then allocated an additional $11.0 million, representing 25% of the current under-earnings relative to the system-average achieved rate of return.[26]

Q: WOULD THE COMPANY'S PROPOSAL PROVIDE FOR A FAIR ALLOCATION OF THE REQUESTED BASE REVENUE INCREASE TO THE RESIDENTIAL RATE CLASSES?

A: No. As discussed above in Section II, the Company's COSS does not provide a reasonable basis for the allocation of the requested revenue increase to the residential rate classes. Specifically, the Company's COSS over-allocates distribution plant costs to the residential rate classes by: (1) misclassifying a portion of such costs as customer-related; and (2) misallocating the remaining demand-related portion of such costs.

Based on the results of the Company's COSS, Mr. Pirro proposes to increase residential base revenues by 21.2%. In contrast, if the misclassification of distribution plant costs in the Company's COSS were corrected, residential base revenues would increase by only 19.6% under Mr. Pirro's approach for allocating the requested base revenue increase. In fact, with distribution plant costs classified in accordance with cost-causation principles, the Company's COSS shows that the residential rate classes in aggregate are currently over-earning relative to the system-average achieved rate of return. The increase in

[26] Pirro Supplemental Exhibit 4.

residential base revenues would be even less than 19.6% under Mr. Pirro's approach if the misallocation of demand-related distribution plant costs in the Company's COSS were also corrected.

Q: HOW SHOULD ANY BASE REVENUE INCREASE AUTHORIZED BY THE COMMISSION BE ALLOCATED TO THE RESIDENTIAL RATE CLASSES?

A: In light of the magnitude of the misallocation of distribution plant costs in the Company's COSS and the impact of correcting for such misallocations to the residential rate classes, I recommend that base revenues for the residential rate classes be increased on a percentage basis by no more than the overall system-average increase authorized by the Commission, if any.

IV. <u>THE CURRENT BASIC CUSTOMER CHARGE FOR RESIDENTIAL CUSTOMERS IS NOT COST-BASED</u>

Q: WHAT IS THE BASIC CUSTOMER CHARGE?

A: The BCC is a fixed fee charged to each customer on their monthly bill regardless of the customer's energy usage during that month.

Q: WHAT IS THE COMPANY'S PROPOSAL WITH RESPECT TO THE BCC FOR RESIDENTIAL CUSTOMERS?

A: The Company proposes to maintain the residential BCC at its current rate of $14.00 per monthly bill.[27]

Q: IS THE COMPANY'S PROPOSAL FOR THE RESIDENTIAL BCC REASONABLE?

A: No. As discussed in detail below, the current rate for the residential BCC inappropriately recovers usage-driven costs through the BCC. This recovery of

[27] Pirro Direct, 12.

usage-driven costs in the fixed BCC rather than through the volumetric energy rate gives rise to cross-subsidization within the residential rate classes and dampens energy price signals to consumers for controlling their bills through conservation, energy efficiency, or distributed renewable generation.[28]

A. DEP's Proposal for the Residential BCC Violates Principles of Cost-Based Rate Design

Q: WHAT ARE THE RELEVANT CONSIDERATIONS IN DESIGNING COST-BASED RATES FOR RESIDENTIAL CUSTOMERS?

A: The primary challenge in rate design is to reflect the costs that customers impose on the system, both to encourage them to use utility resources responsibly and to share costs fairly. Accordingly, fixed customer charges should reflect the fact that each customer contributes equally to certain types of costs (e.g., billing costs) regardless of that customer's energy usage. Volumetric energy rates, on the other hand, recognize that customers of different sizes and load profiles contribute to other types of costs (e.g., distribution-grid costs) at different levels. If usage-driven costs are inappropriately collected through fixed customer charges, then customers will have reduced incentives to control their bills through conservation or investments in energy efficiency or distributed renewable generation.[29]

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[28] These problems of cross-subsidization and economically inefficient pricing would be even more pronounced if the residential BCC were increased to the level that Mr. Pirro believes would "better reflect all customer-related costs." [Pirro Direct, 11.] For example, Mr. Pirro believes that it would be appropriate to increase the BCC for residential customers to $31.75 per bill. [Pirro Exhibit 7.] However, such an increase would result in the inappropriate recovery through the BCC of demand-related costs that had been misclassified as customer-related through application of the Company's flawed minimum-system analysis.

[29] National Association of Regulatory Utility Commissioners, *Distributed Energy Resources Rate Design and Compensation*, 118 (November 2016), available at https://pubs.naruc.org/pub/19FDF48B-AA57-5160-DBA1-BE2E9C2F7EA0.

Q: GIVEN THESE CONSIDERATIONS, WHAT CATEGORIES OF COSTS ARE APPROPRIATELY RECOVERED THROUGH THE VOLUMETRIC ENERGY RATE?

A: In order to provide efficient price signals, volumetric energy rates should be set at levels that recover those categories of costs that tend to increase with customer usage over the long run, including plant, fuel, and O&M costs for the production, transmission, and distribution functions, along with certain customer-service costs that tend to vary with usage such as uncollectible costs.[30] In other words, volumetric energy rates should reflect long-run marginal costs.

As James Bonbright explains in his seminal text, *Principles of Public Utility Rates*:

> In view of the above-noted importance attached to existing utility rates as indicators of rates to be charged over a somewhat extended period in the future, one may argue with much force that the cost relationships to which rates should be adjusted are not those highly volatile relationships reflected by short-run marginal costs but rather those relatively stable relationships represented by long-run marginal costs. The advantages of the relatively stable and predictable rates in permitting consumers to make more rational long-run provisions for the use of utility services may well more than offset the admitted advantages of the more flexible rates that would be required in order to promote the best available use of the existing capacity of a utility plant.[31]

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[30] Uncollectible costs are the billed amounts not recovered from customers as a result of those customers' non-payment of all or a portion of their monthly bills.

[31] James C. Bonbright, *Principles of Public Utility Rates*. Columbia University Press, 334 (1961), available at: http://media.terry.uga.edu/documents/exec_ed/bonbright/principles_of_public_utility_rates.pdf.

> I conclude this chapter with the opinion, which would probably represent the majority position among economists, that, as setting a general basis of minimum public utility rates and of rate relationships, the more significant marginal or incremental costs are those of a relatively long-run variety – of a variety which treats even capital costs or "capacity costs" as variable costs.[32]

Almost three decades later, Alfred Kahn affirmed Bonbright's opinion in his text, *The Economics of Regulation*:

> … the practically achievable benchmark for efficient pricing is more likely to be a type of average long-run incremental cost, computed for a large, expected incremental block of sales, instead of SRMC [short-run marginal cost] ….[33]

Q: WHICH COSTS ARE APPROPRIATELY RECOVERED THROUGH FIXED CUSTOMER CHARGES?

A: In contrast to the volumetric energy rate, the fixed customer charge is intended to reflect the cost to connect a customer who uses very little or zero energy to the distribution system. Such "customer connection costs" are generally limited to plant and maintenance costs for a service drop and meter, along with meter-reading, billing, and other customer-service expenses. As Bonbright explains:

> But this twofold distinction [between demand and energy in rate design] overlooks the fact that a material part of the operating and capital costs of utility business is more directly and more closely related to the number of customers than to energy consumption on the one hand or maximum kilowatt demand on the other hand. The most obvious examples of these so-called customer costs are the expenses associated with metering and billing.[34]

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[32] *Id.*, 336.

[33] Alfred E. Kahn, *The Economics of Regulation*, The MIT Press, 85 (1988).

[34] Bonbright, *op. cit.*, 311.

In their text, *Public Utility Economics*, economists Paul Garfield and Wallace Lovejoy also describe which costs are truly customer-related and therefore appropriately recovered through the fixed customer charge:

> The purpose of both the connection charge and the minimum charge is to cover at least some of the costs incurred by the utility whether or not the customer uses energy in a particular month. For small customers under the block meter-rate schedule, a charge of this kind is intended to cover the expenses relating to meter service and maintenance, meter reading, accounting and collecting, return on the investment in meters and the service lines connecting the customer's premises to the distribution system, and others. Such expenses as these represent as a minimum the "readiness-to-serve" expenses incurred by the utility on behalf of each customer.[35]

More recently, Severin Borenstein restated these principles for designing cost-based fixed customer charges as follows:

> When having one more customer on the system raises the utility's costs regardless of how much the customer uses – for instance, for metering, billing, and maintaining the line from the distribution system to the house – then a fixed charge to reflect that additional fixed cost the customer imposes on the system makes perfect economic sense. The idea that each household has to cover its customer-specific fixed costs also has obvious appeal on ground of fairness or equity.[36]

Q: IT IS OFTEN CLAIMED THAT FIXED COSTS SHOULD BE RECOVERED THROUGH FIXED CHARGES. HOW DOES THIS CLAIM SQUARE WITH LONG-STANDING PRINCIPLES OF COST-BASED RATE DESIGN?

A: The notion that fixed costs should be recovered through fixed charges sounds appealing, but is often applied inappropriately. The fixed customer charge should

[35] Paul J. Garfield and Wallace F. Lovejoy, *Public Utility Economics*, Prentice-Hall, Inc., 155-156 (1964).

[36] Severin Borenstein, "What's So Great About Fixed Charges?" (2014), available at https://energyathaas.wordpress.com/2014/11/03/whats-so-great-about-fixed-charges/.

be designed to recover only those costs that are truly fixed, in other words, those costs that do not vary with customer usage over the long run. Sunk costs that vary with usage over time, but appear to be "fixed" only from a short-run accounting perspective, should not be treated as fixed for purposes of rate design.

Q: IS THE COMPANY'S PROPOSAL FOR THE RESIDENTIAL BCC CONSISTENT WITH THESE LONG-STANDING PRINCIPLES OF COST-BASED RATE DESIGN?

A: No. Contrary to these principles, the Company's proposal would recover through the residential BCC not just customer connection costs – i.e., the costs for meters, service drops, and customer services – but also the costs allocated to the residential class under the Company's COSS for: (1) uncollectible accounts; and (2) customer-related distribution-grid plant.

Q: WHY IS IT INCONSISTENT WITH COST-BASED RATE DESIGN TO RECOVER UNCOLLECTIBLE COSTS THROUGH THE RESIDENTIAL BCC?

A: Uncollectible costs tend to vary with revenues and thus with usage, because the larger the bill amount (due to either increased usage or higher rates), the greater the amount of the bill at risk of being unaffordable and therefore uncollectible. Thus, as discussed above, such costs are appropriately recovered through the volumetric energy rate.[37]

[37] This part of my testimony addresses rate design, not cost allocation. I do not dispute the Company's classification of uncollectible costs as customer-related for the purposes of allocating such costs to rate classes. However, no matter how classified for cost-allocation purposes, recovering uncollectible costs through the BCC would be contrary to longstanding principles of cost-based rate design.

Q: HOW DOES DEP ESTIMATE THE CUSTOMER-RELATED DISTRIBUTION-GRID COSTS THAT ARE INAPPROPRIATELY RECOVERED THROUGH THE CURRENT RESIDENTIAL BCC?

A: As discussed in Section II, DEP relies on the results of its minimum-system analysis to estimate the "customer-related" portion of distribution-grid costs.

Q: WHY WOULD IT BE UNREASONABLE FOR DEP TO RECOVER COSTS THROUGH THE RESIDENTIAL BCC THAT WERE CLASSIFIED AS "CUSTOMER-RELATED" USING A MINIMUM-SYSTEM ANALYSIS?

A: As discussed in Section II, any distribution-grid costs that are currently recovered through the residential BCC are actually demand-related costs that have been misclassified as customer-related in the Company's minimum-system analysis. Recovering such demand-related costs through the residential BCC would be contrary to long-standing principles of cost-based rate design.

Even if the results of the Company's minimum-system analysis were accepted for *cost-allocation* purposes, such results should not be used for *rate-design* purposes. Minimum-system analyses overstate the minimum cost *per customer* because they assume that a minimum system carrying minimal load would have the same amount of distribution equipment (e.g., the same number of transformers) as would a distribution system designed to carry actual distribution load. In other words, the minimum-system method assumes that each piece of distribution equipment would serve the same number of customers on average, regardless of whether the customers are average-sized (as for the actual system) or have minimal demand (as for the hypothetical minimum-size system.)

This is not a realistic assumption, since even a minimally sized piece of distribution equipment should be able to serve more minimal-usage customers than the number of average-usage customers served by an average-sized piece of distribution equipment. Consequently, the true distribution-grid cost to serve a customer with minimal usage is likely to be less than that derived using a minimum-system analysis. Indeed, since the minimum-system method attempts to estimate the distribution-grid cost incurred regardless of usage – i.e., the cost to serve load approaching zero – the true minimum distribution-grid cost per customer is zero since distribution equipment that carries zero load can serve an infinite number of customers with zero load.

Q: ONCE THE EXCESS UNCOLLECTIBLE AND CUSTOMER-RELATED DISTRIBUTION COSTS FROM THE MINIMUM-SYSTEM ANALYSIS HAVE BEEN REMOVED, WHAT IS THE RESULTING COST TO CONNECT A RESIDENTIAL CUSTOMER TO THE DISTRIBUTION GRID?

A: As shown in Table 2 below, I estimate that a residential BCC of $9.63 per bill would recover the truly customer-related costs of meters, service drops, and customer services allocated to the residential rate classes. I therefore recommend that the residential BCC be reduced from its current rate of $14.00 to $9.63.

Q: HOW DID YOU DERIVE YOUR ESTIMATE OF THE COST TO CONNECT A RESIDENTIAL CUSTOMER TO THE DISTRIBUTION GRID?

A: In response to a data request, DEP provided the unit cost results from a cost of service study that classifies distribution costs using the basic customer method.[38] These results show an allocation to the residential rate classes of about $147.3 million in customer-related costs. I reduced this amount by my estimate of the customer-related revenues recovered through the $2.85 per bill incremental meter

[38] DEP response to Public Staff Data Request Item No. 60-15. Attached as Exhibit JFW-6.

charge for residential TOU customers.[39] I then further reduced this amount in order to remove uncollectible costs for the reasons discussed above. Dividing the net amount of $138.9 million by the number of residential bills yields a connection cost per residential customer of $9.63 per month.

Table 2: Derivation of the Cost to Connect a Residential Customer

	Residential Cost	Residential Bills	Cost per Bill
Customer-Related Cost	$147,293,543	14,423,192	$10.21
Less			
TOU Meter Incremental Revenue	(795,230)	14,423,192	($0.06)
Uncollectible Expense	($7,615,021)	14,423,192	($0.53)
Total	$138,883,292		$9.63

Q: WHAT ACCOUNTS FOR THE $4.37 DIFFERENCE BETWEEN YOUR $9.63 ESTIMATE OF THE RESIDENTIAL CONNECTION COST AND THE CURRENT RATE OF $14.00 FOR THE RESIDENTIAL BCC?

A: The $4.37 difference between my $9.63 estimate of the cost to connect a residential customer and the current $14.00 BCC represents usage-driven costs that would be inappropriately recovered through the fixed customer charge under the Company's proposal.

Q: WHY SHOULD THE COMMISSION BE CONCERNED ABOUT THE RECOVERY OF $4.37 IN USAGE-DRIVEN COSTS THROUGH THE CURRENT RESIDENTIAL BCC?

A: As I discuss below, this recovery of usage-driven costs in the fixed customer charge rather than through the volumetric energy rate gives rise to cross-subsidization within the residential class and dampens energy price signals to consumers for controlling their bills through conservation, energy efficiency, or distributed renewable generation.

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[39] I estimate TOU meter incremental revenues based on data provided in NCUC Form E-1 Data Request, Item No. 42(c).

B. The Current Residential BCC Creates Intra-Class Cost Subsidies

Q: HOW DOES THE CURRENT RESIDENTIAL BCC CAUSE SUBSIDIZATION WITHIN THE RESIDENTIAL CLASS?

A: As discussed above, the current residential BCC recovers usage-driven costs. Such costs are driven by residential load and are therefore appropriately recovered from each residential customer in proportion to their contribution to class load. To the extent that usage-driven costs are recovered through the fixed customer charge rather than through the volumetric energy rate, residential customers with below-average usage bear a disproportionate share of usage-driven costs and consequently subsidize customers with above-average usage. In other words, a residential customer with below-average usage pays more, and a residential customer with above average-usage pays less, than their fair share of such costs.

Q: WHAT IS THE EXTENT OF THE INTRA-CLASS SUBSIDIZATION UNDER THE CURRENT RESIDENTIAL BCC?

A: The Company estimates about 14.4 million residential bills in the test year.[40] This means that about $63.0 million of usage-driven costs are inappropriately recovered annually through the current residential BCC.[41]

If the usage-driven costs recovered through the current residential BCC were instead recovered through the volumetric energy rate, each residential customer would appropriately contribute to recovery of these costs in proportion to their usage. The Company estimates residential sales in the test year of about

[40] The Company's estimate of the number of residential bills in the test year is provided in NCUC Form E-1 Data Request, Item No. 42(c).

[41] The $63.0 million result is derived by taking the product of the annual number of residential bills (14.4 million) and the amount of the current residential BCC in excess of residential connection cost ($4.37 per bill).

16.7 million megawatt-hours.[42] Therefore, if the $63.0 million of usage-driven costs were instead recovered through the volumetric energy rate rather than through the current residential BCC, recovery of those costs would be charged at a rate of 0.38 cents per kilowatt-hour ("¢/kWh").[43] In this case, a residential customer with below-average monthly usage of 600 kWh would contribute about $27 per year toward recovery of the $63.0 million of usage-driven costs while a customer with above-average monthly usage of 1,800 kWh would contribute about $82 per year.[44] Thus, the 1,800 kWh customer would contribute three times more than the 600 kWh customer, in direct proportion to their usage and consistent with accepted principles of cost-causation.

In contrast, with the current recovery of $63.0 million of usage-driven costs through the residential BCC, each residential customer contributes about $52 per year toward recovery of such costs, regardless of that customer's usage. A below-average 600 kWh customer therefore pays almost double their fair share of these usage-driven costs with the current BCC while an above-average 1,800 kWh customer pays only 64% of their fair share.

Q: WOULD SUBSIDIZATION OF HIGH-USAGE RESIDENTIAL CUSTOMERS BY LOW-USAGE CUSTOMERS BE ELIMINATED IF THE RESIDENTIAL BCC WERE SET AT YOUR RECOMMENDED RATE OF $9.63?

A: No. Even with the residential BCC set at my estimate of residential connection cost, low-usage customers would likely continue to subsidize high-usage

[42] The Company's estimate of residential sales in the test year is provided in NCUC Form E-1 Data Request, Item No. 42(c).

[43] The 0.38¢/kWh result is derived by dividing $63.0 million by residential sales of 16.7 million megawatt-hours.

[44] Based on data provided in NCUC Form E-1 Data Request, Item No. 42(c), I estimate monthly usage of 1,157 kWh for an average residential customer.

customers' costs because customer charges and energy rates are priced at the cost to serve an average-usage customer. For example, Rate Schedule RES customers who reduce their on-peak (and overall) usage with energy efficiency or rooftop solar generation pay the same energy rate as larger, peakier customers even though the latter customers may impose more generation costs per kWh of usage than the former due to their proportionately greater on-peak usage.

Likewise, lower-usage customers in an apartment building will typically share a service drop, whereas higher-usage single-family homes will typically be connected with their own service drop. Yet, the lower-usage apartment resident will contribute through the BCC the same amount toward recovery of service-drop costs as the higher-usage single-family customer even though the cost of a service drop per customer is lower for the former than for the latter customer.

Finally, all residential customers will contribute the same amount for recovery of Advanced Metering Infrastructure ("AMI") costs through the residential BCC even though these customers will probably not share equally in the benefits from the Company's investment in residential AMI meters. The National Association of Regulatory Utility Commissioners describes cost causation as "an attempt to determine what, or who, is causing costs to be incurred by the utility."[45] In this case, the "what" causing DEP to make discretionary investments in AMI meters is the expectation that such investments would provide benefits to customers, and the "who" are the customers who would share in these benefits as a result of the Company's AMI investments. Thus, in the case of AMI meters, cost-causation requires that customers contribute toward recovery of AMI costs in proportion to their share of the AMI benefits.

[45] National Association of Utility Regulatory Commissioners, *Electric Utility Cost Allocation Manual*, 38 (January 1992).

Within the residential class, higher-usage energy consumers will likely reap greater benefits than lower-usage customers from AMI technologies and services.[46] For example, these higher-usage customers will have more opportunities to take advantage of (and to benefit from) innovative rate designs that reward load shifting than will their lower-usage counterparts. It therefore would be consistent with cost-causation principles for larger users to contribute a greater share toward recovery of AMI costs than smaller users. However, even with the residential BCC set at the cost to connect a residential customer, each residential customer regardless of usage will contribute the same amount toward recovery of AMI costs.

In all of these cases, any differences in the cost to serve smaller and larger customers are socialized across the residential class, resulting in subsidization of high-usage customers by low-usage customers.

C. The Current Residential BCC Dampens Energy Price Signals

Q: DOES THE CURRENT RESIDENTIAL BASIC CUSTOMER CHARGE SEND APPROPRIATE PRICE SIGNALS?

A: No. As discussed above, the current residential BCC is set at a rate that exceeds the cost to connect a residential customer. The amount in excess of customer connection cost represents usage-driven costs that are more appropriately recovered in the volumetric energy rate. The recovery of these usage-driven costs in the current fixed BCC rather than in the volumetric energy rate dampens price signals and discourages economically efficient behavior by residential customers.

[46] For a description of the expected direct customer and utility benefits from the Company's investment in AMI meters, see *Direct Testimony of Donald L. Schneider, Jr. for Duke Energy Progress, LLC*, Docket No. E-2, Sub 1219 (October 30, 2019).

Q: TO WHAT EXTENT DOES THE CURRENT RESIDENTIAL BCC DAMPEN PRICE SIGNALS PROVIDED BY THE RATE SCHEDULE RES VOLUMETRIC ENERGY RATE?

A: With a fixed amount of revenue requirements to be recovered from Rate Schedule RES customers, the higher the BCC, the lower the volumetric energy rate, and vice versa. With the fixed BCC set at its current rate of $14.00 per bill, DEP proposes a volumetric energy rate of 12.24¢/kWh for Rate Schedule RES customers.[47] If, instead, the BCC were set at the cost-based rate of $9.63, I estimate that the volumetric energy rate would have to be increased to 12.62¢/kWh to recover the same allocated revenue requirement.

In other words, DEP is proposing a Rate Schedule RES energy rate that is 0.38¢/kWh, or about 3%, less than what the volumetric rate would be if the BCC were set at the cost-based rate of $9.63. Thus, the current residential BCC dampens the price signal provided by the volumetric energy rate by about 3%.[48]

Q: HOW WOULD RATE SCHEDULE RES CUSTOMERS LIKELY RESPOND TO THE REDUCTION IN THE ENERGY PRICE SIGNAL RESULTING FROM THE COMPANY'S PROPOSAL TO MAINTAIN THE RESIDENTIAL BCC AT ITS CURRENT RATE?

A: Since the volumetric energy rate under the Company's proposal for the residential BCC would be lower than the volumetric energy rate with a cost-based BCC of $9.63, we would expect Rate Schedule RES customers to consume more energy with the current BCC than they would with a cost-based BCC. The magnitude of

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[47] DEP proposes a summer rate of 12.63¢/kWh and a non-summer rate of 12.03¢/kWh. The sales-weighted average of these two seasonal rates is 12.24¢/kWh.

[48] If the BCC were instead set at $31.75 per bill, as Mr. Pirro believes would be appropriate, I estimate that the volumetric energy rate would have be set at 10.69¢/kWh in order to recover the Company's proposed allocation of revenue requirements to the RES rate class. At $31.75, the residential BCC would dampen the price signal provided by the volumetric energy rate by about 15%.

the increase in energy consumption would depend on: (1) the extent to which the volumetric energy rate with the current BCC is lower than the volumetric energy rate with a cost-based BCC; and (2) the price elasticity of electricity demand.

Q: WHAT IS THE PRICE ELASTICITY OF ELECTRICITY DEMAND?

A: Residential customers respond to the price incentives created by the electrical rate structure. Those responses are generally measured as price elasticities, i.e., the ratio of the percentage change in consumption to the percentage change in price. Price elasticities are generally low in the short term and rise over several years, because customers have more options for increasing or reducing energy usage in the medium to long term. For example, a review by Espey and Espey (2004) of 36 articles on residential electricity demand published between 1971 and 2000 reports short-run elasticity estimates of about −0.35 on average across studies and long-run elasticity estimates of about −0.85 on average across studies.[49] In other words, on average across these studies, consumption decreased by 0.35% in the short term and by 0.85% in the long term for every 1% increase in price.

Studies of electric price response typically examine the change in usage as a function of changes in the marginal rate paid by the customer.[50] Table 3 below lists the results of seven studies of marginal-price elasticity over the last forty years.[51]

[49] The citation for this study is provided in Exhibit JFW-7.

[50] For Rate Schedule RES customers, that would be the energy rate.

[51] The citations for these studies are provided in Exhibit JFW-7.

Table 3: Summary of Marginal-Price Elasticities

Authors	Date	Elasticity Estimates
Acton, Bridger, and Mowill	1976	−0.35 to −0.7
McFadden, Puig, and Kirshner	1977	−0.25 without electric space heat and −0.52 with space heat
Barnes, Gillingham, and Hageman	1981	−0.55
Henson	1984	–0.27 to –0.30
Reiss and White	2005	−0.39
Xcel Energy Colorado	2012	–0.3 (at years 2 and 3)
Orans et al., on BC Hydro inclining-block rate	2014	–0.13 in 3rd year of phased-in rate

Q: WHAT WOULD BE A REASONABLE ESTIMATE OF THE MARGINAL-PRICE ELASTICITY FOR CHANGES IN THE RATE SCHEDULE RES VOLUMETRIC ENERGY RATE?

A: From Table 3, it appears that –0.3 would be a reasonable mid-range estimate of the impact over a few years.

Q: WHAT WOULD BE A REASONABLE ESTIMATE OF THE EFFECT ON ENERGY USE FROM THE COMPANY'S PROPOSAL TO MAINTAIN THE CURRENT RATE FOR THE RESIDENTIAL BCC?

A: As discussed above, if the residential BCC continued at $14.00, the Rate Schedule RES volumetric energy rate would be about 3% less than it would be if the BCC were set at $9.63. Assuming an elasticity of –0.3, this 3% reduction in the volumetric energy rate would result in an increase in energy consumption of about 0.9% for the average Rate Schedule RES customer. This means that all else equal, Rate Schedule RES load after a few years with a $14.00 BCC is expected to be about 0.9% higher than it would be if the BCC were set at the cost-based rate of $9.63.

For comparison, DEP forecasts that residential energy-efficiency savings in both North and South Carolina will increase each year over the next five years by an amount equivalent to about 0.3% of forecasted annual residential energy sales.[52] Assuming that such savings are spread uniformly across all residential rate classes in the Company's North and South Carolina service territories, the consumption increase from customers on Rate Schedule RES due to the Company's proposal to retain the current $14.00 BCC would undo about three years of energy-efficiency savings.

V. THE PUBLIC STAFF MSM REPORT FAILS TO MAKE THE CASE FOR MINIMUM-SYSTEM CLASSIFICATION METHODS

Q: WHY DID THE PUBLIC STAFF ISSUE ITS REPORT ON THE MINIMUM SYSTEM METHODOLOGY?

A: In its order in the previous rate case for Duke Energy Carolinas, the Commission directed the Public Staff to determine whether continued use of minimum-system approaches is warranted for cost-allocation purposes:

> Just considering the grid modernization programs alone suggests that distribution system cost allocation among customer classes will take on heightened importance in future rate cases. The implications of using a suboptimal methodology or incorrectly applying an otherwise acceptable methodology, could be significant in the future. The Commission concludes that a more focused and explicit evaluation of options for distribution system cost allocation and an assessment of the extent to which any single allocation methodology is being consistently applied by the utilities is warranted. Therefore, the Commission directs the Public Staff to facilitate discussions with the electric utilities to evaluate and document a basis for continued use of minimum system and to identify specific changes and recommendations as appropriate.[53]

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[52] Estimated based on data regarding residential sales and energy efficiency savings for the entire DEP service territory provided in response to NC Justice Center et al. Data Request Item No. 4-1. Attached as Exhibit JFW-8.

[53] North Carolina Utilities Commission, *Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction*, Docket No. E-7, Subs 819, 1110, 1146, and 1152, 87 (June 22, 2018).

Q: DOES THE PUBLIC STAFF MSM REPORT COMPLY WITH THE COMMISSION'S DIRECTIVE TO "DOCUMENT A BASIS FOR CONTNUED USE OF MINIMUM SYSTEM" FOR COST-ALLOCATION PURPOSES?

A: No. In fact, the Public Staff MSM Report offers no specific guidance or recommendations regarding the appropriate approach for classifying distribution costs in a cost of service study. Nor does the report address whether the specific minimum-system methods used by each of the electric utilities are reasonable. Instead, the Public Staff simply states in the report that it "believes" generally that it is reasonable to use the results of a minimum-system approach "for establishing the maximum amount to be recovered in the fixed or basic customer charge" and to use the results a basic customer approach to determine the "minimum amount recovered in the fixed charge."[54]

This general belief notwithstanding, the Public Staff recommends that the Commission "request that NARUC, or some other independent entity, undertake a study of these issues from a national perspective, so as to gain insight from best practices and ideas across the country."[55]

Q: HOW DO YOU RESPOND TO THE PUBLIC STAFF'S RECOMMENDATION FOR A NATIONAL STUDY OF DISTRIBUTION COST CLASSIFICATION BEST PRACTICES?

A: The Regulatory Assistance Project ("RAP") commissioned such a national study and published the results of that study in January of this year. <u>The RAP study concludes that the basic customer method represents best practice with respect to the classification of distribution costs.</u>[56]

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[54] Public Staff MSM Report, 16-17.

[55] *Id.*, 17.

[56] RAP Cost Allocation Manual, 18.

Q: WHAT IS THE BASIS FOR THE PUBLIC STAFF'S BELIEF THAT THE RESULTS OF A MINIMUM-SYSTEM ANALYSIS SHOULD BE USED TO SET THE MAXIMUM AMOUNT TO BE RECOVERED THROUGH THE CUSTOMER CHARGE?

A: The Public Staff's endorsement of minimum-system methods as the basis for designing the customer charge rests on its unsubstantiated belief that there is a minimum portion of the cost for the distribution grid which is incurred regardless of demand.[57] By the Public Staff's logic, these minimum costs are "fixed" – i.e., they do not vary with customer demand – since they are incurred regardless of customer demand. Consequently, Public Staff asserts that recovery of such costs in the volumetric energy rate would give rise to intra-class cross-subsidization.[58]

Q: IS THIS IDEA OF A MINIMUM PORTION OF UTILITY SPENDING ON DISTRIBUTION SYSTEMS A REALISTIC PORTRAYAL OF TYPICAL DISTRIBUTION PLANNING PRACTICE?

A: No. As discussed above in Section II, this notion of a minimum distribution cost which lies at the foundation of minimum-system methods simply does not comport with standard practice for distribution planning and spending. Utilities do not first incur "minimum" distribution-grid costs for the purposes of connecting customers at zero load and then incur additional costs to meet expected demand. Instead, as described in the textbook *Electric Power Distribution System Engineering*, utilities typically size and invest in distribution systems based on an expectation of customer demands on those systems:

[57] Public Staff MSM Report, 8.

[58] *Id.*, 9.

> The objective of distribution system planning is to assure that the growing demand for electricity, in terms of increasing growth rates and high load densities, can be satisfied in an optimum way by additional distribution systems … which are both technically adequate and reasonably economical.[59]
>
> Therefore, distribution system planning starts at the customer level. The demand, type, load factor, and other customer load characteristics dictate the type of distribution system required.[60]
>
> The load growth of the geographical area served by a utility company is the most important factor influencing the expansion of the distribution system.[61]

In other words, the notion that there is a minimum portion of a distribution grid whose costs are incurred regardless of customer demand is unrealistic. The reality is that distribution-grid costs in total are primarily driven by customer demand.

Q: IS THIS NOTION OF A MINIMUM PORTION OF DISTRIBUTION INVESTMENTMENT ANY MORE PLAUSIBLE WHEN APPLIED TO THE COMPANY'S PROPOSED INVESTMENTS IN THE GRID IMPROVEMENT PLAN ("GIP")?

A: No. To the contrary, it makes no sense to apply the minimum-system construct to GIP costs since these investments are in no way intended to simply connect customers to the distribution grid. Instead, as described by Company witness Jay W. Oliver, DEP has purportedly designed the Grid Improvement Plan to more reliably, intelligently, and economically serve load in the 21st century.[62]

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[59] Turan Gonen, *Electric Power Distribution System Engineering*, McGraw-Hill, Inc., 3-4 (1986).

[60] *Id.*, 4.

[61] *Id.*, 5.

[62] *Direct Testimony of Jay W. Oliver for Duke Energy Progress, LLC*, Docket No. E-2, Sub 1219, 9 (October 23, 2019).

Q: SHOULD ALL GIP COSTS INSTEAD BE ALLOCATED ON THE BASIS OF CLASS PEAK DEMAND?

A: Not necessarily. According to Mr. Oliver, the primary driver of the Company's discretionary investments in the Grid Improvement Plan is the expected economic benefits from such investments.[63] Thus, from a cost-causation perspective, these discretionary investments are "caused" by, and therefore appropriately allocated in proportion to, the expected benefits from such investments.

The Maryland Public Service Commission came to just such a conclusion with respect to Baltimore Gas and Electric's proposed allocation of its discretionary "Smart Grid Initiative" costs:

> [Maryland Office of People's Counsel] notes, and we agree, that <u>contrary to cost-causation principles</u>, the [embedded cost of service study] does not allocate Smart Grid Initiative costs to customer classes commensurate with the allocation of Smart Grid benefits to those classes.[64]

On that basis, the Maryland commission committed to considering a benefits-based approach for allocating smart grid investments in future rate cases.[65] I urge the Commission to likewise consider the merits of a benefits-based approach to allocating the Company's discretionary GIP costs to the extent those costs are authorized.

[63] *Id.*, 12.

[64] Maryland Public Service Commission, Order No. 87591, Case No. 9406, 187 (June 3, 2016) [emphasis added].

[65] *Id.*, 184.

Q: DOES THE PUBLIC STAFF LOOK TO THE NATIONAL ASSOCIATION OF REGULATORY UTILITY COMMISSIONERS' ("NARUC") *ELECTRIC UTILITY COST ALLOCATION MANUAL* FOR SUPPORT OF ITS ENDORSEMENT OF MINIMUM-SYSTEM METHODS?

A: Yes. Noting that NARUC's Electric Utility Cost Allocation Manual ("NARUC Manual") "continues to be considered an important resource for the calculation and allocation of electric utility cost of service," the Public Staff MSM Report highlights the fact that the NARUC Manual describes only minimum-system methods and not the basic customer method as possible approaches for classifying distribution-grid costs.

Q: IS IT TRUE THAT THE NARUC MANUAL DOES NOT INCLUDE THE BASIC CUSTOMER METHOD AS A POSSIBLE APPROACH FOR CLASSIFYING DISTRIBUTION PLANT COSTS?

A: No. The Public Staff is incorrect in its claim that the basic customer classification method is not included in the NARUC manual. To the contrary, the NARUC Manual describes the basic customer method as a classification option in the discussion of marginal cost of service studies:

> A number of analysts have argued, and commissions have accepted, that the customer component of the distribution system should only include those features of the secondary distribution system located on the customer's own property. Portions of the distribution system that serve more than one customer cannot be avoided should one customer cancel service. Similarly, if the customer component of the marginal distribution cost is described as the cost of adding a customer, but no energy flows to the system, there is no reason to add to the distribution lines that serve customers collectively or to increase the optimal investment in the lines that are carrying the combined load of all customers. Therefore, the marginal customer cost of the jointly used distribution system is zero.[66]

[66] National Association of Regulatory Utility Commissioners, *Electric Utility Cost Allocation Manual*, 136 (January, 1992).

Moreover, according to a 1992 letter from the Washington Utilities and Transportation Commission ("WUTC") to the chair of the NARUC task force responsible for drafting the NARUC Manual, earlier drafts of the manual included a discussion of the basic customer method in the chapter on embedded cost of service studies.[67] This discussion was inexplicably removed from the chapter on embedded cost of service studies before final publication.

Q: DOES THE FACT THAT THE BASIC CUSTOMER METHOD WAS NOT DISCUSSED IN THE CHAPTER ON EMBDEDDED COST OF SERVICE STUDIES INDICATE THAT THIS METHOD WAS NOT WIDELY USED AT THAT TIME?

A: No. Despite the short shrift given to the basic customer method in the NARUC Manual, the fact is that the use of this classification method was long-established and widespread at that time. According to the 1992 letter from the WUTC:

> Our Commission has been extremely clear about one thing in this area: that the "minimum-distribution" [i.e., minimum-size] and "minimum-intercept" methods are not acceptable, and that the <u>only</u> costs which should be considered customer-related are the costs of meters, services, meter reading and billing. Our staff believes that is the most common approach taken by Commissions around the country.[68]

Indeed, as discussed above in Section II, the Company or its predecessor was using the basic customer method in South Carolina before the NARUC Manual was published and continued to rely on this classification method for more than two decades thereafter. And despite the fact that the chapter on embedded cost of service studies does not discuss the basic customer method, the

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[67] I attach a copy of this letter as Exhibit JFW-9.

[68] Exhibit JFW-9. Emphasis in original.

Company's affiliate in Indiana chose to adopt this classification method two years after publication of the NARUC Manual.

Q: DO YOU HAVE ANY OTHER COMMENTS REGARDING THE PUBLIC STAFF MSM REPORT?

A: Yes. The Public Staff contends in its report that costs classified as demand-related in a cost of service study should be recovered through demand charges.[69] The Public Staff furthermore recommends that electric utilities "utilize data gained from AMI meters to implement … demand charges for all rate classes."[70]

The Commission should reject any such recommendation for the residential rate classes. Residential rates designed to formulaically reflect cost classifications in a cost of service study would neither reflect cost causation nor provide appropriate price signals. In particular, recovery of demand-related costs through a residential demand charge would dampen price signals for conservation, promote inefficient customer behavior, and undermine customers' ability to control electricity costs.

Q: WHY WOULD A RESIDENTIAL DEMAND CHARGE DAMPEN PRICE SIGNALS FOR CONSERVATION, PROMOTE INEFFICIENT CUSTOMER BEHAVIOR, AND UNDERMINE CUSTOMERS' ABILITY TO CONTROL ELECTRICITY COSTS?

A: Demand charges on a monthly bill are typically determined based on the customer's maximum demand, whenever that maximum occurs during the month. In order to control monthly demand costs, customers would therefore need to have detailed information regarding their load profiles for each day of the month as well as an in-depth understanding of which combination of appliance- or

[69] Public Staff MSM Report, 8.

[70] *Id.*, 17.

equipment-usage gives rise to monthly maximum demands. Even with such information and knowledge, it would be difficult for a residential customer to reduce demand charges, since even a single failure to control load during the month would result in the same demand charge as if the customer had not attempted to control load at all.

A demand charge would also provide little or no incentive for residential customers to take actions that reduce distribution-system costs. As discussed above in Section II, distribution equipment costs typically are driven by the diversified peak load for all customers sharing the equipment. An individual customer is unlikely to reach her maximum demand at the same time as when the diversified peak on the distribution system occurs. Thus, a demand charge would provide an incentive to a residential customer to control load at the time that customer reaches her individual maximum demand, which does not necessarily correspond to the time of peak load on the distribution system. In fact, some customers might respond to a demand charge by shifting loads from their own peak to the peak hour on the local distribution system, thereby increasing their contribution to maximum or critical loads on the local distribution system and further stressing the system during peak periods.

Finally, shifting recovery of demand-related costs from the energy rate to a demand charge would send the wrong energy price signal. Shifting demand-related costs to a demand charge would lower the energy rate and thereby perversely encourage increased energy consumption, some of which might occur at times of peak load on the distribution system – when energy conservation is most needed. Shifting costs from the energy rate to a demand charge could therefore increase distribution system costs and offset any (limited) benefits from a residential demand charge.

Severin Borenstein aptly summed up the shortcomings (and the antiquated nature) of demand charges when he wrote: "It is unclear why demand charges still exist."[71]

Q: WHAT DO YOU CONCLUDE FROM YOUR REVIEW OF THE PUBLIC STAFF MSM REPORT?

A: The Commission should give no weight to the Public Staff's endorsement of minimum-system classification methods since that endorsement rests on the Public Staff's unsubstantiated belief that there is a minimum portion of the cost for the distribution grid which is incurred regardless of demand. This notion of a minimum distribution cost is an unrealistic hypothetical construct which does not comport with standard practice for distribution planning and spending.

The reality is that distribution-grid costs are primarily driven by customer demand. And it is the basic customer classification method, not minimum-system methods, which classifies distribution-grid costs consistent with this reality. In other words, the basic customer method represents best practice for classifying distribution costs.

It is long past time for North Carolina's electric utilities to discard this false notion that there is a minimum portion of distribution-grid costs. It is also past time to stop treating a 1992 NARUC Manual as the final, cast-in-stone word on distribution cost classification, and to finally acknowledge that the NARUC Manual does not accurately portray best practice at the time of its publication or represent best practice for classifying distribution spending by electric utilities today.

[71] Severin Borenstein, "The Economics of Fixed Cost Recovery by Utilities," in *Recovery of Utility Fixed Costs: Utility, Consumer, Environmental and Economist Perspectives*, Lawrence Berkeley National Laboratory, 60 (2016). Available at http://eta-publications.lbl.gov/sites/default/files/lbnl-1005742.pdf.

VI. RECOMMENDATIONS

Q: WHAT DO YOU RECOMMEND TO THE COMMISSION?

A: I recommend that the Commission:

- Reject the Company's use of a minimum-system analysis to classify distribution plant costs in its COSS and instead direct DEP to classify such costs using the basic customer classification method.
- Reject the Company's use of the NCP allocator to allocate demand-related distribution plant costs in its COSS and instead direct DEP to allocate such costs based on class diversified peak demand.
- Increase base revenues for the residential rate classes by no more than the overall system-average percentage increase authorized by the Commission, if any.
- Deny the Company's request to maintain the residential BCC at its current rate of $14.00 per bill and instead direct DEP to reduce the rate to $9.63 per bill.
- Investigate whether discretionary GIP costs, to the extent authorized, should be allocated to rate classes in the Company's COSS commensurate with the benefits to those classes from GIP spending.

Q: DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A: Yes.

MR. NEAL: Thank you.

COMMISSIONER CLODFELTER: Mr. Neal, I don't remember right now whether you had any testimony being carried over. I do not believe you do by stipulation, correct?

MR. NEAL: No, sir. I think that covers us. Thank you.

COMMISSIONER CLODFELTER: That's consistent with my notes, then. All right. Let's take our afternoon break, and we will come back and resume with Mr. Smith and Mr. Barnes at 3:15.

(At this time, a recess was taken from 2:59 p.m. to 3:15 p.m.)

