PLACE: Held Via Videoconference REDACTED

DATE: Friday, September 4, 2020

TIME: 2:00 P.M. - 4:31 P.M.

DOCKET NO.: E-7, Sub 1214

E-7, Sub 1213

E-7, Sub 1187

BEFORE: Chair Charlotte A. Mitchell, Presiding

Commissioner ToNola D. Brown-Bland

Commissioner Daniel G. Clodfelter

Commissioner Lyons Gray

Commissioner Kimberly W. Duffley

Commissioner Jeffrey A. Hughes

Commissioner Floyd B. McKissick, Jr.

IN THE MATTER OF:

DOCKET NO. E-7, SUB 1214

In the Matter of

Application by Duke Energy Carolinas, LLC,

for Adjustment of Rates and Charges Applicable to

Electric Utility Service in North Carolina

DOCKET NO. E-7, SUB 1213

In the Matter of

Petition of Duke Energy Carolinas, LLC,

for Approval of Prepaid Advantage Program

DOCKET NO. E-7, SUB 1187

In the Matter of

Application of Duke Energy Carolinas, LLC,

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

VOLUME 17

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P R O C E E D I N G S

CHAIR MITCHELL: All right. It’s 2:00. Let’s go back on the record, please. Mr. Mehta, we are with you.

MR. MEHTA: Thank you, Chair Mitchell

CONTINUED CROSS EXAMINATION BY MR. MEHTA:

Q Mr. Hart, good afternoon. And what I would like to do is turn, if you would, with me to your -- the issues raised in your supplemental testimony. And I realize -- at least I think I realize that as a result of your errata filing, the supplemental testimony is now included in what you call your “entire testimony” and the page numbers are different. But originally you filed testimony with respect to your attempts to quantify cost disallowances for Duke Energy Carolinas, correct?

A Yes. The supplemental testimony, that’s correct.

Q Okay. Now, I think similar to the morning session, Mr. Hart, you may as well have available to you and handy two documents that we will be referring to, I suspect, repeatedly. One of them is Duke Exhibit or DEC Exhibit 5 and the other one is DEC Exhibit 6.

A Okay.

MR. MEHTA: And Chair Mitchell, if we could mark DEC Exhibit 5 as DEC Hart Cross Examination Exhibit 5, that would be marvelous.

CHAIR MITCHELL: All right. The document will be so marked.

(Whereupon, DEC Hart Cross Examination Exhibit Number 5 was marked for identification.)

MR. MEHTA: And if we could mark DEC Exhibit 6 as DEC Hart Cross Examination Exhibit 6, I would appreciate it.

CHAIR MITCHELL: All right. The document will be so marked.

MR. MEHTA: Thank you, Chair Mitchell.

(Whereupon, DEC Hart Cross Examination Exhibit Number 6 was marked for identification.)

Q And Mr. Hart, just to level set us, the document marked as DEC Hart Exhibit 5 -- Cross Examination Exhibit 5 is your workpapers associated with your quantification of disallowance, correct?

A Yes. I’m sorry. I was in my -- I was in my testimony Exhibit 5. Sorry. Yes. Workpapers. Yes. Sorry. I’m there.

Q And DEC Hart Cross Examination Exhibit Number 6 is that portion of your deposition taken April 28th, 2020, by video that deals with your supplemental DEC testimony, correct?

A Yes, it is.

Q Now, Mr. Hart, the quantification that you presented to -- in your supplemental testimony is in two basic buckets, correct, if I'm looking at it correctly. One deals with the disallowance of public water supply hookups and the other dealing with various amounts based on what you call your time value of money analysis. Did I frame that correctly?

A Yes. The water supply connection removal and then what I call the time value of money. It may not be the actual accounting correct term, but it's just an adjustment for inflation over time. And then I also took out the Charah contract cost and didn't consider that in my analysis at all.

Q Okay. And so that when we look at your workpapers, Cross Examination Exhibit 5, even though it deals with a number of different time frames, 1989, 1995, 2003, 2010, in each of those time frames you removed the alternative water supply cost amount, which is about 17 and a half million dollars, from each of those time periods, correct?

A Correct.

Q And we'll come back to the alternative water supply in a few minutes, Mr. Hart. And you also, as you just indicated, removed the Charah fee item from each of the time periods, correct?

A Yes, yes. I -- yes, I removed that. I just didn't consider it. It didn't factor into my evaluations. I'm not making a conclusion about whether it's reasonable or appropriate or not. I just took it out because I didn't know how to address its money. It's a contractual issue.

Q So you're actually expressing no opinion in this case on whether the Charah fee should or should not be included in DEC's recoverable costs, correct?

A That is correct.

Q Now, beginning on page 127 of your supplemental testimony, which I think under the errata filing is now page 128 of your entire testimony, you set out a series of bullet points that you say are illustrations of increased costs, correct?

A Yes. Correct.

Q And the first one deals with the impact of acceleration, Mr. Hart; is that right?

A Yes.

Q And in order --

A Yes. Accelerated time frames to do work, yes.

Q And in order to quantify the impact of acceleration, you would need to compare the costs actually incurred in their accelerated mode to what they would have been in a nonaccelerated mode calculated to a reasonable degree of engineering certainty, correct?

A Well, it's just a general statement to come up with an actual number, yes. Now, I did not factor in -- the only thing I took into account was inflation, so I did not take into account, you know, in terms of cost disallowance the accelerated actions. My point is just based upon my experience, the accelerated actions can lead to increased cost typically because you can't necessarily dispose of coal ash at your own facility. You have to dispose of it offsite. So, again, that didn't factor into my ultimate analysis cost; just an evaluation statement about how costs are likely higher because of the accelerated actions caused by the Dan River spill.

Q And Mr. Hart, you're actually not an engineer, so I guess even if you wanted to make that assessment, a quantification assessment of the impact of acceleration, you would not be able to do that, would you?

A No. I think I could if I wanted to. It's not -- you know, it's a -- it would be analysis of what the cost would be under a nonaccelerated time frame versus an accelerated. It's not necessarily an engineering thing.

Q So you don't -- you think somebody who is not an engineer and not an expert in engineering could do that analysis and present a comparison of costs on an accelerated versus nonaccelerated mode?

A Well, I guess it depends on what costs you're talking about. If it's just remediation costs, coal ash removal, I think certainly like I could do that. If you're talking about constructing -- or somebody like myself could do that, an environmental professional. If you're talking about accelerated cost to do a dry ash conversion, that would not be my area.

Q Okay. In any event, you didn't do a comparison of accelerated versus nonaccelerated cost, did you?

A I did not, no.

Q And your second bullet on page 127 of your supplemental, which, again, I think is page 128 of your entire testimony under the errata format, indicates that regulators and the public lost confidence in DEC and prompted higher cost requirements, correct?

A Yes.

Q And, likewise, you have not calculated and presented in your testimony the dollar difference between what the costs would have been had regulators and the public not lost confidence in DEC and what the actual costs were, correct?

A That is correct.

Q And in your third bullet you indicate that had DEC taken action sooner, it would have been able to include cost of service earlier while the plants were in use, correct?

A Correct.

Q You’re not a ratemaking expert, are you, Mr. Hart?

A No, I’m not.

Q So in order to actually calculate that difference, you would have to make an assessment of the amount by which the rates were too low in the past, and you have not made that kind of assessment in this case, have you?

A I have not, no, other than -- I mean, I have not done a specific calculation, no.

Q And if you look back, for example, Mr. Hart, at page 127 of your supplemental testimony -- excuse me -- 126 of your supplemental testimony, which I think might be 127 of the reformatted entire testimony, you indicate that DEC should have instituted a systematic plan sooner, including conversion -- converting to dry ash handling, correct?

A Well, yeah, and beginning the process of converting to dry ash handling, eliminating other waste streams, developing basin closure plans, and evaluating methods to reduce the environmental impact while the basins are still operational.