CHAIR MITCHELL: Let's resume, and the case is now with NCSEA. Mr. Smith?

MR. SMITH: Good afternoon, Commission. Commission Clodfelter, NCSEA calls Mr. Justin Barnes to the stand.

COMMISSIONER CLODFELTER: All right. Mr. Barnes, I see you there.

Whereupon,

JUSTIN R. BARNES,

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

COMMISSIONER CLODFELTER: Thank you.

Mr. Smith, it's all yours.

MR. SMITH: Thank you.

DIRECT EXAMINATION BY MR. SMITH:

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

A. My name is Justin R. Barnes. My business address is 1155 Kildaire Farm Road, Suite 202, Cary, North Carolina.

Q. Thank you. And on whose behalf are you testifying?

A. I'm testifying on behalf of the North Carolina Sustainable Energy Association.

Q. Thank you. And did you cause to be prefiled in this docket on April 13, 2020, direct testimony consisting of 47 pages and nine exhibits?

A. I did.

Q. And if I were to ask you the same questions today, would your answers be the same as given in your testimony as corrected?

A. Yes, they would.

Q. Mr. Barnes, did you prepare a summary of your testimony that was filed with the Commission?

A. Yes, I did.

Q. Thank you.

MR. SMITH: Commissioner Clodfelter, at this time, I'd move that the prefiled testimony of Mr. Barnes and his summary be copied into the record as if given orally from the stand.

COMMISSIONER CLODFELTER: All right. You have the motion. Unless there is objection, it will be so ordered.

(Barnes Exhibits 1 through 9 were identified as they were marked when prefiled.)

(Whereupon, the prefiled direct testimony and testimony summary of Justin R. Barnes was copied into the record as if given orally from the stand.)

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I. INTRODUCTION

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

A. My names is Justin R. Barnes. My business address is 1155 Kildaire Farm Rd., Suite 202, Cary, North Carolina, 27511. My current position is Director of Research with EQ Research LLC.

Q. ON WHOSE BEHALF ARE YOU SUBMITTING TESTIMONY?

A. I am submitting testimony on behalf of the North Carolina Sustainable Energy Association ("NCSEA").

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY BEFORE THE NORTH CAROLINA UTILITIES COMMISSION ("THE COMMISSION")?

A. Yes. I submitted testimony on behalf of NCSEA in Docket No. E-7, Sub 1146 on the Duke Energy Carolinas, LLC's ("DEC") 2017 general rate case application, in Docket No. E-2, Sub 1142 on the Duke Energy Progress, LLC's ("DEP" or "the Company") 2017 general rate case application, and in Docket No. E-7, Sub 1214 on the DEC 2019 general rate case application.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND OCCUPATIONAL BACKGROUND.

A. I obtained a Bachelor of Science in Geography from the University of Oklahoma in Norman in 2003 and a Master of Science in Environmental Policy from Michigan Technological University in 2006. I was employed at the North Carolina Solar

Center at N.C. State University for more than five years as a Policy Analyst and Senior Policy Analyst.[1] During that time I worked on the *Database of State Incentives for Renewables and Efficiency ("DSIRE")* project, and several other projects related to state renewable energy and energy efficiency policy. I joined EQ Research in 2013 as a Senior Analyst and became the Director of Research in 2015. In my current position, I coordinate and contribute to EQ Research's various research projects for clients, assist in the oversight of EQ Research's electric industry regulatory and general rate case tracking services, and perform customized research and analysis to fulfill client requests.

Q. PLEASE SUMMARIZE YOUR RELEVANT EXPERIENCE AS RELATES TO THIS PROCEEDING.

A. My professional career has been spent researching and analyzing numerous aspects of federal and state energy policy, spanning more than a decade. Throughout that time, I have reviewed and evaluated trends in regulatory policy, including trends in rate design and utility regulation. For example, as part of my current duties overseeing EQ Research's general rate case tracking and regulatory tracking services, I have reviewed dozens of utility rate design proposals and the associated regulatory determinations.

I have submitted testimony before utility regulatory commissions in Colorado, Hawaii, Georgia, New Hampshire, New York, Oklahoma, South Carolina, Texas, Utah, and Virginia as well as to the City Council of New Orleans,

[1] The North Carolina Solar Center is now known as the North Carolina Clean Energy Technology Center.

on various issues related to clean energy policy, rate design, and cost of service.[2] These individual regulatory proceedings have involved a mix of general rate cases and other types of contested cases. My *curriculum vitae* is attached as **Exhibit JRB-1**. It contains a full list of proceedings where I have submitted testimony and related information such as docket numbers and the subject matter addressed.

Q. PLEASE DESCRIBE THE PURPOSE OF YOUR TESTIMONY AND HOW IT IS ORGANIZED.

A. The purpose of my testimony is to propose that the Commission direct DEP to establish electric vehicle ("EV") specific rates for both home charging and commercial charging applications. I use the term "EV-specific rates" throughout my testimony to refer to rate options that apply to separately metered EV charging loads to the exclusion of any other loads on the premises. In Section II of my testimony, I discuss in general why EV rates hold benefits for DEP's ratepayers as a whole and general principles for their design. In Section III, I describe the shortcomings in current residential rate options for EV charging and make my residential EV rate proposal. In Section IV, I discuss and make recommendations for non-residential EV rate options. Section V contains my concluding remarks.

Q. WHAT ARE YOUR RECOMMENDATIONS TO THE COMMISSION?

A. First, I recommend that the Commission direct DEP to, within 60 days of a final order, file separate, targeted EV-specific tariffs for both residential and non-

[2] The City Council of New Orleans regulates the rates and operations of Entergy New Orleans in a manner equivalent to state utility regulatory commissions.

residential dedicated EV charging. These tariffs should reflect core characteristics that are consistent with effective EV rates that I discuss in my testimony. The Commission should allow a comment period on these tariffs but generally seek to expedite their approval and deployment as soon as possible.

Second, I recommend that the Commission establish an investigatory docket to receive further information and permit further discussion of EV-specific rates, lessons learned, and potential refinements. DEP should be directed to file quarterly reports updating the Commission and parties on deployment status, tariff enrollment, ratepayer savings, system cost savings, and any other information that the Commission deems relevant to support evaluation of the tariffs and their future evolution. If the Commission adopts the recommendation for a comprehensive rate design study made by Public Staff Witness Floyd in DEC's pending rate case, the investigatory docket could become part of this larger review.

Finally, I recommend that any rates established pursuant to a Commission decision remain available, at a minimum, until any successors or replacements are adopted pursuant to the system of Commission review that I recommend. As reflected in my recommendations for non-residential EV-specific rate characteristics, the duration should also reflect the certainty needed for ratepayers that make large investments in higher powered charging equipment such as Direct Current Fast Chargers ("DCFCs").

Q. WHAT IS YOUR RECOMMENDATION FOR THE ESTABLISHMENT OF A RESIDENTIAL EV-SPECIFIC RATE?

A. I recommend that existing Schedule R-TOU be made available for submetered home EV charging with a modest submetering charge in place of the tariffed Basic Facilities Charge ("BFC"). The amount of the submetering charge should consider the incremental costs of the additional metering as well as the impact that the charge would have on cost savings for the EV owner in order to ensure that the additional cost of taking submetered service does not create a barrier to enrollment.

With the exception of not being available for submetered use, Schedule R-TOU already contains several characteristics that are supportive of home EV charging, as follows:

1. Three pricing periods and short duration on-peak periods;
2. A price differential between the off-peak rate and the otherwise applicable flat rate that should be sufficient to produce meaningful bill savings for EV charging, taking into account a modest incremental metering charge and a typical amount of home EV charging; and
3. An off-peak pricing period with a duration of at least eight hours that allows ample time for low voltage charging to produce a battery charge sufficient for a reasonable length trip or commute.

Q. WHAT IS YOUR RECOMMENDATION FOR THE ESTABLISHMENT OF A NON-RESIDENTIAL EV-SPECIFIC RATE?

A. I recommend that a rate or rates for submetered and standalone EV charging be established for non-residential ratepayers under a design that features time variation and mitigates the outsized effects that demand charges have on charging costs. More specifically, the rate or rates should:

1. Address the issues presented by demand rates for non-residential EV charging installations by doing one or both of the following: (a) modifying Schedule SGS-TOUE to permit submetering for EV loads and eliminating or relaxing the maximum demand-based availability limitations currently contained in Schedule SGS-TOUE for EV load, or (b) applying a demand charge limit to Schedules SGS-TOU and LGS-TOU that caps demand charges at an implied maximum volumetric rate, or alternatively, a percentage of the ratepayer's monthly bill;
2. Use the otherwise applicable BFC for standalone charging stations and a submetering charge in place of the BFC for charging units located behind an existing meter; and
3. Remain available to participants for ten years from the date of their enrollment in order to provide a reasonable level of investment certainty to prospective equipment owners.

My testimony also discusses two other options for mitigating the punitive effects that demand rates can have on high voltage EV charging equipment owners:

(a) allowing multiple meters serving EV load to be aggregated for the purpose of determining demand charges, and (b) basing demand charges on the sum of daily maximum demand rather than monthly maximum demand. Due to the relatively more novel nature and additional complexity of these options I do not recommend that they be adopted at this time. However, the Commission should consider both as longer-term options as it pursues future refinements.

Q. PLEASE EXPLAIN THE PRACTICE OF SUBMETERING AS REFERRED TO IN YOUR RECOMMENDATIONS.

A. The measurement of EV load as separate from other load located on the same premises can be accomplished with an additional dedicated electricity meter or with a submeter installed between the existing meter and the EV charger. Submetering can be less costly than the installation of a separate revenue grade meter and associated equipment (e.g., a new meter socket, conduit, etc.). The relatively lower costs mitigate the potential for incremental metering costs to become a barrier to enrollment in the rate.

II. RATIONALE AND JUSTIFICATION FOR EV-SPECIFIC RATES

Q. PLEASE EXPLAIN THE DIFFERENCE BETWEEN AN "EV RATE" AND AN "EV-SPECIFIC RATE" AS YOU USE THE TERMS IN YOUR TESTIMONY.

A. EV-specific rates are a sub-genre of EV rates. As I use the term, an EV rate refers to any rate that is applicable only to ratepayers with an EV charging load. An EV-specific rate refers to a rate that is applied exclusively to EV charging load as opposed to any other electric load that exists on a premises. An EV-specific rate requires the EV load to be separately measured. Both types of rates may have a place in supporting transportation electrification, but EV-specific rates have the potential to be more targeted so as to take advantage of the unique usage patterns and flexibility that characterize EV loads relative to whole home or building loads.

Q. PLEASE ELABORATE ON THE MERITS OF EV-SPECIFIC RATES RELATIVE TO EV RATES AND THE IDEA OF "TARGETING" WITHIN EV-SPECIFIC RATES.

A. The merits of EV-specific rates and targeting are best illustrated by examples. For instance, a declining block whole home rate that is available only for ratepayers with an EV qualifies as an EV rate and could potentially reduce costs for EV owners and support EV adoption. However, it would not take advantage of ratepayers' ability to manage their charging behavior in a manner that reflects the time-varying costs of electric service.

Furthermore, within the definition I use for an EV-specific rate is a further sub-genre of rates that are *specifically designed* to take *full* advantage of the unique attributes of EV load (i.e., targeted EV-specific rates). For instance, a generally available time-varying rate that can be used for submetered EV load is an EV-specific rate. However, such a rate may display characteristics such as simplified peak and off-peak windows and/or minimal rate spreads that reflect the challenges of managing whole home or whole building use. This fails to take advantage of relatively greater flexibility and controllability of home EV charging relative to other loads. Alternatively, a non-residential rate adapted for EV submetering may still reflect a pass-through of more generally deployed rate designs such as demand-based charges in a way that creates barriers for EV charging.

Q. WHY WOULD THE DEPLOYMENT OF EV RATES BE BENEFICIAL TO THE STATE OF NORTH CAROLINA AND DEP RATEPAYERS?

A. There are several reasons. First, well-designed EV rates encourage EV owners to charge their vehicles during off-peak times. Off-peak charging helps mitigate the potential that growing EV load could exacerbate peak demands and create additional costs, and in doing so can improve system load factor. Second, EV-specific rates could potentially be used to help mitigate "duck curve" issues that can arise due to the combination of low loads and high solar generation during some parts of the year. This can play a role in avoiding renewables curtailment and more generally concentrating load at times of low marginal greenhouse gas emissions.

Well-designed EV rates also produce cost savings for EV owners relative to what they might otherwise pay under a standard rate. Cost savings are directly beneficial to EV owners and could also be seen as a generally fairer outcome under circumstances where a large portion of EV charging is expected to occur during off-peak hours anyway due to EV owners' work and personal schedules. Finally, potential cost savings are an important consideration for ratepayers considering purchasing an EV or installing charging equipment. The development of greater charging accessibility is a critical element in transportation electrification. In turn, EV rates are an important element in increasing the availability of cost-effective charging options in homes, and perhaps even more importantly, in public settings.

Ultimately, strategic use of rate structure can be a more scalable support mechanism for EV deployment than "programmatic" solutions, which tend to be inherently limited in size. Programmatic solutions certainly still have a place in transportation electrification, such as targeting specific sectors or barriers. Rate structure, on the other hand, is a critical tool for transforming the broader market.

Q. HOW DOES NORTH CAROLINA POLICY ADDRESS TRANSPORTATION ELECTRIFICATION?

A. North Carolina has not established any statutory mandates or guidance on transportation electrification. However, the North Carolina Clean Energy Plan stemming from Executive Order 80 (2018) ("EO 80") recommends that utilities be required to develop innovative rate design pilots for EVs to encourage off-peak charging and test the effectiveness of different rate structures at shifting energy usage.[3] EO 80 itself sets a goal of achieving 80,000 registered zero-emission vehicles in the state by 2025.[4]

Q. IS IT NECESSARY FOR THE COMPANY TO CONDUCT FURTHER STUDY OF CHARGING BEHAVIOR BEFORE DEPLOYING EV-SPECIFIC RATES?

A. No. The charging behavior of EV owners under a generally applicable pricing regime would not be representative of their charging behavior under a well-designed EV rate. If one makes the reasonable assumption that EV charging will in the future take place principally, or even entirely, under time-varying rate designs, an analysis of EV charging under traditional rates that are not designed for EV charging is not predictive of the long-term impacts of EV charging.

Q. WOULD IT MAKE SENSE TO DELAY ADOPTING EV RATES IN ORDER TO STUDY EV CHARGING BEHAVIOR UNDER TRADITIONAL RATES?

No, delaying analysis of charging behavior under rates designed specifically for EV charging while studying charging behavior under traditional rates would only delay the results of a comparative analysis. There is no reason why both sets of evaluations could not be undertaken concurrently if the goal is to reach conclusions on the effects that rate design has on EV charging behavior.

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[3] North Carolina Clean Energy Plan. October 2019. p. 137. Available at: https://files.nc.gov/governor/documents/files/NC_Clean_Energy_Plan_OCT_2019_.pdf

[4] N.C. Exec. Order No. 80 (October 29, 2018), https://files.nc.gov/governor/documents/files/EO80-%20NC%27s%20Commitment%20to%20Address%20Climate%20Change%20%26%20Transition%20to%20a%20Clean%20Energy%20Economy.pdf.

Q. IN DOCKET NO. E-7, SUB 1214, DEC'S GENERAL RATE CASE, PUBLIC STAFF WITNESS FLOYD RECOMMENDED THAT THE COMMISSION ORDER A COMPREHENSIVE RATE DESIGN STUDY TO ADDRESS MANY RATE MODERNIZATION ISSUES, INCLUDING EV RATES. DO YOU AGREE WITH THIS RECOMMENDATION IN THE CONTEXT OF EV RATE DEPLOYMENT IN DEP'S SERVICE TERRITORY?

A. I agree with Witness Floyd that a comprehensive rate design study would be worthwhile, and also that it would be a "lengthy undertaking" that "takes a significant amount of time to develop, as well as to implement."[5] While it is not clear to me what sort of timeline Witness Floyd envisions for the deployment of new rate options, I do not think that conducting a lengthy, all-encompassing study is necessary or advisable prior to making EV-specific rates available in some form. To the extent that Witness Floyd's recommendation would result in such a delay, I respectfully disagree with that aspect.

Q. PLEASE ELABORATE ON WHY AN EXTENDED STUDY PERIOD IS NOT NECESSARY OR ADVISABLE AS A PRECURSOR TO EV RATE DEPLOYMENT.

A. My concern is that such a study and associated stakeholder processes could easily extend several years. By that point, North Carolina is likely to be well behind the curve with respect to EV rate and infrastructure deployment, to the detriment of the

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[5] *Testimony of Jack L. Floyd on Behalf of the Public Staff – North Carolina Utilities Commission*, p. 24, ll. 9-18, Docket No. E-7, Sub 1214 (February 18, 2020).

potential near-term benefits to ratepayers and achieving the EO 80 goal of 80,000 zero-emission vehicles by 2025.

In addition, while an extended study process is appropriate for considering an overarching re-design of DEP's and DEC's respective rates, it is not necessary for the deployment of EV-specific rates because the shortcomings of current rate options are very basic and do not raise the same issues as a broader re-design of rates. For home charging, the basic problem is that customers do not have access to a time-varying rate option that does not require them to take whole home time-varying service. For non-residential charging, the basic problem is the outsized impacts that demand charges have on the cost of EV charging, in particular DCFC. Both issues can be mitigated in the near term through relatively simple changes. I discuss these issues and my recommended near-term solutions in more detail in subsequent sections of my testimony.

Finally, a broader re-design of rates that is undertaken to establish durable solutions would benefit from the information gleaned from the deployment of EV-specific rates in the near term. As I observed previously, at present we lack data on EV charging behavior under EV-specific rates in DEP's (and DEC's) service territories. While considerable insight can be gleaned from evaluating the results of studies performed in other jurisdictions, more recent and more targeted data certainly would not hurt for the purpose of refining EV rate options.

Q. HOW SHOULD THE COMMISSION VIEW REVENUE AND COST IMPACTS AND THE POSSIBILITY FOR CROSS-SUBSIDIES TO OCCUR?

A. The averaging nature of rates ensures that intra-class subsidies will exist within any rate. Under averaged rates, no ratepayer pays their exact cost of service, even if that amount could be determined with precision. The same is true for inter-class cost of service relationships. Furthermore, when designing rates that target a specific type of new load and seek to direct ratepayer behavior, it is unavoidable that mismatches will occur between costs and revenue and the distribution of both among ratepayers as a whole.

While such issues bear attention, the magnitude of EV load at present and in the near future is small relative to other loads. As a consequence, the scale of any mismatches that do exist is bound to be small as well. In any case, it is not possible to know how costs and revenue align without the information gleaned from deployment and evaluation of EV rates. Class averages that might be applied to make a whole-site load rate theoretically revenue neutral cannot be applied to new EV load. In addition, as I previously observed, charging behavior under traditional rates is not an accurate predictor of charging behavior under an EV rate. Ultimately, revenue and cost distribution uncertainties are unavoidable, and they should not function as a pretext for delaying the deployment of EV-specific rates. Allowing them to do so amounts to creating a Catch-22 where assembling the information on which to base future decisions is prevented by a failure to establish means by which the information can be gathered.

Q. GIVEN THESE UNCERTAINTIES, HOW SHOULD THE COMMISSION ATTEMPT TO ENSURE THAT EV-SPECIFIC RATES ARE LIKELY TO BENEFIT RATEPAYERS AS A WHOLE?

A. The design of EV-specific rates should have a solid foundation in time-varying marginal costs in recognition of the fact that new EV load, if well-managed, need not contribute to additional costs driven by peak demands. It is my understanding that DEP does not study the marginal costs of transmission and distribution. However, the pricing periods in existing rates, and in Schedule PP,[6] reflect the time-varying nature of energy and capacity costs and can serve as a guide for defining higher cost and lower cost time periods. For instance, transmission costs are driven by the same system-wide peak demands as generation capacity costs, even if a marginal transmission cost is not studied itself. As long as the pricing periods for an EV-specific rate are generally aligned with established pricing periods, they should be aligned with the additional costs of EV charging at different times. From the standpoint of new load, as long as the rate a ratepayer pays is at or above the marginal cost, other ratepayers are indifferent or accrue benefits.

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[6] Schedule PP contains time-varying rates for the purchase of energy and capacity from small power production facilities. Those pricing periods have been updated more recently than the pricing periods used for existing time-varying retail rates.

III. RESIDENTIAL EV RATE OPTION

Q. WHY ARE EV-SPECIFIC RATES IMPORTANT FOR RESIDENTIAL RATEPAYERS?

A. Viable home charging options are important for residential EV owners because the vast majority of residential EV charging occurs at home. A 2015 study by the Idaho National Laboratory examined the charging habits of Americans, and found that a typical driver charges their EV at home 84-87% of the time.[7] While it is plausible, and even likely, that the availability of public or workplace charging options could diminish the amount of home charging, it is difficult to envision any near-term scenario where home charging does not comprise a large portion of residential EV charging. Home charging is simply highly convenient and likely to remain so.

Q. DOES DEP CURRENTLY OFFER AN EV-SPECIFIC CHARGING RATE FOR RESIDENTIAL RATEPAYERS?

A. No.

Q. IS DEP PROPOSING AN EV-SPECIFIC CHARGING RATE FOR RESIDENTIAL RATEPAYERS IN THIS RATE CASE?

A. No.

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[7] Idaho National Laboratory, "Plugged In: How Americans Charge Their Electric Vehicles," 2015. Available at: https://avt.inl.gov/sites/default/files/pdf/arra/PluggedInSummaryReport.pdf.

Q. IS DEP PROPOSING AN EV-SPECIFIC CHARGING RATE FOR RESIDENTIAL RATEPAYERS IN ANY OTHER FORUM?

A. No. DEP's transportation electrification proposal includes proposed tariffs for each EV pilot program, but it does not propose new residential rate designs for EV charging as a component of these tariffs. For example, the Residential EV Charging Program tariff would provide certain incentives for residential Level 2 EV charging, but usage would still be "billed under the applicable residential schedule." These tariffs would also be limited to the size and duration of the EV pilot programs.[8]

Q. WHAT RATE OPTIONS ARE CURRENTLY AVAILABLE FOR A PROSPECTIVE RESIDENTIAL EV OWNER?

A. DEP's residential ratepayers can choose from several rate schedules. The generally-available rate options and their basic rate designs are as follows:

- Schedule RES – Includes a monthly BFC and flat seasonal energy charges with a slightly lower rate during winter months.
- Schedule R-TOU – Includes a monthly BFC and seasonal time-varying energy charges under a three-period design (on-peak, shoulder, and off-peak), with fairly sizable rate spreads between rates for each pricing period.

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[8] *Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Application for Approval of Proposed Electric Transportation Pilot*, Docket Nos. E-2, Sub 1197 and E-7, Sub 1195 (March 29, 2019).

- Schedule R-TOUD – Includes a monthly BFC, seasonal on-peak demand rates, and time-varying energy charges with a modest rate spread between peak and off-peak rates under a two-pricing period design (on-peak and off-peak).

Q. WHAT FACTORS ARE IMPORTANT FOR DESIGNING EV-SPECIFIC RATES THAT ENCOURAGE RESIDENTIAL ENROLLMENT?

A. Both the price differential between peak and off-peak rates, as well as the duration of off-peak period windows are important for encouraging residential EV owner enrollment. The price differential refers to the difference between the applicable rate for off-peak usage compared to the applicable rate for on-peak usage, and can also be expressed as a ratio. The price differential or ratio needs to be sufficiently large to result in meaningful changes in ratepayer charging behavior. The larger the price differential, the more the ratepayer is incentivized to conduct EV charging during off-peak periods and avoid charging during on-peak periods.

A 2018 presentation from the Brattle Group summarizing residential EV rate options from U.S. utilities indicates the median summer season price ratio is greater than 3:1 and the median winter season price ratio is well above 2:1, with larger average price ratios for three-period TOU rates compared to two-period TOU rates. When comparing the peak rate to the lowest available off-peak rate, the median price differential for the summer season is $0.17/kWh for two-period TOU rates and $0.28/kWh for three-period TOU rates. Price differentials are lower during the winter season, averaging $0.09/kWh and $0.12/kWh for two-period and three-or-more-period TOU rates.[9] A more recent report from the Smart Electric Power Alliance ("SEPA") shows a median differential ratio of 3.6:1 and a median price differential of $0.20/kWh.[10]

The duration of the peak and off-peak windows is also important because EV owners must have an off-peak charging window that is long enough achieve a sufficient charge for commutes or normal daily driving. A common rate design for residential EV-specific rates is to incorporate an off-peak window that allows EV charging to occur overnight, allowing residential EV owners to charge their vehicle in advance of a morning commute. Nearly all residential EV rates use an off-peak charging window of at least six hours. The median off-peak window for residential EV-specific rates is 8 hours for both the summer and winter seasons, although some rates have off-peak periods for up to 16 hours.[11]

The charging duration necessary for an individual EV owner depends on the ratepayer's driving needs, charging equipment, and access to charging outside of the home. Table 1 shows the broad characteristics of different types of EV charging equipment.

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[9] Ahmad Faruqui, Ryan Hledik, and John Higham. "The State of Electric Vehicle Home Charging Rates." October 15, 2018. Attached as **Exhibit JRB-2**.
[10] SEPA. "Residential Electric Vehicle Rates that Work." November 2019. Attached as **Exhibit JRB-3**.
[11] **Exhibit JRB-2**. The rates used to develop these statistics appear to include a significant percentage of rates that apply to the entire residence. The survey includes 31 unique rate offerings, 18 of which are whole home rates, 8 of which are exclusively for EV charging, and 5 of which can be used either on a whole home or EV-specific basis.

Table 1: Types of EV Chargers[12]

Type	Voltage (V)	Capacity (kW)	Minutes to Supply 80 Miles of Range
Level 1	120 V	1.4 - 1.9	630 - 860
Level 2	240 V	3.4 - 20	60 - 350
Level 3 (DCFC)	480 V	50 - 400	3 - 24

The added charging speed associated with Level 2 charging comes at a cost in terms of the price of the charging equipment, and any possible electric upgrades necessary to accommodate the additional load. The price differential is critical for producing ratepayer savings that can help offset incremental EV costs and the costs of higher capacity charging equipment.

Q. WHAT ARE THE MERITS OF A RATE DESIGN WITH THREE PRICING PERIODS RELATIVE TO ONE WITH ONLY TWO PRICING PERIODS?

A. Greater granularity of pricing periods provides a more accurate reflection of the time-varying nature of the cost of electric service. In particular, a three-period rate design typically enables shorter duration peak periods that correspond to hours of particularly high demand. The relative flexibility and controllability of EV loads lends itself to a more complex rate design than what might be attractive to customers if applied to whole home or whole building loads.

In the context of EV charging, shorter duration peak periods help avoid circumstances where a small amount of non-off-peak charging produces an

[12] Garrett Fitzgerald and Chris Nelder. "From Gas to Grid: Building Charging Infrastructure to Power Electric Vehicle Demand." Rocky Mountain Institute, 2017. p. 33. Available at: https://rmi.org/wp-content/uploads/2017/10/RMI-From-Gas-To-Grid.pdf. Attached as **Exhibit JRB-4**.

incremental cost increase that offsets the cost savings of a much larger amount of off-peak charging. This phenomenon is highly pronounced for rates with a demand component, but can also be present under fully volumetric rates if the difference between an otherwise applicable flat rate and the on-peak rate is significantly larger than the difference between the flat rate and the off-peak rate. A shorter duration peak period makes it easier to avoid peak charges even if an EV owner occasionally needs to charge a vehicle during non-off-peak hours (*e.g.,* during the daytime). A mid-peak or shoulder rate applicable to periods of intermediate demand can send a moderated price signal that avoids significantly rewarding or penalizing charging that takes place during medium demand periods.[13]

Q. IS IT IDEAL FOR RATEPAYERS WITH EVS TO CHARGE THEIR VEHICLES ONLY DURING OFF-PEAK PERIODS?

A. Of course it is, but that may not be practical for all EV owners at all times. EV charging loads can be highly flexible, but that does not make them infinitely flexible. From time to time, an EV owner may need to charge their vehicle during peak periods. For instance, a 2018 report by Synapse Energy Economics ("Synapse") notes that EV-specific rates offered by California investor-owned utilities ("IOUs") have been highly successful at encouraging off-peak charging, but not 100% successful. Synapse's analysis showed that 93% of charging on occurred during off-peak hours for Pacific Gas and Electric's EV-specific rate

[13] Depending on the underlying cost structure and pricing period design, the "middle" pricing period could have a small premium or a small discount relative to a flat rate. The shoulder rates in DEP Schedule R-TOU have a small premium relative to the flat rate under Schedule RES.

while 88% percent of charging is off-peak on Southern California Edison's EV-specific rate.[14]

EV rates should encourage EV owners to charge during off-peak times, but the risk-reward relationship must be balanced and consistent. A rate that is not forgiving of occasional departures from the ideal makes perfect the enemy of the very good. Rates with demand components such as Schedule R-TOUD do not provide this balance.

Q. ARE THESE EXISTING RATE OPTIONS WELL-SUITED FOR RESIDENTIAL EV HOME CHARGING?

A. No. Schedule RES features flat energy charges and as a consequence fail to take advantage of the potential for managed charging. Schedule R-TOU has one major shortcoming: the lack of a submetering option. This is problematic in two ways. First, managing usage behavior for a whole home is far more complex than doing so for a single, and theoretically highly flexible, EV load. Second, the BFC for Schedule R-TOU is $16.85/month, which is $2.85/month higher than the BFC for Schedule RES. The higher BFC diminishes the potential for a customer to realize cost savings relative to what they would pay under Schedule RES.

Schedule R-TOUD has the same shortcoming as Schedule R-TOU (*i.e.,* lack of a submetering option and a higher BFC than Schedule RES), but also has two additional features that could make it unattractive for ratepayers with EVs. First,

[14] Whited, M., Allison, A., and Wilson, R. ("Whited et al.") June 25, 2018. Driving transportation electrification forward in New York: Considerations for effective transportation electrification rate design. p. 2. Cambridge, MA: Synapse Energy Economics. Attached as **Exhibit JRB-5**.

the demand component in Schedule R-TOUD contributes an added level of complexity for a ratepayer that is accustomed to volumetric rates and likely has little or no understanding of demand rates generally, their own demand patterns, and how demand rate service could affect their electric bill. Second, the two-period design contains extended on-peak periods, totaling 11 hours per day from April – September (10 AM – 9 PM) and 12 hours per day from October – March (6 AM – 1 PM and 4 PM – 9 PM.[15]

Q. ARE THERE ANY OTHER RATE DESIGN ELEMENTS ASSOCIATED WITH ESTABLISHING AN EFFECTIVE EV-SPECIFIC RATE FOR HOME CHARGING?

A. Yes. It is reasonable for EV ratepayers to pay for the cost of additional metering required to measure EV charging usage, but any incremental fixed charge associated with the submetered load should be limited to the incremental metering cost. This would be equivalent to how monthly fixed charges were assessed under DEC's now closed rate schedule for submetered controlled water heating (former Schedule WC).

The Commission should be aware that the costs of separate meter and even submetering (to a lesser extent) have been cited as a barrier to some EV-specific home charging rates.[16] However, it is not clear whether submetering costs would present a barrier in North Carolina. At the time of its closure former DEC Schedule

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[15] These on-peak periods are limited to non-holiday weekdays.
[16] *See* **Exhibit JRB-3** and **Exhibit JRB-5** for an additional discussion of metering cost issues and submetering options.

WC had modest submetering charge of $1.71/month, an amount that could easily be offset and exceeded by ratepayer savings even with a relatively moderate price differential between a flat rate and the off-peak rate.

Costs for additional EV load metering among Virginia utilities are slightly higher. Dominion Virginia's Schedule EV contains an additional monthly fixed charge of $2.73/month.[17] Appalachian Power's Schedule PEV uses a different approach, translating the incremental monthly submetering cost to a volumetric rate based on an assumed amount of monthly off-peak charging and adding that amount to the off-peak rate. The submetering cost used in this calculation is $2.37/month.[18]

Q. HOW DO YOU RECOMMEND THAT AN EV RATE BE ESTABLISHED FOR DEP'S RESIDENTIAL CUSTOMERS?

A. I recommend that existing Schedule R-TOU be opened for submetered EV charging, with modest submetering charge. My recommendation is based on the fact that Schedule R-TOU already contains several of the attributes that are important for an effective home charging rate. It has a three-period design with a 5-hour peak period from April – September and a 3-hour peak period from October – March, and long duration off-peak periods that measure 15 hours from April – September and 10 hours from October – March. At the rates proposed by DEP in

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[17] Virginia Electric and Power Company, Schedule EV, *available at* https://www.dominionenergy.com/library/domcom/media/home-and-small-business/rates-and-regulation/residential-rates/virginia/schedule-ev.pdf?la=en&modified=20190401150009.

[18] Virginia State Corporation Commission. Docket No. PUR-2019-00067. *Petition of Appalachian Power Company for approval to implement a voluntary schedule for owners of Personal Electric Vehicles*. Exhibit 2. April 23, 2019, *available at* http://www.scc.virginia.gov/docketsearch/DOCS/4g2w01!.PDF

this proceeding, the off-peak rate from July – October is $0.04262/kWh lower than the flat rate under Schedule RES while from November – June off-peak rate is $0.0366/kWh lower. The off-peak rates, at $0.0837/kWh are considerably higher than the off-peak marginal costs for energy and capacity found in Schedule PP, which are generally approximately $0.03/kWh or less.

Collectively these features would allow an EV owner to accrue meaningful savings for off-peak charging as long as the submetering charge is reasonable, while also producing benefits for other ratepayers because the off-peak retail rate is well above off-peak marginal costs. Table 2 shows estimated savings under proposed rates with sensitivities total monthly charging, the amount of non-off-peak charging,[19] and the amount of a hypothetical submetering charge.

Table 2: Estimated Customer Savings Under Submetered R-TOU

Monthly Charging (kWh) & Off-Peak %	Annual Gross Savings ($)	Annual Net Savings ($2.00/month metering charge)	Annual Net Savings ($3.00/month metering charge)
200 (100% off-peak)	$92.66	$68.66	$56.66
200 (90% off-peak)	$61.48	$37.48	$25.48
300 (100% off-peak)	$138.98	$114.98	$102.98
300 (90% off-peak)	$92.22	$68.22	$56.22

[19] The "on-peak" charging rate for the purpose of this estimate is the average of the proposed on-peak and shoulder rates, which would represent 5% on-peak period charging and 5% shoulder period charging.

IV. NON-RESIDENTIAL EV RATE OPTIONS

Q. HOW DO CONSIDERATIONS FOR NON-RESIDENTIAL EV CHARGING RATE OPTIONS DIFFER FROM THOSE FOR RESIDENTIAL CHARGING?

A. The main difference between non-EV rates for residential charging and non-residential non-EV rates is the use of demand charges in non-residential tariffs. Demand charges under standard utility rate schedules for non-residential ratepayers have been repeatedly shown to be the largest barrier to non-residential EV charging, especially DCFC charging.[20] Demand charges assessed for EV charging can easily overwhelm any potential revenue a public EV charging station would generate, or create extraordinarily high costs for charging in non-public applications (e.g., fleet charging or workplace charging). For example, a study by the Rocky Mountain Institute found that demand charges can be responsible for more than 90% of a DCFC ratepayer's electric bill under existing typical utilization rates.[21] While the overall bill impact will be smaller for ratepayers with Level 2 chargers, which have a considerably smaller demand than DCFCs, demand charges can still have a significant impact on these ratepayers' electricity bills under low utilization rates.

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[20] *See, e.g.,* David Farnsworth, Jessica Shipley, Joni Sliger, and Jim Lazar. "Beneficial Electrification of Transportation." Regulatory Assistance Project, January 2019; Dane McFarlane, Matt Prorok, Brendan Jordan, and Tam Kemabonta. "Analytical White Paper: Overcoming Barriers to Expanding Fast Charging Infrastructure in the Midcontinent Region." Great Plains Institute, July 2019; Garrett Fitzgerald and Chris Nelder. "EVgo Fleet and Tariff Analysis." Rocky Mountain Institute, 2017, attached as **Exhibit JRB-6**; Garrett Fitzgerald and Chris Nelder. "DCFC Rate Design Study for the Colorado Energy Office." 2019. Rocky Mountain Institute.

[21] **Exhibit JRB-6**.

EV charging stations today tend to have relatively low utilization rates due to the modest adoption of EVs to date, but since EV charging stations have a fixed demand that is based on the type of charger installed, an EV charging station with a low utilization rate still pays the same demand charge as a highly utilized charging station. This creates a "chicken or the egg" problem for EV deployment: widespread DCFC deployment is needed to encourage adoption of EVs, but DCFC infrastructure cannot be affordably deployed until conditions are present that would lead to higher utilization rates of DCFC equipment (i.e., greater EV adoption).

Q. WHY IS IT IMPORTANT TO FOSTER THE GROWTH OF VIABLE NON-RESIDENTIAL CHARGING OPTIONS?

A. It is commonly accepted that a lack of public EV charging infrastructure presents a considerable barrier to the growth of personal EVs, as fast charging enables long distance travel. Separately, public charging options are important for EV owners that live in multi-family dwellings or rely on street parking. Higher capacity charging stations also support fleet electrification for vehicles that have intensive charging needs (e.g., buses). All of these applications are important in the context of broader transportation electrification, hence the need to create near-term bridging mechanisms that address the barrier that demand rates pose for high capacity charging.

Q. DOES DEP CURRENTLY OFFER AN EV-SPECIFIC RATE FOR NON-RESIDENTIAL RATEPAYERS?

A. No.

Q. WHAT RATE SCHEDULES ARE AVAILABLE TO DEP'S NON-RESIDENTIAL RATEPAYERS FOR EV CHARGING?

A. Since DEP does not currently offer any EV-specific rates, generally applicable non-residential rates would apply to all usage for EV charging at a Level 2 or DCFC stations, whether the station is for public charging or restricted use. Non-residential ratepayers can generally choose between a standard rate and a voluntary time-varying rate. The options mapped to customer size are shown below.

Table 3: Current Non-Residential Rate Options

Demand (kW)	Rate Option	Energy Charges	Demand Charges
> 50	SGS	3-tier declining block	None
	SGS-TOUE	3-period TOU, large rate spread	None
	SGS-TOU	2-period TOU, small rate spread	Seasonal on-peak & off-peak excess
50 - 1,000	MGS	Flat	All hour
	SGS-TOU	2-period TOU, small rate spread	Seasonal on-peak & off-peak excess
< 1,000	LGS	Flat	3-tier declining block, all hour
	LGS-TOU	2-period TOU, small rate spread	3-tier seasonal on-peak & off-peak excess, with on-peak declining block

One of the time-varying rates, Schedule SGS-TOUE, is designed in much the same way as Schedule R-TOU rate. Schedule SGS-TOUE would likely not be an option for any ratepayer that installs a DCFC station or for a standalone DCFC station because it is only available to ratepayers with maximum demands of 50 kW or less and a contract demand of 30 kW or less. As shown previously in Table 1 DCFC stations often exceed this demand threshold.[22]

Q. ARE THESE RATE OPTIONS WELL-SUITED TO NON-RESIDENTIAL EV CHARGING?

A. No. Schedule MGS and Schedule LGS do not contain any time variation and Schedule LGS charges higher rates to ratepayers with low load factors. Two of the available time-varying rate options shown in Table 3, SGS-TOU and LGS-TOU, provide the principal time-varying price signal through the on-peak demand component. For both of these rates the on-peak demand charges is determined by monthly maximum demand, which in both cases applies to monthly maximum demand from 10 AM – 10 PM period during April – September (12 hours) and 6 AM – 1 PM and 4 PM – 9 PM during October – March (12 hours). As a consequence, a single instance of on-peak charging during a month would incur a demand charge that drives a ratepayer's bill. The on-peak demand windows would be virtually impossible to avoid entirely.

[22] DCFC stations typically have a charging capacity of 50 kW per charging port and often have multiple ports.

Schedule SGS-TOUE could be attractive for non-residential EV charging but it is not available for submetered use. Furthermore, as noted above it would likely not be available for higher capacity charging units due to the maximum demand limit. Even the addition of a Level 2 charging unit could easily push a non-residential ratepayer beyond that demand threshold and cause the rate to become unavailable for even whole building use.

Q. CAN YOU PROVIDE AN EXAMPLE OF HOW DEMAND CHARGES CAN AFFECT THE COST OF EV CHARGING?

A. Yes. Table 4 illustrates the impacts of demand charges based on the proposed rates in DEP Schedules TOU-SGS and MGS on a hypothetical DCFC station with two charging ports that each have a 50 kW demand. It assumes that the units are in use by multiple vehicles at the same time at least once per month, resulting in a 100 kW maximum demand. For the Schedule SGS-TOU example, it is assumed that at least one 100 kW monthly demand is registered during an on-peak period each month.[23]

[23] The calculation uses the average of the summer and winter on-peak demand charge from Schedule SGS-TOU. Off-peak excess demand is assumed to be zero because off-peak demand is never higher than the 100 kW rating for the station itself.

Table 4: Demand Charge Impacts on DCFC Charging Costs

	SGS-TOU	MGS
BFC ($/month)	$35.50	$28.50
Demand Charge ($/kW)	$10.66	$6.72
On-Peak Energy	$0.07100	$0.08068
Off-Peak Energy	$0.05754	$0.08068
Energy/Session (kWh)	50	50
Demand (kW)	100	100
15 Total Sessions/Month, Composed of 14 Off-Peak Sessions and 1 On-Peak Session		
Annual Bill	$13,738	$9,132
Cost/Session	$76.32	$50.73
Cost/kWh	$1.53	$1.01
60 Total Sessions/Month, Composed of 59 Off-Peak Sessions and 1 On-Peak Session		
Annual Bill	$15,292	$11,310
Cost/Session	$21.24	$15.71
Cost/kWh	$0.42	$0.31

Two important details are shown in Table 4. First, even with a relatively high utilization rate of 60 sessions per month (two per day), the cost of charging is still fairly high on a $/kWh basis under both rates. Second, a charging unit owner would be better off under Schedule MGS, which is not time-differentiated, because it has a lower demand charge.

Q. IS DEP PROPOSING AN EV-SPECIFIC CHARGING RATE FOR NON-RESIDENTIAL RATEPAYERS IN THIS RATE CASE?

A. No.

Q. IS DEP PROPOSING AN EV-SPECIFIC CHARGING RATE FOR NON-RESIDENTIAL RATEPAYERS IN ANY OTHER FORUM?

A. Not really. The tariffs associated with the Company's transportation electrification proposal generally refer to existing non-residential rates for the purposes of billing, although DEP does propose a few modest modifications under several pilot programs. The non-residential rate options allow for separately metered EV charging, but not submetering, and either fail to provide time-varying price signals or fail to consider the detrimental effects that the existing rate designs would have on charging costs. For instance, the proposed fleet charging program uses the existing SGS-TOU rate. It requires the customer to pay a full BFC and rates under a design for which the principal price signal is an on-peak demand charge assessed during a long-duration peak window.