Q And in order to quantify, just for example, the disallowance of costs involved with that systematic plan and, just for example, on dry ash handling, you would have had to establish, with a reasonable degree of engineering certainty, what it would have cost to make -- have made the dry ash conversion at some earlier point in time, which you have not done and which you do not possess the expertise to do; is that correct?

A I mean, not other than the increase in cost related to inflation, but not specifically to any dry ash handling, diversion of waste streams, that kind of thing. Those are certainly part of the costs, as I understand it, that are being requested for, so to the extent they're included in them, I looked at different time periods and what inflation did to those costs over time, assuming the cost today.

Q Well, in order to quantify the impact of -- or, you know, in order to fully quantify the impact of earlier dry ash handling systems being put into place, you would also have to quantify the impact of DEC being entitled to recover those earlier incurred dry ash conversion costs, plus a return on its increased rate base over the period, whatever the period is, from the time that the dry ash conversion took place to today, correct?

A I'm not sure I know how to answer that. I don't know that I have enough expertise on ratemaking to know that.

Q Well, Mr. Hart, let's actually look at what you did do as opposed to what you didn't do. And why don't you turn to Cross Examination Exhibit 6, which is the sort of part 2 of your deposition testimony.

A Okay.

Q And Mr. Hart, at pages 22 and 23 of Exhibit 6, you testified that you discussed the idea of doing a time value of money analysis with the Attorney General's Office as early as January 2020, correct?

A Where do I say January 2020?

Q Looking at the top of page 23.

A I see it. Yes. Correct. Probably January, yes, 2020.

Q And your testimony, your original testimony, not the supplemental, was filed in March of 2020 without that analysis, right?

A That’s correct.

Q Why didn’t you include that analysis?

A Well, as I think I indicated in my deposition that we just had some -- you know, there were some uncertainty about the -- how we wanted to approach cost, whether we wanted to include specific costs or not, and so we decided not to include specific costs in the original testimony. But then sometime after I filed that original testimony, we discussed it, that the Attorney General’s Office did want to include some specific costs in my testimony.

Q And looking again at Exhibit 5, Cross Examination Exhibit 5, the time periods at which you performed the time value of money calculations were 1989, 1995, 2003, and 2010, correct?

A Correct.

Q But initially you were only going to perform the calculations for 2003 and 2010; is that right? Is that what you indicate at page 25 of your deposition?

A Yes. Early 2000s to 2009 time frame or 2010. That's correct.

Q And it's the attorneys for the Attorney General's Office that asked you to go back to the 1980s and 1990s, correct?

A Yes.

Q Are you in the habit, Mr. Hart, of letting your client tell you how to do your analyses?

MS. TOWNSEND: Objection for the record.

A Well, I certainly listen to my clients as I --

CHAIR MITCHELL: Mr. Hart -- Ms. Townsend, would you state the basis for your objection?

MS. TOWNSEND: Yes. Client-attorney privilege. You know, we -- what our discussions were, et cetera, we objected to them at the time of the deposition and we object to them now.

CHAIR MITCHELL: Mr. Mehta?

MR. MEHTA: Well, I'm looking at the deposition, and Mr. Hart says that they, meaning the attorneys, suggested going back to the earlier times. And I think to the extent that that is even part of the attorney-client privilege, which I doubt sincerely, it's been waived.

CHAIR MITCHELL: All right. I'll allow the question. Overrule the objection.

Q Mr. Hart, are you in the habit of letting your clients tell you how to do your analyses?

A No, but I'm certainly in the habit, as I think we all are, of listening to our clients and taking their suggestions, and so I think the thought process was, is we would give different time frames and let the Commission determine which time frame they felt most appropriate.

Q And in any event you did add, at the suggestion of the Attorney General's Office, 1989 and 1995 to your calculations, correct?

A That's correct.

Q Mr. Hart, why don't we walk through the calculation just using 1989 as an example. And the -- but the -- and the methodology you used for each of these years is basically the same, correct?

A Yes. That's correct.

Q And you started -- and you can see this on Exhibit 5 -- you start with a total cost figure of a shade under $406 million, correct?

A Correct.

Q And you got that from Ms. Bednarcik's direct testimony; is that right?

A Yes. Well, it was -- yes, I did.

Q And I think we discussed this at your deposition, but that number, that 400 and -- almost $406 million number, is a system number, not a North Carolina retail number, correct?

A That’s what I understand, yes.

Q And what that number represents is the cost incurred on a system basis by DEC for coal ash basin closure activities from January 1st, 2018, through June 30th, 2019, correct?

A I would have to go back and check Ms. Bednarcik’s testimony, but I believe that’s the correct time.

Q And then you took that total cost number, you removed, as we discussed earlier, the Charah fee, correct?

A Correct.

Q And the water supply, and you come up with what you call a revised cost of about $342 million, right?

A Correct.

Q And what you did next was work your way back in time to 1989, and using average inflation rates came up with what you call the equivalent cost, correct?

A Well, it would just be the increase in cost from 1989 to present, yes, for the cost they're asking for now, considering inflation, just inflation.

Q Well, I'm looking again at Exhibit 5, Mr. Hart, and there is a number sort of to the left of the revised cost of $342 million of $171,500,000; is that right?

A I'm sorry. Where are you? Which number?

Q I'm right below your revised cost and a little bit to the left, 171---

A One hundred seventy-one thousand, five -- a hundred and seventy-one million, five hundred, yes.

Q Okay. And the -- there's a number right next to it which I think is the average inflation rate between 1989 and the time frame that you were evaluating, correct, today?

A Well, to 2014. So you could -- two ways to look at it. One is 1989 to 2014, or you could just move up to five years earlier and you basically get the same number, but, yes, over a 26-year period.

Q Okay. And that -- and then you keep going across the page, there's some words, "Net present value of approximately $342 million over 26 years." Do you see that?

A Yes, yes.

Q And then right below that there's some more words, “Difference between revised cost and equivalent cost 26 years earlier,” right?

A Correct, yes, if the work had been done at that time, right.

Q Yes. And if we looked actually at the Excel spreadsheet from which your workpapers from which Exhibit 5 are derived, and you looked at the formula there, you would see that you were subtracting $171,500,000 from the $342 million figure, correct?

A Correct.

Q And so when you say the difference between revised cost and equivalent cost 26 years earlier, equivalent cost 26 years earlier equates to $171,500,000, correct?

A Yes, yes, roughly.

Q And you arrived at that figure, 171,500,000, through trial and error, correct?

A Correct, until the number -- the calculated number, which is to the right of the inflation rate, .027, was roughly equivalent to the revised cost of 342 million, one hundred and some change, yes.

Q And what that dollar figure represents, the equivalent cost, $171,500,000, is the cost expressed in 1989 dollars of the work done in 2018 and the first half of 2019, which in today’s dollars would have been about $342 million, correct?

A Yes, if the work had either been done or the money had been set aside, yes, or accrued.

Q And to make it work, to make the equivalent cost actually be an equivalent cost, you have to assume that exactly the same work as was done in 2018 and the first half of 2019 would have been done in 1989, don’t you?

A Yeah. That is the assumption, right. And so in my thought process that would overestimate because you’re starting at a much higher cost. In other words, there’s a lot of things that -- for example, full removal of coal ash may have not been an option -- may have not been conducted in 1989, or beneficiation probably would have not been done because it was an unproven technology, so my calculations, even though they assume these things would have happened in 1989, are actually on the low end of what would be excluded because there were much more lower cost alternatives available back in 1989.

Q Well, you actually have no idea what would have to have had -- have to have occurred in 1989, do you, Mr. Hart?

A Well, you know, it just depends on what would have happened and, no, I can't say for certainty. Nobody can. But you can -- you can also go back. You can't say I can't know what something costs until I actually do it in something like this because you would never have ratemaking, right, where you look forward. You have to look forward to the future for some of the costs, and so in order to do that -- you can't always do that with certainty, so you have to look back sometimes.

Q Mr. Hart, you don't know if in 1989 the Company would have had to do more, do less, what the Commission would or would not have allowed, what the Commission would or would not have disallowed, or any of those things, do you?

A I don't, but I can say that there were certainly lower cost alternatives available to the Company to start planning. I didn't say they had to do all these things at a particular time to shut down, but they did need to respond to the groundwater contamination at some point and do some of these things, like dry ash conversions, closure of the ponds. And certainly back in 1989 people were closing out ponds in this state, and they were doing it by closing in place, and people were addressing groundwater contamination and things of that nature, so it's not something that didn't occur in 1989.

I can't say for certainty what would have been required, no.

Q And you did not factor at all in your time value of money disallowance recommendation for 1989 or any of the other years the impact of DEC being able to recover and earn on some or all of those costs incurred at earlier points in time, correct?

A That's correct. I did not.

Q All right. Now, Mr. Hart, in the final step of your time value of money analysis for 1989, you took what you call the equivalent cost, which is that $171,500,000 figure, and subtracted it from 342 million, the revised cost, to come up with a difference of approximately $171 million, correct?

A Correct.

Q So that -- what you did was subtract a figure expressed in 1989 dollars from a figure expressed in today's dollars, and indicated that the difference was meaningful to your analysis, correct?

A Right. That's the additional cost because of inflation from $171 million, roughly, to $342 million today.

Q But Mr. Hart, those two figures, 171,500,000 and 342 million are the same dollars for the same work, just expressed in dollar values reflecting different points of time; isn't that correct?

A Well, that's only correct if you actually did the work or set aside the money, but no one did that. So you can't say I had $171 million set aside. Duke didn't do that, and so it's not the same money. It can't be. If you're just saying, well, all I had to do was say I'm going to spend 171 million in 1989 and now it costs me 342 million, that's -- you didn't spend the 171 million back in 1989, nor did you set it aside. It's not the same money.

Q But it's the same figure, just expressed at different points in time and adjusted by inflation, under your own analysis, isn't it?

A It's the same figure if the money had been spent or accrued.

Q But the whole purpose behind what you're doing, Mr. Hart, is to say "x" amount of money should be disallowed, and the "x" amount of money is the equivalent amount of money that is being spent today, just 26 years earlier, according to your analysis, in the year -- for the year 1989; isn't that right?

A I don't see it that way. What I see is because of Duke's delay in addressing its groundwater contamination, it had to spend extra money because it delayed, and because of inflation, that money is more today than it would have been previously and, therefore, it's going to cost more. And should the ratepayers today -- their delay be foisted upon the ratepayers today for their delay and inaction when they knew they had groundwater problems at their coal ash basin a long time ago that they had to address in some fashion? It didn't have to be closure, necessarily, but it could have been dry ash conversions like they did for selenium in surface water. They could have been starting a closure process. So I disagree with what you're saying.

Q Mr. Hart --

A If I have $50,000 in the -- you know, say I'm going to put $50,000 away and I put it in an account, yes, from inflation, and it's earning an inflation rate, yes, the time in the future would be more money, but if you don't put that money away, that money -- you know, if I have zero in my account, it doesn't cost me $50,100. I just don't magically have that.

Q Mr. Hart, in your deposition, Exhibit 6, I asked you if you knew of any standard text or peer-reviewed article that supports this just subtraction methodology that you've been talking about. Do you recall those questions?

A Yes, yes.

Q And your answer was that you don’t know of any; is that right?

A Well, I don’t -- where are you, because I think I had some qualifications on that, but it’s -- you know, I think it’s a fairly simple analysis to do an escalation or de-escalation for inflation for money, for cost over time. I mean, it’s -- Duke did it in all their -- in their projections for the future. They use an inflation rate. Why do that if it’s all the same money? Why would you account for inflation? If it’s the same money, I don’t have to account for inflation, right, but it’s not the same money.

Q Well, Mr. Hart, I’m looking at page 76 of your deposition, line 2. That’s Exhibit 6. Question, “So the answer to my question, is there a standard text or a peer-reviewed article that” -- should say no -- perhaps there’s an error in transcription or perhaps I just said it wrong, but your answer was you don’t know of one, correct?

A Well, I said to me it’s subtraction. I don’t know any specific -- "I don’t know what specific methodology you would want, but I’m not aware of any other than just it’s subtraction.”

Q Okay. So you, in fact, do you not know of any standard text or peer-reviewed article or journal that supports your “just subtraction” methodology and application of just subtraction to a time value of money methodology, correct?

A I don’t, other than to say it is standard practice for us to look at cost increases from inflation over time for certain -- for projects like this. What is the delay -- is the delay going to cost me more, and the answer is yes. And so those are factors we've taken into account. We have to do financial assurance calculations for our clients for reserves analysis, and so, you know, the State now requires you to do an inflation adjustment. Well, if it’s the same money, why would I have to do an inflation adjustment every year? It’s because the -- it’s going to cost me more now. I don’t have enough money anymore, right? So to me, it’s a standard methodology.

Q But you can’t point to a standard text or a peer-reviewed article that indicates that just subtraction in this context is a standard methodology, right?

A Again, it’s based upon my experience, so that’s what I’m relying upon.

Q Well, Mr. Hart, let’s switch over to the 17-and-a-half-million-dollar disallowance recommendation that you've made dealing with alternative water supplies.

A Okay.

Q And, again, just to level set us, see if I -- see if I frame this correctly -- the 2016 amendments to CAMA, Coal Ash Management Act, obligated DEC to establish permanent replacement water supplies to replace drinking water supply wells located within a half-mile radius of the compliance boundary for its coal ash basin sites, correct?

A Yes. That’s my understanding, yes.

Q And those amendments became effective in July of 2016?

A That sounds right, yes.

Q And in your supplemental testimony at page 128, which I think may be 129 now in your errata testimony, you testified that the alternate water supply requirement was another manifestation of the lack of confidence on the part of regulators and the public, correct?

A I don’t believe I used that terminology.

Q Well, you’re right. You’re right. That was actually in your deposition. So if you turn to your deposition, page 176 and 177, I believe that's where you talked about it.

A A hundred and twenty-six (126), is that what you said?

Q One seventy-six (176) to --

A Oh, 176.

Q -- to 177.

A One seventy-six (176). Okay.

Q I'm sorry. We have to go back to your first deposition. That would be Exhibit 1.

A Yeah, yeah. Yes. Right. First deposition. Yes. I see here.

Q Yeah. I was at 176 of your second deposition and I was reading all about Duke Energy Progress stuff and I thought, well, that's just not right.

A Right.

Q It's the first deposition. And you indicate there that the CAMA amendments with respect to water supply, this is around line 13, 14, was because of a lack of confidence, correct?

A Well, that's -- yes. That's what I say here. Now -- and I would also supplement with what I said in my testimony, which is that they failed -- DEC failed to determine the extent of groundwater impacts, reliably establish background concentrations, and perform adequate receptor evaluations.

Q I understand. And, actually, the specific testimony that you gave in your deposition at line 19 was a lack of confidence in DEQ, not DEC. Do you see that?

A Yes, yes.

Q And when I saw that, I thought, well, Mr. Hart was simply mis-transcribed by the court reporter, so I went back and actually listened to the video of the deposition and, in fact, you said DEQ. You may have meant DEC. Or did you, I guess, is my question?

A I -- I think I meant DEC. I believe I meant DEC, and under the context of what I meant by lack of confidence was these issues in my testimony, which is that the extent of groundwater impacts hadn’t been determined, background groundwater concentrations hadn’t been determined, and then inadequate receptor evaluation hadn't been determined.

Q Now, when the General Assembly passed the 2016 CAMA amendments, it did not tell us why it included the alternate water supply requirement in that legislation, did it?