For multi-family dwelling and public Level 2 charging services, ratepayers would be charged a Level 2 Charging Fee comprised of the utility's first block energy rate of Schedule SGS, plus $0.02/kWh (*i.e.,* no time differentiation). For DCFC charging, DEP's proposed Fast Charging Fee, to be updated quarterly, only applies to its proposed network of utility-owned and operated DCFCs, and would not be available for usage by third-party-owned DCFCs. The pilot programs are also limited in size and duration, and do not reflect permanent offerings that would result in a sustained incentive for off-peak charging.[24]

[24] *Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Application for Approval of Proposed Electric Transportation Pilot*, Docket Nos. E-2, Sub 1197 and E-7, Sub 1195 (March 29, 2019).

Q. WHAT RATE OPTIONS ARE AVAILABLE FOR ADDRESSING THE EFFECTS OF DEMAND CHARGES ON OWNERS OF HIGH CAPACITY EV CHARGING STATIONS?

A. There are several options as follows:

1. Substitution of time-varying volumetric charges for demand charge components.
2. Establishing limits or caps on demand charges.
3. Allowing aggregation of multiple meters for the purpose of calculating demand charges.
4. Modifying the calculation of demand charges from being based on monthly maximum demand to the daily maximum demand.

Q. HOW COULD THE SUBSTITUTION OF TIME-VARYING ENERGY CHARGES FOR DEMAND CHARGES BE ACCOMPLISHED IN AN EV-SPECIFIC NON-RESIDENTIAL RATE?

A. The simplest way would be to open Schedule SGS-TOUE to submetered EV charging and eliminate or relax the existing 50 kW monthly demand and 30 kW contract demand limits for submetered EV loads. Like Schedule R-TOU, Schedule SGS-TOUE already features attributes that are supportive of EV charging, making it a reasonable place to start for design of a non-residential EV-specific rate.

As a submetered EV rate option, Schedule SGS-TOUE would feature a submetering charge if the EV load is located behind an existing whole building meter, or the otherwise applicable BFC under either Schedule SGS-TOUE or

Schedule SGS-TOU for standalone charging installations. The Schedule SGS-TOU BFC would apply for larger capacity installations that would otherwise only qualify for Schedule SGS-TOU. An increase in the demand limit for submetered EV load could correspond to the 1,000 kW threshold used in Schedule SGS-TOU.

Q. ARE THERE EXAMPLES OF NON-RESIDENTIAL EV-SPECIFIC RATES THAT FEATURE A SIMILAR USE OF VOLUMETRIC RATHER THAN DEMAND CHARGES?

A. Yes. There are several examples of this general design feature, with variations based on the state and utility. In some, but not all cases, the substitution is subject to a specific term and/or phase-out system. This kind of feature provides predictability for charging station owners, helps mitigates cross-subsidization concerns, and reflects an expectation that the impacts of demand charges will be reduced by higher utilization rates in the future. Below are several examples illustrating this model. The examples below should not be viewed as an exhaustive list.

- California (SCE): Southern California Edison ("SCE") offers rates under Schedules TOU-EV-7 through TOU-EV-9 for separately metered EV charging stations with different load sizes (e.g., TOU-EV-8 applies to loads from 20 kW – 500 kW). The rates offer a demand charge free rate for five years (from March 1, 2019 through March 1, 2024), followed by the phase-in of a modest demand charge over the following five years for the TOU-EV-8 and TOU-EV-9 rate schedules. Customers on Schedule TOU-EV-7 (demand of less than 20 kW) retain an energy-only option. Time-varying volumetric energy charges are increased to recover costs that would otherwise be recovered in the demand charge.[25]

- Connecticut (Eversource): Eversource Energy's Electrical Vehicle Rate Rider allows separately metered public charging stations to pay energy charges in place of any otherwise applicable demand rate that would apply under the standard general service rate schedules. The energy charge is determined by the average rate for that rate component. This rider does not have a sunset or phase-out clause.[26]
- Nevada (Nevada Power Company & Sierra Pacific Power Company): Both utilities offer Schedule EVCCR-TOU to customers under the larger commercial rate schedules that install separately metered DCFC stations. The rates offer at ten-year discount schedule under which demand rates are reduced by 100% in the first year (starting April 1, 2019) and the discount declines by 10% each year thereafter to zero after the tenth year (starting April 1, 2029). Customers pay a substitute transition energy charge in place of the demand charges.[27] [28]

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[25] *See e.g.,* SCE Schedule TOU-EV-8. Available at: https://library.sce.com/content/dam/sce-doclib/public/regulatory/tariff/electric/schedules/general-service-&-industrial-rates/ELECTRIC_SCHEDULES_TOU-EV-8.pdf.
[26] Eversource Connecticut. Electric Vehicle Rate Rider. Available at: https://www.eversource.com/content/docs/default-source/rates-tariffs/ct-electric/ev-rate-rider.pdf?sfvrsn=e44ca62_0.
[27] Nevada Power Company. Schedule EVCCR-TOU. Available at: https://www.nvenergy.com/publish/content/dam/nvenergy/brochures_arch/about-nvenergy/rates-regulatory/electric-schedules-south/EVCCR-TOU_South.pdf
[28] Sierra Pacific Power Company. Schedule EVCCR-TOU. Available at: https://www.nvenergy.com/publish/content/dam/nvenergy/brochures_arch/about-nvenergy/rates-regulatory/electric-schedules-north/EVCCR-TOU_Electric_North.pdf.

- Pennsylvania (PECO): PECO Energy Company's Electric Vehicle DCFC Pilot Rider (Schedule EV-FC) applies a five-year discount to billed distribution demand for customers with publicly available or workplace DCFC charging stations. The demand discount is set at 50% of the maximum nameplate capacity of connected DCFCs.[29]

Q. PLEASE DESCRIBE WHAT YOU MEAN BY A DEMAND CHARGE LIMIT OR CAP OPTION.

A. A demand charge cap limits the portion of a ratepayer's monthly bill that is associated with billed demand charges to either a specified percentage of the ratepayer's bill or an implied volumetric rate. Such a rate could be applied more generally as a way to reduce the adverse impacts of demand charges on ratepayers with low load factors. However, in the present context, it more specifically addresses circumstances where EV charging load contributes to demand charges being a very high percentage of a ratepayer's bill due to a low utilization rate and low load factor. A demand charge cap could be deployed as a special condition for ratepayers with under Schedules SGS-TOU or LGS-TOU for ratepayers with EV load (i.e., not separately metered), or it could be reflected in a tariff for dedicated EV charging.

[29] PECO Electric Tariff. Schedule EV-FC at tariff p. 84. Available at: https://www.peco.com/SiteCollectionDocuments/CurrentTariffElec.pdf.

Q. CAN YOU PROVIDE ANY EXAMPLES OF THE DEPLOYMENT OF A DEMAND CHARGE LIMIT OPTION?

A. Yes. In 2019, Minnesota Power received approval to deploy a rate for commercial EV charging that caps demand charges at 30% of a ratepayer's bill. The Order that approved the rate also directed Minnesota Power to establish a three-period time-varying rate design for the commercial EV charging tariff.[30] Minnesota Power's proposal was based in part on an evaluation of six of its customers with on-site EV charging equipment and the effective energy rate those customers paid due to the demand charge. The results of this analysis are shown below in Table 5 followed by the rate that these customers would have paid under the capped demand charge in Table 6. The percentage-based cap produced approximately the same effective energy rate for five of the six customers and only a slightly higher rate for the one remaining customer. The applicable demand rate for this comparison is \$6.50/kW of on-peak demand.[31]

[30] Minnesota Public Utilities Commission Docket No. E015/M-19-337. *In the Matter of Minnesota Power's Docket No. Petition for Approval of its Electric Vehicle Commercial Charging Rate Pilot.* "Order Approving Pilot with Modifications and Setting Reporting Requirements." December 12, 2019.

[31] Minnesota Public Utilities Commission Docket No. E015/M-19-337. *In the Matter of Minnesota Power's Docket No. Petition for Approval of its Electric Vehicle Commercial Charging Rate Pilot.* "Petition for Approval of Electric Vehicle Commercial Charging Rate." p. 13. May 16, 2019.

Table 5: Bills Under Generally Applicable Commercial Rate

Customer	Demand Charge (% of Bill)	Rate Paid ($/kWh)	Percentile Rank (Bill/KWh) Among GSD Customers
1	56%	$0.19	94.80%
2	75%	$0.34	98.80%
3	73%	$0.31	98.70%
4	78%	$0.38	99.10%
5	78%	$0.39	99.10%
6	88%	$0.78	99.70%

Table 6: Bills Under Proposed Commercial EV Rate

Customer	Demand Charge (% of Bill)	Rate Paid ($/kWh)	Percentile Rank (Bill/KWh) Among GSD Customers
1	30%	$0.12	65.50%
2	30%	$0.12	67.00%
3	30%	$0.12	67.70%
4	30%	$0.12	69.70%
5	30%	$0.12	69.80%
6	30%	$0.14	82.70%

I have attached Minnesota Power's application as **Exhibit JRB-7**. Attached **Exhibit JRB-8** contains Minnesota Power's compliance tariff addressing the modifications made by the Minnesota Public Utilities Commission in approving the tariff, most notably shortening the on-peak period from 14 hours to 5 hours.

Incidentally, Duke Energy Kentucky's rates contain a similar limiter. In Duke's Kentucky territory, the generally applicable rate for non-residential service at distribution voltage caps maximum monthly charges, excluding the monthly fixed charge, at a rate of roughly 23.7 cents/kWh. This rate is not specific to EV ratepayers and is available to non-residential ratepayers with demands up to 500 kW.[32]

Q. HOW COULD A DEMAND CHARGE CAP BE SET FOR AN EV-SPECIFIC NON-RESIDENTIAL RATE?

A. One method would be to set the cap as a volumetric rate equivalent or, approximately so, to the rate that a residential ratepayer would pay on flat rate service (*i.e.,* Schedule RES). Since a residential ratepayer has a choice between charging at home or charging at a commercial location, setting the cap in this manner ensures that owners of EV chargers are not effectively paying more than a residential ratepayer would pay to charge an EV at home.

Q. HOW COULD A DEMAND CHARGE LIMIT FOR EV LOAD BE ESTABLISHED IN THE FORM OF A TARIFF?

A. A demand charge limit for dedicated EV charging could be established by modifying Schedules SGS-TOU and LGS-TOU to apply the limit to EV-only loads. For standalone installations, the otherwise applicable BFC would apply. Submetered EV loads behind another meter would incur an incremental submetering charge. I note that this approach would fail to address the long on-peak windows found in Schedules SGS-TOU and LGS-TOU, but it would help mitigate the outsized role that the demand charge plays in determining charging costs.

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[32] Duke Energy Kentucky. Rate DS: Service at Secondary Distribution Voltage. Available at: https://www.duke-energy.com/_/media/pdfs/for-your-home/rates/electric-ky/sheet-no-40-rate-ds-ky-e.pdf?la=en.

Q. PLEASE EXPLAIN THE CONCEPT OF A METER AGGREGATION OPTION FOR THE PURPOSE OF CALCULATING DEMAND CHARGES.

A. Currently, the bills of ratepayers with multiple meters are calculated individually for each meter. For example, a business that has multiple locations within a utility's service territory will pay a separately calculated electricity bill for each location. A policy that allows the aggregation of multiple meters for purposes of calculating demand charges for EV charging would permit these ratepayers to aggregate their demand across all participating locations for the sole purpose of calculating the demand charge. In the context of EV charging, this policy recognizes that a ratepayer with multiple EV charging stations installed across multiple locations could experience diversity with respect to when the charging stations are used. When EV charging station utilization rates are relatively low, and individual metered loads have relatively low load factors, this policy can help reduce the total demand charges paid by a ratepayer with multiple accounts.

It is important to note that this is different from the concept of aggregated billing. Under aggregated billing, a ratepayer's individual charges are combined onto a single bill. In contrast, aggregating meters to calculate demand charges only affects the billing determinant used to calculate demand charges.

Q. ARE THERE EXAMPLES OF UTILITIES PROPOSING TO ALLOW THE AGGREGATION OF MULTIPLE METERS TO ENCOURAGE THE DEPLOYMENT OF EV CHARGING?

A. Yes. As part of its June 2019 rate case filing, Puget Sound Energy ("PSE") in Washington state proposed establishing a five-year Conjunctive Demand Pilot that would allow its Large General Service ratepayers that have accounts in multiple locations to aggregate the demands in the different locations for the purpose of calculating transmission and generation demand charges.[33] Under PSE's proposal, the utility would use the highest hourly interval of demand across a participating ratepayer's multiple accounts during a billing period to calculate billed demand for purposes of recovering power and transmission costs. Distribution costs would still be billed using demands at the ratepayer's individual locations.

In its supporting testimony, PSE noted that "from the perspective of power and transmission cost causation, customers served by PSE through multiple locations look no different to PSE (i.e., have no materially different cost of service) than a single customer with similar load characteristics," yet they could pay more in demand charges than a single customer.[34] PSE expressly justified its proposal as a way to mitigate high demand charges that pose a barrier to EV deployment.[35]

[33] Washington Utilities and Transportation Commission, Docket No. UE-190529.
[34] *Prefiled Direct Testimony of Jon A. Piliaris*, Washington Utilities and Transportation Commission, Docket No. UE-190529 (June 20, 2019).
[35] PSE cited several other examples of utilities that have proposed or implemented such a system in Michigan (Consumers Energy and Detroit Edison) and Minnesota (Northern States Power Company, or Xcel Energy). However, I have not verified the accuracy of these other examples.

PSE's proposed tariffs for implementing the program are attached as **Exhibit JRB-9**.

Q. PLEASE EXPLAIN THE CONCEPT OF A DAILY DEMAND CHARGE.

A. A daily demand charge occupies something of a middle ground between traditional demand charges based on monthly maximum demand and fully volumetric rates. A daily demand charge uses the highest recorded demand each day to calculate charges, either during all hours or during a time-varying demand pricing period. In doing so it reflects an averaged contribution to costs and does not penalize ratepayers for a small number of anomalously high demands. The averaging effect is less than that embodied within a volumetric charge because it derives from peak daily demands whereas a volumetric rate charges a ratepayer based on fully averaged demand across all intervals in a given time period.

Q. HOW COULD A DAILY DEMAND CHARGE DESIGN SUPPORT TRANSPORTATION ELECTRIFICATION?

A. Substituting volumetric charges for demand charges provides the greatest benefit to ratepayers with low load factors. At present, many non-residential EV charging loads have this characteristic. A daily demand charge design could be beneficial to EV charging stations with higher utilization rates and higher load factors because at a certain load factor threshold a ratepayer prefers demand charges to energy charges. Such could be the case for fleet charging, where reasonably predictable charging needs can be managed to consistently cycle vehicles in and out in a way that optimizes the use of charging equipment.

Q. WHAT ARE YOUR RECOMMENDATIONS TO THE COMMISSION ON THE ESTABLISHMENT OF A NON-RESIDENTIAL EV-SPECIFIC RATE?

A. I recommend that the Commission direct DEP to deploy a non-residential EV-charging rate under options (1) or (2). Option 1 would accomplish the substitution of energy charges for demand charges by using the fully volumetric time-varying rate design found in Schedule SGS-TOUE. Schedule SGS-TOUE should be modified to allow submetering of EV load, and to eliminate or relax the maximum 30 kW contract demand and 50 kW maximum demand limits for EV load in order to permit high capacity charging. The 1,000 kW demand limit found in SGS-TOU could be applied to separately metered or submetered EV load. Submetered load behind an existing meter would be subject to a submetering charge limited to the cost of the additional metering, while standalone installations would be subject to the otherwise applicable BFC under Schedule SGS-TOUE or SGS-TOU.

Option 2 establishes a demand charge limit for separately metered or submetered EV charging load within Schedules SGS-TOU and LGS-TOU, and uses the same submetering charge and BFC system as Option 1. I recommend that the demand charge limit be designed to produce a maximum implied volumetric rate that is approximately the same as a residential ratepayer would pay to charge an EV under a standard flat rate option such as Schedule RES. Alternatively, a cap based on a percentage of a ratepayer's bill attributable to demand charges could be used to similar effect.

I do not recommend Option (3), demand aggregation, or Option (4), a daily demand charge design, for immediate deployment because both involve greater complexities and consideration of additional issues. However, both of these options should have a place in continued discussions of EV-supportive rates and innovative rate designs more generally. Such a discussion could take place as part of the larger rate design study recommended by Public Staff Witness Floyd in DEC's pending rate case if the Commission adopts that recommendation.

V. CONCLUSION

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS TO THE COMMISSION?

A. I recommend that the Commission direct DEP to file separate, targeted EV-specific tariffs for both residential and non-residential dedicated EV charging, reflecting the core characteristics discussed in my testimony. I believe this should occur within 60 days of the order in this rate case.

I also recommend that the Commission establish an investigatory docket to receive further information and permit further discussion of EV-specific rates, lessons learned, and potential refinements, including quarterly reports from DEP updating the Commission and parties on deployment status, tariff enrollment, ratepayer savings, system cost savings, and any other information that the Commission deems relevant to support evaluation of the tariffs and their future evolution. If the Commission orders the comprehensive rate design study recommended by Public Staff Witness Floyd in DEC's pending rate case, this investigatory docket could become part of or be used to support that effort.

Finally, I recommend that any rates established pursuant to a Commission decision remain available, at a minimum, until any successors or replacements are adopted pursuant to the system of Commission review that I recommend above.

Q. WHAT IS YOUR RECOMMENDATION FOR THE ESTABLISHMENT OF A RESIDENTIAL EV-SPECIFIC RATE?

A. I recommend that existing Schedule R-TOU be made available for submetered home EV charging with the modest submetering charge described above in place of the tariffed BFC. With the exception of not being available for submetered use, Schedule R-TOU already contains several characteristics that are supportive of home EV charging, as follows:

1. Three pricing periods and short duration on-peak periods;
2. A price differential between the off-peak rate and the otherwise applicable flat rate that should be sufficient to produce meaningful bill savings for EV charging, taking into account a modest incremental metering charge and a typical amount of home EV charging; and
3. An off-peak pricing period with a duration of at least eight hours that allows ample time for low voltage charging to produce a battery charge sufficient for a reasonable length trip or commute.

Q. WHAT IS YOUR RECOMMENDATION FOR THE ESTABLISHMENT OF A NON-RESIDENTIAL EV-SPECIFIC RATE?

A. I recommend that a rate or rates for submetered and standalone EV charging be established for non-residential ratepayers under a design that features time variation and mitigates the outsized effects that demand charges have on charging costs. More specifically, the rate or rates should:

1. Address the issues presented by demand rates for non-residential EV charging installations by doing one or both of the following: (a) modifying Schedule SGS-TOUE to permit submetering for EV loads and eliminating or relaxing the maximum demand-based availability limitations currently contained in Schedule SGS-TOUE for EV load, or (b) applying a demand charge limit to Schedules SGS-TOU and LGS-TOU that caps demand charges at an implied maximum volumetric rate, or alternatively, a percentage of the ratepayer's monthly bill;
2. Use the otherwise applicable BFC for standalone charging stations and a submetering charge in place of the BFC for charging units located behind an existing meter; and
3. Remain available to participants for ten years from the date of their enrollment in order to provide a reasonable level of investment certainty to prospective equipment owners.

I also recommend that the Commission consider the demand aggregation and daily demand charge options discussed in my testimony as it pursues future refinements.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

North Carolina Sustainable Energy Association
Summary of the Testimony of Justin R. Barnes
NCUC Docket No. E-2, Sub 1219

Commissioners, thank you for the opportunity to testify before you today. My name is Justin Barnes, and I am the Director of Research at EQ Research LLC. I am appearing here on behalf of the North Carolina Sustainable Energy Association ("NCSEA").

The purpose of my testimony is to propose the establishment of targeted electric vehicle-specific ("EV-specific") charging rate options for both residential and non-residential customers. I use the term EV-specific to refer to rates that apply to EV charging separately from a customer's other non-EV electricity use, and the term "targeted" to refer to rates specifically designed to take advantage of the unique attributes of EV charging load to produce benefits for EV owners and non-EV ratepayers.

In my testimony I first discuss the rationale and justification for targeted EV-specific rates, the case is compelling. Well-designed EV rates that incentivize off-peak charging can produce cost savings for EV owners that help offset the higher up front cost of an EV and the cost of home charging equipment, and produce more equitable rates for EV owners whose charging needs largely coincide with low cost periods for other reasons, such as personal and work schedules. Those same rate designs can produce cost savings for other ratepayers by flattening the load curve, avoiding the need for costly grid investments that might otherwise be needed to accommodate increased EV charging load, and aiding in renewable energy integration. Furthermore, the availability of targeted EV-specific rates is a core element of achieving transportation electrification, which in turn is a core element of North Carolina's Clean Energy Plan developed pursuant to Executive Order 80.

Next, I discuss the attractiveness of the current rate options available for residential home EV charging and present my proposal for a residential home charging rate. My evaluation of the available rates concludes that existing Schedule R-TOU could be an attractive rate for home EV charging except that it does not permit separately measured home EV charging. I therefore recommend that Schedule R-TOU be modified to permit separately measured EV charging with a modest, cost-based submetering charge in place of the otherwise applicable basic facilities charge ("BFC").

For non-residential EV charging, including public charging, insufficiencies in the current suite of rate options center on the facts that the available options either: (1) lack a time-varying price signal, or (2) provide a time-varying price signal principally through demand charges, which tends to produce extraordinarily high effective electric rates for higher capacity charging units, such as direct current fast charger ("DCFC") stations, which are commonly used for non-residential charging applications. I describe several options for addressing the issue of demand charges specifically, which include substituting volumetric rate components for the demand charges, establishing limits or caps on demand charges, allowing load aggregation for the purpose of calculating demand charges, and modifying the application of demand charges to be based on daily maximum demands rather than monthly maximum demand.

I conclude that existing Schedule SGS-TOUE, which uses a volumetric time-varying price signal, could be an attractive rate for non-residential EV charging if it is modified to: (1) allow separate measurement of EV load and (2) to relax or eliminate the 30 kilowatt ("kW") contract demand and 50 kW monthly maximum demand limits in order to make it available for DCFC charging stations, whose demand typically exceeds these limits. I therefore recommend two options for a non-residential EV charging rate. Under Option #1, Schedule SGS-TOUE is modified in this manner for separately measured EV charging. Under Option #2 Schedules SGS-TOU and

LGS-TOU are modified to permit separate measurement of EV charging load and to establish a demand charge limit that produces a maximum implied volumetric rate that approximates the rate a residential customer would pay to charge an EV under a standard flat rate option such as Schedule RES. Under both options, I recommend that where EV charging takes place in concert with other load behind the same meter, the customer pay a modest, cost-based submetering charge rather than an additional BFC, and that standalone charging units be charged the otherwise applicable BFC.

This concludes the summary of my pre-filed testimony.

MR. SMITH: Also, Commissioner Clodfelter, in accordance with the direction from the Commission as well as the joint stipulation of live testimony and exhibits, certain rate design and cost allocation witnesses, I move that NCSEA witness Barnes' live testimony in Docket E-7, Sub 1214 located at transcript Volume 17, pages 606 to 608, and pages 659 to 671; and transcript Volume 18, pages 14 to 22 be copied into the record in this proceeding.

COMMISSIONER CLODFELTER: Hearing no objection on the motion, the motion is granted.

(Whereupon, the testimony from Docket Number E-7, Sub 1214, transcript Volume 17, pages 606 to 608; Volume 17, pages 659 to 671; and Volume 18, pages 14 to 22 were copied into the record as if given orally from the stand.)

McKissick?

COMMISSIONER MCKISSICK: No questions, Madam Chair.

CHAIR MITCHELL: Okay. All right, Mr. Howat. It looks like you, too, are off the hook today. Thank you for being here. You may step down, sir.

MR. HOWAT: Thank you.

CHAIR MITCHELL: All right. It looks like NCSEA is up now. Mr. Smith?

MR. SMITH: Good afternoon, Madam Chair. Again, Ben Smith for NCSEA. NCSEA calls Mr. Justin Barnes to the stand.

CHAIR MITCHELL: All right. Mr. Barnes, there you are. Would you raise your right hand, please?

Justin Barnes; Having been duly affirmed,
Testified as follows:

CHAIR MITCHELL: Okay. All right, Mr. Smith. You may proceed.

DIRECT EXAMINATION BY MR. SMITH:

Q Mr. Barnes, please state your name and business address for the record.

A My name is Justin Robert Barnes. My business address is 1155 Kildaire Farm Road, Suite 202, Cary, North Carolina.

Q And can you state on whose behalf you are testifying?

A I'm testifying on behalf of the North Carolina Sustainable Energy Association.

Q Thank you. And did you cause to be prefiled in this docket on February 18, 2020, direct testimony consisting of 43 pages and eight exhibits?

A I did.

Q And if I were to ask you the same questions today, would your answers be the same as if given in your testimony, as corrected?

A It would be.

MR. SMITH: Madam Chair, at this time I would move that the testimony and exhibits of Mr. Barnes be copied into the record as if given orally from the stand.

CHAIR MITCHELL: All right. Hearing no objection, Mr. Smith, the motion is allowed.

MR. SMITH: Thank you.

(Whereupon, the prefiled direct testimony of Justin R. Barnes was copied into the record as if given orally from the stand.)

(Whereupon, Exhibits JB-1 through JRB-8 were identified as premarked.)

efficient use of our time together in this hearing, let's comply with -- with the Orders that we've provided on procedure.

All right. I'm going to allow counsel for the parties who have had testimony summaries introduced this afternoon, allow their witnesses to read those testimony summaries if they so choose, and I will start with witness Ryan, Center for Biological Diversity.

(No response.)

CHAIR MITCHELL: Assuming we haven't lost Mr. Crystal. All right. We may have lost Mr. Crystal already. All right. Mr. Neal?

MR. NEAL: I appreciate the opportunity, Chair Mitchell, but that won't be necessary.

CHAIR MITCHELL: All right. Thank you, Mr. Neal. All right. Counsel for any other witness who falls into this category whose -- whose witness has presented testimony, but was asked no questions?

(No response.)

CHAIR MITCHELL: All right. We will proceed with cross examination for the NCSEA witness. Any cross examination for witness Barnes?

(No response.)

CHAIR MITCHELL: All right. Questions from the

Commissioners, beginning with Commissioner Brown-Bland?

COMMISSIONER BROWN-BLAND: I don't have any questions.

CHAIR MITCHELL: All right.

COMMISSIONER GRAY: Lyons is next. No questions.

CHAIR MITCHELL: Commissioner Gray. Thank you for reminding me, Commissioner Gray. It's been a long day. Commissioner Clodfelter?

COMMISSIONER CLODFELTER: Yes. Thank you.

EXAMINATION BY COMMISSIONER CLODFELTER:

Q Mr. Barnes, can you hear me okay?

A I sure can. Yes.

Q Thank you. The Company is proposing that EV-specific rates be rolled up into the comprehensive rate design study that they're proposing. Do you have any comment on that?

A Well, my chief concern is that it seems to lack the amount of urgency, and not knowing exactly how long that comprehensive rate design proceeding is going to last, you know, it seems plausible that it could be several years, and during that time there won't be much of an opportunity to support, you know, beneficial EV charging in North Carolina. And I think also, a second factor that kind of comes to mind is that I think what I've suggested is not -- are not necessarily solutions to very complicated problems. They are very simple solutions to problems that are pretty well acknowledged. So the idea that, you know, a comprehensive study is necessary to devise solutions to these two specific issues that I've identified, to me, that -- it seems like it's making perfect the enemy of the good. And even though, you know, I certainly think a comprehensive rate design review is a worthwhile exercise, I don't necessarily think that, you know, simple solutions to simple problems with a relatively pressing need, need to be, you know, kind of bound up in that and ultimately kind of delay for a potentially considerable period of time.

Q Let me explore that with you a little bit further here because I'm trying to get at the question of whether this is a detachable piece that can be dealt with separately, and so I want to ask you a couple follow-up questions. We've got some quantity of electric vehicles already on the road in North Carolina. I don't remember the exact number now. It's not -- it's not an inconsequential number, but it's not as the -- if you look at it relative to system load for Duke Energy

Carolinas, it's an inconsequential portion of the system load currently. I think that's correct. So let's -- for purpose of the questions I want to ask you, let's just take that off the table and act like it didn't exist, all right, so for purposes of these questions, I want to just ignore the existing load that comes from existing electric vehicles now in use, okay?

A All right.

Q So if I understand, then, if we had an EV-specific rate schedule, we would be dealing with incremental load. We would be hoping to attract incremental load by the use of that rate schedule, correct?

A Right, yeah, assuming kind of a zero point as the starting point, yes.

Q Sure. If we assume a zero point, we ignore the electric vehicles now on the road and we assume a zero point, then any additional load that we would attract to an EV-specific rate would be incremental load, and it would produce, therefore, incremental revenue, right?

A That's correct.

Q It wouldn't really require any reallocation of existing revenue requirement among any of the existing rate classes, would it? It's incremental revenue.

A Right. It's, you know, found money, I guess is what you could call it.

Q Well, found money is -- I'm not sure what Duke would call it. I'm not sure if that's correct, but I understand the concept you've got. Would the same be true on the cost side? At least under the EV rate structures that you are proposing, would all of the cost, the incremental cost, be captured and offset against the incremental revenues resulting from those EV-specific rates? Would it be self-contained to the rate?

A Well, you know, if we assume that, you know, this -- we make this assumption of incremental load and we price that load at or above its marginal cost, which, you know, for the purposes of this question we could, you know, say like Duke's avoided cost -- avoided energy and capacity cost, you know, as long as there aren't any incremental costs beyond that produced, then as long as you price, you know, say an off-peak rate at or above the incremental cost, then, you know, the -- the EV customer experiences some savings and, you know, presumably other customers would experience some savings as well because, you know, they're collecting more revenue from that EV ratepayer than is necessary to, you know, to cover those incremental costs.

You know, that's not to say that there wouldn't necessarily be other incremental costs, you know, and I could, you know, look at submetering as a potential incremental cost that, you know, would have to be recovered from someone and, you know, I think it's reasonable for, you know, at a minimum, those EV customers to pay, you know, a portion of that cost, hopefully it's not excessive, while still -- you know, if it -- if it might be excessive, kind of taking a long view and thinking, well, if this is going to deter the creation of benefits, maybe we can, you know, reach a conclusion that the long-term benefits of, you know, this off-peak load are sufficient for us to justify, you know, maybe some flexibility on, say, metering costs. If we think about, you know, other costs, like distribution systems cost, you know, it's certainly plausible that there could be, especially for like DC fast-chargers, that there could be system upgrades that are required in order to just, you know, simply host, you know, these, you know, large capacity chargers. It's not an issue that I addressed in my testimony. My assumption is that, you know, the cost causer would pay that, that is if you -- if you require system upgrades and they are, you know, considered special facilities or excess facilities, then you're going to be charged for those.

Q Thank you, Mr. Barnes. I understand you. I appreciate your -- I appreciate your time.

COMMISSIONER CLODFELTER: That's all I have. Thank you.

CHAIR MITCHELL: All right. Commissioner Duffley?

COMMISSIONER DUFFLEY: No questions.

CHAIR MITCHELL: Commissioner Hughes?

COMMISSIONER HUGHES: No questions.

CHAIR MITCHELL: All right. And Commissioner McKissick?

COMMISSIONER MCKISSICK: Madam Chair, I do have one or two quick questions.

CHAIR MITCHELL: All right.

EXAMINATION BY COMMISSIONER MCKISSICK:

Q Let me ask you this, sir. I know you discuss in your testimony the idea of submetering for consumer use, and more importantly, you talk about a six-hour off-peak period that would be available for people to use. Is this being done in any other jurisdictions that you're aware of at this time?

A Well, the topic of submetering, in terms of separately measuring, you know, EV usage from other whole home load, yeah, I mean, absolutely. And I believe -- I can't point to the specific number that was included in some of the exhibits in my testimony, but there are -- there are dozens of EV-specific rates that allow you to separately meter EV usage. Now, the specific topic of submetering is -- you know, to be truthful, I wish I would have spent a little bit more time on it in my testimony because it's not -- there are, I think, nuances to it that defy the simplicity of just the term submetering, because submetering can mean just separate measurement with a whole new utility revenue rate meter. It could also mean, you know, the installation of, you know, what would be considered a secondary meter that, you know, maybe doesn't cost quite as much as a new revenue meter. It could mean metering through capabilities that are integrated within kind of your more advanced chargers, your electric vehicle supply equipment. That is the -- you know, you don't need a separate utility meter because you're already getting the measurements that are communicated to the utility, you know, directly from the charger and -- or even from the -- from the EV itself.

Traditionally, utilities have gone, at least over the course of like the last, you know, say, five years or so, towards kind of the more revenue grade or, you know, submetering option that you would find for things like, you know, off-peak water heating or something like that. There are some programs and tariffs that have started to explore the EVSE, electric vehicle supply equipment integrated submetering. You know, there are probably half a dozen examples of that. That might be understating it. There are quite a few. So it's -- it's relatively tried and true. I think the reason why -- the reason why EVSE integrated metering probably hasn't been explored to the degree that -- that kind of call it more traditional metering options are, is just because, you know, one, it's new; two, there have been, you know, at least some instances of, you know, metering accuracy issues or communications issues or integration into utility billing system issues. So it's -- it's not quite as plug and play as something utilities have been doing for, you know, a really long time. Does that answer your question? Or -- I have kind of gone off a little bit.

Q No. You did answer, and I think you identified the different categories of submetering that you had -- that you intended to capture in your direct testimony, even though they were not all specifically laid out in your testimony. Now, another thing which you spoke of was the aggregation of multiple meters for the purpose of calculating demand charges and things of that sort. Can you elaborate a little bit further on that concept and whether that is, in fact, being employed within the utility industry at this time?

A It's being employed at a minimal level at the moment, as far as I'm aware. I've heard of a few examples for, you know, special -- in some cases that were very specialized. The specific example I cited was from a PacifiCorp general rate case where they had revoked what they called a conjunctive demand pilot. As far as I know, it's one of the kind of like most broadly applicable pilots of its type. And the basic idea is that if you are, you know, a single customer with multiple meters, the system itself is indifferent to what your non -- the generation and transmission system is indifferent to when the individual demands at those multiple meters are; what matters for the purposes of this system is, you know, when do those demands coincide.

And so what PacifiCorp had proposed is that since the system is indifferent, if we allow multiple meters to be aggregate together -- aggregated together for the purposes of determining, you know, those charges at the system level that, you know, it doesn't matter -- it doesn't matter what you -- what you use at an individual meter, you know, on off-peak hours, that, you know, it would be fairer to customers with multiple meters, and potentially -- and that could be, you know, EV customers or not, but also -- also potentially beneficial to, you know, have multiple kind of separately metered charging loads. And, you know, it possibly kind of introduce some flexibility into the way they operate those loads, but, you know, also potentially produce kind of broader benefits because, from a cost causation standpoint, using non-coincident demand charges to recover costs that are incurred based on coincident demand, frankly, is not the greatest reflection of cost causation.

Q And I could ask you dozens of questions, but in the interest of time, I won't. There's one last question, though. In terms of creating, perhaps, incentives that can help get equipment into the homes of consumers where they are able to able to go ahead and utilize, you know, charging stations for electric vehicles, what have you seen successfully done and introduced in other jurisdictions? I mean, can you give some examples? I know we looked at some things that have been proposed, but what have you seen successfully done in terms of incentives that have worked?

A Well, I can't -- off the top of my head, I can't quote kind of like specific project program success statistics. On the residential level, a lot of what has been done has been rebates to offset the incremental cost of buying a networked charger. That is a more advanced, you know, Level 2 EV charging equipment, as well as offset the additional cost that might be incurred through having to install a -- basically, like a separate meter base to house the submeter.

And I believe Mr. Huber mentioned this, you know, that -- that additional, say, service panel and meter base even to house a submeter can be relatively expensive. You know, it can be certainly, potentially more than $1,000. That's not necessarily going to be the case for everybody. You know, some of the kind of just broad estimates I've seen say maybe 14, $1,500, depending on where you are, depending on what the existing electrical setup is. So, you know, if you think about a residential home-charging EV rate that is going to save a customer $100 a year, well, if you start layering on, you know, $1,500 to install the meter base and submeter and then maybe an additional $1,200 or $1,500 for a Level 2 EV charger, you know, that $100 a year doesn't necessarily go that far, or at least it's never going to repay, you know, the cost of the equipment itself. You know, some of that EVSE integrated metering can, you know, potentially save -- save on some of those costs. You know, some of the numbers I've seen have been where you have to buy a slightly more advanced charger, so it costs a little bit more, but you don't have to install that separate meter base. And maybe, at the end of the day, you save something like $400, relative to if you didn't install a -- an advanced charger and just, you know, basically plugged into the wall, but still installed the separate submeter.

So most of the programs that I have seen have kind of gotten -- have gotten at that up-front cost issue through, you know, provide a $400 or $500 rebate for the incremental cost of, you know, basically getting a high quality network capable EV charger into the home.

COMMISSIONER MCKISSICK: I don't have any further questions.

CHAIR MITCHELL: All right. We've come to the end of the day today. We will go off the record; go back on the record tomorrow morning at 9:00. Thank you very much.

(The hearing was recessed, to be continued consideration before we begin?

(No response.)

CHAIR MITCHELL: All right. Hearing none, we will return to NCSEA witness Barnes.

Whereupon,

JUSTIN R. BARNES,

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

CHAIR MITCHELL: I believe we were with questions on Commissioners' questions. Any questions on Commissioners' questions?

MS. EDMONDSON: I had a couple of questions.

CHAIR MITCHELL: Is that Ms. Edmondson?

MS. EDMONDSON: Yes.

CHAIR MITCHELL: Ms. Edmondson, you may proceed.

EXAMINATION BY MS. EDMONDSON:

Q. Good morning, Mr. Barnes. Lucy Edmondson with the Public Staff.

Mr. Barnes, do you agree that there is value to capacity in all hours?

A. That's an interesting question. There is a certain amount of value to having, you know, base load capacity, not just capacity that's available, say, only during peak times. You know, traditionally, though, we assign a value of capacity, or we assign, you know, responsibility for costs based on contribution to, you know, some measure -- some measure of peak load, though.

Q. Do you agree that some value should be allocated to off-peak loads?

A. From -- you know, from simply kind of a cost allocation standpoint; is that your question?

Q. Yes.

A. I guess it depends on system -- on system conditions and exactly, kind of, how you -- you know, there are different ways in which you might attribute, you know, some level of cost responsibility to off-peak load. You know, which one you choose depends on the circumstances and the system conditions, though.

Q. Are you advocating that ED rates should not be allocated any existing rate base cost?

A. Well, my specific recommendations on -- you know, would -- my specific recommendations were based on existing rates. So modifications of existing rates, such as OPT-V. It's less clear exactly how you would do it from the standpoint of residential rates, but since though existing rates include embedded costs, you know, simply translating them or, you know, modifying them in the way that I suggested, you know, would kind of automatically account for the fact that you do have embedded costs. So it wouldn't be strictly kind of marginal cost-based pricing if you're utilizing existing rates.

Q. Another question. Aren't there some incremental investments beyond the meter that will be required to serve this additional load?

A. I think it depends -- you know, there certainly could be. It depends on, you know, the specifics of that additional load as to what those costs might be. You know, it's certainly plausible that if a, say, residential customer installs a certain size level 2 charger, they could, you know, exceed their existing service entrance capacity and potentially have to, you know, have that replaced or exceed the transformer capacity or, you know, cause some form of upgrade to be incurred.

It's certainly also possible that, if you're thinking about larger loads, you know, DCFC chargers, especially, say, concentrations of them, that you could certainly -- certainly have impacts on, say, like the primary distribution system from loads of that type that are not, maybe strictly speaking, kind of customer specific, if that makes sense.

Q. Yes.

A. So yeah, it's certainly plausible there could be, you know, say, additional distribution costs that would be presumably recovered through rates.

Q. How would you recover those?

A. Well, the specific recommendation I had for nonresidential customers was that the existing on-peak demand rates be translated to volumetric rates. And what that would accomplish is, you know; one, mitigating the effects of demand charges on, you know, relatively low utilization rate stations; two, you know, making the charges effectively kind of based on average contribution to during peak -- to load during peak periods.

Now, I did not suggest that the economy-demand charge, which is president OPT-V, and which I interpret is kind of like a -- you know, basically it's a noncoincident distribution to band charge. I did not recommend that that be translated into a volumetric rate. So just to kind of make that clear, you would have -- still have this kind of demand rate component for facilities in close proximity to the customer, whereas you're kind of more system-level demand costs would be assumed through a volumetric rather than an on-peak demand rate.

Q. Have you done any analysis of the cost in revenue curves associated with the incremental load of EVs?

A. No, I have not.

Q. And how do you propose the incremental cost in revenues associated with the load of EVs be recovered?

A. Well, I suppose you don't know, you know, right off kind of right at the start, if we assume -- you know, we don't know exactly how much EV load we are going to have. We don't exactly know how much the costs are going to differ, say, from embedded rates. I think you could, you know, possibly -- you could possibly track it and true it up as we do in, you know, many other ways in a rate case or -- you know, I'm not sure what the, kind of, regulatory, you know, ratemaking implications are of tracking it kind of like in a programmatic way and possibly establishing some form of other kind of, like, review interrupt. I suppose that's one possibility. But I would imagine that, you know, existing mechanisms, such as rate cases, kind of function as true-ups as well.

Q. And my last question. You -- you're familiar with Mr. Floyd's proposal for a rate study.

If we didn't create an EV rate here, but what would you think if we were able to do the rate study and prioritize development of EV rate in that rate study?

A. I would certainly be supportive of if we didn't, you know, adopt an EV rate here, that EV rates be prioritized. I can -- not knowing what the timeline is or what prioritization means, I guess I'm a little bit reluctant to venture an opinion on, you know, a very specific, kind of, I-approve-of-that approach. But yes, in principle, expediting is better than not expediting.

Q. All right. Thank you.

CHAIR MITCHELL: All right. Additional questions on Commissioners' questions?

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

CHAIR MITCHELL: Mr. Neal, you may proceed.

EXAMINATION BY MR. NEAL:

Q. Good morning, Mr. Barnes.
A. Good morning.
Q. Just a quick follow up on part of your conversation with Commissioner Clodfelter around the same issue that you were just talking about, in terms of timing of adopting new rates.
Are you -- you are familiar with the pending Duke Energy Carolinas electric transportation pilot in Docket E-7, Sub 1195, correct?
A. I am somewhat familiar, insofar as I've reviewed it. I was most specifically kind of looking at, you know, rate proposals and whether they're not -- whether there were or were not rate proposals, but I'm fairly conversant, I would say.
Q. Would you agree that one way to address the timing concern that you've expressed would be for the Commission to order adoption of pilot EV-specific rates in the ET pilot, itself?
A. I'm not sure if I would refer to them as pilots. But that's, I guess, one procedural venue. Whether or not that's, kind of, procedurally appropriate, I don't know, but it's -- you know, it is one opportunity to take a bite of the apple, I suppose.
Q. Thank you.