A Not that I’m aware of, no.

Q And you did not survey the members of the

General Assembly who passed the 2016 CAMA amendments to try to find out what motivated them to include the alternate water supply requirement in that legislation, did you?

A I did not.

Q And you did not survey the general public to determine whether it had lost confidence in DEC, did you?

A I did not. It was based upon my experience with working in groundwater for 30 years, and specifically contamination issues related to water supply wells, that it is unheard of that you would have to connect people to a municipal water supply if you hadn't impacted their wells. So it's an extraordinary event, especially within a half mile, you know.

So in my opinion, that was because Duke had failed to determine the extent of groundwater impacts at its facilities, even though they had known for 10 or more years in some cases that they were impacted. They hadn't established background concentrations until fairly recently, which it didn't support their allegation that the concentrations were background. And in some cases they hadn't done an adequate receptor evaluation so they can even know where these water supply wells were until they were required to do so.

Q Well, surveys, Mr. Hart, are a systematic way of gauging public sentiment, are they not?

A Yeah. I think in this case I really wasn't talking about lack of confidence. I may have -- I think I used that term earlier, but I think I may have misspoke when we were talking here in my deposition about -- I think I was talking more about, as I stated in my testimony, that the requirement to hook up people that aren't affected or aren't even reasonably in the path of groundwater contamination to alternate water supplies is an extraordinary measure, and there had to be a reason for that. And, you know, I think it was certainly related to the fact that DEQ had not -- I mean, DEC had not determined the extent of the groundwater impact so that they could go to the public and say these wells are clearly not impacted by our contamination and here's our rationale why, and working with the regulators to show that and get their buy-in on that. That did not happen for my analysis until much more recently.

Q And Mr. Hart, if you turn the page in your deposition, Exhibit 1, to page 178 and on to page 179 as well, you indicate, and particularly at the top of 179, that you, yourself, directly experienced, through press and newspaper articles and things of that nature, the concerns that were out there regarding potential groundwater issues around these plants, correct?

A Yes. It's something that I was certainly interested in as a professional in the field, yes.

Q And you, yourself, had a client in Belmont that asked you to test their water supply well, correct?

A That's correct.

Q And you tested that well, correct?

A Correct.

Q And you found no impact in that well from the coal ash basins at the Allen plant which is also in Belmont, correct?

A Well, we were specifically looking at contamination from a large fill area that Duke had placed on these people's property of coal ash. It was a home for disadvantaged children and adults from the Belmont -- um, home, and so they were very concerned that they had allowed Duke to give them free fill back in the day, and it was all coal ash, and they filled in probably a 30 or 40 foot deep ravine with coal ash, and I believe it was in the hundreds of thousands of tons, and so they were very concerned that that was going to lead to groundwater contamination and this camp was serviced by a water supply well. But we did not find groundwater --

significant groundwater contamination. There was fairly significant surface water contamination that was discharging to Lake Wylie from the coal ash that they had filled onto this property, that Duke had.

Q Okay. But the coal ash fill which was a permitted fill, correct?

A It was permitted, yes.

Q Had no impact on your client's water supply well, correct?

A No. Just Lake Wylie, which is the water supply for several places.

Q Now, Mr. Hart, look, if you would, at DEC Exhibit 11.

A Okay.

MR. MEHTA: And Chair Mitchell, I would like to have DEC Exhibit 11 marked for identification as DEC Hart Cross Examination Exhibit 7.

CHAIR MITCHELL: All right. The document will be so marked.

MR. MEHTA: Thank you, Chair Mitchell.

(Whereupon, DEC Hart Cross Examination Exhibit Number 7 was marked for identification.)

Q And Mr. Hart, DEC Hart Cross Examination

Exhibit Number 7 is an article in the Charlotte Observer, published at least in the paper-paper on March 9th and online if you go to the back of the last two pages of the exhibit, online published on March 8th, 2016, right?

A That's correct, yes.

Q I think the online piece is a little easier to read, so let's look at that.

A Yes. That's what I have in front of me.

Q And the headline is "NC lifts warnings against drinking well water near Duke Energy ash ponds," correct?

A Correct.

Q And so this is March of 2016, so right at this time, actually, the CAMA amendments were being debated in the General Assembly or were about to be debated in the General Assembly, correct?

A I don't know when they were debated in the General Assembly.

Q But in any event, the article recounts a public outcry when the State of North Carolina shifted gears and reversed an earlier drinking water advisory, said that water in people's wells was good to drink, correct?

A Yes. It said it would rescind the advisory issued last spring after tests found elevated levels of vanadium and hexavalent chromium in private wells.

Q And the article says, if you look at the last page of the exhibit in the second full paragraph, “The state’s health and environmental departments sparred for months over the screening levels, internal emails showed, with the environmental agency warning they were too stringent.” Do you see that?

A I’m sorry. I lost you.

Q Just look at the very last page of the exhibit.

A Yes.

Q The second full paragraph.

A Oh, I see. Yes, yes. Sorry.

Q And the words “sparred for months” are underlined on the paper version of what we’ve got here, right, Mr. Hart?

A Correct. And then it says “The departments eventually agreed.”

Q Yeah. And I’ll represent to you that sparred for months underlined is really a hyperlink when you look at online. And the hyperlink takes you to another article, and that article would be what has been previously marked as DEC Exhibit 12. So if you could get that one in front of you, that would be great.

A Okay.

MR. MEHTA: And Madam Chair, if you -- I would like to have DEC Exhibit 12 marked for identification as DEC Hart Cross Examination Exhibit Number 8.

CHAIR MITCHELL: All right. The document will be so marked.

(Whereupon, DEC Hart Cross Examination Exhibit Number 8 was marked for identification.)

Q And this article, again, Mr. Hart, was published in the Charlotte Observer in January of 2016 prior to the time the CAMA amendments were passed, correct?

A Correct. Yes.

Q And, again, since they're easier to read, we probably should just read the online version which is the last two pages of the article.

A Yes.

Q And the headline there is "Legislators probe conflicting messages on water drinking safety standards," correct?

A Yes, that's what it says. Correct. Yes, that's the title, uh-huh.

Q And if you read the article -- and let me summarize it, you tell me if I'm wrong -- what the legislators were probing, Mr. Hart, was this ongoing fight between the State health agency which issued the water advisory and the DEQ, the environmental agency which wanted it rescinded, correct?

A Well, I mean, yes. So there's -- the State Health Department had determined a screening level -- I think this one references hexavalent chromium -- and that DEQ had felt that it was "too tough," but that DEQ eventually consented to the tougher standard, is what it says.

Q Well, actually, Mr. Hart, if the advisory was rescinded, as we saw in the prior exhibit, Exhibit 7, the fight between the DEQ, which wanted it rescinded, and the State Department of Health, which didn't want it rescinded, was won by the DEQ, correct?

A I mean, it says it was -- in March 8th, 2016 letter it says it was DHHS' decision to lift the don't-drink advisory.

Q And DHHS is the health department which issued the advisory, correct?

A Correct. Yes. Health and Human Services, correct.

Q And DHHS rescinded the advisory based on whatever the fight was between DHHS and DEQ, correct?

A It doesn't say why they did. I'm looking at the article. I don’t see anything in here about why DHHS rescinded the advisory. It just says "followed a meeting Monday in Lee County where coal ash was disposed of in a former clay mine." I don’t know why.

Q Well, if you just keep reading, Mr. Hart, in Exhibit 8, which is the January article --

A Okay.

Q -- the very bottom of the second-to-last page, so the bottom of the -- the online version, says the Department of Health and Human Services is the one that issued the advisory, correct?

A Yes.

Q Then it says in the very next paragraph, which would be the first full paragraph on the last page, the Department of Environmental Quality officials expressed alarm about the screening levels for hexavalent chromium, et cetera; they were too tough, right?

A Correct.

Q And they expressed alarm because public water systems have only to meet a far higher federal standard for total chromium, which includes hexavalent chromium, correct?

A Correct.

Q And the next paragraph, exactly one sentence, says "Conflicting standards, DEQ argued, would mislead the public," right?

A Correct. That's what it says.

Q And then it says "DEQ eventually consented to the tougher standard," that is, it didn't stand in the way of the advisory, correct?

A Yes. That's correct.

Q But ultimately, its view that the tougher standard should not be applied prevailed because the advisory was lifted, correct?

A Right. And at the -- yeah -- the end of the January 2016 article says "The health agency will reassess its recommendation when more groundwater test data are reported in the next month." So, I mean, I think this is a classic case of why you don't delay addressing your groundwater contamination and determining the extent of it, reliably establishing background levels, and doing receptor evaluations so you can, with confidence, go to the public and the Agency and say we know where our groundwater contamination is, we know it doesn't extend into these neighborhoods, or if it does, here's where it goes. We have background data. We've done background data not only for our site, but regional, which is what ended up happening in some cases. They did a much broader study. And so those -- that's what happens when you address proactively groundwater contamination. When you are reactive to groundwater contamination, this is the kind of thing that happens.

Q Well, are you saying that Duke Energy Carolinas did not undertake steps with the DEQ and the health department to try to address this fight between the DEQ and the health department?

A Well, I mean, they were working on it during this time frame, but, no, they hadn't established the extent of their contamination, they hadn't completed -- they didn't even complete receptor evaluations until required to do so in 2014. And so, you know, if those issues had been addressed before, which is what should have happened, then I think this all could have been avoided.

Q Well, Mr. Hart, why don't we take a look at what was previously marked as DEC Exhibit 14.

A Okay.

MR. MEHTA: And Madam Chair, if we could have this exhibit identified as DEC Hart Cross Examination Exhibit Number 9, that would be great.

CHAIR MITCHELL: All right. The document will be so marked.

(Whereupon, DEC Hart Cross Examination Exhibit Number 9 was marked for identification.)

Q And Mr. Hart, this is another Charlotte Observer article, this one actually postdating the CAMA amendments in October of 2016, right?

A Correct.

Q And, again, just for ease of reading, we can go to the last two pages of the exhibit which are the online versions.

A Yes.

Q And the headline of which is “Coal ash not the source of well contaminant, Duke University study finds,” right?

A Yes. That’s the title, uh-huh, yes.

Q And the lead paragraph, opening paragraph, states “A contaminant at the center of a months-long furor over coal ash and polluted wells doesn’t come from ash after all, Duke University scientists report in a study published Wednesday,” correct?

A Correct.

Q And a couple paragraphs down below says “The state's decision to rescind the health advisories in March,” which was the subject of Exhibit 7, “prompted bitter exchanges among two state health officials, department leaders, and Governor Pat McCrory’s office,” correct?

A Yes. That’s what it says.

Q So Mr. Hart, in coming to your conclusion that the CAMA amendments mandated alternate water supply hookups because of loss of confidence in DEC, how did you eliminate the possibility that what the General Assembly was doing was simply settling a fight within and among two State agencies with overlapping authority over the issue of drinking water safety?

A Well, first of all, I'd say just think if this assessment work about background levels of hexavalent chromium and vanadium had been done a long time ago and has resolved the issue when it should have been done. Because when you have groundwater contamination from metals, yes, it’s very important to determine the background concentrations, and so if you go sample water supply wells, you need to find out if they’re consistent with background or not. But that hadn’t been done yet. And so my belief is if this study or any other study that Duke Energy could have certainly implemented had been done before then, it would have resolved the issue and this wouldn’t have been a problem. But it’s unheard of to have to connect people that don’t have contaminated wells, allegedly from your facility, to municipal water or some sort of supplied water.

Q Well, my question to you, Mr. Hart, was if it’s unheard of to be required to connect to municipal water supply wells that are not contaminated or households that are serviced by wells which, in fact, are not contaminated, how do you know that the General Assembly didn’t mandate that because it was fed up with its own agencies of the State government as opposed to anything relating to DEC?

A Well, what they’re fighting about is whether that DEC -- this is associated with the DEC coal ash problem. So if that had been determined long ago and, for example, at the Allen plant we knew as -- in 2004 that there was groundwater impacts, we knew as early as 1984 that there was groundwater impacts there, and so if the things that had been required to be done under the 2L rules which determine the extent, reliably establish background concentrations, come up with a plan to mitigate the sources, come up with a corrective action plan, do adequate receptor surveys, all that could have been avoided if it was done proactively and not reactively to the Dan River spill.

Q Well, Mr. Hart, if you go back to page 176 of your deposition, Exhibit 1 --

A Okay.

Q -- where you indicate on line 19 a lack of confidence in the DEQ. Do you see that?

A Yes.

Q I'm wondering if that was just a Freudian slip. You actually -- or not a Freudian slip -- you actually meant to say DEQ as opposed to DEC in connection with your answer to my question that you answered on that page and in that paragraph.

A No. I meant DEC, and so I think the court reporter got it wrong. I don't think it was a Freudian slip.

Q Well, actually, I think if you go back and listen to the tape, you said DEQ, but perhaps you didn't mean it.

A Well, it's very easy to run those two together.

MR. MEHTA: Madam Chair, I don't have any further questions for Mr. Hart at this time.

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

(No response.)

CHAIR MITCHELL: All right. Redirect for the witness?

MS. TOWNSEND: Thank you. Just a few questions.

REDIRECT EXAMINATION BY MS. TOWNSEND:

Q First of all, Mr. Hart, I wanted to ask you if you had reviewed the rebuttal testimony of Mr. Lioy, L-I-O-Y -- I'm not quite sure how to pronounce that -- who filed his testimony specifically as a result of your supplemental testimony. Have you had a chance to review that?

A Yes, I did. Yes.

Q And can you give us your opinion of his testimony regarding his remarks about your calculations?

A Well, yeah. In my opinion, it's -- I certainly understand what he was getting at, and I think the confusion is my use of the term time value of money which probably isn't a correct accounting term. And, again, I'm not an accountant, but what I was trying to do and what I did was just determine the increase in cost from different periods of time from inflation or the work that's being done now if it had been started or initiated sooner. And so I understand that maybe time value of money isn't the right term from an accounting standpoint, but maybe it's de-escalation from inflation, I'm not sure what it is, but that’s how I read it.

Q Thank you. Also, just to clarify, Mr. Mehta asked you a question about whether or not your decision to add other years was because your client told you to do so. Wasn’t, in fact, what happened was that we asked what your testimony would support, and that is when you decided to add the earlier years?

MR. MEHTA: Objection, Madam Chair. Leading.

CHAIR MITCHELL: All right. Restate the question, Ms. Townsend.

MS. TOWNSEND: All right.

Q Again, just to clarify, Mr. Mehta asked you if the reason you used additional years of calculation was based on your client’s request; is that correct?

A That’s what he asked me, yes.

Q All right. And is that, in fact, the totality of what happened during our discussions?

A Well, we did discuss other dates after we discussed the original, which was the early 2000s to 2009/’10, and, you know, I suggested some other time frames that might also -- well, that would also potentially be appropriate, including some of the early -- late ‘80s and then also the mid ‘90s, and I gave some examples of why I chose that in my test--- why I chose those dates in my testimony.

Q Thank you. And one final question. In your 30 years of experience you've done a lot of -- you've been a witness for many people. Have you ever done similar calculations in other cases?