MR. NEAL: No further questions, Chair Mitchell.

CHAIR MITCHELL: Okay. Additional questions on Commissioners' questions?

MS. JAGANNATHAN: Chair Mitchell, this is Molly Jagannathan for the Company. We don't have any questions.

CHAIR MITCHELL: Okay. Mr. Smith, any questions from NCSEA?

MR. SMITH: No questions from NCSEA.

CHAIR MITCHELL: Okay. All right. With that, Mr. Barnes, I believe you are off the hook for now, and you of may step down.

Do I need to entertain any motions, Mr. Smith?

MR. SMITH: Yes. Madam Chair, as this concludes Mr. Barnes' testimony in the Duke Energy Carolinas rate case, I'd move that his eight exhibits which were included with his prefiled direct testimony be admitted into the evidence for this case.

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

(Exhibits JRB-1 through JRB-8, were

admitted into evidence.)

CHAIR MITCHELL: All right. Mr. Barnes, thank you for your testimony.

THE WITNESS: Thank you. Have a nice day.

CHAIR MITCHELL: All right. We are now with Sierra Club.

MS. CRALLE JONES: Good morning. Cathy Cralle Jones on behalf of the Sierra Club. Good morning, Chair Mitchell and Commissioners.

CHAIR MITCHELL: Good morning, Ms. Cralle Jones. You may call your witnesses.

MS. CRALLE JONES: Sierra Club calls Mr. Mark Quarles to the stand.

CHAIR MITCHELL: All right. Mr. Quarles, there you are. Would you raise your right hand, please, sir.

Whereupon,

MARK QUARLES,

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

CHAIR MITCHELL: All right. You may proceed, Ms. Cralle Jones.

DIRECT EXAMINATION BY MS. CRALLE JONES:

MR. SMITH: Thank you.
Commissioner Clodfelter, Mr. Barnes is available for cross examination.

COMMISSIONER CLODFELTER: Mr. Smith, just to be sure I'm complete, are there any exhibits that need to be imported from the DEC case? I don't see any on my list, but just wanted to confirm with you.

MR. SMITH: None, no.

COMMISSIONER CLODFELTER: Okay. That's great. Just wanted to confirm.

Ms. Goldstein, I believe the witness is available for you.

MS. GOLDSTEIN: Thank you, Commissioner Clodfelter. I realize Hornwood, Inc. reserved five minutes for Mr. Barnes. We actually do not have any questions for this witness.

COMMISSIONER CLODFELTER: All right. That's the only party I had on my list to ask any reserved cross examination. Let me ask to be sure.

Are there any other parties who wish to cross examine Mr. Barnes? If not, Mr. Smith, then, quite obviously, there's no redirect, so let's see if Commissioners have any questions.

Commissioner Brown-Bland?

COMMISSIONER BROWN-BLAND: No questions.

COMMISSIONER CLODFELTER: Commissioner Gray?

COMMISSIONER GRAY: No questions for Mr. Barnes.

COMMISSIONER CLODFELTER: Chair Mitchell?

CHAIR MITCHELL: I do have a question for Mr. Barnes.

EXAMINATION BY CHAIR MITCHELL:

Q. Mr. Barnes, in the DEC rate case hearing several weeks ago, Commissioner Clodfelter asked you several questions about EV rate design. And I want to ask you sort of a general question about what you would recommend the Commission do at this point in time on the pending EV pilot application that's before the Commission. If you have any thoughts or suggestions, I'd welcome those at this time.

A. Well, it's been a little while since I reviewed the details of, you know, Duke's proposed programs.

Q. Mr. Barnes, I'm sorry, I want to interrupt you. I want to tailor my question a little bit there just to sort of put some sort of boundaries around your answer. But, specifically in light of the proposal that the Company has made in these cases to undertake a comprehensive rate design study.

A. Well, I mean, I note that in their application they didn't really pose anything, you know, substantive or, you know, particularly meaningful with respect to EV rate design. And, you know, in the -- taking that in the context of the comprehensive rate design study, I kind of continue to believe that, if you were to conduct a comprehensive rate design study seeking to produce, you know, rates for EV charging, you're ultimately going to end up pretty much in the same place as I recommended in my testimony. Realizing that, yes, you know, demand charges are a huge limitation for nonresidential customers, particularly noncoincident demand charges. And not having a separately metered option, you know, presents a lot of challenges for home EV charging or nonresidential charging.

So, I guess, you know, from the standpoint of a comprehensive evaluation, I'm not sure a comprehensive evaluation is necessary to kind of reach those basic conclusions.

With respect to the transportation docket, you know, if the Commission were to pursue something along the lines of what I've recommended in the transportation docket, then, you know, certainly I would be -- I would be pleased with that. But whether it's in this docket or in that docket, I feel like it's something that needs to be addressed in the relatively short term. And like I said, it's -- they're fairly, kind of, common problems and known solutions to those problems.

Q. Okay. Thank you.

CHAIR MITCHELL: Nothing further for the witness.

COMMISSIONER CLODFELTER: Okay. Thank you.

Commissioner Duffley?

COMMISSIONER DUFFLEY: No questions.

COMMISSIONER CLODFELTER: Commissioner Hughes?

COMMISSIONER HUGHES: No questions.

COMMISSIONER CLODFELTER: Commissioner McKissick?

COMMISSIONER McKISSICK: No questions.

COMMISSIONER CLODFELTER: Okay. Are

there any questions on the Commission's question?

(No response.)

COMMISSIONER CLODFELTER: If not, then I think we are ready, Mr. Smith. I'm not sure you have any additional motions you need to make, but I'll ask you.

MR. SMITH: Sure. I just have two more things. Commissioner Clodfelter, as this concludes Mr. Barnes' testimony in the Duke Energy Progress rate case, I'd move that his nine exhibits which were included with his prefiled testimony be admitted into the evidence for this case.

COMMISSIONER CLODFELTER: Without objection, they will be so admitted.

(Barnes Exhibits 1 through 9 were admitted into evidence.)

MR. SMITH: And lastly, I'd ask that Mr. Barnes be excused from the proceedings at this point.

COMMISSIONER CLODFELTER: Okay. Unless someone wants to make Mr. Barnes cool his heels for a while longer, hearing no one, he can be excused. Thank you, Mr. Barnes.

THE WITNESS: Thank you, Commissioner,

Chair. Good afternoon, everyone.

COMMISSIONER CLODFELTER: Thank you.

MR. SMITH: Thank you.

COMMISSIONER CLODFELTER: Mr. Smith, anything further from NCSEA?

MR. SMITH: Nothing at this time. Thank you.

COMMISSIONER CLODFELTER: Thank you.

Ms. Goldstein, are you ready to go?

MS. GOLDSTEIN: Yes, sir. Thank you, Commission Clodfelter. Hornwood, Inc. would like to call witness Brian Coughlan at this time. Mr. Coughlan, if you would please turn on your camera.

MR. COUGHLAN: It is turned on, and I am here.

COMMISSIONER CLODFELTER: Mr. Coughlan, would you -- is it Coughlan?

MR. COUGHLAN: Coughlan, that's correct.

COMMISSIONER CLODFELTER: Okay. Great.

Whereupon,

BRIAN W. COUGHLAN,

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

COMMISSIONER CLODFELTER: Proceed, Ms. Goldstein.

MS. GOLDSTEIN: Thank you.

DIRECT EXAMINATION BY MS. GOLDSTEIN:

Q. Mr. Coughlan, would you please state your full name for the record?

A. Brian Walker Coughlan.

Q. Okay. Mr. Coughlan, by whom are you employed and what is your business address?

A. Utility Management Services. We are at 6317 Oleander Drive, Suite C, Wilmington, North Carolina 28403.

Q. Okay. Mr. Coughlan, what is your occupation at Utility Management Services?

A. I am the president and owner of Utility Management Services.

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

A. Hornwood, Inc.

Q. Thank you. Mr. Coughlan did you cause to be prefiled on April 13, 2020, direct testimony consisting of 34 pages?

A. I did.

Q. Okay. Mr. Coughlan, do you have any changes to your testimony?

A. No.

Q. We did actually have two changes that we prepared an errata sheet for, the two clerical issues; do you remember those?

A. Yes. There were two slight clerical admin issues, and we did correct those and submit an errata testimony.

Q. Okay. Thank you. And with those corrections, if I were to ask you the same questions today, would your answers be the same?

A. Yes.

Q. Okay. Thank you, Mr. Coughlan. Have you made a summary of your testimony?

A. Yes, I have.

Q. Okay. And did you cause to be filed on September 29, 2020, a summary of your testimony?

A. Yes, I did.

Q. Thank you.

MS. GOLDSTEIN: Commissioner Clodfelter, at this time, I'd ask that Mr. Coughlan's direct testimony, the errata sheet regarding the same, as well as Mr. Coughlan's summary be copied into the record as if given orally from the stand.

COMMISSIONER CLODFELTER: Okay. You've heard the motion from Ms. Goldstein. Are there any objections to the motion?

(No response.)

COMMISSIONER CLODFELTER: Hearing no objections, it will be so ordered.

(Whereupon, the prefiled direct testimony, errata, and testimony summary of Brian W. Coughlan were copied into the record as if given orally from the stand.)

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-2, SUB 1219

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of:

Application of Duke Energy Progress, LLC
For Adjustment of Rates and Charges Applicable
to Electric Service in North Carolina

DIRECT TESTIMONY

OF

BRIAN W. COUGHLAN

ON BEHALF OF HORNWOOD, INC

April 13, 2020

Q. Please state your name, business address, and current position.

A. My name is Brian W. Coughlan. I am the President, founder and owner of Utility Management Services, Inc. ("UMS"). My address and contact information are:

Utility Management Services, Inc.
6317 Oleander Drive, STE C
Wilmington, NC 28403
Email: BCoughlan@UtilManagement.com
Phone: (910) 793-6232 x 102
Cell: (910) 471-1512

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A. I received a Bachelor of Science in Electrical Engineering from Virginia Tech in 1982, a Master of Science in Electrical and Computer Engineering from North Carolina State University in 1990 and an Executive Master of Business Administration from the University of North Carolina – Chapel Hill in 2000.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL BACKGROUND PRIOR TO FOUNDING UMS.

A. From June of 1982 through December of 1997, I worked in a variety of customer service, engineering and management roles at Carolina Power & Light Company ("CP&L", now Duke Energy Progress) . In my first position at CP&L, I was responsible for providing customer service, rate analysis, rate consulting and contract administration services to industrial, governmental and larger commercial customers in several counties in northern North Carolina.

By the end of my career at CP&L, I managed a workforce of 240 employees and 240 contractors. These individuals were responsible for providing customer service to 330,000 customers in 19 counties in eastern North Carolina as well as designing, building, operating and maintaining the distribution system throughout that territory. These individuals were also engaged in providing rate consulting services to our customers.

Q. DO YOU HAVE ANY PROFESSIONAL DESIGNATIONS?

A. Yes. I am a registered Professional Engineer in North Carolina. I am also a Certified Energy Manager, Certified Energy Auditor, Certified Demand Side Management Professional and Certified Energy Procurement Professional by the Association of Energy Engineers.

Q. WHAT SERVICES DOES UMS PROVIDE?

A. UMS is an electric bill auditing and rate consulting company. We enter into agreements with our clients which establish UMS as the customer's agent. As their agent, we work to reduce our clients' electric bills by identifying billing errors, overcharges and rate savings opportunities. We also advocate on behalf of customers to increase the fairness of electric rates and increase pricing options.

We have been in business for 22 years. We are the largest business of our type in the southeastern U.S. We have worked with almost 10,000 business customers with approximately 300,000 electric service accounts. We work within the Duke Energy Progress service territory as well as the service territories for many other power providers and many other states.

Q. HAVE YOU TESTIFIED BEFORE THE COMMISSION IN THE PAST?

A. Yes. I have testified before the NCUC and in front of other state regulatory commissions on numerous occasions.

Q. WHO ARE YOU REPRESENTING IN THIS RATE CASE?

A. We are representing Hornwood, Inc. Hornwood is a service-oriented, solution based vertical manufacturer of warp and circular knitted fabrics. Hornwood's manufacturing processes include warping, knitting, dyeing, finishing, face finishing, and inspection, along with a fully functional color development and physical testing lab. Hornwood thrives on driving innovation and creating value for all customers.

Hornwood cares deeply about reducing its impact on the environment and offers sustainable solutions such as yarn made from recycled or renewable resources. Hornwood has been a bluesign system partner since 2016 and an ISO 9001 registered company since 1997. Hornwood has been in continuous operation in

North Carolina since 1946. The Lilesville, NC plant is served by Duke Energy Progress, has 300,000 square feet of production and office space and 350 employees.

Q. WHAT RELIEF IS HORNWOOD REQUESTING IN THIS RATE CASE PROCEEDING?

A. Hornwood is requesting the following changes:

1. <u>Eliminate Cap of 85 Customers on the DEP Large General Service (Real Time Pricing) Schedule LGS-RTP (RTP).</u>
2. <u>Reduce the minimum demand requirement to qualify for RTP from 1,000 KW to 75 KW.</u>
3. <u>Change the name of this rate to the General Service (Real Time Pricing) Schedule GS-RTP (RTP).</u>

The first sentence under the <u>AVAILABILITY</u> section of the RTP rate currently says:

> "This Schedule is available for electric service to a maximum of eighty-five (85) nonresidential Customer accounts with a Contract Demand that equals or exceeds 1,000 kW."

We are requesting that this sentence be changed to read:

> "This Schedule is available for electric service to any nonresidential Customer accounts with a Contract Demand that equals or exceeds 75 kW."

Q. IS HORNWOOD REQUESTING ANY OTHER CHANGES IN THE DESIGN, USE AND APPLICATION OF THE RTP RATE?

A. No. We request that the rest of the design, use and application of the rate continue to exist as it does today.

Q. WHEN WAS THE RTP RATE INTRODUCED AND HOW DOES THE RATE WORK?

A. The RTP rate was proposed by CP&L in 1996. Excerpts from the December 16, 1996 letter proposing the new rate from CP&L Associate General Counsel Len S. Anthony in NCUC Docket E-2 Sub 704 are copied below.

> "During the past several years, Carolina Power & Light Company ("CP&L") has reviewed the "Real Time Pricing" rate design concept to determine the potential benefits it may offer that are not available under any of the Company's other standard tariffs. CP&L requests that LGS-RTP-1 be available on an experimental basis to a limited number of customers to permit a thorough evaluation of program costs, administration issues, and customer reaction prior to a decision on introduction of the tariff on a permanent basis. Schedule LGS-RTP-1 will

be available to no more than twenty-five (25) customers with contract demand requirements of 1,000 kW or greater."

" LGS-RTP-1 offers hourly marginal cost-based prices for electricity consumption in excess of a Customer Baseline (CBL). The hourly rates are developed daily and provided to participants prior to 4 p.m. on the preceding business day. The CBL is established individually for each participant and is intended to represent the customer's hourly consumption during the previous year under standard tariffs. The CBL is the basis for achieving revenue neutrality with the appropriate standard tariffs currently used to provide electric service."

"LGS-RTP-1 will provide CP&L an opportunity to improve utilization of its existing generation resources and will provide customers cost-based prices to influence their electric usage. When CP&L has generation resources available, hourly rates will be low to encourage increased consumption. Conversely, when generation resources are constrained, customers will be provided hourly rates that encourage a reduction in consumption. Customers may benefit under this rate design by either (1) shifting consumption away from high cost periods or (2) increasing consumption during low cost periods."

Q. WAS THE CAP ON THE NUMBER OF CUSTOMERS WHO MAY RECEIVE SERVICE UNDER THE RTP RATE SUBSEQUENTLY INCREASED?

A. Yes. In a letter dated December 14, 1998, CP&L requested multiple changes in the rate that were intended to simplify and clarify the tariff making it more easily understood and to help avoid misunderstandings in its application. In an indication that CP&L was satisfied with the initial testing of the rate, they also requested that the maximum number of customers eligible to receive service under the RTP rate be increased from 25 to 85. In an order dated December 22, 1998, the Commission agreed to the proposed changes and ordered, among other changes:

> "5. The customer limitation is increased from 25 to 85."

Q. IS THE RTP RATE FULLY SUBSCRIBED?

A. Yes. Hornwood requested to be served under the RTP rate and was told it was fully subscribed.

Q. DOES EXPANDING ELIGIBILITY FOR THE RTP RATE REQUIRE UPGRADES IN METERING TECHNOLOGY OR BILLING SYSTEMS TECHNOLOGY?

A. No. The rate has been in use for 23 years. The metering and billing systems have been successfully measuring customer usage and billing customers for that usage for 23 years. There is nothing new about this metering technology or billing system technology.

Q. DO THE PROPOSED CHANGES NEED TO BE DESIGNED, TESTED OR ANALYZED FURTHER BEFORE THEY CAN BE IMPLEMENTED?

A. No. The RTP rate has existed for 23 years. It is well designed and has been used successfully by many customers for many years.

Q. DO THE HOURLY PRICES ON REAL TIME PRICING RATES VARY WIDELY DEPENDING ON WEATHER AND OVERALL POWER DEMANDS IN A REGION?

A. Yes. The pricing on RTP rates during critical peak periods can be 5,000% or more of the pricing during low-priced hours. These types of rates are offered by many power providers throughout the U.S. They are often tied to the hourly pricing offered by the Independent System Operator (ISO) (eg – PJM) serving the region.

The RTP hourly rates offered by DEP are presently confidential and proprietary. However, in other areas it is not unusual for the RTP to be less than $.01/KWH during many hours of the year and to go as high as $.50/KWH or more during a very few extremely hot or cold peak hours per year. The very high-priced hours could easily occur during less than 20 hours per year while low priced hours could easily occur during 7,000 hours per year or more.

Q. DOES THE RTP RATE PROVIDE A FAIR RATE OF RETURN FOR DEP?

A. Yes. As stated in Len Anthony's above referenced letter, the RTP rate is designed to be revenue neutral with DEP's other rates. In theory, if all eligible customers transitioned to the RTP rate, DEP would neither gain nor lose revenue.

Also, DEP analyzed the RTP rate as a part of this rate case proceeding. DEP has proposed increases in the facilities demand charges that range from 13.6% to 27.5% depending on the voltage and transformation requirements for the customer to ensure that the RTP rate continues to provide them a fair rate of return.

Q. HAS DEP PROPOSED ELIMINATING THE RATE AT ANY TIME OVER THE PAST 24 YEARS?

A. No. They have continued to maintain and use the rate and have not proposed eliminating it at any point.

Q. DO THE 85 CUSTOMERS CURRENTLY SERVED UNDER THE RTP RATE ENJOY AN UNFAIR ADVANTAGE OVER THE THOUSANDS OF

CUSTOMERS WHO ARE NOT ALLOWED TO RECEIVE SERVICE UNDER THIS RATE?

A. Yes. This very small and selective customer sample has a distinct competitive advantage over the thousands of customers that would qualify for the rate under our proposal. The customers served under this rate have the ability to shift their load in response to strong pricing signals. This allows them to reduce their overall electric bills giving them a competitive advantage over other customers.

Q. DO CUSTOMERS ON THE RTP RATE HAVE THE ABILITY TO SHIFT THEIR LOAD IN RESPONSE TO PRICING SIGNALS AND REDUCE THEIR ELECTRIC BILLS?

A. Yes. This is the purpose of RTP rates. RTP rates send very strong pricing signals. Customers that respond to those signals by reducing their usage during high priced periods or increasing their usage during very low priced periods can reduce their electric bills.

Q. DOES DEP BENEFIT WHEN CUSTOMERS RESPOND TO PRICING SIGNALS?

A. Yes. DEP receives significant short-term benefits by customers reducing their loads during times of critical peak loading on the DEP system. Customers who respond to the pricing signals sent by the RTP rate help reduce the system peak demands on the DEP system. This helps DEP reduce the need to build additional peaking plants and transmission system infrastructure, reducing overall cost for DEP. Similarly, customers who increase their usage during low priced hours help to increase the system load during otherwise lightly loaded hours. This leads to better utilization of DEP's fleet of generating plants.

Q. WILL ELIMINATING THE CAP OF 85 CUSTOMERS AND REDUCING THE PEAK DEMAND REQUIREMENT TO 75 KW OR HIGHER INCREASE THE NUMBER OF CUSTOMERS WHO QUALIFY FOR THIS RATE?

D

Q. WILL ELIMINATING THE CAP OF 85 CUSTOMERS AND REDUCING THE PEAK DEMAND REQUIREMENT TO 75 KW OR HIGHER INCREASE THE COMPETITIVENESS OF PARTICIPATING CUSTOMERS?

A. Yes. Participating customers would have the ability to manage their electric bills by responding to pricing signals. This would enhance their overall competitiveness and put them on a more level playing field with competitors in other states and countries that offer these types of rates.

Q. WHAT ARE THE POTENTIAL BENEFITS TO CUSTOMERS OF AN RTP RATE?

A. Customers on the RTP rate have greater control over their overall electricity costs. By shifting their load in response to pricing signals, they can manage their electricity costs. This could make the difference between staying in business vs. going out of business for some customers.

Q. WHICH TYPES OF CUSTOMERS ARE MOST LIKELY TO BENEFIT FROM THE RTP RATE?

A. Industrial customers frequently have the ability to shift load and schedule production in response to pricing signals. These customers are most likely to participate in the RTP rate, shift load and save money for themselves, DEP and other customers. Many commercial and governmental customers also have the ability to shift load and take advantage of the pricing flexibility offered in the RTP rate. This includes municipal water treatment plants, sewage treatment plants and others.

Q. IS DEP OFFERING ANY OTHER NEW TYPES OF DYNAMIC PRICING, REAL TIME PRICING, OR CRITICAL PEAK PRICING FOR CUSTOMERS IN THIS RATE CASE?

A. No. The direct testimony of DEP witness Michael J. Pirro in this rate case proceeding includes the following:

"Q. IS THE COMPANY PROPOSING ANY NEW PEAK TIME PRICING RATE DESIGNS OFFERING REAL TIME PRICE SIGNALS IN THIS PROCEEDING?

A. No, not at this time. However, the Company is actively monitoring DE Carolinas' recently implemented dynamic pricing pilots to evaluate the effectiveness of dynamic pricing on residential and small nonresidential customers. The pilots review and analyze rate designs that offer customers opportunities to respond to price signals to achieve a lower cost for electric service. The Company is upgrading its billing system infrastructure to better support these types of designs. Smart Meters, currently being installed for the majority of customers, will provide the interval level data that is required to develop and bill these innovative designs, as discussed in the testimony of Witness Don Schneider……."

Q. WILL THE PLAN DESCRIBED ABOVE BY WITNESS PIRRO ADDRESS THE CONCERNS OF HORNWOOD AND OTHER CUSTOMERS WITH PEAK DEMANDS OF MORE THAN 75 KW?

A. No. As stated by witness Pirro, the rates being piloted by DEC only apply to residential and small commercial customers. One of those rates applies to commercial customers with peak demands up to 75 KW. The other commercial rates only apply to customers up to 30 KW.

Also, the plan described by Pirro will postpone the introduction of any new rates by four to five years or longer.

Finally, the rates referenced by Pirro require Smart Meters and an upgrade to the billing system infrastructure. As previously mentioned, the RTP rate is already being administered with existing metering technology and existing billing system infrastructure. In other words, there is no need to postpone the expansion of the RTP rate.

Q. ARE THERE SOCIETAL FINANCIAL BENEFITS TO OFFERING RTP RATES?

A. Yes. The RTP rate gives participating customers strong financial incentive to reduce their peak loads during times of extreme system loading. This reduction in individual customer peak load helps to reduce the overall system peak load. The reduction in overall system peak load means that less peak generating plants and less transmission system infrastructure need to be built. The reduction in peak generating units and transmission infrastructure reduces the overall rate base which ultimately saves money for all customers.

Q. ARE THERE SOCIETAL ENVIRONMENTAL BENEFITS TO OFFERING RTP RATES?

A. Yes. RTP rates reduce the overall peak system load. In today's nomenclature, they flatten the curve. In doing so, they result in less reliance on running existing peak generating units. Peak generating units often are the most environmentally harmful plants. By reducing the amount of time these plants must be run, we all benefit from cleaner air, reduced carbon and other emissions and reduced global warming. If enough customers switch to the RTP rate and respond to the pricing signals, some older units could be retired earlier than planned or the construction of other generating units could be canceled or postponed by many years.

Q. ARE THERE REASONS THAT DEP MIGHT BENEFIT BY NOT EXPANDING THE RTP RATE?

A. Yes. Duke Energy only earns profits on their investments in capital. The metering upgrades, billing system infrastructure upgrades, generating plants and transmission system upgrades that DEP is proposing are capital intensive projects that will be profitable for their shareholders. Expanding the RTP rate does not require metering system upgrades and billing system upgrades and may postpone or eliminate the need for some future generating plants and transmission system upgrades. These changes may not be in the best long-term interest of shareholders, but are very much in the best short-term and long-term interest of DEP customers and the state of North Carolina.

Q. IS DEP BEHIND MANY OTHER INVESTOR OWNED UTILITIES IN OFFERING REAL TIME PRICING, DYNAMIC PRICING AND CRITICAL PEAK PRICING RATES?

A. Yes. DEP was ahead of most power providers in offering an RTP rate in 1996. However, by maintaining a cap of 85 customers and failing to offer this rate to smaller customers, they are now well behind many other power providers in offering real time pricing rate options to customers. A small sample of some of the other power providers that offer real time, critical peak pricing or dynamic pricing rates are shown below:

Power Provider	Rate	KW Applicability	Max. # of Customers
Duke Energy Carolinas (NC)	Schedule HP – Hourly Pricing For Incremental Load	> 1,000 KW	150
Duke Energy Carolinas (NC)	Schedule SGS-CPP (NC) Small General Service Critical Peak Pricing (Pilot)	< 30 KW	500 (pilot)
Duke Energy Carolinas (NC)	Schedule SGS-TOU-CPP (NC) Small General Service Time of Use –	< 30 KW	500 (pilot)

	Critical Peak Pricing (Pilot)		
Duke Energy Carolinas (NC)	Schedule SGS-TOUD-DPP (NC) Small General Service Time of use Demand – Daily Peak Pricing (Pilot)	< 75 KW	500 (pilot)
Duke Energy Carolinas (SC)	Schedule HP – Hourly Pricing For Incremental Load	> 1,000 KW	150
Duke Energy Ohio	Rate RTP – Real Time Pricing Program	> 15 KW	Unlimited
Dominion North Carolina Power	Schedule 10 – Large General Service	> 500	Unlimited
Dominion North Carolina Power	Schedule LGS – RTP With Customer Baseline Load	> 3,000 KW	Unlimited
Dominion Virginia Power	Schedule 10 – Large General Service	> 500 KW	Unlimited
Dominion Virginia Power	Dominion Energy Market Based Rate Pilot	> 5,000 KW	Unlimited

Georgia Power	Real Time Pricing – Day Ahead	> 250 KW	Unlimited
Georgia Power	Real Time Pricing – Hour Ahead	> 5,000 KW	Unlimited
Alabama Power	Rate ILD – Incremental Load – Day Ahead	> 500 KW	Unlimited
Alabama Power	Rate RTP – Real Time Pricing (Industrial Power)	> 3,000 KW	Unlimited
Commonwealth Edison (IL)	Rate BESH – Basic Electric Supply – Hourly Pricing	> 100 KW	Unlimited
Ameren Illinois	Rider RTP – Real Time Pricing	<150 KW (& Residential)	Unlimited
Ameren Illinois	Rider HSS – Hourly Supply Service	> 150 KW	Unlimited

Q. DOES THE ABSENCE OF THESE TYPES OF RATES HURT INDUSTRIAL RECRUITMENT AND RETENTION IN THE DEP SERVICE TERRITORY?

A. Yes. Since the DEP RTP rate is capped and fully subscribed, a real time pricing rate is not available to new customers in the DEP service territory. It is currently only available to the 85 customers who were lucky enough to know about this rate and get enrolled before the rate was fully subscribed. This makes it harder to attract and retain energy intensive manufacturing and other businesses in the DEP service territory. DEP also does not offer and dynamic pricing rates or any critical peak pricing rates at this time, which also harms industrial recruitment and retention.

Q. HAS NORTH CAROLINA LOST MANY INDUSTRIAL PLANTS AND JOBS IN RECENT DECADES?

A. Yes. Both DEC and DEP have requested special consideration for manufacturing customers in recent years to try to stem further loss of industry, industrial production and industrial jobs in NC. In Docket E-7 Sub 1152, DEC (not DEP) proposed a Jobs Retention Rider. In Docket E-2 Sub 1023, DEP proposed an Industrial Economic Recovery rider. In these cases, DEC and DEP argued that rate relief was needed for industrial customers to stop the losses of these jobs in NC. They provided extensive data in support of the need for this relief.

An excerpt from the expert witness testimony of Michael T. O'Sheasy on behalf of DEP in Docket E-2 Sub 1023 is shown below:

> "Q. WHAT IS THE PURPOSE OF INDUSTRIAL RETENTION RIDER IER?
>
> A. Industrial Economic Retention Rider IER is intended to provide a temporary lower rate to industrial customers to assist them in retaining and

increasing employment within PEC's service area.

Q. PLEASE DESCRIBE THE ECONOMIC SITUATION FACING PEC'S INDUSTRIAL CUSTOMERS.

A. Progress Energy's sales to industrial accounts peaked in 1997 and, as shown in O'Sheasy Direct Exhibit No. 6, have declined nearly every year since resulting in 28% fewer kWh sales in 2011 than sold in 1997. This decline of the state's manufacturing base has also been seen in unemployment statistics. Unemployment in the counties served by PEC has more than doubled since 1997 when it was 5% and stood at an average of 11.2% at year-end 2011. O'Sheasy Direct Exhibit No. 7 shows the unemployment rate for PEC's North Carolina service territory by region during this time.

Q. HOW DOES THE LOSS OF INDUSTRIAL SALES AFFECT PEC AND ITS CUSTOMERS?

A. Typically industrial customers have higher load factors than commercial or residential customers (i.e. their kWh consumption relative to their demand is higher); loss pf these customers means that fixed costs historically recovered from these industrial customers must be shifted to other rate classes. There is also the negative impact of the loss of industrial accounts and loss of jobs upon the economy which therefore lowers residential wages and commercial business.

An excerpt from DEC's August 14, 2017 petition for an order approving a Job Retention Rider in Docket E-7 Sub 1152 is shown below:

> "In order to stem further loss of industry, industrial production and industrial jobs in its service territory, Duke Energy Carolinas, LLC ("Company" or "DEC") respectfully petitions the North Carolina Utilities Commission ("Commission") in accordance with the Commission's December 8, 2015 Order Adopting Guidelines For Job Retention Tariffs ("Order") in Docket No. E-100, Sub 73 to issue an order authorizing the Company to offer a Job Retention Rider ("Rider") as a 5-year pilot program for electric service to non-residential customers meeting certain conditions as hereinafter described."

Q. DO THE SAME CHALLENGING ECONOMIC CONDITIONS EXIST TODAY THAT DEP AND DEC DESCRIBED WHEN THEY PROPOSED THESE RIDERS?

A. The economic conditions that exist today appear to be much worse than the economic conditions that existed when the above described riders were proposed.

Q. WILL EXPANDING THE RTP RATE AVAILABILITY PROVIDE RELIEF TO INDUSTRIAL AND COMMERCIAL CUSTOMERS IN NORTH CAROLINA?

A. Yes. Those customers who are willing and able to shift load in response to pricing signals will have the ability to reduce their electric bills under the RTP rate.

Q. DID INTERVENING PARTIES OBJECT TO THE ABOVE DESCRIBED RIDERS ON THE BASIS THAT THEY WOULD RESULT IN OTHER CUSTOMER CLASSES SUBSIDIZING INDUSTRIAL CUSTOMERS?

A. Yes. The above described riders were only available to mining, manufacturing or industrial customers. These riders were a direct credit per kWH to industrial customers. Other customers would pay a rider to cover the cost of that credit. Commercial customers objected on the basis that this was a subsidization of industrial customers at the expense of commercial customers.

Q. WILL EXPANDING THE AVAILABILITY OF THE RTP RATE CAUSE ANY CROSS-SUBSIDIZATION BETWEEN CUSTOMER CLASSES?

A. No. The RTP rate is available to commercial and industrial customers. There would be no subsidization of industrial customers at the expense of commercial customers.

The RTP rate does not come with a rider that other customers must pay to provide a discount to participating RTP customers. In fact, there is no discount to participating RTP customers. The large majority of the KWH sold to customers on the RTP rate will be priced and sold under their normal non-RTP base rate, typically LGS, LGS-TOU, MGS or SGS-TOU. In other words, they will pay exactly the same amount for their baseline energy as customers who are not on the RTP rate.

The only times that the real time prices for electricity will impact the bills for participating customers are when they use more or less than their CBL. In these cases, participating customers will pay the real time market based price for electricity that they use above their CBL and be credited at the real time market based price for electricity when they use less than their CBL. Given that these customers will pay for the actual real time market based price of electricity when they use more or less than their CBL, they will neither subsidize other customers, or be subsidized by other customers, during these times.

Also, the revenue neutral design of the RTP rate ensures that there is not cross-subsidization between RTP customers and any other class of customers. There have been no indications, or objections, that the existing 85 customers are currently subsidizing other customers or being subsidized by other customers. These customers are paying the actual market based prices, including a profit margin, for the electricity that they consume. We are simply advocating for an increase the number of customers who will be able to do what a select group of 85 customers has been doing for 24 years.

Q. WHY IS HORNWOOD PROPOSING THAT THE MINIMUM LOAD TO PARTICIPATE IN THE RTP RATE BE SET AT 75 KW?

A. Hornwood has accounts with peak demands of less than the current minimum of 1,000 KW and would like for those accounts to also be eligible for the RTP rate option. Also, as described above, DEP is monitoring critical peak pricing rates being piloted by DEC that would give pricing flexibility to customers up to 75 KW. No plans appear to be in place to provide greater pricing flexibility for customers over 75 KW. Therefore, we are proposing a minimum eligible demand to be 75 KW.

Q. ARE THERE ADMINISTRATIVE COSTS TO DEP ASSOCIATED WITH THE RTP RATE?

A. Yes. A few of those include:

1. Securing an NDA with the customer. Since DEP considers the real time pricing data to be proprietary and confidential, they require that the customer enter into an NDA before enrolling on the RTP rate. This often requires administrative and attorney expenses for the customer and DEP. Given that there is no retail competition for electricity in NC, and that the two biggest competitors in NC (Duke Energy and Progress Energy) merged years ago, it would appear that this cost could be eliminated entirely. Also, if hundreds or possibly eventually

thousands of customers end up on the RTP rate, even with an NDA with each customer, it will become difficult to maintain the confidentiality of this data.

2. Establishing a CBL and a written agreement with the customer. These are required based on the nature and design of the rate. DEP has already been establishing CBLs for participating customers for 23 years. With the computer technology that is ubiquitous today, the cost of establishing the CBL should be minimal.

3. Maintaining Real Time Pricing data and communicating it to customers. DEP has already been doing this for 24 years. This data is shared by way of a web portal that participating customers can access. Given that this is already being done, adding more customers to the rate causes no additional marginal costs to be incurred by DEP to maintain and communicate this data. In fact, adding more customers to the RTP rate would be spread across many more customers resulting in a greatly reduced cost/customer of maintaining and communicating this data.

Q. DOES THE RTP RATE INCLUDE AN ADMINISTRATIVE CHARGE TO COVER THE ABOVE COSTS?

A. Yes. The RTP rate includes a $ 165/month ($ 1,980/year) RTP Administrative Charge to cover the above costs for participating customers. This is in addition to the Basic Customer Charge on the base rate under which the customer is receiving service. DEP is not proposing to change that charge in this rate case proceeding. Given that the NDA requirement could easily be eliminated, the CBL has been and can easily continue to be established with widely available computer technology and there would be no marginal cost to maintain and communicate real time pricing data, DEP's administrative cost/participating customer would drop materially due to economies of scale.

Q. IF THE REQUESTESTED CHANGES ARE APPROVED, WOULD DEP BE OVERWHELMED WITH REQUESTS FROM CUSTOMERS WISHING TO TRANSFER TO THE RTP RATE?

A. No. It would be a very good outcome if thousands of customers were to quickly contact DEP and request service under the RTP rate because it would mean that many customers were interested in shifting load to reduce peak system loads. However, extensive experience by many power companies introducing new rates in many states clearly demonstrates that it can take years for customers to become aware of new rates and request service under those rates. Even when customers do become aware of the new rate option, the complexity of RTP will deter less sophisticated and analytical customers from participation.

Given that the rate is designed to be revenue neutral and that the majority of KWH sold to customers on the new rate will actually be priced under the customer's existing base rate, there is no incentive for customers who are not willing and able to shift load to enroll for service under the rate.

Finally, the $ 1,980/year RTP Administrative Charge on the rate is a strong disincentive and deterrent for any customer that is not willing and able to shift load in response to pricing signals. Also, most customers with loads of less than about 150 KW would find that even if they are willing and able to shift load, they would not be able to save enough money on the rate to offset the $ 1,980/year RTP Administrative Charge.

The overall number of customers likely to participate in the new rate would be small enough to be easily managed by existing DEP personnel.

Q. DID PROGRESS ENERGY RECEIVE $ 200,000,000 IN 2009 FEDERAL STIMULUS MONEY THROUGH THE SMART GRID INVESTMENT GRANTS TO PURCHASE NEW SMART METERS SO THAT THEY COULD OFFER MORE SOPHISTICATED RATES?

A. Yes. Many web sites clearly document that Progress Energy received $200,000,000 in grant money. That grant included money to install 160,000 new smart meters that would be installed to facilitate new forthcoming pricing options for customers.

https://www.smartgrid.gov/project/progress_energy_service_company_optimized_energy_value_chain

An excerpt from that web site reads:

> "Progress Energy Service Company's (Progress Energy's) Optimized Energy Value Chain project involved deployment of advanced metering and distribution automation systems. The project implemented two-way communications to allow Progress Energy to manage, measure, and verify targeted demand reductions during peak periods. ***New information and communications systems capture commercial and industrial (C&I) meter data for billing and future implementation of new pricing programs and service offerings.*** (emphasis added) Progress Energy implemented a distribution management system, automated switching, and integrated voltage and reactive power control to reduce line losses and improve service reliability. The project also installed advanced transmission systems, including on-line monitoring equipment on key and "at-risk" transmission substations and transformer banks. In addition, Progress Energy installed 255 electric vehicle charging stations in the Carolinas and Florida service territories."

A few of the many web sites with information about this program are below:

https://www.energy.gov/sites/prod/files/2013/10/f3/SGIG_progress_report_2013.pdf

https://www.greentechmedia.com/articles/read/8-charts-to-illustrate-progress-on-does-smart-grid-investment-grants

Q. HAS PROGRESS ENERGY/DEP INSTALLED SMART METERS FOR MOST CUSTOMERS?

A. Yes. According to page 15, line 10 of the October 30, 2019 testimony of witness Pirro in this rate case proceeding, ***"By year-end 2019, 60% of all customers will be served using Smart Meter technology;"****(emphasis added)*

Q. IS A SMART METER REQUIRED TO PROVIDE THE RTP RATE TO CUSTOMERS?

A. No. An interval data meter is required to measure the energy consumed during each billing interval. That is less complicated and sophisticated than what is offered by a Smart Meter.

According to witness Oliver, Exhibit 4, Page 26 of 52 in this rate case proceeding:

> "Smart meters are digital electricity meters that have advanced features and capabilities beyond traditional electricity meters. Some of the advanced features include the capability for two-way communications, interval usage measurement, tamper detection, voltage and reactive power measurement, and net metering capability.
>
> Duke Energy's standard smart meter system utilizes a radio frequency ("RF") mesh architecture, which is flexible in that the meters within the mesh network establish an optimized RF communication path to a collection point either through other meters, through network range extenders, or via a direct cellular connection."

Smart Meters do provide interval usage measurement that is required to serve customers under the RTP rate. However, Smart Meters also provide a great deal of additional two way communications and other functionality that is not required to serve a customer under the RTP rate. A relatively simple interval data meter, as has been used by DEP and many other utilities for decades, is all that is needed to serve customers under the RTP rate.

Q. IF A CUSTOMER REQUESTED PARTICIPATION ON THE RTP RATE AND DIDN'T YET HAVE AN INTERVAL DATA METER OR SMART METER, COULD DEP SIMPLY INSTALL A SMART METER FOR THAT PARTICULAR CUSTOMER?

A. Yes. This would be very easy to do. DEP is already installing many thousands of Smart Meters on a regular and ongoing basis. If a customer requested the RTP rate and didn't yet have a Smart Meter, DEP could simply install a Smart Meter for that customer and then begin providing service under the RTP rate. Alternatively, if the communications infrastructure was not yet present to allow installation of a Smart Meter, a simple interval data meter could be installed. Two way communications has not been, and is not now, required to serve a customer under the RTP rate.

This scenario is quite similar to what CP&L/PEC/DEP has done ever since 1983 for a customer that requested a time-of-use rate. If a time-of-use meter was not already installed for the customer, CP&L/PEC/DEP simply installed a time-of-use meter and began billing under the time-of-use rate. At UMS, we have been through this process with CP&L/PEC/DEP literally thousands of times over the last 22 years.

Q. MUST A CUSTOMER HAVE HAD AN INTERVAL DATA METER OR SMART METER INSTALLED FOR A FULL 12 MONTHS TO ALLOW FOR DEVELOPMENT OF A CBL PRIOR TO ENROLLMENT ON THE RTP RATE?

A. No. If a customer without a Smart Meter requests the RTP rate, DEP and the customer could develop a CBL based on the available metering data. If necessary, that CBL could be adjusted after the smart meter had been installed for 12 full billing months. This would be a very rare circumstance since almost all of the customers that would qualify for the RTP rate would already have either an interval data meter or a Smart Meter installed at their facility.

Q. DOES WITNESS PIRRO IMPLY THAT SMART METER TECHNOLOGY IN CONJUCTION WITH DEP'S PROPOSED CUSTOMER CONNECT BILLING SYSTEM MUST BE FULLY DEPLOYED BEFORE MORE ADVANCED RATES CAN BE OFFERED?

A. Yes. On line 5 of page 13 of witness Pirro's testimony in this case he says:

> **"**In anticipation that more sophisticated designs may be

practical with full deployment of Smart Meter technology and the Customer Connect billing system, only minimal changes to current rate designs are proposed in this proceeding."

Q. MUST THE CUSTOMER CONNECT BILLING SYSTEM BE FULLY DEPLOYED BEFORE A CUSTOMER CAN BE SERVED UNDER THE RTP RATE?

A. No. Customers have been getting billed for 23 years under the RTP rate with the existing billing systems at DEP. The existing billing systems can continue to be used until Customer Connect is completed and fully deployed. At that time, DEP could switch the customer over to being billed under the Customer Connect billing system if that provided beneficial for DEP or the customer. There is no need to wait until Customer Connect has been developed and deployed to serve customers under the RTP rate.