A Well, yes. I mean, I certainly have looked at the cost of inflation and what that will do to the cost over time and the increase in cost and that -- what that does to the cost, because it will increase the cost over time. Of course, this was a little unique because we're going backwards in time, but nevertheless, if I was -- I think I could say just Ms. Bednarcik yesterday said she could transport herself to 1981 to talk about what a plant manager would do from reading a coal ash publication from the EPA, I think in the same way I was trying to say, well, if I'm here in 2003 and I've got to address these environmental liabilities, what's that going to cost me, and if I wait, how much more is it going to cost me in the future? So it's similar kind of, you know, in my opinion, similar to what I've done before.

Q Thank you.

MS. TOWNSEND: No further questions.

CHAIR MITCHELL: All right. Questions from the

Commissioners, beginning with Commissioner Brown-Bland?

COMMISSIONER BROWN-BLAND: No questions at this time.

CHAIR MITCHELL: Okay. Commissioner Gray?

COMMISSIONER GRAY: No questions at this time.

CHAIR MITCHELL: Commissioner Clodfelter?

COMMISSIONER CLODFELTER: Nothing from me.

CHAIR MITCHELL: All right. Commissioner Duffley?

COMMISSIONER DUFFLEY: I did have one question. It's just a clarification question.

EXAMINATION BY COMMISSIONER DUFFLEY:

Q So we heard, and I apologize to the witness, witness Bednarcik -- hopefully I have her name correct -- that she stated that there were no water supply wells that were impacted. And if you could turn to page 75 of your testimony, please.

A Okay.

Q And if you could go to line 17 through 19, and you state "A receptor survey conducted in 2014 after the Dan River release indicated a number of water supply wells in the adjacent residential area were impacted." So are you saying that because of -- do you have any other impacted wells or know of any other impacted wells besides these wells with respect to the Dan River release?

A I'm sorry. I lost where you were. What page were you on?

Q Seventy-five (75).

A So this is -- I'm talking about Allen plant here.

Q Right. And so as I understand your testimony, you're stating after that release that occurred, because the pipe broke, correct, that there were a number of water supply wells that were impacted. And so my question is, besides those wells that you say were impacted in a receptor survey for 2014 related to Dan River, were there any other wells, water supply or -- yeah -- water supply wells that have been impacted?

A So these were near the Allen plant, adjacent to the Allen plant, so the receptor survey was done after the Dan River release, but I am not aware of any others at the DEC facility.

Q Okay. Thank you.

CHAIR MITCHELL: Anything further, Commissioner Duffley?

COMMISSIONER DUFFLEY: Let me see.

Q So on page 12, if you could turn to page 12, I think this is my last question.

A Okay.

Q Okay. If you could -- you have -- read lines 4 through 13, or actually just the first sentence.

A Okay. "DEC's costs are higher today than they would have been had it undertaken reasonable and prudent actions and practices in a timely manner to address storage and disposal of CCR and closure of its coal ash basins before the Dan River spill occurred in 2014."

Q So are you stating that the Company acted imprudently? Is that a conclusion that you're making in this case?

A Yes. It did not -- DEC did not act prudently with regard to how it addressed its knowledge of groundwater contamination associated with its coal ash basins.

Q But just hypothetically, if one were to say that they did act imprudently, my question is can you have -- maybe not have made the perfect 100 percent perfect decision and not be imprudent?

A I'm not sure I understand your question. I mean, there is a process, in my opinion, in how you deal with groundwater contamination issues that's laid out in the 2L rules, and so following that is the prudent course of action, and so that includes defining the extent of the contamination through additional wells, determining the horizontal and vertical extent, determining what the sources are, determining if there are receptors in the area, and then mitigating those risks and inputs to the groundwater system by doing some sort of corrective action, and then ultimately also remediating the groundwater.

And so that's just kind of -- in my opinion, that is the standard of practice as laid out in the 2L rules. To me, that would be the prudent course of action. And, you know, the longer you wait, the longer you delay implementation of those, it's going to cost more, the groundwater contamination can travel further, you're adding mass to the groundwater system, so it will take longer and could be more expensive to remediate.

Q And so the contaminants that are in the coal ash you talk about that travel further, I'm thinking of MTBE. You know, that was a gasoline additive that was removed because it was a leader, a plume leader, right, and it traveled far distances. I'm just interested, what is the distance that these types of contaminants can migrate?

A Well, so most of the metals are not -- don't travel very far because a lot of times they are converted. So, for example, the coal ash basins, as I mentioned before, have very low -- create a very low oxygenated environment in the groundwater which liberates the metals, but as they move downgradient, those conditions may change. The one that is not consistent with it is boron. Boron is not well absorbed onto any particles, and so it usually -- that and chloride -- if you've got chloride issues -- are the ones that can go the furthest. So it really depends on how far they can go. They could go thousands of feet, but it really depends on the distance between the source and a water body, because most groundwater will discharge to the surface water.

Q Okay. So, but from a groundwater perspective, you're saying thousands of feet; is that accurate?

A Well, something like boron could travel that far, and certainly I think in some of the -- at least the DE--- I know some of the Progress sites I've seen boron go that far.

Q And -- sorry. Did not mean to interrupt.

A Well, movement of something like iron and manganese can also go quite a long distance if the conditions that cause the, for example, the low-dissolved oxygen conditions oftentimes persist downgradient for a long distance because the oxygen that's recharging groundwater has all been consumed by the basin itself.

But, I mean, so I don't know -- I didn't really measure distances of groundwater contamination, necessarily, for all the facilities. I was looking at whether they were outside the compliance boundary in a lot of cases, which is 500 feet, so we certainly had in a lot of cases groundwater contamination above 2L standards outside the compliance boundary which would have been at 500 feet or the property line. And that could have been often iron, manganese. It could have also included things like cobalt and arsenic and vanadium in some cases.

Q Okay. Thank you. In answering one of Mr. Mehta's questions, you stated "Requiring water supply well connections is an extraordinary event, especially within a half mile." What did you mean when you said especially within the half mile?

A Well, so normally if you -- so that half mile is -- so groundwater is going to start, and it flows in a specific direction. So the half mile, first of all, that's regardless of whether the well was upgradient or downgradient of the facility. So in some cases they were connecting people that were a half mile away that had no reasonable potential to be impacted from the site. So if they were downgradient and within, you know, I would say, roughly 1,500 feet or so, that might be reasonable. But usually people aren't connected to alternate water supplies unless their well is impacted or it has an imminent threat of being impacted. So a well that's half mile upgradient wouldn't fall into either one of those categories. So that's why I'm saying it's extraordinary that you would just draw a circle around the facility and say this is where you need connect people to municipal water, because it doesn't make much sense from a scientific perspective, which is what we usually look at when we're looking at -- if we need to connect people to well water, those are the kind of things that we'll look at and work with the Agency on. First, are they impacted and, second, do they have the potential to be affected?

Q Okay. And let me make sure that I heard your answer correctly. The downgradient wells, you're saying that a well within 1,500 -- what did you -- what denomination did you use?

A Feet.

Q Yeah -- 1,500 feet could potentially be impacted, but you don't think that a receptor within a half mile of that plume would be affected; is that what I heard?

A Well, I would say in general, but, you know, every site is a little bit different. So, I mean, you could have a well that's a half mile downgradient of an ash basin or another source and have the potential to be impacted. That would be unusual because in most cases you have a stream within a half mile. And so generally groundwater doesn't cross a stream, so -- and, of course, a number of these facilities where most of them were adjacent to water bodies, and so in most cases the groundwater contamination traveled to the water body and then discharged to Dan River or Lake Wylie or one of those service water bodies. They didn't tend to get go very far in most cases, although certainly outside the compliance boundaries.

Q Okay. And actually I did have one more question. If you could turn -- and I just would like to get your interpretation. If you could turn to your Exhibit Number 11.

A Okay.

Q So I think Mr. Mehta asked you about this as well, this letter. And so I'm just trying to understand your testimony because I do understand that 2L requires certain requirements, but -- and you stated that, you know, that your testimony is Duke did not meet the letter of the law requirements of 2L, but I guess in looking at this December 18th, 2009 letter, if you look at that last paragraph.