Q. HAS THE PROMISE OF NEW, SOPHISTICATED RATES BEEN A LONG-STANDING ARGUMENT BY DEP TO JUSTIFY SMART METER TECHNOLOGY?

A. Yes. For example, in E-100 Sub 126, In The Matter of: Generic Proceeding – Electric Smart Grid Presentations, in testimony on January 26, 2010, witness Becky Harrison on behalf of Progress Energy Carolinas included the following in her testimony on page 15, line 7:

> "Certainly advanced metering would allow us to do things like prepay. They'd allow us to do more sophisticated rates, even dynamic critical peak pricing rates."

More than 10 years later, and after several rounds of metering upgrades, DEP in this case is still not offering any new dynamic pricing, critical peak pricing or real time pricing for any customers.

Q. HAVE THE RATES THAT WERE SUPPOSED TO COME OUT OF THESE METERING INVESTMENTS BEEN PROPOSED IN THIS RATE CASE?

A. No. In spite of hundreds of millions of dollars in metering investments by customers and taxpayers, the long-awaited and long-promised rates have yet to be proposed. In fact, in this rate case proceeding, DEP is indicating that it will be at least four to five more years before they propose more sophisticated rates that will take advantage of the new metering technology. Even then, they are proposing that the new rate options only be available to residential customers and commercial, industrial and governmental customers of 75 KW or less.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, at this time.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, Sub 1219

In the Matter of	**)**	
Application of Duke Energy Progress, LLC	**)**	
for Adjustment of Rates and Charges	**)**	**Hornwood, Inc.'s Corrections**
Applicable to Electric Service in	**)**	**Direct Testimony of Brian**
North Carolina	**)**	**Coughlan**

CORRECTIONS TO THE DIRECT TESTIMONY OF BRIAN COUGHLAN

Utility Management Services, Inc., on behalf of Hornwood, Inc. provides the following corrections to the Direct Testimony of Brian Coughlan originally filed with the Commission on April 13, 2020.

1. Corrections to the page number on the header of page 2 of the Direct Testimony.

   Change Header "2 of 18" to "2 of 34"

2. Corrections to page 12 of 34 of the Direct Testimony.

   Remove duplicate Question, lines 6 – 11

Hornwood, Inc.
Summary of Direct Testimony of Witness Brian Coughlan
Docket No. E-2, Sub 1219

My name is Brian Coughlan. I am a licensed Professional Engineer in North Carolina and I am testifying on behalf of Hornwood, Inc. (Hornwood). Hornwood is an industrial Customer taking service from Duke Energy Progress (DEP) in Lilesville, NC.

The purpose of my testimony is to advocate for changes to the Availability section of Duke Energy Progress' Large General Service – Real Time Pricing (RTP) rate. Specifically, Hornwood is requesting the following changes:

1. Eliminate the Cap of 85 Customers.
2. Reduce the minimum demand requirement from 1,000 KW to 75 KW.

These changes are reasonable, fair, equitable and easy to implement with existing metering and billing technology. RTP was introduced on an experimental basis in 1996. RTP offers hourly marginal cost-based prices for electricity consumption in excess of a Customer Baseline (CBL). This sends pricing signals to participants. When pricing is very high, customers who have the ability can curtail their load and create savings that benefit the customers and DEP. This will lead to higher overall economic development, job creation, customer retention and job retention. Customers who are not able to curtail load during some peak periods will pay high prices during those periods, ensuring DEP is paid based on the real time price of electricity at all times.

The "Experimental" status originally shown on the rate was removed many years ago. However, the limit of 85 customers was not removed. This small, hand-picked group of 85 customers has a significant and unfair competitive advantage compared to other customers in their same size range in the DEP territory. This is not fair to customers who could otherwise receive service under the RTP rate. Limiting the non-experimental RTP rate to 85 Customers is unreasonable and discriminatory.

RTP was implemented with the metering technology that existed in 1996. Since then, metering technology has improved dramatically. Hundreds of millions of dollars has been spent by DEP customers and federal taxpayers to upgrade metering technology many times since 1996. The metering technology DEP has today can easily implement RTP on a much wider basis. A smart meter is not required; only an interval meter.

RTP was implemented with the computer billing technology that existed in 1996. The computers that are widely used by almost everyone today are scores of times more powerful than what existed in 1996. The computer technology currently in use can easily be used to bill additional customers on RTP.

DEP is not offering any new types of Dynamic, Real-Time or Critical Peak pricing rates at this time. DEP said in this case that they will closely monitor the new rates being piloted by DEC for residential and small non-residential customers. That approach provides no relief for many years and only addresses the concerns of customers less than 75 KW. In these challenging economic times, relief is needed now and it is needed for larger customers. RTP has been successfully administered by DEP for 23 years and requires no further design, testing or analysis.

North Carolina is at a competitive disadvantage to many states who already have real time pricing rates available to Customers. Businesses are closing and jobs are disappearing throughout North Carolina. The relief being requested by Hornwood will provide pricing flexibility to customers, help attract new businesses and jobs and help retain existing businesses and jobs.

We respectfully request the Commission approve this request. Thank you for consideration and I look forward to answering the Commission's questions.

MS. GOLDSTEIN: Thank you. Mr. Coughlan is now available for cross examination.

COMMISSIONER CLODFELTER: All right. Let me say that my notes do not indicate that any party -- okay. I'm getting some feedback. I'm not sure where it's coming from. All right. Let's try it again.

I don't have any indication that any party requested reserve cross examination on Mr. Coughlan. So I ask now, is there any party who has cross examination for this witness?

(No response.)

COMMISSIONER CLODFELTER: All right. Then, Ms. Goldstein, no redirect.

And I'll ask for any questions from Commissioners, starting with Commissioner Brown-Bland.

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

COMMISSIONER CLODFELTER: Okay. Commissioner Gray?

COMMISSIONER GRAY: No questions.

COMMISSIONER CLODFELTER: Chair Mitchell?

CHAIR MITCHELL: No questions for the witness.

COMMISSIONER CLODFELTER: Commissioner Duffley?

COMMISSIONER DUFFLEY: No questions.

COMMISSIONER CLODFELTER: Commissioner Hughes?

COMMISSIONER HUGHES: No questions.

COMMISSIONER CLODFELTER: Commissioner McKissick?

COMMISSIONER McKISSICK: No questions.

COMMISSIONER CLODFELTER: All right. And I have no questions also. So, Ms. Goldstein, is there anything else we need to do?

MS. GOLDSTEIN: Yes, sir. At this time I would ask that the Commissioners entertain a motion to excuse Mr. Coughlan from this hearing.

COMMISSIONER CLODFELTER: All right. You've heard the motion. Any party have any objection to the motion?

(No response.)

COMMISSIONER CLODFELTER: If not, then, Mr. Coughlan, thank you for your appearance, albeit brief this afternoon, and you are excused.

THE WITNESS: Thank you, Commissioner Clodfelter.

COMMISSIONER CLODFELTER: Thank you.

Ms. Goldstein, anything further from Hornwood?

MS. GOLDSTEIN: No, sir, thank you. That concludes our testimony.

COMMISSIONER CLODFELTER: Very good. Thank you. I will move now to Sierra Club. And, Ms. Cralle Jones, Ms. Lee, which of you is going to lead off for us?

MS. CRALLE JONES: That will be me. Thank you.

COMMISSIONER CLODFELTER: All right. You are recognized.

MS. CRALLE JONES: Commissioner Clodfelter, Sierra Club now calls Mr. Mark Quarles.

COMMISSIONER CLODFELTER: Mr. Quarles, I see you there.

Whereupon,

MARK QUARLES,

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

DIRECT EXAMINATION BY MS. CRALLE JONES:

Q. Mr. Quarles, would you please state your full name and business address for the record, please?

A. My name is Mark Anthony Quarles. Business address, 1616 Westgate Circle, Brentwood, Tennessee.

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

A. BBJ Group, and I'm the branch manager of the Nashville office.

Q. On April 13, 2020, did you cause to be prefiled in this docket, direct testimony consisting of 33 pages, seven exhibits, some portions of which contain information designated as confidential by the Company?

A. Yes.

Q. Do you have any changes or corrections to your prefiled direct testimony?

A. Yes, I do. And I have some corrections noted in the errata page that was filed with my testimony.

Q. Can you describe just briefly what those corrections were?

A. Yes. On page 2, line 19, as stated that my previous testimony in the DEP case was in 2018; however, it was late 2017, not 2018. And then the second, on page 18 of my testimony, I discussed the years when the Company was first required to conduct groundwater monitoring at its coal ash sites. And in line 1, I identified required monitoring beginning in 1984 at Sutton, in 1989 at Weatherspoon. And in the table included a line 9 of that same page, I indicate that groundwater monitoring began in 1990 at Sutton and Weatherspoon. And these dates came from two separate responses to data requests by the Company, so I've added a footnote clarifying that fact.

Q. Thank you. If I asked you the same questions again here today with these corrections, would your answers be the same?

A. Yes.

Q. Mr. Quarles, did you also prepare a summary of your prefiled direct testimony?

A. Yes.

MS. CRALLE JONES: Commissioner Clodfelter, we ask that Mr. Quarles' prefiled direct testimony consisting of 33 pages as corrected, and the summary of his testimony which has been served on the parties, be copied into the record as if given orally from the stand.

COMMISSIONER CLODFELTER: All right. Unless there is objection, the motion is granted.

(Whereupon, the prefiled direct testimony, errata, and testimony summary of Mark Quarles were copied into the record as if given orally from the stand.)

I. Professional Qualifications and Purpose of Testimony

Q. Please state your name, occupation, and business address.

A. My name is Mark Quarles. I am a Senior Consultant and Nashville Branch Manager for BBJ Group, an environmental engineering and consulting services firm with multiple offices in the United States. My business address is 1616 Westgate Circle, Brentwood, Tennessee 37027.

Q. Please summarize your educational and professional experience.

A. I graduated from Western Kentucky University in 1985 with a Bachelor of Science of Environmental Engineering Technology. My professional experience includes over thirty years as an environmental consultant. My experience includes clients and projects for industrial manufacturers, municipal governments, non-profit organizations, and legal services. I am a Licensed Professional Geologist in the State of Tennessee, a Registered Professional Geologist in the State of Georgia, and a Licensed Professional Geologist in the State of New York.

My specific experience for coal combustion waste related projects involves numerous years performing coal combustion related investigations at approximately 100 disposal sites located across the United States, with a particular emphasis in these Southeastern states: Alabama, Florida, Georgia, Kentucky, North Carolina, South Carolina, and Tennessee. I was also actively involved in efforts to respond to the Tennessee Valley Authority Kingston, Tennessee coal combustion residuals ("CCR" or "coal ash") impoundment collapse in 2008, and I have been extensively involved in various CCR-related projects since that time.

I have conducted hydrogeologic investigations related to the closing of industrial waste ponds ("surface impoundments") and the siting and design of municipal and industrial waste landfills; developed closure plans for industrial landfills; designed and implemented groundwater monitoring programs for industrial and municipal landfills; and completed investigations to define the nature and extent of environmental contamination.

I have published peer-reviewed technical investigation papers involving soil, groundwater, and surface water associated with industrial waste contamination at national trade association conferences. I have also lectured at regional environmental law conferences.

My CV is attached at Exhibit MQ-1.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of the Sierra Club in this proceeding.

Q. Have you testified previously before the North Carolina Utilities Commission?

A. Yes, I previously testified at the Duke Energy Progress ("DEP" or "the Company") rate case hearing in 2017, Docket No. E-2 Sub 1142, and at the Duke Energy Carolinas ("DEC") rate case hearing in 2018, Docket No. E-7, Sub 1146, and I submitted pre-filed testimony on February 18, 2020 in the DEC rate case hearing, Docket E-7, Sub 1214.

My previous 2018 DEP testimony provided factual background about coal ash and evaluated the methods by which DEP proposed to close existing CCR surface impoundments in-place by leaving wastes in existing disposal areas (i.e., "closure-in-place") at its Mayo and Roxboro coal plants. That testimony evaluated whether or not the

Company could meet the closure performance standards established by the U.S. Environmental Protection Agency ("US EPA") in its Final Rule for Hazardous and Solid Waste Management System; Disposal of Coal Combustion Residuals From Electric Utilities (codified at 40 C.F.R. Part 257) ("CCR Rule"). I concluded in that testimony that, because of the site characteristics and hydrogeologic conditions at the Mayo and Roxboro sites, closure-in-place would not meet the closure performance standards established in the CCR Rule and that groundwater contamination would continue into the foreseeable future.

Q. What is the purpose of your direct testimony in this proceeding?

A. It is my understanding that the Company is seeking recovery from ratepayers for costs associated with the closure of surface impoundments and other disposal units in which CCRs (or "coal ash") have been stored at its facilities in North and South Carolina.

My testimony for this rate case hearing will focus on determining *when* the Company knew or should have known that groundwater and/or surface water contamination was likely due to storage and disposal of CCRs in unlined areas located near—and even sometimes within—rivers and streams and where the ash is saturated with groundwater. In addition, I will discuss how the Company's total coal ash clean-up costs could have been lower if the Company had switched to dry disposal in lined landfills sooner.

Q. What information did you consider when preparing your testimony?

A. I have researched electric power industry practices and standards dating to the 1970s and have reviewed historical governmental documents and regulations, recent investigative reports and analyses completed by the Company or by consultants on its behalf, the Company's Application and certain testimony, as well as documents produced by the

Company during discovery in this proceeding and introduced as exhibits in this and the previous rate case proceeding. Specific documents that I relied upon include:

- Argonne National Laboratory, Environmental Control Implications of Generating Electric Power from Coal, 1976 (Public Staff Junis Direct Exhibit 4, Docket No. E-7, Sub 1146) (hereafter "1976 Argonne Report");
- Los Alamos Scientific Laboratory, The Disposal and Reclamation of Southwestern Coal and Uranium Wastes, May 1979 (Public Staff Junis Exhibit 6, Docket No. E-7, Sub 1146) (hereafter "1979 Los Alamos Report");
- Arthur D. Little, Inc./US EPA, Health and Environmental Impacts of Increased Generation of Coal Ash and FGD Sludges, Report to the Committee on Health and Ecological Effects of Increased Coal Utilization, Environmental Health Perspectives, 1979 (Public Staff Junis Direct Exhibit 7, Docket No. E-7, Sub 1146) (hereafter "1979 EHP Report");
- US EPA/Tennessee Valley Authority, Behavior of Coal Ash Particles in Water, Trace Metal Leaching and Ash Settling, Mar. 1980 (hereafter "1980 EPA Ash Report");
- Electric Power Research Institute, Coal Ash Disposal Manual, Second Edition, Oct. 1981 (Sierra Club Kerin Cross Exhibit 4, Docket No. E-7, Sub 1146) (hereafter "1981 EPRI Manual");
- Electric Power Research Institute, Manual for Upgrading Existing Disposal Facilities, Nov. 1981/Aug. 1982 (Public Staff Junis Direct Exhibit 8, Docket No. E-7, Sub 1146) (hereafter "1982 EPRI Manual");
- Arthur D. Little, Inc., Full-Scale Field Evaluation of Waste Disposal from Coal-Fired Electric Generating Plants, June 1985 (DEC Response to Sierra Club Data Request No. 5-3, January 28, 2020) (hereafter "1985 AD Little Report"), excerpts attached as Exhibit MQ-2;
- US EPA, Report to Congress, Wastes from the Combustion of Coal by Electric Utility Power Plants, Feb. 1988 (Public Staff Junis Direct Exhibit 10, Docket No. E-7, Sub 1146) (hereafter "1988 EPA Report to Congress");
- US EPA & US DOE, Coal Combustion Waste Management and Landfills and Surface Impoundments, 1994-2004, Aug. 2006 (hereafter "2006 EPA/DOE CCR Report");
- US EPA, Monitored Natural Attenuation of Inorganic Contaminants in Groundwater, Volume 2, Oct. 2007 (hereafter "2007 EPA Attenuation");
- Duke Energy Senior Management Committee, Ash Basin Closure Update, January 13, 2014 (Attorney General's Office Fountain Cross Exhibit 6, Docket No. E-7, Sub 1146) (hereafter "2014 Duke Ash Update");
- Duke Energy, Comprehensive Site Assessment Update, Sutton Steam Station, Jan. 2018 (hereafter "2018 Sutton Site Assessment Update");

- Carolina Power and Light, Memorandum from G. B. Mingle regarding Chloride Contamination of Hercules Wells, August 4, 1976 (provided on the Company's Consilio/Relativity database; deemed non-confidential by the Company) ("1976 Mingle Memo re Sutton"), attached as Exhibit MQ-3;
- Carolina Power and Light, Executive Summary, from S. Zimmerman regarding Hercofina / Sutton Background Information, August 23, 1983 (provided on the Company's Consilio/Relativity database; deemed non-confidential by the Company) ("1983 Zimmerman Summary re Sutton"), attached as Exhibit MQ-4;
- Carolina Power and Light, Letter from L.B. Wilson regarding L.V. Sutton Steam Electric Plant, 1984 Ash Basin Expansion, Design Basis Explanation, May 21, 1984 (provided on the Company's Consilio/Relativity database; deemed non-confidential by the Company) ("1984 Wilson Letter re Sutton"), attached as Exhibit MQ-5;
- Carolina Power and Light, Memorandum from Mick Greeson regarding L.V. Sutton Steam Electric Plant – Ash Pond Expansion (DEP Response to Sierra Club Data Request No. 3-10, February 13, 2020, file path: "3.5.3.12.4_16_DUKE_CAIR_003991144_Production_CAIR.pdf") ("Greeson Memo re Sutton"), attached as Exhibit MQ-6;
- Moore Gardner & Associates, Evaluation of the Potential for Contamination of the Ground-Water Aquifer by Leachate from the Coal-Ash Storage Pond at the Mayo Electric Generating Plant Site, January 31, 1979 (DEP Response to Sierra Club Data Request No. 3-10, February 13, 2020, file path: "3.5.3.12.2 - 26_DEPNCRate2017_00006186_native.pdf") ("1979 Mayo Groundwater Report"), attached as Exhibit MQ-7;
- DEP Response to NC Public Staff Data Request No. 2-1, October 30, 2019 ("Ash Disposal DR");
- DEP Response to NC Public Staff Data Request No. 2-10, October 30, 2019 ("Groundwater Monitoring DR");
- DEP Response to NC Public Staff Data Request No. 2-11, October 30, 2019 ("Groundwater Monitoring DR 2");
- DEP Response to NC Public Staff Data Request No. 64-2, January 20, 2020 ("CCR Rule Exceedances DR");
- [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL].

Where appropriate, I will refer to specific pages of these documents in support of my conclusions.

Q. Please summarize your conclusions and recommendation for the Commission for this rate case hearing.

A. I recommend that the Commission make the following findings and give such findings due consideration as it evaluates the Company's request:

1. Historical documents, including the Electric Power Research Institute manuals, available to the Company, demonstrate that the environmental risks associated with the disposal of coal ash in unlined surface impoundments were understood by the electric utility industry in the late 1970s and early 1980s.

2. The Company's continued operation of unlined surface impoundments that were constructed directly in streams, adjacent to rivers and streams, with coal ash saturated in groundwater, and without adequate groundwater monitoring for decades after the industry recognized the risks of such operation, was unreasonable and could be expected to result in the introduction of CCR constituents to surface and groundwater.

3. The Company's 1983 investigation regarding contaminant migration from Sutton and its decision to construct a new ash basin with a liner in order to meet proposed groundwater regulations was a warning sign and early indication that unlined surface impoundments leaked and presented risks to groundwater quality. The Company's failure to take action to end disposal of coal ash in unlined basins was unreasonable.

4. Standing water in the impoundments, leakage of that water into the shallow aquifer below, submerged CCRs in the impoundments, and the mounding effects and radial flow conditions of the aquifer, have resulted in more widespread

contamination and increased groundwater flow velocities of the contaminated aquifer towards receptors and receiving streams.

5. Costs associated with excavation and groundwater monitoring would be lower if the Company had converted to dry disposal in lined landfills sooner.

II. Previous Rate Case Testimony and Subsequent Actions Regarding Coal Ash Pond Closure

Q. Please summarize the conclusions you made as part of the 2017 DEP rate case.

A. My 2017 DEP testimony, based upon my review of internal Company documents, external research, and my experience conducting CCR-related investigations in multiple states, concluded that:

- The Company constructed unlined CCR surface impoundments over existing streams and those former stream valleys became the disposal units over time.
- CCRs in the Company's unlined surface impoundments have been submerged and saturated in groundwater. CCR-related constituents were found in groundwater at concentrations greater than regulatory standards.
- The Company's plan to close surface impoundments via closure-in-place did not include any mechanism to stop groundwater from flowing laterally into wastes and, therefore, would not have prevented continued leaching of metals and other constituents into groundwater or the introduction of those constituents into adjacent rivers and streams. Thus, the Company's closure plans could not satisfy CCR Rule performance standards.
- Excavation and removal of CCRs from ash basins to lined, dry disposal area would reduce the concentrations of groundwater constituents and would reduce the extent of the groundwater contamination.

Q. Has the Company been required since your previous testimony to excavate CCRs from its surface impoundments rather than closing those units in place?

A. Yes. In April 2019, the North Carolina Department of Environmental Quality ("DEQ") ordered the Company to excavate coal ash at its Mayo and Roxboro sites. (DEQ also ordered the Company's sister utility DEC to excavate coal ash at the Allen, Belews Creek, Cliffside, and Marshall plant sites). The Company challenged DEQ's decision, but the Company ultimately agreed to excavate and remove all coal ash except for some limited exceptions and to conduct groundwater monitoring and groundwater remediation.

III. Background on Coal Combustion Residuals (CCRs)

Q. What are coal combustion residuals ("CCRs") and how are they generated?

A. CCRs are solid wastes that are created by the preparation and burning of coal to produce electricity. The primary solid wastes that are generated during that process include bottom ash, fly ash, pyrite/mill rejects, and synthetic gypsum. Bottom ash is heavier and consists of larger particles of ash that are generated during combustion and fall to the bottom of the furnace. Fly ash is the smaller, fine-particle ash that forms during combustion and is carried out of the boiler by the flue gases and is then collected by the air pollution control dust collection system. Synthetic gypsum is created when flue gas desulfurization ("FGD") air pollution control technology is used to scrub air emissions.

At the Company's facilities, CCRs have been mixed with large amounts of water and sluiced to surface impoundments ("ponds" or "ash basins") located at the power plant sites. The heavier substances sink to the bottom of the ponds, and the transport water is discharged into a nearby waterway, evaporates, or seeps into the ground (and groundwater) beneath the pond.

Q. What constituents are commonly found in CCRs?

A. Constituents that are found in the CCRs generally originate from the source coal that is burned. Aluminum, arsenic, boron, calcium, hexavalent chromium, iron, magnesium, manganese, silicon, strontium, sulfate, and sulfur are commonly present.

Q. Are CCRs constituents water-soluble?

A. CCR constituents are water-soluble, and that solubility depends on numerous factors such as the pH of the solid-to-water mixture and the geochemical conditions under which the CCRs exist. Those conditions can change over time after closure and therefore, constituents that had not previously migrated from a disposal unit can become mobile in the future.

Q. Are there risks to the environment posed by exposure to CCR constituents?

A. Yes. CCR constituents can leach from the solid waste when it comes into contact with water—including transport water, groundwater, rainwater, or stormwater run-off. The risks to the water environment originate when those constituents are leached from the solid CCR and then transported away from the disposal area in groundwater and surface water. Constituent risks vary by each constituent—with risks to humans, fish, and other aquatic life being common.

Q. How typical are impacts to surface water and groundwater when CCRs are stored in unlined surface impoundments adjacent to a surface waterbody and/or beneath the groundwater table?

A. In my experience of investigating coal ash disposal sites across the country as well as reviewing historic reports, contamination of surface water and groundwater by CCR constituents that are introduced into the environment via unlined ponds is quite common.

IV. Knowledge of Risks and Costs Associated with Disposal of Coal Ash in Unlined Surface Impoundments

Q. How early were the risks associated with disposing of coal ash in unlined surface impoundments recognized by the scientific community?

A. The risks of groundwater contamination from unlined coal ash ponds were understood as early as the late 1970s. For example, a report prepared by the Argonne National Laboratory in 1976 identified the "potential problems of pollution of surface and subsurface water" associated with ash disposal and noted that "[u]tilities are well aware of these problems." (1976 Argonne Report at 169 [PDF page 57].) Also, a 1979 report by Arthur D. Little consultants and US EPA identified groundwater and surface water contamination as major "impact issues" associated with the storage or disposal of coal ash in unlined units. (1979 EHP Report at 132, 140, 149, 153 [PDF pages 2, 10, 19, 23].)

In addition, a 1979 report regarding the disposal of coal and uranium waste noted a "growing awareness that the discarded wastes from coal combustion are a serious potential source of surface and ground water contamination." (1979 Los Alamos Report at 6 [PDF page 7].) The report went on to explain: "Many trace contaminants that are present in the fly ash or sludge can be mobilized by the waters present in the ponds. The transport of contaminants from the disposal ponds into shallow or deep aquifers could result in the degradation of the quality of these waters." (1979 Los Alamos Report at 7 [PDF page 8].)

Q. Did the US EPA recognize the risks to groundwater associated with coal ash disposal?

A. Yes. Recognition of such risks is reflected in the fact that fly ash, bottom ash, and other coal combustion residuals have been regulated as solid wastes under the Resource

Conservation and Recovery Act ("RCRA") since 1979. That regulation prohibits solid waste disposal facilities, including coal ash disposal sites, from contaminating underground drinking water sources beyond the solid waste boundary or state-approved alternative boundary. (40 C.F.R. § 257.3-4(a).) When promulgating those regulations, US EPA highlighted the importance of groundwater monitoring in order to ensure that solid waste disposal sites were not causing such contamination: "Existing monitoring of ground-water contamination is largely inadequate; many known instances of contamination have been discovered only after groundwater users have been affected. The Act and its legislative history clearly reflect Congressional intent that protection of ground water is to be a prime concern of the criteria." (44 Fed. Reg. 53,438, 53,445 (Sept. 13, 1979).)

In addition, US EPA reports published in 1980 and 1988 documented the agency's concerns about leaking, unlined disposal units. The conclusions of those reports were based on self-reported data regarding industry waste disposal practices from at least the mid-1970s. US EPA's key conclusions include:

- "[A]sh deposited in the bottom of the ash pond may continue to leach where the ash is in contact with groundwater if the surrounding environment is changed to anaerobic and low-pH conditions." (1980 EPA Ash Report at 7 [PDF page 20].)
- "The most significant problems associated with ash disposal in ponds are . . . quantities of trace metals in groundwater leachate." (1980 EPA Ash Report at 3 [PDF page 16].)
- "The primary concern regarding the disposal of wastes from coal-fired power plants is the potential for waste leachate to cause groundwater contamination." (1988 EPA Report to Congress at E-3 [PDF page 17].)

Q. What about the utility industry? When did it recognize the risks associated with disposing of coal ash in unlined surface impoundments?

A. In 1981, the Electric Power Research Institute ("EPRI")—a well-known industry research collaborative—published a manual regarding the handling and disposal of coal ash that noted: "leachate from ash disposal sites is of concern due to the possibility that the heavy metals . . . present in the ash may enter the groundwater system and contaminate present or future drinking water sources." (1981 EPRI Manual at 2-17.)

In addition, that report discussed EPA's solid waste disposal guidelines and noted that "[g]roundwater resources in the vicinity of the site should be surveyed to establish background data on water quality; depth, direction, and rate of flow of groundwater; and potential interaction between the landfill and ground and surface waters; and hydraulic conductivity and attenuating capacity of the site soils" (1981 EPRI Manual at 4-12), that "the bottom of the landfill should be maintained at least 5 feet [] above the seasonal high water table" (1981 EPRI Manual at 4-12), and that "[a] groundwater monitoring system should be installed if the landfill has potential for discharge to underground drinking water sources" (1981 EPRI Manual at 4-14).

While the RCRA regulations discussed in the EPRI report applied to solid waste landfills, the risks created by the storage or disposal of coal ash in unlined units—whether dry landfills or wet impoundments—are comparable. Addressing the risk of groundwater contamination by unlined ash ponds directly, the 1982 EPRI manual stated that "inadequately lined ponds provide a greater opportunity for groundwater contamination, because the soil immediately below the pond is always saturated and under a constant head of pressure from the overlying water. Consequently, seepage may be constant and greater in volume than leachate from a landfill." (1982 EPRI Manual at 2-11.) The manual laid out what any professional engineer, and certainly anyone involved with the construction or operation of an acres-large ash surface impoundment, should understand—that sluicing and impounding waste together with large amounts of water creates a "constant driving force for movement of potentially contaminated water (leachate) through the settled waste and into the surrounding soil." (1982 EPRI Manual at 2-2.)

Q. Did the utility industry recognize the need to monitor groundwater at coal ash disposal sites?

A. Yes. In 1982, EPRI made clear that regulatory compliance by itself might not ensure environmental protection and advised that utilities must achieve both, noting that "[p]otential deficiencies in utility waste disposal practices may be defined by two sets of standards: [1] The disposal practice does not comply with specific federal and/or state regulatory requirements; [2] The site has the potential to contaminate the environment." (1982 EPRI Manual at 4-1.) Accordingly, EPRI reached this conclusion: "[a]n engineering assessment of site adequacy must therefore address (1) whether the operation complies with prevailing regulations, and (2) whether the site poses a threat to the local environment. Both problems must be addressed simultaneously." (1982 EPRI Manual at 4-2.)

The 1982 EPRI manual reported on a survey it had conducted of existing coal ash disposal sites and highlighted the "potential deficiencies . . . noted during several of the site visits" including that "[g]roundwater monitoring was inadequate or nonexistent" and "leachate monitoring was not practiced." (1982 EPRI Manual at 4-19.) The manual further emphasized the risks of groundwater contamination and advised utilities to conduct groundwater monitoring:

> "[A]lthough the requirement for groundwater and leachate monitoring is not specified in federal standards for solid waste disposal facilities, the regulations do emphasize groundwater protection. While groundwater can be protected and leachate generation can be minimized with sound engineering design and site operation, ***monitoring of groundwater and leachate, is nevertheless necessary to provide convincing proof of safe disposal practice***. . . .
>
> "Finally, the potential for groundwater degradation should be noted, ***especially when an unlined ash pond is constructed on a site with relatively permeable soils and a shallow groundwater table***. . . . The existence of a constant hydraulic head (standing water) in the pond ***makes leachate generation and migration inevitable***." (1982 EPRI Manual at 4-19, emphasis added.)

Indeed, the 1982 EPRI Manual identified North Carolina state regulatory requirements designed to protect groundwater at coal ash disposal sites: prohibiting siting of disposal units where the water table is near the surface or within a 100-year floodplain (1982 EPRI Manual at 3-18) and requiring groundwater monitoring at sites with marginal soil permeability characteristics (1982 EPRI Manual at 3-19). Describing federal groundwater monitoring requirements, the 1981 EPRI Manual noted that "the location and depth of a groundwater monitoring well(s) is the single most important aspect of a groundwater monitoring program." (1981 EPRI Manual at 7-10.)

Q. Were disposal options that could lessen the risks associated with disposing of coal ash in unlined surface impoundments available in the 1980s?

A. Yes. For example, the 1981 EPRI Manual noted the trend toward dry ash handling systems (1981 EPRI Manual 3-1), and the 1982 EPRI manual identified as a "promising upgrading technique" "the conversion of a wet disposal system (pond) to a dry system (landfill)." (1982 EPRI Manual at S-2.) EPRI also recognized that "ponding is not considered a method for permanent disposal" and that the "increased land requirement and eventual problem of site closure favor dry disposal." (1982 EPRI Manual at 2-2.)

In addition, the 1988 EPA Report noted a trend toward the construction of disposal units with some sort of clay or composite liner to protect groundwater. Notably, US EPA found that:

- "40 percent of the generating units built since 1975 have liners." (1988 EPA Report to Congress at ES-3 [PDF page 17].)
- "Lining is becoming a more common practice, however, as concern over potential ground-water contamination from 'leaky ponds' and, and to a lesser extent, from landfills has increased." (1988 EPA Report to Congress at 4-24 to 4-25 [PDF pages 164-165].)
- "Mitigation measures to control potential leaching include installation of liners, leachate collection systems, and ground-water monitoring systems and corrective action to clean up groundwater contamination." (1988 EPA Report to Congress at ES-5 [PDF page 19].)
- Regarding the trend towards disposal of coal ash in landfills rather than surface impoundments: "These trends in utility waste management methods have been changing in recent years, with a shift towards greater use of disposal in landfills located on-site. For example, for generating units built since 1975, nearly 65 percent currently dispose of coal combustion wastes in landfills, compared to just over 50 percent for units constructed before 1975." (1988 EPA Report to Congress at 4-25 [PDF page 165].)
- ". . . landfilling has become the more common practice because less land is required, and it is usually more environmentally sound (because of the lower water requirements, reducing leaching problems, etc.)." (1988 EPA Report to Congress at 6-5 [PDF page 323].)

By the 1990s, liners were the rule: from 1994 to 2004, "virtually all newly built or expanded units (97 percent of landfills and 100 percent of surface impoundments)" were constructed with liners. (2006 EPA/DOE CCR Report at 37 [PDF page 67].)

V. <u>DUKE ENERGY'S MANAGEMENT OF COAL COMBUSTION RESIDUALS IN THE CAROLINAS</u>

Q. How has Duke Energy managed CCRs at its North and South Carolina sites?

A. Historically, CCRs generated by the Company's coal-burning units have been stored in unlined impoundments and ash basin located at the power plant sites. For its eight power plants in the Carolinas—Asheville, Cape Fear, HF Lee, Mayo, Robinson (South Carolina), Roxboro, Sutton, and Weatherspoon—the Company (see Ash Disposal DR):

- Constructed surface impoundments from the 1950s through the 1980s and expanded some impoundments as recently as 2001 (Weatherspoon) and 2002 (Robinson).
- Discharged CCRs onto the ground surface without any apparent treatment at the HF Lee and Sutton power plants in the "lay of land" method." The lay of land disposal method at Sutton lasted for seventeen years.
- Constructed all but one impoundment without a liner (the 1984 Ash Basin at Sutton had a 12-inch clay liner).
- Continued to build new, unlined disposal areas throughout the 1980s: Asheville (1982), Cape Far (1985), HF Lee (1980), Mayo (1983), and Roxboro (1988).

Details of the ash basins at each plant (see Ash Disposal DR), including the years of operation and cumulative CCR volume of each basin are tabulated below:

Plant Name	Unlined Disposal Area	Years of Operation	Cumulative Volume (tons / cubic yards)
Asheville	1964 Ash Pond (1971 expansion) 1982 Ash Pond	1964- 1982-2017	3,164,092 tons / 2,636,743 cy 3,700,000 tons / 3,083,333 cy
Cape Fear	1956 Ash Basin 1963 Ash Basin (1970 expansion) 1970 Ash Basin 1978 Ash Basin 1985 Ash Basin	1956-1963 1963-1978 1970-1978 1978-1985 1985-2012	420,000 tons / 350,000 cy 860,000 tons / 716,667 cy 840,000 tons / 700,000 cy 830,000 tons / 691,667 cy 2,820,000 tons / 2,350,000 cy
HF Lee	Lay of Land Inactive Ash Basin 1 Inactive Ash Basin 2 (1970 exp.) Inactive Ash Basin 3 1982 ("Active") Ash Basin Polishing Pond	1950s 1951-1962 1955-1962 1962-1980 1980-2012 1980-2012	99,000 tons / 82,500 cy 270,000 tons / 225,000 cy 530,000 tons / 441,667 cy 910,000 tons / 758,333 cy 4,520,000 tons / 3,766,667 cy 10,000 tons / 8,333 cy
Mayo	Ash Basin	1983-2019	6,600,000 tons / 5,500,000 cy
Robinson (SC)	Ash Basin (1982, 2002 expansion) 1960 Fill Area	1975-2012 1960-1974	2,904,000 tons / 2,420,000 cy 331,200 tons / 276,000 cy
Roxboro	West Ash Pond East Ash Pond (includes stack) Unlined Monofill (subgrade, too)	1973- 1966-1986 1988-2003	12,974,500 tons / 10,812,083 cy 7,073,881 tons / 5,894,901 cy 7,635,600 tons / 6,363,000 cy
Sutton	Lay of Land 1971 Ash Basin (1983 expansion)	1954-1971 1971-2014	686,400 tons / 572,000 cy 3,820,800 tons / 3,184,000 cy
Weatherspoon	1979 Ash Pond ('68, '79, '01 exp.)	1955-2011	2,450,000 tons / 2,041,667 cy

Q. For how long did the Company operate its unlined surface impoundments?

A. The unlined impoundments that the Company constructed in the 1980s were used until recently and amassed sizeable volumes of waste during their periods of operation. The 1982 Ash Pond at Asheville was operated for 35 years, until 2017; the 1985 Ash Basin at Cape Fear was operated for 27 years, until 2012; the 1982 Active Basin at HF Lee was operated for 32 years, until 2012; and the Ash Basin at Mayo was operated for 36 years, until 2019.

Q. When did the Company first monitor groundwater at its coal ash disposal sites?

A. According to its responses to data requests in this proceeding, the first instances of "required" monitoring were in 1984 at Sutton, 1986 at Roxboro, and 1989 at Weatherspoon. The earliest instances of "voluntary" monitoring identified in the Company's responses to data requests were in 2007 at Cape Fear and HF Lee and in 2008 at Mayo. (Groundwater Monitoring DR 2.)

The Company's plants began generating CCRs as early as the 1950s, so disposal activities went unmonitored for 20 or more years—more than 50 years at the Cape Fear and HF Lee sites. The table below shows the lapsed time between the start of waste generation and the start of groundwater monitoring (Groundwater Monitoring DR):

Plant	Voluntary Monitoring Well Installation	Earliest "Required" Monitoring Well Installation	Years Between First Disposal and First Monitoring
Asheville	none	2009	45
Cape Fear	2007	2009	51
HF Lee	2007	2009	56
Mayo	2008	2009	25
Robinson (SC)	none	1995	20
Roxboro	none	1986	20
Sutton	none	1990	36
Weatherspoon	none	1990	35

Q. Was it reasonable for the Company to operate unlined coal ash surface impoundments for decades without monitoring groundwater quality?

A. No. As discussed earlier, the industry was well aware of the risks of contamination associated with the storage or disposal of CCRs in unlined ash basins near waterbodies and groundwater. In addition, the Company itself had knowledge of leaching at the Sutton site in the early 1980s. The only prudent option for learning whether a given ash basin was causing contamination of water resources was to install and sample monitoring wells.

Q. When was the Company first aware of impacts to groundwater resulting from its North Carolina coal ash disposal sites?

A. According to Company records, investigation of potential groundwater contamination from coal ash ponds took place in the 1970s.

Specifically, a facility located near the unlined ash pond at the Sutton site reported elevated concentrations of chloride in groundwater. (Exhibit MQ-3, 1976 Mingle Memo re Sutton.) In response to the elevated chloride concentrations, the Company performed a groundwater study and determined that its new ash basin, constructed in 1984, should be built with a liner. (Exhibit MQ-4, 1983 Zimmerman Summary re Sutton.) The Company's decision to construct its new ash basin with a liner also reflected its conclusion that a liner was necessary in order to comply with then-proposed state groundwater rules. (Exhibit MQ-5, 1984 Wilson Letter re Sutton.)

Also, a 1979 study of the Mayo site evaluated the geologic and hydrogeologic conditions and the potential for contamination of water resources by a proposed ash basin. (Exhibit MQ-7, 1979 Mayo Groundwater Report at 1 [PDF page 2].) That study concluded that contamination from the proposed ash basin "may flow under the dam through possible fractures in the rocks and then into Crutchfield Branch," and that a soil cover of one foot or more would "seal" the pond from leakage due to soil sorption effects (i.e., soil attenuation capacity). (*Id.* at 8, 9, 10 [PDF pages 9, 10, 14].) The report concluded that "heavy minerals" can be reduced by the "filtering" effects of the soil; that soils of at least 90% clay can filter 95% of metals after 10 years of groundwater flow through the soil; that groundwater flow "could occur under the dam and sub-parallel to the channel of Crutchfield Branch for a relatively short distance and then discharge upwardly into the stream;" and that any contamination that reaches the stream would then be diluted. (*Id.* at

14, 15 [PDF pages 21, 22].) The study concluded that at least a one-foot layer of clay beneath the proposed pond was necessary to protect groundwater, but even with such clay lining, not all metals would be filtered, and the duration of the filtering would be limited.

Q. Did the Company conclude that North Carolina groundwater rules necessitated the use of liners at coal ash disposal sites?

A. Yes. According to Company records, the 1984 Sutton Ash Basin was constructed with a clay liner to address the Company's concerns with its ability to comply with proposed new state groundwater rules. (See Exhibit MQ-6, Greeson Memo re Sutton.)

Q. Were any groundwater investigations undertaken at North Carolina coal ash disposal sites in the 1980s?

A. Yes. In the early 1980s, a contractor retained by the US EPA (Arthur D. Little, Inc.) conducted a "generic assessment" to characterize utility wastes and to evaluate the engineering aspects and costs associated with disposal. (Exhibit MQ-2, 1985 AD Little Report.) The assessment identified six power plant sites—including the DEC Allen site—as representative of nationwide conditions and conducted sampling of groundwater, waste, and surface water at each site. The report concluded that arsenic concentrations in groundwater beneath one ash basin at Allen exceeded drinking water standards. (Exhibit MQ-2, 1985 AD Little Report at 5-14, 5-22 [PDF pages 24, 32].)

Q. What did the 1985 Arthur D. Little Report conclude about groundwater contamination at the Allen site and its effect of water quality?

A. At the Allen site, twenty monitoring wells were sampled as part of the Arthur D. Little analysis. (Exhibit MQ-2, 1985 AD Little Report at 5-4 [PDF page 14].) Arsenic concentrations in groundwater beneath the Allen site exceeded drinking water standards.

(Exhibit MQ-2, 1985 AD Little Report at 5-14, 5-22 [PDF pages 24, 32].) Nevertheless, the report concluded that impacts were expected to be "insignificant," apparently looking only at impacts to the adjacent surface waterbody but not to groundwater quality. The "insignificant" conclusion relied upon the dilution of groundwater discharges into the receiving stream due to the stream flow volume being more than the volume of groundwater discharges into the stream.

Q. Did the 1985 Arthur D. Little Report support a decision not to conduct groundwater monitoring at coal ash disposal sites?

A. No. The report acknowledged that steady-state groundwater conditions at the Allen site had not yet been reached in downgradient groundwater monitoring wells—meaning that the full contaminant plume had not yet reached downgradient wells and contaminant concentrations could get much worse. (Exhibit MQ-2, 1985 AD Little Report at 5-23 to 5-24 [PDF pages 33-34].) Also, soil attenuation estimates made using laboratory leaching tests with on-site soil and wastes did not accurately predict actual groundwater well concentrations. (Exhibit MQ-2, 1985 AD Little Report at 5-22 [PDF page 32].)

The report concluded that increasing constituent concentrations in downgradient wells "would be expected;" available data "cannot support a precise estimate of future groundwater quality;" and steady-state concentrations "may range between existing concentrations and concentrations typical of ash leachate." (Exhibit MQ-2, 1985 AD Little Report at 5-24 [PDF page 34].) And despite the report deficiencies, the report did highlight the potential threat to groundwater resources, documenting existing contamination and the risk of downgradient concentrations of CCR constituents increasing over time. Indeed, as discussed before, EPRI recognized that site-specific geologic and hydrogeologic characterizations were necessary to evaluate risks of surface and groundwater contamination.

Q. What is soil attenuation capacity?

A. Soil attenuation capacity is a process in which contaminants can be "attenuated" by chemical processes in aquifer solids (i.e., soil) and the groundwater. Using arsenic as one example because it is prevalent in CCRs, the US EPA concluded that long-term attenuation is dependent upon numerous factors – such as pH, changes in the redox potential, the presence of iron oxides and sulfides, and microbial interactions. These geochemical conditions are site-specific (2007 EPA Attenuation at 43-47) and can change over time. If such changes occur, previously immobilized contaminants like arsenic can be mobilized to form a new contaminant plume. (2007 EPA Attenuation at 49.)

EPRI also recognized in 1982 that site-specific geochemical conditions dictate the attenuation capacity of contaminants by subsurface materials. According to EPRI, the degree of retardation—or the attenuation capacity of the soil—is based upon site-specific factors such as the clay and organic content of the soil, leachate pH over time, the buffering capacity of the soil, the amount of iron and aluminum oxides in the soil, and the oxidation states of metals, as examples. (1982 EPRI Manual at 2-12.) EPRI further concluded that the nature and extent of the leaching threat to groundwater "will have to be evaluated for each waste and disposal site." The key takeaway is that each waste and each site is unique and requires its own analysis to determine the ability of soil to prevent contaminants from migrating over time. (1982 EPRI Manual at 2-13.)

Q. Can soil attenuation capacity protect against migration of CCR constituents over the long term?

A. No. The ability of soil to immobilize contaminants is affected by the "mass" or contaminant loading of contaminants added to the aquifer over time as the leaching continues. (2007 EPA Attenuation at 50.) The longer the impoundments are operated, the more contaminant mass is added to the surface. The soil attenuation capacity can therefore be exceeded and when this occurs, attenuation capacity would not be a long-term remedial measure.

The Company built impoundments throughout its system within streams channels, stream valleys, and within floodplains. As such, soils beneath the ash basins would be variable with intermixed layers of sand, gravel, clay, and silts. Gravel and sand are much less effective at attenuating contaminants compared to clay, for example, because they are preferential pathways for faster groundwater flow and contaminants do not adhere as much to sand and gravel. The soils at each of the ash basin sites likely contain significant amounts of sand and gravel, in addition to clay. As such, the attenuation capacity of the soil within the aquifers at DEP's ash disposal sites cannot be relied upon as a long-term mitigator of contaminants that leak from unlined impoundments without a site-specific analysis that proves effectiveness.

Q. Can information about soil attenuation capacity at one site support a conclusion that soil attenuation would prevent contaminant migration at a different site?

A. No. The ability of soil to attenuate contaminants is based upon numerous waste and site-specific geologic, hydrogeologic, and geochemical factors. Sluiced water, leachate, and groundwater conditions such as pH can change over time and as a result, the attenuation capacity of the soil can also change. Each waste disposal site has unique conditions that will affect the soil attenuation capacity over time. For example, soil conditions of clay, sand, and gravel and the associated preferential flow pathways are site-specific. In addition, even though clayey soils offer more pollutant attenuation capacity than sandy soils, that capacity has a limited life expectancy. The groundwater study at Mayo, for example, identified a ten-year duration for "filtering" of metals by soil. (See Exhibit MQ-7, 1979 Mayo Groundwater Report at 11, 12, and 14).

Q. Has the Company's storage and disposal of coal ash in unlined surface impoundments caused impacts to groundwater?

A. Yes. The Company itself concluded in 2014 that "our coal ash is impacting groundwater at all locations," when referring to its Coal Ash Program. (2014 Duke Ash Update at 3.) DEP has reported statistically significant increases of pH, boron, calcium, chloride, fluoride, sulfate, and total dissolved solids—all constituents that are indicative of coal ash contamination—in groundwater at every DEP coal ash site. (CCR Rule Exceedances DR.) Also, DEP has reported that groundwater protection standards have been exceeded at each site for one or more of the following: arsenic, cobalt, lithium, molybdenum, selenium, thallium, and total radium. (CCR Rule Exceedances DR.)

At several of the Company's sites, contamination has reportedly migrated off-site at several of the Company's sites (in the Carolinas and in other states) and towards groundwater supplies used for public and private drinking and industrial activities. In numerous cases, rather than initiating corrective actions to eliminate or mitigate the contamination, Duke Energy companies have responded by purchasing affected properties or providing alternative drinking water sources. (2014 Duke Ash Update at 46, 65.) At the Sutton site, the Company removed four public drinking water wells from service and provided an alternative supply. At the H.F. Lee site, the Company purchased some of the land within 500 feet of the site because of migrating contamination. At the Mayo site, the Company purchased property immediately downgradient of its ash basin. In Indiana, Duke Energy bought and demolished one home and connected others to the municipal water supply. Both DEC and DEP have provided bottled water to residents near ash sites.

VI. Costs Associated with Coal Ash Disposal, Monitoring, Closure, and Post-Closure

Q. Were landfills more costly than surface impoundments to construct and operate in the 1980s?

A. No. According to a 1988 US EPA study, the total capital and operation and maintenance cost (given in cost per ton) to construct an *unlined* surface impoundment was *more* than the cost to construct a synthetic-*lined* landfill. The cost to construct and operate an unlined surface impoundment ranged from $8.00 to $17.00 per ton, compared to $5.70 to $13.55 per ton for a single clay-lined landfill and $6.45 to $15.15 per ton for a single synthetic-lined landfill. (EPA 1988 at 6-28.)

The study found that capital costs for closure of landfills and surface impoundments were comparable. (EPA 1988 at 6-21.) However, the total annual post-closure care cost of a landfill was *much less* than a surface impoundment: $1.0 to $2.8 million per year for a surface impoundment versus $0.4 to $0.9 million for a landfill.

Q. Could the costs that the Company has incurred or will incur to excavate CCRs from unlined ash basins have been smaller if the Company had switched to dry ash handling sooner?

A. Yes. As previously discussed, the cumulative volume of CCRs increased over the operational life of each impoundment. The Company has estimated excavation costs in dollars-per-ton—[BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] Accordingly, the additional and avoidable cost of excavating ash that could have been sent directly to dry storage is calculable—the volume of ash disposed of after 1988 (or whatever the Commission concludes was the date by which the Company should have known of the risks posed by continuing to store coal ash in unlined ponds and should have switched to dry disposal) multiplied by the Company's estimated cost per ton.

Q. **Could the costs associated with groundwater monitoring at the Company's coal ash disposal sites have been smaller if the Company had switched to dry ash handling sooner?**

A. Yes. Landfills generally use less land per unit volume of waste because wastes can be stacked vertically over a smaller "footprint" or acreage. A smaller area would require fewer wells to monitor groundwater conditions around the unit's perimeter and fewer to define the nature and extent of any contamination that occurs. In addition, because lined landfills are designed to be more protective of groundwater, the likelihood that contamination would occur and require such monitoring to define its nature and extent is lower than with unlined ponds.

The Company's unlined impoundments, which were expanded over time, require more wells to effectively monitor groundwater. For every additional well, monitoring costs increase. As a result, one would expect monitoring costs associated with a large, leaky surface impoundment to be greater than the costs to monitor a smaller, lined disposal area.

Q. Was it reasonable for the Company to continue operating existing unlined CCR disposal units and to expand or build new unlined units during and after the 1980s?

A. No. The utility industry and US EPA recognized since at least the mid-1970s that unlined surface impoundments and landfills represented a threat to groundwater quality. Disposal of municipal and industrial solid wastes in engineered disposal units (e.g., designed with a liner, leachate collection system, etc.) has been commonplace since the mid-1970s. The understanding of these risks only grew in the years that followed. As such, construction or expansion of unlined disposal units after the mid-1970s was unreasonable.

The continued operation of unlined coal ash disposal units after the 1980s also was unreasonable. Despite the industry-wide understanding of the risks of disposing of coal ash in unlined areas near water resources—including the Company's own recognition in the mid-1980s that a liner was needed for a new disposal unit at its Sutton site—the Company continued to dispose of coal ash in unlined ponds for many years to come. This was unreasonable.

In addition, the Company did not operate adequate groundwater monitoring systems around its coal ash disposal areas—most if not all of which were located in stream beds or directly in contact with groundwater—until the 2000s, decades after it began CCR disposal. This also was unreasonable. The ample information available to the Company regarding the risks associated with unlined disposal unit operations should have led the Company to begin to transition away from wet handling and disposal of coal ash much sooner. And, at the very least, the Company should have begun monitoring the groundwater at its sites much sooner.

Also, as previously discussed, costs to a build, construct, and maintain a synthetic-lined landfill were less than the costs for an unlined impoundment. Nevertheless, the Company chose to build new unlined ash ponds at Cape Fear in 1985 and an unlined landfill at Roxboro in 1988.

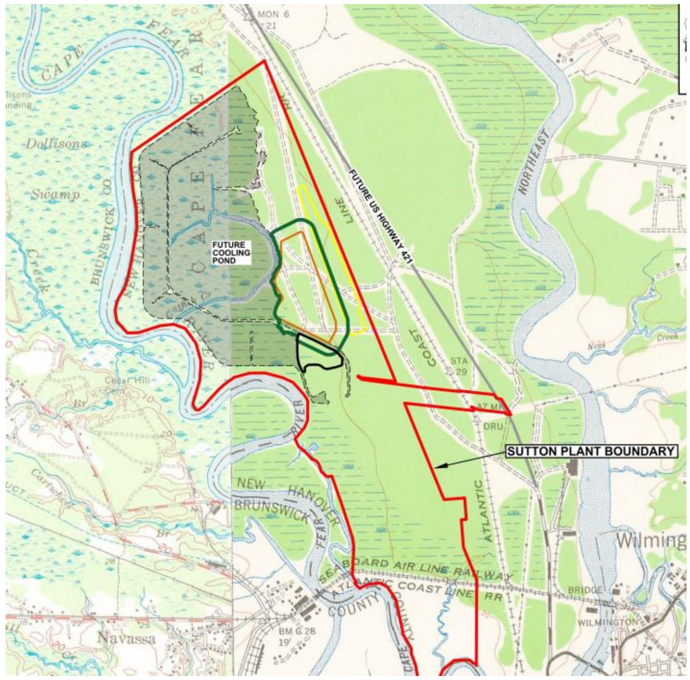
The ample information available to the Company regarding the risks associated with unlined disposal unit operations should have led the Company to begin to transition away from wet handling and disposal of coal ash at least as early as the mid-1980s. Had the Company stopped using unlined ash basins and began filling in lined landfills, the volume of wastes that remained for decades submerged in groundwater that now requires excavation and disposal into a lined landfill would be substantially less—saving millions of dollars in the process.

VII. GROUNDWATER CONTAMINATION AT THE SUTTON SITE

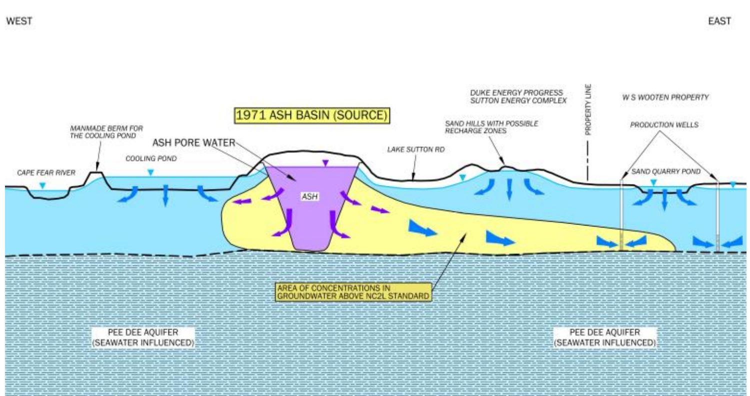
Q. How has DEP stored CCRs at its Sutton facility?

A. The Sutton plant is located on approximately 3,300 acres along the east bank of the Cape Fear River. Power generation began in 1954. Coal ash was first disposed of at the southern end of the property in a lay-of-land disposal area now called the Former Ash Disposal Area ("FADA"). The Company also disposed of CCRs in the 1971 Ash Basin and the 1984 Ash Basin. Collectively, these three disposal areas are called the "ash management area." (2018 Sutton Site Assessment Update at 1-1 [PDF page 32].)

The Ash Management Area was built adjacent to a former swamp next to the Cape Fear River (*id.* Figure 2-1, reproduced here):



Both the 1971 Ash Basin and the FADA extend below the surficial aquifer / groundwater table. The Company dug the 1971 Ash Basin deep within the sand aquifer (*id.* Figure 6-1, reproduced here):



Q. What are the conditions of the uppermost aquifer relative to the CCRs, other groundwater users, and nearby rivers?

A. As illustrated in Figure 6-1, above, the Company constructed the 1971 Ash Basin substantially within the uppermost aquifer and even deeper than the Cape Fear River and the Cooling Pond. Notably, contaminated groundwater from the ash basin extends under the production wells of a neighboring company (W.S. Wooten) to the east.

The uppermost soil beneath the Company's disposal areas consists of well-sorted sands, and the lower portion of the surficial aquifer consists of poorly-sorted sands and layers of fine gravel. As such, groundwater can flow rapidly with little, if any, pollutant attenuation. During the operational life of the 1971 Sutton Ash Basin, groundwater flowed radially (360-degrees) from the ash basin because of the higher standing water in the basins; the additional easterly flow toward the W.S. Wooten site likely is attributable to pumping at that site. (2018 Sutton Site Assessment Update at ES-7 [PDF page 10].)

Q. Is there evidence of groundwater contamination associated with leakage from Sutton and has that contamination negatively affected off-site groundwater users?

A. Yes. CCR-related constituents have been found in upper and lower surficial aquifer at concentrations that exceed local and state groundwater standards. (2018 Sutton Site Assessment Update at ES-2–ES-8, Figure ES-1). The on-site plume in excess of regulatory standards closely mimics the locations of disposal areas. (*Id.*) The contaminated area extends off-site to the east and discharges into Sutton Lake to the west. The contamination led to the following actions:

- Four Cape Fear Public Utility Authority (CFPUA) public water supply wells were removed from service. (2018 Sutton Site Assessment Update at ES-3.) A new water supply line was extended to the area.

- Nine groundwater extraction wells have been installed along the eastern property boundary to recover CCR constituents that have migrated off-site and to prevent further off-site migration. (*Id.* at ES-2.)
- Fourteen private water drinking water wells within a 0.5-mile area have CCR-related constituents in the groundwater above PBTV and 2L standards, and those constituents are attributable to leakage from the plant site. (*Id.* at ES-3.) "Alternate water solutions" are being provided by DEP. (*Id.* at ES-8.)

Constituents that have been reported above North Carolina 2L standards include antimony, boron, cobalt, total dissolved solids (TDS), arsenic, chloride, iron, manganese, selenium, sulfate, and vanadium. (*Id.* at ES-5.)

Q. What does the placement and the number of groundwater monitoring wells tell you about the Sutton site?

A. The system of wells required to monitor groundwater conditions laterally and vertically at the Sutton site is extensive—with wells in the upper portion of the surficial aquifer, the lower portion of the surficial aquifer, and the even lower Pee Dee aquifer. The number and placement of wells can be attributed to the Company's utilization of a large area of land for its ash disposal activities.

Q. Is it reasonable to expect that an unlined surface impoundment with more saturated CCRs and sandy soils beneath would have a higher leakage rate than a pond with less saturated wastes and more separation from the wastes and the uppermost aquifer or than a lined, dry landfill?

A. Yes. The greater the thickness of the saturated and submerged CCRs and the greater the volume of standing water above such CCRs both create a higher "hydraulic head," which leads to additional downward pressure (known as a "vertical gradient") on the underlying water table aquifer, pushing contaminants deeper into the aquifer. That increased hydraulic head also creates a radial groundwater flow pattern (known as "mounding") away from the disposal unit footprint in all directions, in addition to the preferential groundwater flow direction into the nearest stream or river. The "mounding" effect on the uppermost aquifer increases the gradient or slope of the groundwater, thereby increasing the velocity of groundwater that migrates away from the impoundment. Sandy soils are less likely to absorb or attenuate CCR-related constituents. Contaminant migration is even worsened when off-site groundwater users pump enough water from wells to "pull" groundwater towards them—as reported in off-site public, industrial, and private wells at Sutton, as an example. Given the presence of such conditions at the Sutton site and other coal ash sites, the Company's continued reliance on unlined ash basins was unreasonable.

VIII. CONCLUSIONS AND RECOMMENDATION

Q. Do you have any recommendations for the Commission in this proceeding?

A. Yes. I recommend that the Commission make the following findings and give such findings due consideration as it evaluates the Company's request:

1. Historical documents, including the Electric Power Research Institute manuals, available to the Company, demonstrate that the environmental risks associated with the disposal of coal ash in unlined surface impoundments were understood by the electric utility industry in the late 1970s and early 1980s.

2. The Company's continued operation of unlined surface impoundments that were constructed directly in streams, adjacent to rivers and streams, with coal ash saturated in groundwater, without adequate groundwater monitoring for decades after the industry recognized the risks of such operation, was unreasonable and could be expected to result in the introduction of CCR constituents to surface and groundwater.

3. The Company's 1983 investigation regarding contaminant migration from Sutton and its decision to construct a new ash basin with a liner in order to meet proposed groundwater regulations was a warning sign and early indication that unlined surface impoundments leaked and presented risks to groundwater quality. The Company's failure to take action to end disposal of coal ash in unlined basins was unreasonable.

4. Standing water in the impoundments, leakage of that water into the shallow aquifer below, submerged CCRs in the impoundments, and the mounding effects and radial flow conditions of the aquifer, have resulted in more widespread contamination and increased groundwater flow velocities of the contaminated aquifer towards receptors and receiving streams.

5. Costs associated with excavation and groundwater monitoring would be lower if the Company had converted to dry disposal in lined landfills sooner.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1219A

DOCKET NO. E-7, SUB 1219A	
In the Matter of Application of Duke Energy Carolinas, LLC for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina	**SIERRA CLUB'S CORRECTIONS TO DIRECT TESTIMONY OF MARK QUARLES**

Mr. Quarles' direct testimony should be corrected and clarified, as follows:

1. On Page 2, Line 19, "2018" should be changed to "2017."

2. On Page 18, Line 8, add Footnote 1 after "(Groundwater Monitoring DR):" that reads: "The Company's responses to October 30, 2019 NC Public Staff data requests 2-10 and 2-11, identified different dates for the first installation of groundwater monitoring wells at Sutton (1984 and 1990) and Weatherspoon (1989 and 1990)."

Respectfully submitted this 29tt day of September, 2020.

Catherine Cralle Jones
N.C. State Bar No. 23733
Law Office of F. Bryan Brice, Jr.
127 W. Hargett St., Ste. 600
Raleigh, NC 27601
Telephone: 919-754-1600
Facsimile: 919-573-4252
cathy@attybryanbrice.com

CERTIFICATE OF SERVICE

I hereby certify that I have this day serve a copy of the foregoing *Sierra Club's Corrections to the Direct Testimony of Mark Quarles* upon each of the parties of record in these proceedings or their attorneys of record by email transmission.

This the 29th day of September, 2020.

LAW OFFICE OF F. BRYAN BRICE, JR.

By:________________________________
Catherine Cralle Jones

Summary of Direct Testimony of Mark Quarles, P.G., for Sierra Club
Docket No. E-2, SUB 1219

In 2008, approximately 5.4 million cubic yards of coal ash were released into the environment following a dike failure at a coal ash pond at the Tennessee Valley Authority's Kingston coal plant. The Kingston spill brought national attention to the risks associated with the mismanagement of coal ash disposal areas, including risks of catastrophic releases as well as contamination of groundwater and surface waters. In connection with spill response efforts, I was involved with the development of a monitoring program to determine the lateral extent of the release, and I have since been involved with investigations at more than 100 coal ash disposal sites in the U.S. I have gained significant experience regarding coal combustion waste, the potential for constituents of concern to migrate in the environment, the toxicity of such constituents, and sampling programs to determine their extent in soil, surface water, sediment, and groundwater. Based on this experience, I have an acute understanding of the dangers presented by storing coal ash in unlined disposal units—and especially unlined surface impoundments.

For this proceeding, I evaluated the Company's historical coal ash management practices against the backdrop of what the Company knew or should have known, from a scientific and engineering perspective, about the dangers posed by storing millions of tons of coal ash in unlined pits in contact with groundwater and adjacent to lakes and rivers. Historical documents available to the Company demonstrate that the risks of groundwater contamination from unlined coal ash ponds were reported as early as the mid-1970s and were well understood by the early 1990s. The fact that the US EPA did not finalize its federal coal ash regulations until 2014 does not diminish the fact that the Agency concluded in the 1980s that "[t]he primary concern regarding the disposal of wastes from coal-fired power plants is the potential for waste leachate to cause groundwater contamination." (1988 EPA Report to Congress at E-3 [PDF page 17].)

Given this understanding, the Company's continued operation of unlined surface impoundments and even expanded some that were constructed directly in streams, adjacent to rivers and streams, and with coal ash saturated in groundwater, could be expected to result in the introduction of coal ash constituents to surface and groundwater and was therefore unreasonable. At the very least, the Company should have conducted more robust groundwater monitoring earlier at its coal ash sites.

Indeed, industry manuals available in the 1980s also highlighted the risks to groundwater resources and recommended that groundwater monitoring systems be installed where there was the potential for discharge of contaminants to underground water resources. A 1982 EPRI manual explained clearly the hydrogeological underpinnings of such risks, stating that: "the potential for groundwater degradation should be noted, especially when an unlined ash pond is constructed on a site with relatively permeable soils and a shallow groundwater table. . . . The existence of a constant hydraulic head (standing water) in the pond makes leachate generation and migration inevitable." (1982 EPRI Manual at 4-19.) In addition, that manual made clear the importance of adequate groundwater monitoring, stating that: "monitoring of groundwater and leachate, is nevertheless necessary to provide convincing proof of safe disposal practice." (Id.)

The Company's own records from the 1970s and 1980s demonstrated an understanding of the risks that storage of coal ash in unlined basins posed to groundwater resources. A 1979 study of hydrogeologic conditions at the Mayo plant concluded that contamination from a planned basin could flow under the dam and into Crutchfield Branch, a tributary of the Dan River. In 1984, a groundwater evaluation at the Sutton plant led the Company to alter its initial plan to construct an unlined basin to instead build a new clay-lined basin. Nevertheless, the Company's monitoring of groundwater at its coal ash sites was far from timely or adequate. The Company did not even begin voluntary monitoring at any of its sites until after the state regulator required monitoring at a number of sites in the 1980s and 1990s. At four of its coal ash sites—including three at which groundwater had gone unmonitored for 45 years or more—the Company did not beginning routine monitoring of groundwater until the late 2000s. Unsurprisingly, this lack of timely monitoring led to widespread contamination of groundwater at every single one of the Company's coal ash disposal sites.

Had the Company switched to dry handling of ash sooner, the volume of ash that sat submerged in the ponds for decades and that now must be excavated would be much smaller. Consequently, the costs that the Company has incurred and will continue to incur to excavate its coal ash ponds would have been smaller if the Company had switched to dry ash handling sooner. For every additional ton of coal ash that was disposed of in an unlined pond and now must be excavated, the Company will incur additional costs. As discussed in the confidential portion of my testimony, the Company has quantified these costs as a dollar-per-ton rate for excavation, transportation, and placement of ash that is removed from the basins. Similarly, groundwater monitoring costs would have been smaller if the Company had switched to dry ash handling sooner because properly designed landfills are less likely to leak and if so, the plume would be smaller. A smaller more geographically limited plume would require fewer monitoring wells and less associated monitoring costs.

In conclusion, the combination of the historical documents available to the Company and the Company's own identification of risks to groundwater at the Sutton and Mayo sites in the late 1970s and early 1980s should have led the Company to take action to mitigate the risks posed by its unlined ash ponds at some point in the thirty years before the adoption of the federal coal ash rule and the enactment of the North Carolina coal ash law. Instead, the Company sat on its hands. The Company's inaction resulted in more widespread contamination of the state's groundwater resources, jeopardy to present and future drinking water sources, the need for alternative drinking water supplies, and millions of tons more ash to be dewatered, excavated, and redisposed of, all driving higher cleanup and risk reduction costs.

MS. CRALLE JONES: And then we would further move that the prefiled Sierra Club Quarles Exhibits 1 through 7 be marked for identification and premarked and moved into the record at this time.

COMMISSIONER CLODFELTER: Unless there's objection, if will be so ordered.

(Quarles Exhibits 1 through 7 were identified as premarked and admitted into evidence.)

MS. CRALLE JONES: As a party to the amended joint stipulation of September 28th, Sierra Club would finally move that the live testimony of Mr. Quarles given in the DEC proceeding located at DEC transcript Volume 18, page 63, line 1 through page 142, line 23 be copied at this time into the record of these proceedings as if given orally from the stand.

COMMISSIONER CLODFELTER: All right. Unless there is an objection to that motion, motion is allowed.

(Whereupon, the testimony from Docket Number E-7, Sub 1214, transcript Volume 18, page 63, line 1 through page 142, line 23 was copied into the record as if given orally from the stand.)

MS. CRALLE JONES: Mr. Quarles is available for cross examination.

CHAIR MITCHELL: All right. Thank you, Ms. Cralle Jones. Public Staff, you're up first.

MS. LUHR: The Public Staff has no questions.

CHAIR MITCHELL: Okay. Attorney General's Office?

MS. TOWNSEND: No questions, Chair Mitchell.

CHAIR MITCHELL: All right. Duke?

MR. MEHTA: Good morning, Chair Mitchell. It's Kiran Mehta, and I do have a few questions.

CHAIR MITCHELL: Okay. Please proceed, Mr. Mehta.

MR. MEHTA: Thank you, Chair Mitchell.

CROSS EXAMINATION BY MR. MEHTA:

Q. Good morning, Mr. Quarles.

A. Good morning.

Q. Mr. Quarles, the purpose of your testimony, as I understand it, and I'll just paraphrase, is to determine when -- and you emphasize if your testimony the word "when" -- Duke Energy Carolinas knew or should have known that environmental contamination was likely due to storage and disposal of coal ash in unlined basins.

Did I capture the purpose of your testimony correctly?

A. You did.

Q. What do you mean by the term, quote, contamination, Mr. Hart -- Mr. Quarles?

A. Contamination relates to 2L standards. It could also relate to any constituent concentration above naturally occurring background.

Q. So the way you use the term, it's essentially an increase over naturally occurring background and/or an exceedance of 2L standards?

A. So that is a common way of defining contamination. In fact, like in the CCR rule, the Company is required to evaluate constituent concentrations over time relative to other wells and naturally occurring background wells.

Q. And the CCR rule was promulgated in 2015, correct?

A. 2015.

Q. Now, on pages 3 and 4 of your testimony, you provide a list of the documents upon which you relied to inform your conclusion about when DEC knew or should have known about the likely impact of its ash storage in unlined ponds, correct?

A. That's correct.

Q. And I wanted to ask you about a few of them. But let me first see if I can understand how you believe a reader today of these documents should understand and place into context something that was written, you know, in some cases, decades ago.

So first, Mr. Quarles, if you are attempting to assess what was known or understood at some earlier point in time, would you agree that you should refrain from applying today's knowledge to an evaluation of what was known and understood during the time period that you are assessing?

A. The reports that I cited in review were reports that were available and published at the time by governmental agencies, by EPRI, by the industry in terms of what was known and what was expected to happen in the future regarding coal combustion waste disposal.

Q. I understand that, Mr. Quarles, but my question was slightly different. And let me try to restate it.

If you are attempting today to assess what was known or understood at some earlier point in time, would you agree that you should refrain from applying today's knowledge to an evaluation of what was known and understood during that period of time; rather, you should apply that period's knowledge about what was known and understood?

A. So I am -- I am reviewing documents that were written in the late '70s, early '80s that were written at that time, and, of course I was not employed in a capacity as a scientist in the late '70s, early '80s. So my work was evaluating what was known at the time, and those documents describe what was known in terms of the risks associated with coal combustion waste disposal.

Q. Well, I guess my question to you, Mr. Quarles, is as you read them today, are you reading them today through the lens of today, or are you reading them today applying the lens of the late '70s or the 1980s?

A. I am reading them as a scientist. And what information that is available in the documents, putting myself in a position, if I was a consultant back in the '70s, or if I did work for the Company back in the '70s, what kind of data would I find to be important to

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make decisions at that time.

Q. Okay. So if I understand you correctly, Mr. Quarles, what you're trying to do is read the documents that were written in some cases, you know, 30, 40 years ago through the lens of someone reading them at that time?

A. You trailed off.

Q. Let me try it again. If I understand you correctly, Mr. Quarles, you are reading those documents obviously in present day, but trying to read them through the lens of somebody who was reading them or would have been reading them back at the time that they were written and published and available for review by whoever was reading them; did I capture that correctly?

A. Yes. You're reading them as if somebody was reading them back in the '70s and '80s, and what the conclusions and what the data said as a whole means.

Q. Have you reviewed the testimony of Marcia Williams, Mr. Quarles?

A. I reviewed her rebuttal testimony.

Q. Yeah, I think that might be the only testimony that she -- well, I think she also had some supplemental rebuttal, but that deals with Mr. Hart, not you.

The -- on page 67 of her testimony, right at the top of the page --

A. Okay. Is this the PDF page or the hard copy page of the testimony?

Q. I guess it would be the hard copy page.

A. Okay.

Q. And in her testimony -- it's actually the top of page 68, see the reference is -- are you there?

A. I am, yeah.

Q. Okay. She references what she refers to as the, quote, weight of evidence approach; do you see that?

A. I do.

Q. Is that the approach that you also applied in your review of the historical documents that you reviewed that are listed on pages 3 and 4 of your testimony?

A. I didn't refer to my review as a weight of evidence approach. I reviewed those documents and provided my opinion and interpretation of those documents.

Q. Okay. But you didn't -- you didn't follow what she calls the weight of evidence approach?

A. I don't know what her -- how she defines a weight of evidence approach.

Q. Well, I guess she defines it starting on the preceding page. And if you could just read -- you can just read it to yourself, we can all read it ourselves as well. Starting on page 67, line 12, and going on to the top of page 68. I want to know if that is the approach that she outlines called the -- that she calls the weight of evidence approach, if you used that approach.

A. (Witness peruses document.)

Yeah. On page 67 she talks about specifically:

"It's key to recognize that a single research study or a statement on a report does not represent consensus that a particular activity has -- is or is not reasonable."

And then she goes on to say that Mr. Hart, Junis, and I selectively refer to various documents weighing the broader -- without, in my opinion, weighing the broader set of available knowledge.

Q. And the -- weighing the documents within the broader set of available knowledge is what she calls the weight of evidence approach, correct?

A. Yeah. And I would say that I followed the weight of evidence approach, because I had authoritative numerous documents that were specifically related to disposal of coal combustion waste. Information that was available to the industry and written by the industry, and information that was written by EPA specifically related to coal combustion waste at that time.

Q. So would you agree that you, in fact, were trying to follow what Ms. Williams calls the weight of evidence approach? You might call it a different term, but that's what you were trying to do?

A. So what I did was I reviewed numerous documents that were written at the time specific for coal combustion waste.

Q. And does that mean that you were trying to follow what Ms. Williams calls the weight of evidence approach?

A. Whatever you want to call it. Weight of evidence is there were numerous documents that all supported the same conclusions relative to the risk associated with coal combustion waste disposal.

Q. Would you agree that when one looks at a particular publication or study done in the past, that one should try to place that study in the context of what else was going on and what else was known at that time?

A. That's a fair statement.

Q. And would you also agree that it is inappropriate to take a little snippet of a study out of the context in which the study was developed, published, and presented?

A. The -- as you call it, the snippets -- snippets there are important sentences that are included in the documents related to the risks associated with coal combustion waste disposal.

Q. So you would stay that it's appropriate to use a snippet in -- with reference to how you are presenting your testimony, you know, again, relying on these past documents but presenting a point of view with respect to those documents in your testimony today?

A. It's important to review all of the findings of the documents, in addition to bringing out those points regarding the purpose of my testimony.

Q. Okay. But it would be inappropriate, would it not, Mr. Quarles, to take one of those snippets and then portray it today as supporting some proposition on which the study came to a contrary conclusion; is that

correct?

A. I would tend to disagree with that statement. Sometimes these studies, for example, they would look at -- when I say some of the studies, particularly some of the studies that Ms. Williams cited in her testimony. Her studies looked at the use of surface impoundments, for example, as a whole around the country, not just coal combustion waste disposal. So she looked at impoundments that were related to oil and gas, or municipal wastewater, or any sort of industrial-type scenario.

And so, for example, if there was a conclusion out of a report, that was a conclusion that said the risks were minimal, or there was little risk, or no harm, whatever you want to call those kinds of paraphrased conclusions, I would tend to disagree. And actually those documents -- many of the documents would also have other snippets, as you call it, that talk about, for example, a larger impoundment in the greater scheme of things has a greater opportunity for leakage as compared to an impoundment that's less than one acre, for example.

So the context is important in the conclusions that I brought out relative to the surface impoundments that were typical of the Company.

Q. Well, I guess to put maybe a finer point on my question, Mr. Quarles, perhaps it was too broad a question.

If you had a study, for example, that was done in 1980 that concluded the sky is blue except sometimes at sunset it kind of looks red and gold, it would be inappropriate for someone to come along decades later and say only that that study concluded that the sky was red and gold?

A. If I was a scientist in the early 1980s like I am now, I would review the documents in the same way. And, you know, just to use your analogy the sky is blue, let's talk about the A.D. little report as an example. It did come to the conclusion that, you know, the risks were minimal nationally for the six -- using the six sites that were evaluated, but let's put it in the context of six sites, and there were approximately 500 coal combustion waste impoundments around the country. Those six sites represented 1 percent approximately, of the total. And then when you actually get back into the details of the report, was not very flattering at all about what was actually going on at plant Allen as one of those six sites.

So, as a scientist, I reviewed the report in the context of the broader conclusions, not just the -- what was written in the abstract or the findings and conclusions at the end.

Q. And I think you did mention this, but plant Allen was one of the six sites out of 500 or however many there were nationwide, correct?

A. That's right.

Q. That was the focus of the Arthur D. Little report?

A. There was one. The Allen site was one of the six, yes.

Q. Okay. Now, Mr. Quarles, let's actually talk about some of the more -- some -- more specifically about some of the documents that you've cited.

And on page 12 of your testimony, you reference and talk about a manual authored by the Electric Power Research Institute, or EPRI, in 1981, correct?

A. That's right.

Q. And that document is one of the ones that we have marked as a joint exhibit, and I believe it is Joint Exhibit Number 7. And you can certainly refer to Joint Exhibit Number 7, or there are multiple copies of the EPRI 1981 manual floating around, and whichever one you want to refer to is fine.

And you note, on page 12 of your testimony, the concern raised in the manual about the potential for heavy metals to leach into the groundwater system and contaminate present or future drinking water sources, correct?

A. That's right.

Q. And, Mr. Quarles, this particular manual, the 1981 EPRI manual, was published by EPRI for use in designing new landfill facilities; is that correct?

A. That's right.

Q. And Ms. Williams indicates in her testimony, I think it's on page 77 -- and you can certainly look there if you like, but you may just remember it -- but she indicates that the 1981 manual was written in anticipation of EPA regulations that, in fact, were never promulgated.

Do you recall that in her testimony?

A. I do.

Q. Do you agree with her testimony?

A. That's right.

Q. So, for example, Mr. Quarles, on page 12, lines 8 through 16 of your testimony, you list a whole series of things that the EPRI 1981 manual says should be done in connection with new landfills that are developed post publication of the 1981 manual, correct?

A. Yes.

Q. And did those -- did those requirements that are laid out on page 12, lines 8 through 16 of your testimony ever actually become requirements that anybody had to follow?

A. Well, according to EPRI, they referred to at least a couple of those standards as being applicable -- already applicable in North Carolina at the time. For example, not building solid waste disposal facility in a flood plain, or separation between the waste and the water table. So the context of the 1981 EPRI document certainly laid out -- if you were not schooled, educated, or experienced in the risk associated with unlined impoundments in the late '70s, early '80s, this document, although for a new facility, should have informed you that there are risks associated with unlined disposal.

And it talked very methodically about the processes that you should go through on determining whether or not your -- whether or not you have any contamination. For example, I list like eight or nine different factors, if you will, on establishing background data quality -- groundwater quality, the depth, direction, rate of flow, hydraulic conductivity, the attenuating capacity of the soil, the separation distance between the bottom of the waste and the uppermost aquifer.

So it should have spurred that thought process to say if I don't -- if I have an existing facility, is it -- have I done that evaluation to know whether or not my -- my unit is leaking to groundwater. And on that same page, I make reference to a 1982 EPRI document which was a follow-up document for upgrade. And it, again, talks about that same thought process of you should consider an upgrade by following the steps of a groundwater evaluation to know whether or not you're contaminating the underground source of drinking water.

Q. Yeah. We'll get -- I promise you we will get to the 1982 EPRI document shortly. But let me just stick with the 1981 one for a moment.

Mr. Quarles, do you have any information that suggests that, when Duke Energy Carolinas built a new landfill after 1981, that it did not comply with whatever the regulation -- regulatory framework was with respect to building that landfill?

A. When you say "landfill," are you talking landfill, or are you meaning a surface impoundment, or both?

Q. I'm talking about a landfill, since the 1981 document is specifically dealing with landfills.

A. Ask your question again, please.

Q. Do you have any information, Mr. Quarles, that suggests that, when Duke Energy Carolinas built a landfill after 1981, that Duke Energy Carolinas did not comply with whatever regulatory framework governed the development of that landfill?

A. So some of the landfills, like the retired ash basin landfill at plant Allen, had a liner, right. Some of the other landfills perhaps do not have a liner. And then if you didn't have a groundwater monitoring system of a landfill water surface impoundment until the, you know, mid, what, 2011, voluntary monitoring perhaps began in 2005, 2006, then obviously they would not be following the recommendations on establishing groundwater quality, which is a component of design and operation of a landfill.

Q. Well, my question was a little different,

Mr. Quarles.
Do you have any information that suggests that, when Duke Energy Carolinas built a landfill after 1981, that it did not follow whatever the regulatory framework that governed the building of that landfill?
A. And which landfill are you referring to?
Q. Any landfill.
A. Which landfill did they build post 1980?
Q. Well, for example, Mr. Quarles, we know that, as a result of the Belews Creek -- Belews Lake incident in the mid-1980s, that Duke Energy Carolinas changed its operating process, and instead of sluicing fly ash into the ash pond, it started to handle fly ash on a dry basis and built a landfill to store that fly ash, correct?
A. I did hear that yesterday in the testimony of Mr. Hart, but I have not investigated the details of Belews Creek.
Q. Okay. And so, presumably, this -- well, the mid-1980s is after 1981, correct?
A. It is.
Q. And so if they built a landfill to handle the fly ash that was produced as part of the operating process at Belews Creek, they built a landfill, as far

as you know, in complete compliance with whatever the regulatory framework was for building that landfill?

A. I can't -- you know, I can't say as far as I know, because I haven't investigated those landfills. The 1981 EPRI document that I referred to, really the context of that was that if you're going to do this sort of evaluation and consider those eight or nine factors for a landfill, you should especially be considering those factors for surface impoundment because the opportunity for leakage is much greater.

So that -- that is why the '81 EPRI document is so very much relevant. And, in fact, if you look at the bottom of my testimony page 12 -- and again we'll get to it, the 1982 EPRI document -- but it says:

"Inadequately lined ponds provide a greater opportunity for groundwater contamination because the soil immediately below the pond is always saturated and under a constant head of pressure from the overlying water. Consequently, seepage may be constant and in greater volume than leachate from a landfill."

So what that means, if I am a manager in the company that is responsible for CCR disposal, that kind of comment and the eight factors of evaluating the groundwater quality in the '81 document should have --

should have raised some flags and required the Company to ask really hard questions about whether or not my unlined surface impoundments are leaking.

Q. Well, since you're already at the 1982 document, why don't we just go to the 1982 document, Mr. Quarles. And I believe that is Joint Exhibit 8. And it is certainly a lengthy exhibit. I think it's about 500 pages or so.

And first, just to level set us, Mr. Quarles, I think you mentioned this earlier, and do you -- are you actually looking at what we've marked as the joint exhibit, or are you looking at a different version?

A. I don't have that joint exhibit open. You haven't asked me to review a certain page, so if you would like me to do that, I would.

Q. Yeah. I mean, if you're in the joint exhibit, since they have a specific identifying document page at the top of the -- at the top, primarily because all of these came from the appellate record, it would be page 1,455. If you're not in the joint exhibit, it is page romanette v.

A. So if I'm in a hard copy, what page would you like me to look at?

Q. It's the little Roman numeral v.

A. Of the -- I'm sorry, the '82 or the '81?
Q. '82.
A. Oh.
(Witness peruses document.)
So the page numbers of the '82 document are, like, 1-3, 2-14.
Q. Yeah. Well, this is before you get to the 1- --
A. Oh, okay.
Q. It's in the -- sort of in the preliminary stuff. It's called -- the title of the -- or the title at the top of the page is "EPRI Perspective."
A. Yes, sir, I see that.
Q. And in the section right below EPRI perspective, it talks about the project description, correct?
A. It does, yup.
Q. And it says this document is one of a series of manuals, and the '81 document was in that series, correct?
A. Yes, sir.
Q. And it's actually mentioned there, the -- I think that's the coal ash disposal manual, correct, is the 1981 document?

A. Yeah. Coal ash disposal manual, second edition.

Q. Okay. And it goes on to say that:

"Whereas the aforementioned manuals," which would include the 1981 manual, "are intended for use in designing new disposal facilities, this manual," the 1982 manual, "is primarily intended for upgrading existing waste disposal facilities."

Did I read that correctly?

A. Yes, you did.

Q. So if you're interested in EPRI's view on upgrading existing facilities, this is the one you should be looking at as that early 1980s reader or engineer trying to figure out what they're supposed to do, correct?

A. Yeah. And I would add to that, is -- part of the context of this upgrade document is to assist a utility manager to decide whether or not he or she needs to upgrade a disposal facility. So that's where it talks about -- you know, like on page 12 in my testimony, and this specifically mentions it for that purpose, that inadequately lined ponds provide a greater opportunity for groundwater contamination. It's always saturated, it's under constant head of pressure, and seepage may be constant and in greater volume.

So part of that manual was meant to enable a utility manager to make decisions on whether or not it contaminated the groundwater and whether or not they should upgrade because of that greater opportunity for leakage to a dry disposal facility.