A Okay.

Q So it says in light of concerns brought up by your staff in past discussions about combining the compliance boundaries of adjacent, you know, permitted activities is going to be encouraged, and then the letter goes on site by site to make recommendations about monitoring wells. So wasn't Duke working with the regulators on these monitoring wells?

A Well, starting in 2010, I would say they did start working with them with regard to looking at where to put additional wells. So before that, with regards for like the USWAG sampling that was started, and it was started as a voluntary program, but it was a commitment from the Utilities group that if they found contamination, they would implement corrective actions, and so they did do some of that monitoring and they just sent -- as far as I can tell from the information we have, they just sent the data to DEQ without any information about whether it was above or below the 2L standards or where the wells were in relation to the compliance boundary with a background or downgradient, and then implied in their cover letters that the data were consistent with background, which wasn't true, in my opinion.

And so it wasn't until DEQ looked at all this information they had been receiving from DEC in 2009 and asked for, hey, we've been getting all this data from you from this USWAG program; we need to find out more information. We need maps. We need -- you need to put in some more wells. We need to know where the compliance boundaries are. You need to analyze regardless of constituents. And that's when they started to kind of at least get DEQ's input or address it with DEQ, is around the 2010 time frame. And then they did put in some more wells, which showed -- at the compliance boundary which showed even greater -- I mean, did show that there was issues at the compliance boundaries, and then really didn't do anything until the Dan River spill in 2014, and that's when they, you know, were required to start doing full investigations of the sites. But certainly the 2L rules were clear, that if you have groundwater exceedances and violations, that this is the process you should take.

Q Okay. Thank you, Mr. Hart.

COMMISSIONER DUFFLEY: I have nothing further.

THE WITNESS: Thank you.

CHAIR MITCHELL: All right. Mr. Hart, I'm going to follow up on Commissioner Duffley's --

COMMISSIONER HUGHES: I'm sorry. Did you call my name? I'm sorry.

CHAIR MITCHELL: No, not yet. I was going to ask Mr. Hart a question.

COMMISSIONER HUGHES: Okay.

CHAIR MITCHELL: And then I'll -- and then I'll call -- then I'll call on the remaining Commissioners.

EXAMINATION BY CHAIR MITCHELL:

Q I just want to follow up a question that Commissioner Duffley asked, Mr. Hart. And you've explained sort of the USWAG voluntary activities that the Company was undertaking at its sites. Seems like that was kind of the early -- early '80s time period -- I mean, I'm sorry -- the early 2000s. And then I think your testimony, and correct me if I'm wrong -- this is what I've heard just now in response to Commissioner Duffley -- is that in the 2009/2010 time frame, as evidenced by that letter that you attached as Exhibit 11 to your testimony, DEQ initiated discussion with the

Companies, indicating that some additional investigative activities needed to be undertaken. So when should -- help me understand the point in time at which the Company should have done more, because from what I can tell, it was involved with DEQ beginning in 2009 and it was doing the voluntary USWAG work prior to then, so just -- I just want you to sort of nail it down for me.

A Well, yeah, and I think it depends on the facility. I think, you know, where they've been doing groundwater monitoring at Dan River and -- let me get it right -- well, in H.S. Lee, where they had groundwater monitoring dating back to 1993, there were certainly indications of impacts at those facilities. And so I think at least by the, you know, late '90s to early 2000s, after they obviously wouldn't, in most cases, act on data if you only had one or two sampling events; they usually developed some data set initially, and then start investigating the horizontal and vertical extent and determining how we're going to deal with these groundwater contamination issues.

You know, the other facilities -- well, other than Allen, which had some monitoring going on in the 1980s, although I think, you know, you could certainly make a case that at Allen, you know, as early as the early 1980s they should have been doing something to address the groundwater contamination. That might be a little aggressive, so, you know, I think from there most places, you know, once they did the USWAG monitoring, which ranged anywhere at Allen from 2004 until Riverbend in 2008, and also Cliffside, you know, which showed very significant groundwater contamination issues, at least within the compliance boundary, that should have been the trigger to go to DEQ, tell them the issues we have, and start the process of finding the extent of contamination, and then addressing how we -- how are we going to address these issues.

We know in 2003 from Duke documents that they were certainly aware of the changing regulatory landscape and that they might not be able to use coal ash basins because of the groundwater contamination concerns from their 10-year report in 2003. In 2007 they talk about, you know, certainly the possibility that they won't have -- they won't be able to use these basins forever. And so, you know, other than Dan River and H.S. (sic) Lee, I would, you know, generally when they had done the USWAG monitoring and had a few years' worth of data, they -- it should have triggered a substantial investigation and evaluation of how we're going to address this problem, which potentially included dry ash conversions to eliminate the source, getting rid of all the other sources of water that they had conveniently disposed in these basins for long periods of time that really aren’t coal ash related. In fact, there was some question about whether they were hazardous waste, but they were covered under the Bevill Amendment and so were not. And so I would -- hope that answers your question.

Q It does. Thank you.

CHAIR MITCHELL: All right. Commissioner Hughes?

COMMISSIONER HUGHES: Yes. Thank you.

EXAMINATION BY COMMISSIONER HUGHES:

Q I had a question or two about the economic impact analysis that you did. And if I understand it, you have two ways of talking about the customer impact. You have itemized a number of things that you postulate that would have been cheaper if Duke had done it earlier, and then you have this separate time value of money calculation. I think I understand the first part, so what you’re saying is that it wouldn’t have cost three hundred and for--- if you use your numbers, it wouldn't have cost $341 million. It probably would have cost less. And if you move that all the way back into 1989 dollars, then it would have been less than 175 million. So I think I -- is that correct to -- if you moved it back --

A Yes.

Q -- to $189 (sic) -- you don't give a number, but it could have been 150, 125, 100 million, something like that, back in -- is that -- am I following that part of your analysis?

A Yes. That's correct. Yes.

Q So I understand that. The time value of money I'm having a harder time with for some other reason --

A So that is the time value of money.

Q Pardon me?

A That is what I call the "time value of money," quote, unquote.

Q Well, I understand -- I understand the difference between something that would have cost 125 million in 1989 dollars versus 170 million, because from a Duke customer impact, that's -- the Duke customer impact is -- was pretty significant. Just to use your approach, would you say that customers would have less of an impact if something had cost $300 million in 1989 to do versus three hundred and for--- let's say 325 -- if something cost $325 million in 1989 dollars, but move --

if you move forward and it costs $341 -- $341 million in today's dollars, would you say that the customers would have been better off with a $325 million expenditure way back in 1989? I mean, because that's a, you know, that's still like a $16 million savings from your approach.

A Well, I mean, if you had 1989 dollars, 325 million, I don't know. I don't know exactly how rates are made. I can say that the people that were benefiting from the power at the time that were using the power that was obtained from coal-fired power plants would have benefited much more than somebody today where that facility is shut down.

And so if you have a customer today that is paying for coal ash remediation and they got no benefit from it, certainly, the customer in the past would have been much more benefited than the customer today, regardless of price. I don't know if I answered your question, but --

Q Well, I -- it's a different -- it's a different answer.

A Yeah.

Q I'm really concerned about the time value analysis that you presented because it just seems like the customer base would be better off today spending 341 million than spending 325 million in 1989, and the way you presented it, it seems to be saying that any difference between comparing 1989 dollars and 2018 dollars, any difference is beneficial to the customers, and I don’t see that in the way that you would look at the value of money.