Q. Okay. And your testimony goes on on page 13 to make additional reference to more specific pages of the 1982 EPRI manual, which is Joint Exhibit 8, correct?

A. Yes.

Q. And you cite to pages 4-1 and 4-2, correct?

A. I do.

Q. And again, if anybody is following along with me, joint exhibit, those pages are DOCX 1529 and 1530. But if you just -- if you've got the 4-1 and 4-2, we can certainly use those.

A. Okay.

Q. And at the top of 4-1, there is a paragraph under introduction that I think is what you were alluding to.

That is the utility environmental engineer or other individual responsible for waste disposal needs to figure out, you know, what's coming down the pike and does my facility comply, right?

A. Yes, sir.

Q. And that last little parenthetical says if the sites are ultimately required to comply with whatever the new regulations that are coming down the pike are, correct?

A. Yes, sir.

Q. And you then, at the bottom of page 4-1, I think you quote the language from there in your testimony on page 13, correct?

A. I did quote from that page; yes, sir.

Q. So you indicate that potential deficiencies in utility waste disposal practices may be defined by two sets of standards, right? And those two sets of standards are what is down at the bottom, those two bullets at the bottom of page 4-1, correct?

A. Yes, sir.

Q. And the first one is the disposal practice does not comply with, you know, whatever the specific rules and regulations are, correct?

A. Yes, sir.

Q. And then the second one is the site has the potential to contaminate the environment, correct?

A. Correct.

Q. So, Mr. Quarles, what did the authors of the EPRI manual mean by "the site has the potential to contaminate the environment"?

A. Well, if it's an unlined surface impoundment that receives millions of gallons of water every day in a stream valley next to a water body, clearly the site has the potential to contaminate the environment.

Q. Well, I guess by my question, Mr. Quarles, what I'm asking is, do you know whether the authors of the 1982 EPRI manual apply the same definition of contaminate that you do, that is any level above background?

A. I don't know how they define contamination, but, you know, I've been in the environmental consulting business for over 30 years, and the interpretation of contaminate, whether or not -- particularly related to whether or not a facility is leaking and has the opportunity to contaminate the environment, is really -- it's really -- it hasn't really changed in the 30-plus years.

Q. Well, again, if you think back to Ms. Williams' testimony, Mr. Quarles, she made a distinction between contaminate, meaning any level above background, and environmental harm, meaning somebody could actually be hurt by it, correct?

A. I do remember her making that statement.

Q. Okay. Well, do you know if the authors of the 1982 EPRI report used the word contaminate in the sense of any level above background, or did they use the word contaminate in the sense of something that could really hurt?

A. So let's go back to the first part on that page 4-1. And you made reference to this sentence. "If the sites are ultimately required to comply with the regulation." So the 2L regulation did apply, and I think it was promulgated in North Carolina in 1979. So the 2L standards applied in 1979 and certainly in 1982 with this upgrade manual. So we need to understand that those standards were there, and the state had established those standards, and they were -- at a minimum, they have to be at least as stringent as the EPA standards and perhaps -- or even more stringent for North Carolina situation.

So in terms of contaminate the environment, we first need to remember that the regulators have already established those standards on what is an acceptable or not concentration of groundwater; and then secondly, contaminate again could be whether or not there's evidence of leakage beyond background.

So it's -- certainly, the prevailing regulation at the time was the 2L standard.

Q. Mr. Quarles, is it your testimony that the authors of the EPRI 1982 report had in mind the 2L standards when they wrote this report?

A. I can't speak for the authors of the report, but I can tell you that these documents were meant to discuss CCR disposal and risks associated with unlined disposal and the opportunity to contaminate groundwater. That's very consistent in all of the documents.

Q. Okay. Mr. Quarles, if you would -- we'll come back to pages 4-1 and 4-2, but if you would go to -- at the very beginning of the document before the Arabic-numbered pages start, Roman number VI.

A. Roman numeral number VI?

Q. Yes. And for anybody following along in the in the joint exhibit, that would be DOCX 1456.

And you see the section on that page that's headed "Project Results"?

A. Yes, sir.

Q. And the second paragraph there under that page -- under that heading reads as follows:

"Regulations governing the disposal of utility wastes are in a state of suspension at this time. Congress, in the 1980 amendments to RCRA requested a detailed study of the effects of utility waste disposal practices. And the EPA has a multimillion dollar project underway to address some of the questions. The answers are not expected to be known until late 1983. Until that time, there will be no firm design or performance standards applicable to utility waste disposal that can be applied with confidence by the industry. At the present time, state standards for nonhazardous wastes, which are also undergoing change -- undergoing change, apply to utility waste disposal. For these reasons, it may be premature for any utility to embark on a program to update their existing disposal facilities."

Did I read it correctly?

A. You did.

Q. Okay. Mr. Quarles, the authors of this manual were essentially telling the reader, changes in the rules are coming, we want you to get ready for those changes, but don't do anything just yet because they're coming. Is that what that paragraph said?

A. It does say that changes are coming, and it may be premature. I think "may" is a very key word. And that was the whole idea of the EPRI documents is that -- is that you're not going to be able to flip a switch and snap your finger and immediately make decisions without collecting information. And so what these documents, particularly the '82 document on the upgrade, is that you need to start now to assess your facilities on whether or not you're -- you have an opportunity to be out of compliance or contaminate the environment, if you will.

And one of the most important things here in the first part of that paragraph, it says:

"Need to remember that there may not have been design and disposal standards on how to design a CCR disposal facility, but RCRA, itself, and the requirement that you not pollute groundwater has been in effect since 1979."

So while there may not have been design standards for how to build and design a CCR disposal unit, the requirement to protect groundwater has been there since 1979, right. So with that in mind, I think the terms -- the only way to provide convincing proof that you're meeting the 1979 RCRA groundwater standard is to install wells. Wells are necessary, according to EPRI.

So while there may not have been national design standards for CCR landfills, there was certainly a requirement to comply with the groundwater standard.

Q. And when you say "groundwater standard," are you speaking of the federal RCRA standards, or are you speaking of the 2L state standards?

A. So they were both promulgated, my understanding, in 1979, so both would apply.

Q. Okay. If you go back, Mr. Quarles, to pages 4-1 and 4-2.

A. Okay.

Q. And on page 13 of your testimony, you quote from 4-2. That quote, if -- well, the paragraph on 4-2 that you're quoting from starts "if evidence of contamination problem exists."

A. Are you reading from my testimony or are you reading from page 4-1?

Q. I am sorry, that was a confusing question. I'm actually reading from page 4-2.

A. All right. Okay.

Q. And the paragraph that you quote from in your testimony says, "if evidence of contamination problems

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exist."

A. Uh-huh.

Q. Is that right?

A. Yes, sir.

Q. And there again, you don't know in what sense of the word contamination the authors of the EPRI report used the word contamination, correct?

A. That is correct. The context of determining whether or not there's evidence of contamination, certainly according to EPRI, you need groundwater monitoring wells for convincing proof for what they call inevitable and constant seepage. So if evidence of contamination problem exists, the only way that you will know with convincing proof is to have a groundwater monitoring system.

Q. And then the part in your testimony that you do quote is down at the bottom of that paragraph.

"So if evidence of contamination problems exists, then an engineering assessment of site adequacy must therefore address; one, whether the operation complies with prevailing regulations; and two, whether the site poses a threat to the local environment."

Do you see that?

A. Yes.

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Q. And then that is the part that you quoted in your testimony, correct?
A. It is; yes, sir.
Q. And again, the authors don't tell us what they mean by a, quote, threat to the local environment, do they?
A. Perhaps they do in the other parts of the document.
Q. Well, if you look immediately above those words, there may be a clue, because they talk about current federal regulations promulgated under Superfund authority ultimately hold the operator liable for environmental degradation regardless of what regulations applied or who permitted the facility, correct?
A. Yes, sir.
Q. Now, the Superfund law is what Congress enacted following the Love Canal disaster to deal with hazardous waste dumps, right?
A. Yeah. Uncontrolled -- initially it was for these uncontrolled hazardous waste sites, correct.
Q. Now, Mr. Quarles, there are no Duke Energy Carolinas ash basins that are Superfund sites, are there?

A. I'm not aware, but I haven't researched to know if they are.
Q. Well, as far as you know, there are no Duke Energy Carolinas ash basins that are Superfund sites, correct?
A. Yes, as far as I know.
Q. But in any event, you indicate, again on page 13 of your testimony, that through the EPRI 1982 manual, the utility industry should have known that it should engage in groundwater monitoring, right?
A. I did.
Q. And you've stated that repeatedly this morning, correct?
A. I did.
Q. And, Mr. Quarles, you know that, when this manual was published by EPRI in 1982, Duke Energy Carolinas was already engaged in a multiyear study of the impact of coal ash basins on groundwater, focused specifically on the Allen plant, but intended to apply to all of DEC's power plants; isn't that correct?
A. I am aware of the 1984 document, yes.
Q. Are you also aware that it was not just DEC's own internal investigation at plant Allen, but also an EPA investigation under contract with Arthur D. Little

and an EPRI investigation under contract with another contracting environmental entity altogether, all in the same general time frame?

A. Same general time frame, yes.

Q. And the Duke study indicated -- which is Joint Exhibit 9; we can certainly look at it if you'd like -- but indicated that this groundwater monitoring program had been in place since 1978, correct?

A. That's right, at plant Allen.

Q. At plant Allen. 1978 is four years before 1982 EPRI manual was published, correct?

A. Before the upgrade manual in 1982, yeah.

Q. And the report of that study, which again is Joint Exhibit 9, concluded when it was published in 1984, two years after the 1982 EPRI manual came out, that there was no significant impact on groundwater, didn't it?

A. Are you referring to the internal Duke 1984 or the A. D. Little report? I'm sorry.

Q. I'm referring to the 1984 Duke report.

A. Okay. I'm sorry, repeat your question.

Q. The 1984 Duke report, which is Joint Exhibit 9, and was published two years after the EPRI manual, 1982 EPRI manual, it concluded that there was no significant impact on groundwater, didn't it?

A. Maybe you can refer me to that conclusion. I have a hard copy, if you'd would like to tell me what page that is.

Q. I will -- I will find it. It's Joint Exhibit 9, and if anybody's following with the joint exhibits, it's DOCX 9395. It's an unnumbered page directly in front of the introduction on page 1, and the page is headed "Executive Summary."

A. I see that, yes.

Q. And the executive summary -- what is an executive summary, Mr. Quarles?

A. It's supposed to summarize what the author feels are the main conclusions of the report.

Q. Okay. And then, so the executive summary starts:

"Beginning in 1978, field and laboratory investigations of the composition of leachate and its behavior in the disposal environment were conducted by Duke Power and outside contractors," correct?

A. Yes.

Q. And the outside contractors would include the Arthur D. Little contractor and whoever did the work for EPRI, correct?

A. I believe -- yeah. In the back, starting on page 31, A. D. Little is shown as the prime contractor.

Q. Okay. And the executive summary continues sort of in the middle of that paragraph:

"Groundwater monitoring in 13 test wells installed by Duke Power around a retired and active ash basin found, over a four-year period, that drinking water quality was maintained in the wells downgradient of the sites after groundwater stabilization had occurred following well installation."

It goes on to say in the next sentence:

"Additional groundwater monitoring and soil testing from the same sites done by an EPA contractor," and that's Arthur D. Little, "also found the downgradient groundwater to be drinking water quality, and suggested the high ion exchange capacity of the soil lining the ash basin to be the mechanism preventing migration of soluble metals from the ash basin."

Did I read that one correctly?

A. You did.

Q. And then the executive summary concludes:

"These field and laboratory studies confirm that wet disposal of coal ash by Duke Power has no significant impact on groundwater," correct?

A. Correct.

Q. Mr. Quarles, let's take a look at a couple of other documents on that list.

A. Can we talk -- would you like to talk more in depth about the 1984 study?

Q. I have no further questions to you on the 1984 study, but I'm sure, if your counsel would like to ask you more questions about it, they are free to do so.

A. Well, what I'd like to do is I would like to respond to the executive summary, the conclusion. So in the beginning of this testimony today, you asked me if you read a summary and conclusions, should you -- should you believe all of that information that's in that one-page executive summary, as you have here. And I responded by saying, well, many times if you look further back into the document, you'll find that it's -- the executive summary really doesn't give the whole picture.

And I can walk you through why this executive summary doesn't give the whole picture relative to the findings. And, for example, the second sentence, the leach test.

Q. Before you go further, Mr. Quarles, let me just ask you this, and you can certainly answer it as fully as you want.

Are you saying that the -- that last sentence in the executive summary is incorrect?

A. Well, what I'm saying is that they have some bad information. For example, to keep it really simple, midway in the paragraph, all results -- "toxic metals to be nonhazardous according to EPA criteria." And what that means, nonhazardous --

Q. Where are you? I'm sorry.

A. There's no line numbers, but I'll count them. One, two, three, four, five lines down beginning with the word "all" on the right-hand side.

Q. Okay. So the sentence immediately above. Okay. I got you.

A. So what that means is that the nonhazardous, according to EPA criterion -- and they make reference to the EPA and ASTM protocols on the leach test. And leach tests were designed to determine whether or not a waste is a characteristically hazardous waste by definition according to EPA, not -- not which would regulate it as a subtitle C waste versus a subtitle D.

So just because it's a nonhazardous waste doesn't mean that it doesn't have hazard constituents and hazards and risk associated with it. And the next sentence:

"Groundwater monitoring in 13 test wells installed by Duke found over a four-year period that the groundwater quality was maintained."

All right. So a couple of points to that. The groundwater testing results showed that we had arsenic in well number 4 up to 112.5 part per billion. That's over 10 times the current arsenic standard, and over two times the arsenic standard at the time, which was 50. All right. That's --

Q. Where was groundwater monitoring well number 4, Mr. --

A. It was -- it was in the area of the inactive basin. The other thing that I think is especially relevant, if you go to page 23 of the hard copy, 23, there's a Table 7. And remember, they talked about they make that conclusion based on the results of 13 test wells. And most importantly, as it relates to the Table 7, as far as being a good scientist and relying upon an executive summary, is that you'll see that the wells -- 6 of the 13 wells were finished what they call below the perched water table.

So the relevance of what that means is it hasn't changed for the 30-plus years that I've been an environmental consultant. EPRI pointed out the two most important aspects of a groundwater monitoring program are the locations and depth of the wells. So if you installed 6 of your 13 wells below a perched water table, that implies that you've installed your wells too deep and not closest to the bottom of the ash pond of the part of the aquifer. Particularly when we recognize that it ash is sitting in the water table. So from a groundwater monitoring design program, you would want to monitor the uppermost portion of the uppermost aquifer.

And then if you refer for simplicity purposes to try to illustrate that, there is a diagram on page 28 that I included in my testimony, but it refers -- and it illustrates a leachate plume coming from the ash basin, shows the groundwater flow, but what it doesn't show in those wells is the screened interval.

So what they're implying -- or what they're saying in Table 7 is that the screen portion of the interval that they're collecting water from is below the uppermost portion of the aquifer. So, therefore, it's quite possible that they're not reporting the highest concentrations of constituents. All right.

So the -- you know, again, when you read beyond the executive summary and get into the details as a scientist of what really matters, that would -- that would have raised a flag -- red flag to any competent engineer or hydrogeologist back in the early '80s.

Q. Did it raise a red flag to Arthur D. Little?

A. Apparently not. And we -- I'd love to talk to you about the A. D. Little report, but if you'll let me proceed. For the '84 report, it goes on to say:

"Also found that the downgradient groundwater to be of drinking water quality and suggested the high exchange capacity of the soil lining to be the mechanism preventing migration of soluble metals from the ash basin."

Q. And, Mr. Quarles, let me just interrupt you just there for a moment, but that suggestion came from the Arthur D. Little report; did it not?

A. Perhaps it did. I guess my point is, suggested is much different than concluded.

The other thing that I would add is that one of the purposes of this '84 investigation was to determine leachable -- it's on page 14 of the hard copy document. The objectives of the monitoring program were to provide data documenting the condition and quality of the groundwater at the ash basin site. Number 2, predict and assess the effects on the adjacent groundwater, chemical quality of adjacent groundwater. And then number 3, determine the projected length of time that the ash basin substrate; i.e., the soils, can retain leachate. And that gets into the argument about attenuation of soils, of contaminates. And then number 4, predict and calculate the life expectancy with respect to the ion exchange capabilities of the underlying soils.

What this report did not do -- that's why they said "suggested" -- is that they didn't make any conclusions about the length of time that the substrate/soil can retain the leachates. Nor did they predict or calculate the life expectancy of that attenuation.

So with that said, when you read the details of this report, if you only read the executive summary, it sounds like there's no harm, no foul; but a competent engineer, or environmental manager, or hydrogeologist would have made the same evaluation and conclusions that I just made.

And so now when we're talking about A. D. Little, the A. D. Little report again refers to this, and there's been, you know, some discussions about soil attenuation capacity, and that the Piedmont soils are very clay -- clayey soils. But the A. D. Little report for plant Allen actually refers to the soils as sandy soils.

And then just as a review for this testimony, I looked back at a comprehensive site assessment, CSA that was done by HDR in 2015, and they create a conceptual site model for plant Allen. And again, the predominant type of soil at the site plant Allen is a sandy, gravelly soil, right.

So in terms of, you know, this prediction, they weren't able to make a prediction because their leaching tests didn't -- didn't match the results of the groundwater monitoring, and that's perhaps because the wells were too deep. And -- and what, in fact, is more prevalent is that there's less clay and more sandy soils, according to HDR, the consultant that recently completed the comprehensive site assessment.

So the body of work of this '84 document is -- it's impressive if you want to just read the executive summary, but if you read the details behind it, it has lots of technical problems.

Q. So, Mr. Quarles, you would disagree with the conclusion drawn by the report that there is no significant impact on groundwater from the operations of the ash basin?

A. I would. I mean, the data in this report shows that arsenic was over 10 times higher than the current drinking water standard.

Q. And you would disagree with whatever the conclusions -- the similar conclusions made in the Arthur D. Little report, correct?

A. So when we talk -- when you're ready to talk about the A. D. Little report, it's a very similar -- it's a very similar situation where the executive summary is. If you only read the executive summary, then you can be led to believe that all is well and there's no risk associated with it. But when you dig into the details of the A. D. Little report, similar to this 1984 Duke document, there's all kinds of limitations, and exceptions, and generalizations that are made by A. D. Little that I don't agree with.

Q. Okay. I think we understand that you don't agree with those conclusions, and we can move on.

A. Okay.
Q. But I did want to talk to you a little bit about the -- about -- I think there were a couple of your documents that relate to the EPA. Let me see if I can locate where they are referred to in your testimony. Bottom of page 11.
A. Okay.
Q. And you refer to two different EPA reports. One published in 1980, and then the 1988 report to Congress, correct?
A. I did, yeah.
Q. And the 1980 report -- again, they're both in the joint exhibits. 1980 report is Joint Exhibit 6, and looks like sort of a joint effort by the EPA and the TVA, correct?
A. That's right.
Q. And it's called "Behavior of Coal Ash Particles in Water," correct?
A. Correct.
Q. And, Mr. Quarles, you site a couple of sentences from the report that indicate impacts on groundwater, or refer to impacts on groundwater, correct?
A. It did.

Q. This particular report is really focused on ash pond effluents, correct?
A. It is talking about pond effluents, standing water in the pond.
Q. And, Mr. Quarles, if you -- just so we can get our terms defined -- if you look in the DEC exhibits to Exhibit 16.
A. What document is that?
Q. DEC Cross Exhibit 16.
A. (Witness peruses document.)
What is -- what is the title of that document?
Q. Let's see. It is your testimony, or a portion of your testimony in the prior Duke Energy Progress proceeding. So it's transcript Volume 13, Docket Number --
A. So under DEC cross exhibits -- what is the -- what exhibit number am I looking for?
Q. 1-6, 16.
A. (Witness peruses document.)
Is that a -- it looks like at the top it says Dobbs Building, Raleigh, North Carolina?
Q. That would be it, yes; you're right.
A. Okay.

MR. MEHTA: Madam Chair, if we could, let's go ahead and mark this as DEC Quarles Cross Exhibit 1.

CHAIR MITCHELL: The document will be so marked.

(DEC Quarles Cross Examination Exhibit 1 was marked for identification.)

Q. And just to get us straight here, Mr. Quarles, I'm looking at page 196 of the transcript. Are you there?

A. No. I'm trying to -- it's --

Q. If you're looking at it on a PDF, it's probably PDF page 14.

A. So I haven't downloaded this. Hold on. What page did you say?

Q. The page number of the transcript page number is 196.

A. So I'm looking at -- mine shows that there are 27 pages. What --

Q. Right. If you're looking at it in the PDF form on your computer, it's probably going to be PDF page 14.

A. 14. Okay.

(Witness peruses document.)

Okay.

Q. And, again, I'll represent to you, Mr. Quarles -- and this is actually a very simple question, so maybe we didn't have to go through all of this setup -- but the -- on page 196, you are answering questions that were posed to you by Chairman Finley in the DEP -- the last DEP case, Docket Number E-2-1142. And in the -- starting at line 7, you are answering one of Chairman Finley's questions and you talk about the reasons utilities sluice.

And you state that the reasons utilities sluice is, quote, to take an ash that's created at the boiler, then mix it with water, then they pump it to a pond so that the solids can settle out. And then the water, some of it will evaporate, some of it seeps into groundwater, and some of it overflows through a permitted, regulated, what we call an outfall to a receiving stream.

A. Correct.

Q. Chairman Finley then asks, "Is a technical name for whatever that is discharged, that is that's going through the outfall to a receiving stream," and you indicate, "We call it effluent," correct?

A. That's right.

Q. So I apologize. That was a long setup for probably what was a very simple question.

So the 1980 EPA TVA report that you reference at page 11, which is Joint Exhibit 6, deals with effluent, correct? I mean, I'm looking, for example, at page 1, I believe.

A. So -- yeah. The report -- the report was written to primarily talk about -- it's titled "Behavior of Coal Ash Particles in Water." And sub to that, "Trace Metal Leaching and Ash Settling," and it does speak a lot about the effluent of the water that is the sluice water that's pumped to a pond, and the quality of the effluent in the pond, in addition to talking about, as I have cited here, what happens or what their conclusions were about leaching of constituents from the effluent in the ash to groundwater.

Q. Okay. And I'm looking -- I was actually looking for what the report, itself, indicated was its scoping document. Scoping -- the scoping for the report. And it's located at the bottom of page 3, top of page 4. If you're following in the joint exhibits, those are DOCX 17 and 18.

A. Are we looking at the -- I'm sorry, are we looking at the EPA 1980 report now?

Q. Yes.

A. And what hard copy page are we looking at?

Q. 3 to 4.

A. 3 to 4 of the abstract or -- Roman numeral III and IV or --

Q. No, Arabic numeral 3 and 4.

A. Okay. So let me get to that. I'm sorry. And what was the joint exhibit number?

Q. 6.

A. (Witness peruses document.)

So the DEC Exhibit 6, I must be in the wrong one. This looks --

Q. Yeah. Mr. Quarles, it should be the Joint Exhibit 6, not the DEC Exhibit 6.

A. (Witness peruses document.)

There we go.

Q. But if you have a different copy of -- your own copy of the 1980 EPA report, we can walk through there.

A. I have it open now in the PDF. So I'm looking for hard copy page 3 and 4?

Q. Yes. And if you're on a PDF, it's probably about page 17 or 18.

A. Okay. I'm on 17 and it begins, first word is "considerations is still an important factor for ash disposal."

Q. Right. So the last paragraph on that page says:

"The scope of this study involves field survey, et cetera."

A. Yes.

Q. And the report addresses six major areas of concern. And those areas of concern relate to -- primarily to effluents, correct?

A. It says:

"This report addresses six major areas of concern in wet ash disposal, namely the characteristics of ashes, which is the solid, and ash pond effluent. Number 2, the effects of ash, solids, and raw water characteristic on the pH. And then" --

Q. pH of ash pond water, correct?

A. That's right. And then methods for pH adjustment, number 3. And then 4, settling characteristic --

Q. Well, and number 3 is methods of pH adjustment of ash pond effluents, correct?

A. That's right, yes.

Q. And then the settling characteristics, and the leaching of minerals, and the relationship of trace metals to pH --

A. Yes.

Q. -- and the concentration of suspended solids.

A. Yes.

Q. And then in the next paragraph it says:

"This report is complimentary to two other studies, one of which is the effects of coal ash leachates on groundwater quality," correct?

A. It -- yup.

Q. And that was one that we discussed with Mr. Hart yesterday. It's Joint Exhibit 5.

Do you recall any of that discussion?

A. I don't.

Q. Okay. You did not refer to the EPA TVA report titled "Effects of Coal Ash Leachate on Groundwater Quality" in your testimony, correct?

A. I don't think so, no. I have not reviewed that document.

Q. Okay. I mean, is there some reason why -- I mean, they are both done by the TVA and the EPA. They're both March of 1980. One of them is titled "Effects of Coal Ash Leachate on Groundwater Quality," which I thought was a focus of your testimony, and you didn't refer to it. But you referred to the other one that deals with effluents.

A. Yeah. So part of the issue is, you know, finding documents through the old NEPIS EPA website and downloading those documents, you know, and you do it by keyword searches, and so sometimes you get a thousand documents that show up. So you try to identify. And I would have -- yeah, I would've loved to have seen this document and reviewed it. If -- particularly if it's written by EPA and TVA, I'm quite familiar with TVA coal ash disposal.

Q. Okay. Mr. Quarles, why don't we move on to the other EPA document that you reference on page 11, which is 1988 report to Congress.

A. Can I close this document?

Q. Yeah. We're done with both 5 and 6, so you can close out of those.

A. Okay. So now we're moving to the report to Congress in '88?

Q. Yes.

A. (Witness peruses document.)

And what -- what is the exhibit name of that?

Q. It is Joint Exhibit 13.

A. Okay.

Q. And at the bottom of page 11, you -- I guess you have three bullets. The first two deal with the 1980 document that we just talked about, and the third bullet deals with the 1988 EPA report to Congress, correct?

A. That's right.

Q. And immediately above the bullets, you state:

"EPA's key conclusions include" --

And then with respect to the 1988 report to Congress, the third bullet is:

"The primary concern regarding the disposal of wastes from coal-fired power plants is the potential for waste leachate to cause groundwater contamination."

Did I read that correctly?

A. You did.

Q. So, Mr. Quarles, the EPA report to Congress has a whole chapter on conclusions and recommendations; does it not?

A. It does, yeah.

Q. Okay. And we can read that whole chapter, which is Chapter 7, backwards, forwards, and upside down, and we won't find what you call a key conclusion in that chapter, will we?

A. So the key conclusion relative to the likelihood of contamination of groundwater from coal combustion sluicing in unlined basins, which was the context of my testimony.

Q. Well, did you think that the actual conclusions of the EPA report to Congress were not relevant to your testimony?

A. Again, it's the key conclusion related to concerns about leaking impoundments relative to groundwater quality, that is a -- that's an obvious conclusion made by EPA.

Q. It is not a conclusion that it chose to include in Chapter 7 called "Conclusions and recommendations," is it?

A. Okay.

MR. MEHTA: Madam Chair, I think I'm finished with Mr. Quarles for right now.

CHAIR MITCHELL: All right, Mr. Mehta, thank you. Any additional cross examination for this witness?

(No response.)

CHAIR MITCHELL: All right. Redirect for the witness?

REDIRECT EXAMINATION BY MS. CRALLE JONES:

Q. Mr. Quarles, we began talking about Joint Exhibit 6, which I believe was the 1980 EPA report, and you were asked why you focused on that report related to effluent in the context of concern about impacts to groundwater.

Would you explain why those you found were important conclusions from that report?

A. Yes. So let me pull that report, please. The ash transport water -- I will read you from the abstract of that document.

"The chemical characteristics of ash pond effluents are affected by the ash material and the quantity and quality of the water for sluicing." And it says, "TVA ash pond effluents vary from a pH of 3 to 12."

So when we talk about the opportunity of degradation of water, we have to remember that effluent is what is pumped to the surface of the ash pond. And one of the -- one of the factors associated with the leachability of constituents from coal ash is pH. And so, therefore, pH, if it ranges from 3 to 12, according to TVA, what that means is two things. Their surface discharge permit probably has a pH limitation that they are required to meet, and sometimes that requires the addition of chemicals, like ferric chloride, for example, to adjust the pH.

The pH also plays a role in the leachability of the constituents that adhered to the particles of fly ash, for example. Some metals preferentially leach in an acidic environment. Some metals preferentially leach at neutral, near neutral, and some at basic. And then some leach regardless of pH. All right?

So understanding effluent quality to the pond is important, according to this document and according to my experience. All right? So -- and then my experience too is that the quality of the water beneath the standing effluent in the pond, in the pore space of the ash, can vary as well. Can change pH dissolved oxygen, those geochemical changes, which can also affect the leachability of metals.

That's why this document was kind of a good starting point, in terms of understanding how constituents might get to groundwater from an effluent sluicing operation.

Q. And then also earlier we were talking about the studies done at Allen, and you noted that 6 of the 13 monitoring wells were located below the water table and unlikely to provide helpful data for assessment.

Do you know, why would -- why would a decision be made to place wells so deep?

MR. MEHTA: Objection, Chair Mitchell. This calls for sheer speculation.

CHAIR MITCHELL: All right. Ms. Cralle Jones, respond, please.

MS. CRALLE JONES: Okay. I'm just -- if he -- he may not -- he may read in the documents, in the A. D. Little report, I'm just not sure whether or not there was a rationale for that being there, or if, by putting them so deep, you're not going to get the data that you need.

CHAIR MITCHELL: All right. I'm going to overrule the objection, allow the question to proceed, and we'll give it the weight that it's due.

THE WITNESS: I'm sorry. Does that mean that I can answer the question?

CHAIR MITCHELL: It means that your counsel may proceed to ask -- please ask the question again, Ms. Cralle Jones, for purposes of the record.

Q. You noted in the Allen study that 6 of the 13 wells were located below the perched water table.

Are you aware of -- or aware of any reason for placing those wells below where the upper -- below -- below the -- in the deepest aquifer? What would the reason for that be?

A. Well, if your goal is to understand that the -- whether or not an unlined disposal area, or any disposal area, or any pile of waste, if you want to know the effects of the uppermost aquifer on any leakage from those disposal units, good engineering, good hydrogeology, good geology, good common sense practices say that you would want to screen your well in the interval that is most likely to be nearest the waste, and therefore would have the highest concentrations, if the impoundment is leaking. All right?

So if -- and I'll refer you to page 21 of my -- of my testimony as a good exhibit, if you will, for the Commission and other folks to understand what that means. So if you look at those -- that's a cross section, and the ash basin is shown on the right. And this comes from the 1984 internal Duke report. The wells are the vertical rectangles that have the dark triangles in them. The dark triangles are water levels. Okay? Water levels meaning they drilled the well, and after they completed the well, those are the water levels that rose in the well.

You'll see that we have a leachate plume at well 11, and Lake Wylie off to the left. And notice that the triangle in well 13 is nearly the same as the full pool level of Lake Wylie, which is what you would expect in a water table aquifer, because the water table flows into the nearest receiving stream.

So if the -- and the scale of this drawing is on the left, and it looks like every notch is 10 feet. A well screen is typically 10 feet. Sometimes I've seen 5 feet and sometimes 15. They're not shown on here. But the bottom line is, if you drill a well and screen it deeper than the triangles, and what they called the perched water table, then, in all likelihood, they missed the evidence of leakage and perhaps the highest concentrations of constituents that would be indicative of that leakage that's flowing into Lake Wylie.

So it's fundamentally -- I would -- I'm not going to, you know, try to answer why they chose to not sample the purchased water, but I can tell you that a competent hydrogeologist who's trying to determine whether or not a surface impoundment is leaking would not have done that.

CHAIR MITCHELL: All right. We are going to stop at the moment. We will go off the record. We will take a 15-minute break, and we'll go back on at 11:00.

(At this time, a recess was taken from 10:48 a.m. to 11:00 a.m.)

CHAIR MITCHELL: All right. Let's go back on the record, please. We will continue with redirect of Mr. Quarles. Ms. Cralle Jones, you may proceed.

MS. CRALLE JONES: I have no more questions.

CHAIR MITCHELL: All right. Questions from Commissioners, beginning with Commissioner Brown-Bland.

COMMISSIONER BROWN-BLAND: All right.

EXAMINATION BY COMMISSIONER BROWN-BLAND:

Q. Mr. Quarles, can you hear me?

A. Yes, ma'am.

Q. At -- in your testimony, on page 18, starting at the top there, you were answering a question about the Company's conclusion that CCR constituents detected during the groundwater monitoring were naturally occurring, and whether that conclusion was reasonable. And your answer was no. And you go on to say, because it's been shown to be -- or at least you offer one of the reasons, it's to be shown to be incorrect. That in -- that in 2014, the Company concluded that it was the coal ash that was impacting the groundwater.

A. Yes, ma'am.

Q. And that conclusion that the Company made, was that based -- from your understanding, that was -- you were speaking of it emanating from the voluntary monitoring they were doing from the mid-'90s up to, say, 2007 or so?

A. No. That -- that statement came from a 2014 internal corporate slideshow where they concluded our coal ash is impacting groundwater at all locations.

Q. So -- so they made -- this conclusion was made in 2014, that it was naturally occurring?

A. No. 2014, they admitted that the coal ash disposal is impacting groundwater at all locations, which would override any prior determinations that any constituents were related to naturally occurring conditions.

Q. And so the question was about the reasonableness of that conclusion, about the naturally

occurring. And you said no, that -- am I interpreting you correctly that no, that conclusion was not reasonable at that time, or just that it has since been shown to be incorrect?
A. Well, without doing a thorough evaluation, you would not know if it is naturally occurring or not, and so you can only do that by installing wells and having a representative background determination of your constituents. That's step number 1. And step number 2 is ultimately sampling the water. And then they made the determination in 2014, and DEQ agreed with that conclusion, that's why they had to excavate their ash. That it was not all related to naturally occurring conditions or concentrations.
Q. So at what point in time had they made the naturally occurring conclusion; do you know?
A. There was a --
Q. That's the basis of the question.
A. Yeah. There was a -- there was a direct -- I might be able to find it. Yeah, here we go. It's in my Exhibit 4. Exhibit 4, and I have a hard copy, but it's the Public Staff Request 36-2. And the timing of this Exhibit 4 is dated January 2018. And at the bottom of page 1 of 2, it says:

"Initial results appeared consistent with naturally occurring conditions. So between the installation of voluntary monitoring wells in 2009, DE Carolinas continued monitoring the wells and submitted semiannual reports."

So what they're saying -- what they said in 2018 was that initial appeared to be naturally occurring. And then if you look at page --

Q. And initial is 2009; is that how you interpret it, or earlier?

A. Yeah. So on page 17 of my testimony, it has a table that shows the voluntary monitoring well installation, which the Company used the term "voluntary," and I'm assuming that that was the USWAG information, and then required monitoring installations. And then you'll see that the detection of a 2L standard generally came within the same year, perhaps a year after the voluntary monitoring. So that's when they would have apparently made that conclusion that it was all naturally occurring.

Q. With the exception there of Cliffside, there's a 1995 --

A. Yeah. And Dan River 1993, yeah.

Q. Well, Dan River 1993, there's a detection in

1993.

A. That's right.

Q. Cliffside 1995 -- there was 1995, 2005, and 2007 --

A. Yes, ma'am. Oh-oh.

CHAIR MITCHELL: It seems that we have lost connection to Commissioner Brown-Bland. Let's give it a few seconds to see if she returns.

(Pause.)

CHAIR MITCHELL: All right. Looks like she's back.

Commissioner Brown-Bland, can you hear us?

COMMISSIONER BROWN-BLAND: Are we back?

CHAIR MITCHELL: Commissioner Brown-Bland, are you there?

COMMISSIONER BROWN-BLAND: Yes, I hear you.

CHAIR MITCHELL: All right. We lost you temporarily.

COMMISSIONER BROWN-BLAND: That's my morning departure. Hopefully that's the last time.

Q. So I was just getting to what's your basis for the answer to the question there, that it was --

that the naturally occurring conclusion was not reasonable at the time that that -- that they came to that conclusion, which appears to be after 2009 is according to what you were reading; is that right?

A. Let me see that again.

(Witness peruses document.)

That's right.

Q. So what was your basis for saying it was not reasonable? Should they have known at that point, or was there a failure to do a certain degree or type of monitoring?

A. So it's hard to imagine how we've gone from -- let me back up. So I've looked at coal combustion waste disposal sites across the country, a lot of them, and I've seen arguments for what is background and what is naturally occurring, and it's very, very true that metals, arsenic, boron, they do naturally occur. All right? But you also have indicator parameters like sulfate that are directly associated with coal combustion waste. It naturally occurs too, but it's very prominent in coal combustion waste.

So it was -- as a scientist, it was hard to imagine how the Company could have claimed in 2009 that every disposal facility and all the contamination, the constituents that are in the well is all naturally occurring. That's just not reasonable given the size and the way that these materials were disposed of.

So it's not surprising that they changed their mind and came to the conclusion that it was related to coal combustion waste.

Q. And so your answer was based on more than -- I mean, is it correct that your answer was based on more than just the fact that ultimately they got it wrong, but even at the time that they came to that conclusion, it was an unreasonable conclusion?

A. Yeah. So my statement was really is ultimately it was -- they admitted in 2014. I haven't looked at each of the individual facilities where they perhaps tried to make the argument that they were naturally occurring or not to know how valid or not that was back in 2009, if they made such a -- you know, a public determination of that.

Q. But is that a basis for the unreasonableness that -- I guess that's what I'm trying to get at. Is it unreasonable in your mind just because ultimately it was proven and shown to be wrong, or was it unreasonable because of some action, or inaction, or misunderstanding, or something like that on their part, on the Company's part?

A. I think it's unreasonable -- it's unreasonable to make a blanket determination that everything was naturally occurring, in my experience. Because the signature of coal combustion waste constituents from a leaky disposal unit is very clear.

Q. And did the Company, at that point in time when they became aware of the detection of these CCR constituents, did they have a specific response that you learned about as a result of that, you know, at that time when they first learned about the constituents?

A. My research didn't look at the Company's responses to those post 2009, per se.

Q. All right. And on page 19 there, you're answering the question:

"Was the Company's reliance on the Little 1985 report for a decision not to monitor groundwater at Allen and other disposal sites; was that reasonable?"

And you answered no, and you give some reasons. And what I'm looking at is lines 8 through 10. And there you address the soil attenuation estimates and say that they did not accurately predict.

What's the significance of that?

A. So what they tried to do is they tried to -- one of the purposes of the '84 study, the internal document, and then the A. D. Little too, they looked at -- leaching tests are laboratory tests where you can collect samples of CCR, and then you can -- they referred to the EPA leaching method and the ASTM leaching method. What those methods try to do is to predict, at those laboratory conditions, what the concentrations of constituents are going to be that come out of or come away from the solid and get into water, right?

Those -- and then -- and then you make calculations based upon the clay content of the soil and the ability of the clay to capture or attenuate the constituents. And it's true, soil attenuation is one of the eight factors that EPRI talked about in the early 1980s as an important consideration. But the report did not accurately -- they didn't accurately predict whether or not it would attenuate and whether or not -- and how long that attenuation would last. So they couldn't rely on that portion of the investigation.

Q. Now, is that a flaw of the -- of the study, or was that a flaw of some of Duke's work? Whose -- whose estimate, I guess?

A. It was -- I'm not sure what A. D. Little -- if they relied upon the study that Duke did for their 1984 study or not. But the bottom line was that the laboratory test, and then the calculations that they used to predict that the constituents would be attenuated by the clay soils did not come true. Therefore, they were not reliable predictors of the soil attenuation capacity.

Q. At the time that they made that -- you know, those attenuation studies, should they have been able to do so, you know, in a more reliable manner, a better test?

A. Well, so --

Q. At that time.

A. So what -- what's really amazing is they talk about the clay content of the soil in the reports, and what's really -- when you dig in the A. D. Little report, it also talks about the predominant soil at Allen is more of a sandy soil, right. So if they assumed in their attenuation capacity calculations that the soil was clayey, and then instead it's sandy, then that would have been a mistake by whomever made that calculation.

Q. All right. And then I'm on page 21, and this is testimony regarding the 1984 internal investigation of groundwater at Allen. Lines 10 through 16 is speaking to the issue with monitoring well construction and location or placement of the monitoring wells -- this is what you were addressing a moment ago -- and the role that played in not adding more monitoring wells, I assume, or continuing to monitor.

And you explained using that diagram why it would have been maybe better other placements, but at the time back in 1984, or even assuming that they started it in '83 maybe, I don't know, but at that time, would the Company have known or should have known a better way to capture any leakage -- as you called it, capture at the perch -- at the perch level?

A. Well, so --

Q. Was that part of the science at that time that they should have known or placed it differently, you would have thought?

A. So EPA and EPRI talk about the two most important factors of a groundwater monitoring system are the location and the depth of the well. All right.

The Company installed wells along the perimeter of the ash basin, in this case between the ash basin and Lake Wylie, and that was a good move. But the mistake that seems to have been made is that they screened the wells deeper and missed the perched water zone that would be more indicative of leakage associated with the impoundment.

Q. And when you're monitoring groundwater, doing groundwater monitoring, it would have been appropriate still to check at the perch level?

A. It would, yeah. So what commonly happens is that you start your investigation at the uppermost portion of the uppermost aquifer. And what you're also able to do, and what we found, kind of if you will, the evolution of, you know, groundwater monitoring is that we've learned because of the constant head of standing water -- and Allen, for example, had 100 feet of saturated ash in 2015. So that constant head has a vertical -- it pushes groundwater deeper over time, right.

So a common investigation is to start with a shallow well and understand whether or not you have a vertical gradient that pushes it further into the deeper portion of the aquifer or if the preferential

flow is horizontal.
Q. About what you described now, it would not have been known to the engineers or the people who were performing this investigation back at the time that they were doing the investigation?
A. They -- they would have known that, and EPRI talks about that, is that seepage is inevitable, and it's under a constant pressure head. And so, therefore, they should have understood the importance of monitoring the uppermost portion of the uppermost aquifer nearest the bottom of the waste, and whether or not there was any contamination that could be pushed deeper into the aquifer, or if the preferential flow was horizontal into Lake Wylie. The fundamentals of a groundwater monitoring system have been consistent in that knowledge certainly since the early '80s.
Q. All right. And on page 23, you talk about gravel and sand in the impoundments. And I'm in the area of line 11 through 19. And there you talk about gravel and sand naturally occurring. Or no, that's my question to you.
Are you saying that the gravel and sand in those impoundments were naturally occurring in there, or are you suggesting that the Company built the

impoundments with the sand and gravel as part of the construction?

A. So the sand and gravel is the soil type that is in the area site-wide, according to the comprehensive site assessment in 2015, is the common most popular populous soil type at the Allen plant. All right. So with that in mind, gravel and sand are much less effective in attenuating or mitigating contaminants that might leak from an impoundment and get into the groundwater.

Q. And so it would have been natural that you would build the impoundment using the soil that was there? And during the time, they would not have necessarily brought in a better attenuator; is that correct?

A. Well, so let's think about this. The way that they built the impoundment was they took an existing stream valley and built a dam across the valley, and then started pumping water into the impoundment. So there was no construction or placement of soil as a line or any other sort of barrier or separator between the uppermost aquifer and the bottom of the waste.

And what is possible, to build the dike, the dirt has to come from somewhere or the material has to come from somewhere. And most times that material is excavated from onsite and moved to build the dam. In addition, it's quite common that ash was used to build the dike. So if -- if the material was removed from the stream valley to build the dike, then, in the case of Allen, there is bedrock that is relatively shallow there, and they would have removed a buffer that would be associated with any soil that would be above the bedrock.

And why that's important is that -- is that the groundwater velocity -- the groundwater seeps through the material that makes up the aquifer, and the material is soil and bedrock. And the groundwater flow velocity in bedrock is much faster than the groundwater flow velocity in soil at Allen.

Q. Okay.

A. But the sand and the gravel was consistent and very common across the Allen site before they built the impoundment.

Q. All right. Thank you. And then on, I think, page 24 you -- moves on to discuss the River Bend site a little bit, and we're say -- you're saying here that the Company had incorrectly assumed that there was enough similarity between the Allen and the River Bend sites to warrant not installing monitoring wells, and to not recognize that the differing or changing conditions that occur over time.

So in your opinion, the Company got that wrong. Could it have been reasonably known, at that time of their conclusion, that there was a flaw in this assumption or in the way that -- or in their work that led to the assumption?

A. So EPRI was -- EPRI was very clear about the need to do a site-specific analysis of each of these sites. Allen and River Bend were located 12 miles apart. So it is -- it is unreasonable to assume that the exact conditions and attenuation factors, if you will, exist at Allen and also at River Bend. And when you look at the River Bend report, then, in fact, they brought out some information on the borings and the soil type that was at River Bend. The problem with that is none of the borings were underneath where they put the ash. They're up on top of the hill. What's important is the soil type beneath the ash. All right. So they didn't do an evaluation of that.

They didn't collect basic information like the soil hydraulic conductivity, how fast water flows through the soil, the soil type. So there were lots of flaws in that use of Allen data to support no monitoring at River Bend.

Q. So, Mr. Quarles, so we -- as you sit here today, we know that, and we know that that's what we should be doing. And I guess just to be clear, should we have known it and should the Company have known it back when they were making these assumptions and decisions? Is the state of knowledge similar enough to what it is today that they should have known that?

A. Yes. So it is very clear, EPRI determined that leakage from an unlined surface impoundment is inevitable, and it is under a constant head of pressure. And the only way to have convincing proof that you are not contaminating an underground source of drinking water is to install wells, right? And wells are not very expensive. Like, a 20-foot well may cost, in today's dollars, $2,000. You know, the leaching test that they may have done, who knows how many thousands of dollars they spent on a test which ultimately relied on assumptions for a site 12 miles away without collecting any site-specific data that could have been collected at River Bend.

Q. And so if there was a decision made that they had done enough work over at Allen and it was close enough and good enough for soil similarities, your opinion is it wasn't good enough, and it was known not to be good enough at that time?

A. So again, it's inevitable. Leakage is inevitable. It's a constant head of pressure. And the convincing proof to know whether or not you're impacting groundwater is to install a well. And it's up to the generator to have convincing proof to determine whether or not they're in compliance with the 2L standard.

Q. All right. Thank you, Mr. Quarles.

A. You're welcome.

COMMISSIONER BROWN-BLAND: That's all I have right now.

CHAIR MITCHELL: All right. Commissioner Gray?

COMMISSIONER GRAY: No questions at this time.

CHAIR MITCHELL: Okay. Commissioner Clodfelter?

COMMISSIONER CLODFELTER: I have no questions for Mr. Quarles. Thank you.

CHAIR MITCHELL: All right.

Commissioner Duffley?

COMMISSIONER DUFFLEY: Yes. I just have one follow-up question.

EXAMINATION BY COMMISSIONER DUFFLEY:

Q. Commissioner Brown -- I just want to understand what I heard you say. So Commissioner Brown-Bland asked you about the placement of wells, and I thought I heard you say, you know, the hydraulic head would push potential contaminants deeper into the aquifer. And so I just want to make sure I understand your testimony.

So you said that they put wells, stream wells deep in the aquifer, but your testimony is that they should have also put in shallower well; is that an accurate description of what I heard?

A. Yes, sort of. So if you want to know if a disposal unit is leaking, you put wells in the uppermost portion of the uppermost aquifer; that is step number 1. And what that does is tells you whether or not you've got a good indication of leakage from the disposal unit. What can also happen is that, with the constant head and the constant pressure, that there can be a downward push, and you won't know that unless and until you've installed wells in the upper portion and in the deeper portion.

Q. Okay. Thank you.

COMMISSIONER DUFFLEY: I don't have anything further.

CHAIR MITCHELL: All right. Commissioner Hughes?

COMMISSIONER HUGHES: No questions. Thank you.

CHAIR MITCHELL: Commissioner McKissick?

COMMISSIONER McKISSICK: No questions at this time.

CHAIR MITCHELL: All right. Questions on Commissioners' questions? Any party have questions on Commissioners' questions?

MS. LUHR: I have no questions.

MS. TOWNSEND: No questions.

MR. MEHTA: No questions from Duke.

CHAIR MITCHELL: All right. Ms. Cralle Jones, any questions on Commissioners' questions? All right. Ms. Cralle Jones, I believe you're muted, but I believe you've said no questions. Okay.

All right. Mr. Quarles, you may step down at this time. Ms. Cralle Jones, I'll entertain motion from you.

MS. CRALLE JONES: At this time, we now move that Sierra Club Quarles Exhibits 1 through 4 be admitted into the record.

CHAIR MITCHELL: All right. Hearing no objection to your motion, Ms. Cralle Jones, it will be allowed.

(Sierra Club Quarles Exhibits 1 through 4, were admitted into evidence.)

MS. CRALLE JONES: And would request that the witness be excused for the DEC portion of this hearing.

MR. MEHTA: Chair Mitchell, I would also move -- this is Kiran Mehta, would also move the introduction into evidence of DEC Quarles Cross Examination Exhibit Number 1.

CHAIR MITCHELL: All right. Mr. Mehta, hearing no objection to your motion, it is allowed, and the witness may be excused.

(DEC Quarles Cross Examination Exhibit Number 1, was admitted into evidence.)

CHAIR MITCHELL: All right. Thank you very much, Mr. Quarles, for your testimony today.

MS. CRALLE JONES: And we also would move that the cross examination exhibits entered into the record in the DEC proceeding, which I believe is only DEC Quarles Cross Exam 1, which was moved into the record on page 142 of DEC Volume 18, be moved into the record of this proceeding at this time and designated as it was in the DEC record.

COMMISSIONER CLODFELTER: All right. Again, unless there is objection, hearing none, the motion is allowed.

(DEC Quarles Cross Examination Exhibit Number 1 from Docket Number E-7, Sub 1214 was admitted into evidence.)

MS. CRALLE JONES: Thank you, Commissioner Clodfelter and Commissioners. The witness is now available for cross examination.

COMMISSIONER CLODFELTER: All right. I believe we start off with -- actually, we start and who knows where we go with this, Mr. Mehta. We may end with you also. You're on.

MR. MEHTA: One can only hope, Commissioner Clodfelter.

CROSS EXAMINATION BY MR. MEHTA:

Q. Good afternoon, Mr. Quarles.

A. Good afternoon, Mr. Mehta.

Q. Good to see you again, as always.

A. You as well.

Q. Do you have available to you, Mr. Quarles, DEP Cross Examination Exhibit 75?

A. Okay. Let me -- and what is that document?

Q. It's -- it's the testimony of your colleague Rachel Wilson in the Georgia Power rate case attaching your -- I think it was your report as an exhibit to that testimony.

A. Yeah. I have access to my -- the report that I wrote that was attachment to this.

Q. Okay. That's what we'll be talking about.

MR. MEHTA: Commissioner Clodfelter, this is the document that was the subject of a motion filed probably Monday, granted perhaps yesterday, concerning the introduction of a late cross exhibit. And the parties obviously got it when we served the motion, because it was attached to the motion. I do not know if the Commission actually -- the Commissioners actually have it, and if they don't, we're certainly -- it's very easy to just send it to you by email, and we can, of course, follow up with a paper copy.

COMMISSIONER CLODFELTER: Mr. Mehta, that exhibit would not have been in our notebooks, and so I have not, myself, seen it yet come across the transom, so I would suggest that you email to the Commissioners and the Commission staff who are working the case copies of that, and then we can follow up with you later for hard copies if necessary.

MR. MEHTA: Sure. I'm going to go ahead and ask Ms. Monika Smith to institute whatever the email protocol is for getting these kinds of documents, late breaking news, to the -- to the Commission.

COMMISSIONER CLODFELTER: I believe -- thank you for that. I believe there may have been one other party who may have had a similar late exhibit, and we'll take care of that also in the same manner. Mr. Mehta, let me confirm to you that I believe, in fact, the order approving the late designation was entered either this morning or yesterday, one of the two.

MR. MEHTA: Thank you, Commissioner Clodfelter. And I'll go ahead and -- with the examination of Mr. Quarles, and then we can always -- if the Commission doesn't get the document, we will make sure that the Commission gets the paper document.

COMMISSIONER CLODFELTER: Well, I suspect the important thing is let's get it to the Commissioners before we get to the point where we have Commissioners' questions on this witness. Let me just confirm, for safety's sake, and it may not be necessary, but the document is available to Mr. Quarles, of course.

MR. MEHTA: Okay. And I actually see Ms. Smith visible on the video monitor, and I'm hoping that she is going ahead and getting the transmission in place.

COMMISSIONER CLODFELTER: You may proceed.

MR. ROBINSON: Kiran, if you can, if you could just restate the document to ensure that he has the document in hand, please.

MR. MEHTA: Sure. It is DEP Cross Examination Exhibit 75 consisting of the testimony of Rachel S. Wilson in the Georgia Public Service Commission Georgia Power rate case of last year, 2019 rate case, testimony submitted

October 17, 2019. And it attaches, as Exhibit 4, a report that the testimony, itself, references as the Quarles report, which as I understand it was prepared by Mr. Quarles.

MR. ROBINSON: Thank you. The Commission and the parties will have it momentarily.

MR. MARTS: May I interrupt, Commissioner Clodfelter? This is Derek Mertz with the Commission staff.

COMMISSIONER CLODFELTER: Yes.

MR. MARTS: I just sent the Lincoln STAR, which is the DEP filing from two days ago, which contained as an exhibit the requested exhibit, and it -- you know, after the motion, itself, it's attached to the motion. So it's several pages down. But this is also Exhibit 75, so the Commissioners should have that link before them now.

COMMISSIONER CLODFELTER: Okay. That's great. Thank you, Mr. Mertz. I greatly appreciate that.

Mr. Mehta, are you going to mark this here?

MR. MEHTA: Yes, Commissioner Clodfelter. I would like to mark the document previously marked as DEP Exhibit 75 as Quarles DEP Cross Examination Exhibit Number 2.

COMMISSIONER CLODFELTER: It will be so marked.

MR. MEHTA: Thank you, sir.

(Quarles DEP Cross Examination Exhibit Number 2 was marked for identification.)

Q. Mr. Quarles, would you just again confirm for us that this is the testimony filed by Ms. Wilson, your colleague, in the Georgia Power 2019 rate case, and it attached as its Exhibit 4 what Ms. Wilson referred to in her testimony as the Quarles report?

A. It is.

Q. And the Quarles of the Quarles report is you, I take it?

A. Correct.

Q. And if you would look at the report, itself, and in the -- in the document -- in the exhibit --

MR. MEHTA: Commissioner Clodfelter, this begins at page 41 of the PDF. If you're looking at what Mr. Murtz may be circulating, it's a little bit further on than that, because that would have the motion and some additional pages, so it's probably about page 44 or 45 of the motion as filed attaching the proposed exhibit.

Q. Mr. Quarles, just curious, is there some reason that you did not file your own testimony in the Georgia Power case as opposed to having your report introduced through Ms. Wilson?

A. I don't know why the Sierra Club did not file this directly.

Q. Did you review Ms. Wilson's testimony back when it was filed?

A. I did not.

Q. Have you ever reviewed Ms. Wilson's testimony?

A. I have not.

Q. Well, why don't we just deal with your report, then, and we'll let the testimony speak for itself since it's going to be an exhibit anyway. And if you would turn to the top of page 7 of your report.

A. Okay.

Q. Or actually just to page 7. I'm looking at the bottom of page 7. There's a Section 3.0 called "Historical industry practices and knowledge of risks," correct?

A. Yes, sir.
Q. And the first line of that section reads, quote:
EPA issued reports in 1980 and 1988 documenting its concerns about leaking unlined CCR disposal units.
Did I read that correctly?
A. Yes, sir.
Q. And the 1980 and 1988 EPA documents you referred to in the Georgia Power report were the same 1980 and 1988 EPA documents you referred to in your DEP testimony in this case at page 11 of that testimony; is that correct?
A. Yes, sir.
Q. The quotes that you site in your Georgia Power report that actually are on the following page, so page 8, are the same quotes that you pull out of the EPA documents and state on page 11 of your DEP prefiled testimony; is that correct?
A. I haven't compared them line by line. If you would like me to do that, I will.
Q. Well, go ahead.
A. And what page -- on 11 of my direct testimony?

Q. Yes, sir.

A. (Witness peruses document.)

Yes, sir; they are correct. They're the same.

Q. Do you know how the Georgia Public Service Commission ultimately decided the issue of coal ash recovery in the Georgia Power case, Mr. Quarles?

A. I do not.

Q. Your Georgia Power report, Mr. Quarles, if you go to the first page, is on a letterhead of an entity called Global Environmental, LLC; do you see that?

A. I do.

Q. What is Global Environmental, LLC?

A. It's the firm that I worked for as the principal consultant and owner prior to working at BBJ.

Q. Oh, so this is your own company, Global Environmental, LLC?

A. Correct.

Q. How long were you associated with that company, your company?

A. Roughly 15 years.

Q. What happened to it?

A. I essentially closed that business and took a job with BBJ Group to start the office here in Nashville.

Q. And when did you start with BBJ Group?

A. February of this year.

Q. So up until February of this year, if you were doing the kind of work that you're doing for BBJ, it would have been done under the Global Environmental banner?

A. Right.

Q. And at the end of the report, Mr. Quarles, is your CV. I guess it starts on page -- right after page 40 of the report; is that correct?

A. Yes, sir.

Q. And this would be the CV that was associated with Global Environmental, LLC; is that right?

A. Yup.

Q. And you indicate on that CV that you have extensive coal ash combustion residuals experience, correct?

A. I do.

Q. And if I'm looking at this correctly, the coal ash combustion residual experience starts right under the heading, "Range of technical experience"; is that right?

A. That's correct.

Q. And the first one that you list there is your work for the Sierra Club in North Carolina in expert testimony at rate case hearings, correct?

A. Right.

Q. And I guess, based on the timing of this, those -- the rate case hearings that you're referencing here would be the prior cases for DEC and DEP that were filed back in 2017 and decided in 2018, correct?

A. Correct.

Q. And your client was the Sierra Club, just like it is today, correct?

A. Correct.

Q. Just like it was for the Georgia Power case, correct?

A. Correct.

Q. And the Sierra Club is an environmental advocacy organization, correct, Mr. Quarles?

A. Correct.

Q. And the next entry is multiple clients, and you indicate that you conducted file reviews and groundwater data analyses for approximately 100 CCR disposal sites in 12 states, correct?

A. Correct.

Q. And none of the clients with respect -- your clients with respect to those 100 sites were utilities, were they?

A. That's right.

Q. And you skip on down a few bullets, and we have another Sierra Club in Georgia, reviewed surface impoundment dewatering, et cetera; do you see that?

A. I do.

(Reporter interruption due to sound failure.)

Q. I'm sorry?

A. You broke up. I didn't hear your question.

Q. The client references to the Sierra Club, which is the same Sierra Club that you're representing today, correct?

A. That's correct.

Q. And the one next -- after that is Southern Environmental Law Center; do you see that?

A. I do.

Q. And the Southern Environmental Law Center is, again, an environmental advocacy organization?

A. Yes.

Q. And you skip on down towards the bottom of the page, there's one involving, I think, a facility in

Ithaca, New York, which is near and dear to my heart, involving the Chris Dennis Environmental Fund, correct?

A. That's right.

Q. And I take it the Chris Dennis Environmental Fund is also some kind of an environmental organization, correct?

A. It's an individual who oversees that fund.

Q. Does he fund environmental causes?

A. Probably, yes.

Q. And the CV goes on for a number of pages, Mr. Quarles, and I don't think we need to go over every single one of them.

MR. MEHTA: And, Commissioner Clodfelter, that's all the questions that I have of this witness at this time.

COMMISSIONER CLODFELTER: Thank you, Mr. Mehta. There are no other parties I'm showing as having reserved cross examination, but I will ask.

Is there any other party who has cross examination for Mr. Quarles?

(No response.)

COMMISSIONER CLODFELTER: If not, Ms. Cralle Jones, he's back with you on redirect.

MS. CRALLE JONES: I don't -- that was such a limited cross, I don't think I have any other direct -- redirect. You're on mute.

COMMISSIONER CLODFELTER: I was going to say you're not obliged to have redirect, but you're entitled to any that you wish. Let's see if Commissioners have any questions.

Commissioner Brown-Bland first.

COMMISSIONER BROWN-BLAND: Yes, I do have just a few, but I'm moving back and forth. Hold on.

EXAMINATION BY COMMISSIONER BROWN-BLAND:

Q. All right. Mr. Quarles, Marcia Williams testified, as did you, in the DEC portion of the hearing, and she testified that it was 1992 before EPA had clear groundwater monitoring standards.

In your opinion, would DEP have been prudent if it had waited until 1992 to perform groundwater monitoring at its CCR basins?

A. So let me begin by saying the 1992 date, I guess I would disagree with that. The 2L standard in the RCRA groundwater protection standard came out in 1979, so I'm not sure where the 1992 came from. In terms of waiting until 1992 to be prudent on the groundwater monitoring, I mean, the data were very clear in the late '70s, early '80s of the need to conduct groundwater monitoring at coal combustion waste disposal sites, in particular those that were unlined and in direct proximity to groundwater and surface water. And that's really clear too, you know, in the Company's own documents, particularly, you know, using Sutton as an example.

When they had the chloride issue that was migrating off site in 1979, some of their internal documents that I cite speak very clearly about their need to install a liner on the 1984 basin, and also very clearly about their knowledge that groundwater protection standards necessitated a design of that new basin that would not leak to groundwater. And so that same memo talked about the need to install groundwater monitoring wells around that basin. So that was in, you know, late '70s, early '80s, and not necessarily having to wait until 1992.

Q. All right. And then witness Williams also testified that the EPA attempted to define the perch zone from 1978 to 1986. Took them a while, and that they ended up saying that utilities should work with their agencies -- or your agency was her word -- on that issue.

Was there no definition of perch water or perch zone before 1978, to your knowledge?

A. So the bottom line is, when you look at a land disposal unit, you want to know if it's leaking, and you're required to look at the uppermost portion of the uppermost aquifer. And when we talk about the uppermost aquifer in terms of knowing whether or not a disposal unit is leaking, we're not talking about looking for a well that provides potable water to a city. We're looking for a well that could provide perhaps 4 or 5 gallons to be able to purge it and to sample it.

So if you want to know if a unit is leaking, you measure the quality of the water of the uppermost aquifer. And, you know, sometimes, call it perched, call it whatever you want, but the uppermost aquifer, in terms of leaking -- knowing whether or not a unit is leaking, you need to be looking at that uppermost portion.

Q. All right. And -- but still, was there any definition prior to '78?

A. No. So -- so what was well defined and talked about was underground source of drinking water and an aquifer. So -- so I've seen it time and time again about, you know, sometimes a regulated entity will argue that they should not monitor the perched zone, which is the shallowest zone below a disposal unit, for example, but instead to monitor the deep aquifer. Where that goes wrong is, if -- and we talked about this in the DEC hearing and having the illustration. Sometimes I've seen wells installed even deeper -- deeper than the adjacent receiving stream, right. So it's not going to be representative of the uppermost portion of the uppermost aquifer.

So, you know, EPA and EPRI talk about it very, very clearly in their documents that there's two things that are very critical in a groundwater monitoring system. That's the location of the well and the depth of the well. So if you want to know if a unit is leaking, you need to be monitoring that uppermost portion. Perched or not, it's an aquifer, a body of underground water that's nearest the bottom of the waste in the Southeastern United States that flows into the receiving stream. So it's important to monitor that.

Q. So from what you just testified, I would be correct to say that, in your opinion, DEP would not --

it would not have been prudent for them to wait to perform groundwater monitoring at its basins until some date after DEQ had finally made definitions of these perch terms, perch water or perch zone?

A. Yeah, it would not have been prudent, because in 1979, the 2L and the RCRA standard says you shall not contaminate underground source of drinking water. That's very clear.

Q. And do you have knowledge that, in 1978, a reasonably competent engineer or hydrologist would have been capable of designing effective groundwater monitoring system for a CCR base?

A. Oh, sure, yeah. And even like the Sutton internal documents, when they had the chloride issue that came to their attention in 1979, they investigated that and ended up -- ended up with extraction wells and groundwater monitoring wells. And then plant Mayo, for example, same thing. They investigated that site in the early '80s, determined that groundwater protection was going to be required and that, in fact, the ash basin would leak through and underneath the dam, all right.

So the understanding of groundwater hydrogeology, and the need to monitor groundwater, and how to monitor the groundwater was well understood in the late '70s and early '80s.

Q. All right. And your testimony from before is entered into the record in this case, but to bring it back to make it specific to DEP, when, in your opinion, should DEP have known that the continued use of unlined surface impoundments that were constructed in or near streams or rivers for the purpose of containing these CCRs would have been unreasonable?

A. Well, we know, starting in 1979, that there's the allegation that it traveled off site. All right. So we also look at the EPRI documents that talk about the need for groundwater monitoring. EPA was very consistent at the same time in the use of liners and leachate collection systems and groundwater monitoring systems, all of that.

So, certainly, after the early -- early to mid-1980s, they should have known better. And they should have known and did at plant Sutton, for example, that the CCR-related contaminates cannot only contaminate groundwater but can move off site. And so waiting beyond the mid-1980s is just -- I don't see any good reason to have waited to monitor groundwater beyond the early to mid-1980s.

And what we saw, for example, at Sutton, you know, it began operation in 1954, and then 1979 we got the high chlorides that are off site to the east. So that 25-year period demonstrated that it had already migrated off site, and then that result was closing down four municipal water supply wells, impacting 14 private water wells, and having to install extraction wells. So waiting -- the longer you wait, the bigger the problem becomes.

Q. And so the information, as it related to Sutton, should have also been informative as to other basins?

A. Yeah. I mean, unlined surface impoundments leak, and it is very clear in the EPRI documents, the industry documents that talk about particularly large unlined basins have a greater potential for groundwater contamination. So there's plenty of -- plenty of good -- good evidence and good information that necessitated the need for groundwater monitoring.

Q. In terms of -- so you -- I'm correct in saying that, at least by the mid-1980s, you believe that's when DEP should have known that it was not reasonable to continue in the manner that they had operated?

A. That's correct.

Q. So -- and you've related that to -- somewhat especially to Sutton.

Do you have any similar information that you could provide with regard to Mayo?

A. Yeah. Same thing. They built the impoundment in Crutchfield Branch, which was a water of the U.S., it was a stream. They built a dam that was essentially designed to leak. It has a toe drain at the bottom, so the water flows through the dam collected in the toe drain. And then if you look at my prior testimony in the prior rate case in 2017, there's a nice cross-section that illustrates that.

It shows the groundwater flowing through the dam, in the dirt in the rock at the bottom of what used to be Crutchfield Branch, and also in the bedrock. And so the water that flows out of the ash impoundment is Crutchfield Branch, right. And so Crutchfield Branch then flows into Mayo Creek which then makes its way into Dan River.

Q. And with regard to the timing, what's the timing on Mayo? Can you --

A. That was 1984. There was a report that was published about Mayo in the groundwater hydrogeology there.

Q. All right. And then just once having some of this background, general knowledge that you've been testifying about, were there incremental migration options available to the Company? Options that along the way might have had a mitigating effect that would have -- that are options that are shy of closing or excavating?

A. So the early EPRI in EPA documents talk about corrective actions that are possible. Groundwater extraction wells, for example. Slurry walls, which are barrier walls that are built around disposal units. And so, for example, here at Mayo, we've got a dike that was essentially designed to leak, right. So -- so people talk about it. And I have a project that I'm working on in the Northeast where, in 1972, they built a slurry wall around thousands of feet of a dike, right. So there were technologies that existed back in the late '70s, early '80s that could have kept that groundwater from migrating off site.

Q. And even while -- I mean, presumably even while waiting for some greater regulatory guidance or directive?

A. That's right.

Q. Now, would -- with regard to various corrective actions or the start of some corrective actions, would going to the regulator -- whether it was EPA or the state regulator, would going to them with proposals, would that have been an option? Proposals for some of these other alternative or mitigating options, as I described them a minute ago; would that have been something that a company could have or should have done in your opinion, go to regulator with a proposal to begin to implement some of these types of options?

A. So it's up to the generator, the owner of the property, the generator of the waste to be compliant. And Ms. Bednarcik talked about that in the DEC rate case. If there's a regulation, we're going to follow it, right? So there was a 2L standard to protect groundwater. And there was probably -- I've not looked at the 1979 2L standard, but certainly 1979 RCRA standard has a requirement for corrective action. All right. So that's there.

And if the Company was, you know, having questions about, you know, their interpretation of the rule, what was required, they could have certainly gone to the regulatory agency and put a proposal in front of them to address the groundwater contamination, if it existed in the wells that they would have installed during that time.

Q. Well, based on sort of the evolution as you described -- I think you went back with Sutton, for example, from 1950s up through '79, I think.

In terms of attempting to comply and having discussions with the regulator, would some of these types of options, like a slurry wall, or extraction wells, or anything of that nature, have been reasonable to have been put forth as a proposal?

A. Certainly, those would have been part of the conversation.

Q. All right. And do you know or do you have any reason to know whether, in the DEP's case, that they had any such discussions? Have you seen reference to that in any documents that you reviewed?

A. No. The only -- the only thing that I've seen in the early times was -- it was my Exhibit 6, MQ-6. If you go to -- it was written by -- memorandum from Mick Greason (phonetic spelling), and this was regarding Sutton. And it's handwritten on the outside. It says I work mostly with the regulators, you know, so he 's -- this person has a regulatory responsibility within the Company. So then had you go to the third page. They had already had approval to build an unlined basin that eventually became the 1984 basin. All right.

And so then it talks about:

"CP&L already had all the approvals that were needed to construct the ash pond, but we could not ignore the accusations by our neighbor or the new groundwater regulations. For additional clarification, it should be noted that the groundwater regulations did not specifically require liners. Instead, they simply established standards. It was up to the facility to design their pond such that these standards would not be violated."

And then it went on to say, for the first time, I require specifically six groundwater monitoring wells. All right.

So the regulations were clear back -- back in the -- again, early '80s, late '70s, that you had to investigate leakage, and there would be a need for corrective action, particularly if you've got contaminants that were leaving the site. And you would not know that unless you put groundwater monitoring wells in. And in this case, the neighbor had industrial wells that they felt were contaminated by the Company's operations. And so they didn't have a monitoring system in place to detect it prior to it migrating off site.

Q. So in back, let's say, the mid-'80s, so let's just say we're choosing 1985. You mention Mayo had '84 -- had a published report. But if we were looking at 1985 --

A. So let me -- I'm sorry to interrupt. So the Mayo investigation was actually January 1979.

Q. All right.

A. So I misspoke. And that's my Exhibit MQ-7. And it's written by Edwin Floyd, professional engineer PE groundwater hydrologist. And the title of that document is "Evaluation of the potential for contamination of the groundwater aquifer by leachate from the coal ash storage pond at the Mayo electric generating plant site" dated January 31, 1979.

Q. All right. Thank you. But I'll stick with -- since you said at least -- as I find -- understood your testimony, the latest time is mid-1980s when the Company should have been aware that they needed to --

A. That's right.

Q. -- move away from what they were doing.

A. Right.

(Due to the proprietary nature of the testimony found on page 737, it was filed under seal.)

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(Testimony on the open record resumed.)

MR. MEHTA: Commissioner Clodfelter, I hate to interrupt, but I believe these cost figures are part of the confidential part of Mr. Quarles' testimony, and therefore should not be testified about in public session. I don't think he needs to testify about the specific dollars in public session, but if he needs to, then we should go into the confidential session.

COMMISSIONER CLODFELTER: All right. Mr. Quarles, are you able to talk in a general term without talking about the specific numbers and respond adequately to Commissioner Brown-Bland's question?

THE WITNESS: Yeah. The bottom line is I don't know how much a slurry wall or an extraction system would have cost back in 1979 or the early 1980s. You know, there's -- obviously a groundwater investigation would have been done to support the design of that, and I can't give you a cost for that.

Q. And so without a specific cost -- let's move to today. If you would start it today -- I guess I'm trying to determine, if you know, whether -- and it may be so fact specific that you don't know -- but whether any of these other options were less cost options than excavation. So would they be less cost today if you were doing it today, or you're not able to say?

A. I'm not able to say. But it's hard to imagine that -- and I've never seen a groundwater extraction system that cost in the hundreds of millions of dollars, right? Typically, you know, you're talking hundreds of thousands as opposed to hundreds of millions of dollars.

Q. And is there more of a range of options -- I heard you mention extraction wells, slurry walls. Are there other, you know, layered types of actions that could have been taken that would have been -- had some mitigation effect on groundwater contamination?

A. Yes, there was. So, for example, we know -- we know that the reason groundwater is contaminated is because the CCRs are saturated and they're seeping into the groundwater. So arguably, early on, had they converted to a dry disposal and dewatered the old ash, then that would have been a way that could improve groundwater quality over time, right? So that you've taken away the source that's in the groundwater, and then, again, over time, that groundwater would improve.

The quality of that groundwater would improve. So that certainly was an option to them at the same time period.

Q. All right. Thank you, that's all my questions.

A. You're welcome.

COMMISSIONER CLODFELTER: All right. Thank you. Commissioner Gray?

COMMISSIONER GRAY: No questions.

COMMISSIONER CLODFELTER: All right. Chair Mitchell?

CHAIR MITCHELL: No questions for the witness.

COMMISSIONER CLODFELTER: Commissioner Duffley?

COMMISSIONER DUFFLEY: No questions.

COMMISSIONER CLODFELTER: Commissioner Hughes?

COMMISSIONER HUGHES: No questions.

COMMISSIONER CLODFELTER: Commissioner McKissick?

COMMISSIONER McKISSICK: No questions.

COMMISSIONER CLODFELTER: All right. We're back on redirect, then. Well, questions on

Commissioners' questions. I'm sorry, it's getting late in the day. We are on now questions on Commissioners' questions.

Mr. Mehta, any from you?

MR. MEHTA: Just a few, Commissioner Clodfelter. And I apologize in advance to Ms. Cralle Jones. It was limited, but that's the beauty of the stipulation process, and I really appreciate the Sierra Club and other participants in that process, because I think it really has allowed us to streamline this proceeding, and that's to everybody's benefit.

EXAMINATION BY MR. MEHTA:

Q. Mr. Quarles, Commissioner Brown-Bland asked you that if -- if it was -- if by 1992, groundwater standards, groundwater monitoring standards from the EPA had been sort of defined, if it would have been prudent for a company to wait until 1992 to engage in groundwater monitoring; do you recall that question?

A. I do.

Q. In fact, Mr. Quarles, DEP had engaged in groundwater monitoring long before 1992 at multiple of its sites, correct?

A. I think there were -- there were two or three that were prior to 1992.

Q. And the -- and certainly with respect to Sutton, which is one that you and Commissioner Brown-Bland talked a lot about, the monitoring had been put into place well before 1992, probably in the mid-1980s, correct, if not --

A. Let me see what -- so page 18, Sutton 1990 is what I reported for Sutton.

Q. What was your source for that, Mr. Quarles?

A. There were a couple of documents that were document requests, I think, from -- it was groundwater monitoring DR is the citation that I have. It was a direct request, Number 2-10, October 2019.

Q. Mr. Quarles, do you have access to Mr. Hart's exhibits?

A. I don't -- I don't know that I do or not, to tell you the truth.

Q. In particular, to Hart Exhibit 24B.

A. Is that under joint cross exhibits or?

Q. No. It would be an exhibit that Mr. Hart had attached to his prefiled testimony.

A. And what's the exhibit number?

Q. 24B. Hart 24B. It is a copy of the microfiche documents maintained by the DEQ on the

Sutton site for a period that begins in the late 1970s and goes into the late 1980s.

A. I'm sorry, tell me -- I see an exhibit -- a DEP Exhibit 4. No, that was a deposition.

Q. No. I'm sorry, Mr. Quarles, this would be one of Mr. Hart's, the AG's witness --

A. No.

Q. -- prefiled exhibits.

A. I don't -- I don't think I have a copy of that, I'm sorry.

MR. MEHTA: Commissioner Clodfelter, let me ask you, are we planning to stop at 4:30 this afternoon?

COMMISSIONER CLODFELTER: We are planning to stop at 4:30, yes.

MR. MEHTA: Well, I tell you what. Mr. Hart's exhibits are already a matter of record, they say what they say, and I think they give a pretty good history of groundwater monitoring at Sutton. And I'm just going to let them speak for themselves, and we won't need to go into them with Mr. Quarles since he doesn't have access to the document anyway.

Q. Mr. Quarles (sound failure) --

COMMISSIONER CLODFELTER: Mr. Mehta, you're cutting in and out right now. Your audio is cutting in and out.

MR. MEHTA: Let me try to get closer to the mic.

Q. Mr. Quarles, in response to another one of Commissioner Brown-Bland's questions, you were talking about the construction of the ash pond at Mayo in the late 1970s, correct?

A. Correct.

Q. And you indicated in response to her question that, quote, they built the impoundment in the Crutchfield Branch, correct?

A. I don't remember exactly what I said, but they -- I may have used the word "they."

Q. And the "they" you meant was DEP, I take it, correct?

A. Whoever the owner was at that time, the company as it is today.

Q. Okay. So whatever the name of the company was, but we know it today as DEP; that's who you meant by "they," correct?

A. Yes, sir.

Q. And DEP received, at that time, authorization and approval of the DEQ, whatever name it went by then, to build that ash basin; did it not?

A. I haven't seen the approval letter, so I can't respond to that.

Q. You think they would have built a basin without some kind of regulatory process going on and approval?

A. It certainly makes sense that there would be, but I can't speak to whether or not that exists.

Q. Well, we can let Mr. Wells talk about that or Ms. Bednarcik when they come back.

You mentioned, again in response to some of Commissioner Brown-Bland's questions, your Exhibit 6, which is what we -- what you call the Greason memo, correct?

A. I think actually in the citation I call it the -- no, that's it. Yes, sir; that's right.

Q. The memo from Mick Greason?

A. Yes, sir.

Q. And you indicate that the -- and I'll just paraphrase -- that the memorandum itself said that -- that -- or either the memo said or your testimony indicates that DEP had had approval in 1983 to build a new unlined basin at the Sutton plant,

correct?

A. It says CP&L already had all the approvals that were needed to construct.

Q. And, in fact, what CP&L, now DEP, did was build a lined basin in 1984, correct?

A. Correct.

Q. And that lined basin had ash deposited in it from 1984 until sometime in the relatively recent past, correct?

A. Correct.

Q. And all of that ash in that lined basin is being ordered to be excavated by either CAMA or the DEQ, correct?

A. I don't -- I don't know whether -- I think this -- this Sutton basin was part of the order for excavation, but I can't tell you for sure.

Q. And back then -- and you talked about this off-site issue with the neighboring industrial plant, correct?

A. Yes, sir.

Q. And back then they investigated that issue; did they not? That is DEP investigated along with DEQ that issue; did they not?

A. I don't -- I don't know about DEP's

involvement with that.

Q. Well, you mentioned that somebody put in a bunch of groundwater monitoring wells. Was that DEP or was that the neighbor?

A. I assumed that that was CP&L.

Q. Okay. Now DEP, correct?

A. Correct.

Q. Now, you mentioned, again in response to another of Commissioner Brown-Bland's questions, that, at some point in the past, DEP could have converted to dry ash handling of the -- of its plants so that it would not have to sluice ash into ponds, correct?

A. That's right.

Q. And had they done so, they would have incurred cost, correct?

A. Correct.

Q. You did not take that cost into account when you did your per-ton analysis, did you?

A. I did not.

Q. And had they done so, the capital investment that they would have made in order to create the dry ash handling system would have been included in DEP's rate base at the time that the capital investment came online and was used by the Company, correct?

A. Correct.

Q. And you did not take into account in your per-ton analysis, any recovery of cost that would have been paid for back at that period of time and at some period of time going forward by the customers of DEP, did you?

A. I did not. And so the -- to put it in the context of the testimony, I was presenting the cost of excavation. Pick your point in time that the Commission chooses the range of the excavation cost and the blended cost, not just excavation, but the engineering site preparation, that sort of thing. And then also I discussed costs that were given on a dollar-per-ton basis to build a landfill versus -- a lined landfill versus an unlined surface impoundment. And lined landfills in the early 1980s were less expensive to build than unlined surface impoundments.

Q. Understood. But the costs that you're giving, Mr. Quarles, are costs in today's dollars, correct?

A. Yes. Today's dollars on the blended costs, and then the dollars that I wrote about on the range of costs, those were, you know, the 1980s dollars from that citation.

Q. For what costs are we talking about there, Mr. Quarles?

A. That's building the lined landfills versus unlined surface impoundments, the closure costs, and the post-closure costs.

Q. Where is that in your testimony?

A. (Witness peruses document.)

It's on page 25.

Q. And the testimony that you've provided on page 25 is essentially total capital and operate -- O&M costs relating to unlined surface impoundments, correct? Being more than lined landfills; that's what your testimony is on page 25?

A. Well, as I previously said, the cost to construct and operate an unlined surface impoundment range from $8 to $17 per ton compared to $5.70 to $13.55 for a single clay-lined landfills. Again, compared to $6.45 to $15.50 per ton for a synthetic lined landfill.

Q. And if Duke Energy Progress had built a clay-lined or a synthetic-lined landfill back in 1985, it would have gone into rate base; customers would have been paying for it ever since, correct?

A. I assume that's how CP&L or DEP would pay for that.

Q. Okay. And you didn't factor that into any of your analysis concerning today's costs, correct?

A. I didn't. And again, the purpose of the testimony was really to present those costs that we just talked about to say that lined landfills were actually less expensive than an unlined surface impoundment, just it put it into context. And then the total amount of money for the closure today just -- it brings it into perspective on how much DEP is paying today to excavate the millions of tons of ash.

Q. But you have not done any analysis of what it would have cost back in -- I think your words were "pick a date sometime in the past," you have no idea what it would have cost to excavate these landfills, these ponds at that time, do you?

A. That's correct.

MR. MEHTA: Commissioner Clodfelter, I have no further questions on Commissioner questions.

COMMISSIONER CLODFELTER: Okay. Thank you, Mr. Mehta.

Ms. Cralle Jones, I don't want to

deprive you of your opportunity to ask questions on Commission questions. How long do you think you may take? You're on mute, Ms. Cralle Jones. You're on mute.

MS. CRALLE JONES: I don't have long at all. I did want to apologize to Mr. Mehta, and if we -- if he would like for us to get those exhibits to Mr. Quarles for questioning, we'll be happy to do it. We've been scrambling to try and figure out which one he was referring to without luck. But I do apologize for that hitch, and we could redo that. But I think, in terms of -- so we're happy to revisit that if needed.

MR. MEHTA: Commissioner Clodfelter, it is not necessary. Those documents are in the record. We can deal with them, because they're already in the record.

COMMISSIONER CLODFELTER: That's fine. Ms. Cralle Jones, if we went another five minutes or so, do you think you could get done what you need to get done? I don't want to push you, but I just ask. That would allow us to finish the witness today.

MS. CRALLE JONES: And I think the

witness would love that as well today. I -- can I take just a minute to review, and then I think I can finish up.

COMMISSIONER CLODFELTER: Yes. Yes, you may.

(Pause.)

MS. CRALLE JONES: Commissioner Clodfelter, I don't think I have any questions I need to revisit.

COMMISSIONER CLODFELTER: All right, then. Let's see, then, do we have any motions we need to take, then, here at the conclusion of Mr. Quarles' testimony?

MR. MEHTA: Yes, Commissioner Clodfelter. I would move the admission into evidence of Quarles DEP Cross Examination Exhibit Number 2.

COMMISSIONER CLODFELTER: All right. Without objection, it will be admitted.

(Quarles DEP Cross Examination Exhibit Number 2 was admitted into evidence.)

MS. CRALLE JONES: And I think the only other motion I would have is that we confirm that Sierra Club Quarles Exhibits 1 through 7 were entered into the record previously.

COMMISSIONER CLODFELTER: I think they were, but to the extent we didn't clean that up, we will admit those exhibits into the record.

MS. CRALLE JONES: And then my final motion would be to ask that Mr. Quarles be excused.

COMMISSIONER CLODFELTER: If there is no objection from any party, Mr. Quarles, you are excused. Thank you for your time this afternoon.

THE WITNESS: You're welcome. Have a great day.

COMMISSIONER CLODFELTER: Thank you. Okay. We are, folks, moving at breakneck speed here, and I -- don't take that as a complaint, by the way. So we will resume tomorrow.

Ms. Cralle Jones, is there anything else from the Sierra Club's presentation -- on Sierra Club's presentation? We have witness Wilson's testimony to deal with, right?

MS. CRALLE JONES: That would be tomorrow; yes, sir.

COMMISSIONER CLODFELTER: We'll begin with that in the morning, and we'll start again at 9:00. We will recess until 9 a.m. tomorrow morning. Thank you all.

MS. CRALLE JONES: Thank you.

(The hearing was adjourned at 4:31 p.m. and set to reconvene at 9:00 p.m. on Thursday, October 1, 2020.)

CERTIFICATE OF REPORTER

STATE OF NORTH CAROLINA)
COUNTY OF WAKE)

I, Joann Bunze, RPR, the officer before whom the foregoing hearing was taken, do hereby certify that the witnesses whose testimony appear in the foregoing hearing were duly affirmed; that the testimony of said witnesses were taken by me to the best of my ability and thereafter reduced to typewriting under my direction; that I am neither counsel for, related to, nor employed by any of the parties to the action in which this hearing was taken, and further that I am not a relative or employee of any attorney or counsel employed by the parties thereto, nor financially or otherwise interested in the outcome of the action.

This the 6th day of October, 2020.

JOANN BUNZE, RPR
Notary Public #200707300112