A Well, yeah. I think if it’s 325 million, no, because obviously 1989 dollars, 325 million is going to be more than 342 million today, right, but anything less than 171 million, which was -- which was potentially possible for coal ash remediation back in 1989 because you had other options of dealing with the coal, you wouldn’t have had a beneficiation. It wouldn’t have occurred because it wasn’t a viable technology. It’s by far the most expensive. In fact, Duke’s own studies show that it’s by far the most expensive recycling process, and you have to build a $100 million plant and operate it for 20 years, and so you wouldn’t have something like that. And then you also, you know, would have potentially had the option to close a lot of these basins in place rather than fully excavate them in place. And certainly, that was going on in some facilities in North Carolina, not necessarily power plants, but there were people that were doing that, and they haven’t had to excavate them, you know, since.

So I think there was much lower cost options available in 1989 than there were today, and that's why when I did my analysis, I said, well, absolutely the most expensive options are being used today, and so that's why I felt it was appropriate to scale those back to 1989 dollars. I understand what you're saying, but to me it couldn't have cost any more than 171 million, or it should have cost less than that because there were much more lower cost alternatives available than have been selected now.

Q Right. I understand. Anything less than $171 million back in 1989 is clearly a benefit to the customers.

A Right.

Q Okay. Thank you.

A Yes. Thank you.

CHAIR MITCHELL: All right. Commissioner McKissick?

COMMISSIONER McKISSICK: I don't have any questions at this time. Thank you.

CHAIR MITCHELL: All right. At this time we are going to take a break for the court reporter. Let's go off the record. We'll go back on at 3:50.

(Recess taken from 3:40 p.m. to 3:50 p.m.)

CHAIR MITCHELL: All right. We will proceed with questions on Commissioners' questions. Let's go back on the record, please. All right. Questions on Commissioners' questions?

MR. MEHTA: DEC has no questions, Chair Mitchell.

CHAIR MITCHELL: All right. Thank you, Mr. Mehta.

CHAIR MITCHELL: Any questions from the Public Staff?

MS. LUHR: Nothing from the Public Staff.

CHAIR MITCHELL: Other intervening parties?

(No response.)

CHAIR MITCHELL: All right. Attorney General's Office?

MS. TOWNSEND: Yes. Just a couple questions.

EXAMINATION BY MS. TOWNSEND:

Q Mr. Hart, Commissioner Duffley asked you a question regarding your Exhibit Number 11, if you could pull that back up.

A Yes. I have it up.

Q All right. In the last sentence, or last paragraph which the two of you discussed, it said, "In light of concerns brought up by your staff in past discussions, combining compliance boundaries for adjacent DWQ permitted activities will be allowed, as well as encouraged." There was some inference based on that language that DEQ and DEC were actively involved in discussions; is that correct?

A Yes, yes.

Q All right. If we go to the first paragraph of that letter, the second sentence says "Based on the review of the submitted data, specific recommendations and additional information requests on a site-by-site basis are attached," correct?

A Yes, yes.

Q All right. And if we go to the first attachment, which would be the third page of that exhibit, which refers to Allen Steam Station, Attachment 1. Do you see that?

A Yes, yes.

Q All right. And under Hydrogeology, the very first thing they say is that based on the supplied maps, monitoring wells, and they list quite a few, are located inside the review/compliance boundaries, and it says these wells are not suitable for determining compliance; is that correct?

A That's correct, yes.

Q So prior to this time, there were no -- these wells, at least, were not at the compliance boundary; is that correct?

A At this time, no -- well, yes, those wells were not at the compliance boundary. I believe the Allen, though, was the well that was installed at the compliance boundary in 2004 which showed impacts, but, you know, what, DEQ is saying is we need to install more wells at the compliance boundaries --

Q Okay. The third one?

A -- on these particular wells, yes.

Q Okay. In fact, the third bullet talks about based upon a clarification of the 2L rules, monitoring wells are now required to be located at the compliance boundary, so that requirement was established, evidently, around the 2009 date of this letter; is that correct?

MR. MEHTA: Objection. Leading.

CHAIR MITCHELL: All right. Ms. Townsend, restate the question.

Q What I'm asking is based on the third bullet, what is your interpretation of what was occurring at that time in 2009?

A In 2009, DEQ was asking that monitoring wells

-- well, that they were required to be installed at the compliance boundary. In the past, for the most part, wells had not been installed at the compliance boundary, and DEQ is saying the only way -- the way we determine compliance with the 2L standards is to put wells in at the compliance boundary since you have indications of wells which are inside the compliance boundary that there are groundwater contamination issues.

Q And if we go to bullet 5, does that deal with the last paragraph on page 1 of the letter?

A Yes. I think what they're -- yeah. So I think what that last -- well, I know what that last paragraph in the letter is doing, that I was asked about previously, is about combining -- if there were adjacent coal ash basins, could they combine the compliance boundaries around them so they basically only had one compliance boundary and not a compliance boundary around each facility. In other words, you don't, you know, have a compliance boundary that might go through another ash basin. They can combine them all into one big compliance boundary for all the permitted units.

Q All right. If you would, if you look at each of the other attachments for each of the various sites, do you find the same reference to the fact that there are wells that they consider not suitable for determining compliance?

A I believe that is the case, yes. I will check.

MS. TOWNSEND: No further questions. Thank you.

CHAIR MITCHELL: All right. I'll entertain motions at this time.

MR. MEHTA: Chair Mitchell, I would move the introduction into evidence of DEC Hart Cross Examination Exhibits 1 through 9.

CHAIR MITCHELL: All right. Hearing no objection to your motion, Mr. Mehta, it will be allowed.

MR. MEHTA: Thank you, Chair Mitchell.

(Whereupon, DEC Hart Cross Examination Exhibit Numbers 1-9 were admitted into evidence.)

CHAIR MITCHELL: All right. Mr. Hart, you may step down. Thank you very much for your testimony today, sir.

MR. HART: Thank you.

MS. TOWNSEND: And Chair Mitchell, Ms. Townsend. I would like to put in the record Mr. Hart's exhibits -- premarked Exhibits 1 -- there were 62 exhibits.

CHAIR MITCHELL: All right. Hearing no objection to your motion, Ms. Townsend, Hart's -- Exhibits 1 through 62 to Witness Hart's prefiled testimony shall be allowed into evidence.

(Whereupon, Hart Exhibits 1-55 were admitted into evidence. Confidential Hart Exhibits 16-20 and 31-32 were filed under seal.)

CHAIR MITCHELL: All right. Any additional matters to consider?

(No response.)

(Reporter's Note: With regard to Chair Mitchell's statement in Volume 16, page 314, lines 1-9, the following prefiled testimony and exhibits were inadvertently omitted.)

(Whereupon, the prefiled testimony, Appendix A, supplemental testimony, and testimony supporting second partial stipulation of J. Randall Wooldridge was copied into the record as if given orally from the stand.)

(Whereupon, Exhibits JW-1 through JRw-10, and Exhibit JRW-1 filed with supplemental testimony were admitted into evidence.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1213	)	
	)	
In the Matter of	)	
Application of Duke Energy Carolinas,	)	
LLC, for Adjustment of Rates and	)	TESTIMONY OF
Charges Applicable to Electric Utility	)	J. RANDALL WOOLRIDGE
Service in North Carolina	)	FOR THE PUBLIC STAFF –
	)	NORTH CAROLINA
	)	UTILITIES COMMISSION
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 Utility	)	
Service in North Carolina	)	

Contents

Q. PLEASE STATE YOUR FULL NAME, ADDRESS, AND OCCUPATION.

A. My name is J. Randall Woolridge, and my business address is 120 Haymaker Circle, State College, PA 16801. I am a Professor of Finance and the Goldman, Sachs & Co. and Frank P. Smeal Endowed University Fellow in Business Administration at the University Park Campus of the Pennsylvania State University. I am also the Director of the Smeal College Trading Room and President of the Nittany Lion Fund, LLC. A summary of my educational background, research, and related business experience is provided in Appendix A.

I. SUBJECT OF TESTIMONY AND SUMMARY OF RECOMMENDATIONS

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

A. I have been asked by the Public Staff - North Carolina Utilities Commission (Public Staff) to provide an overall fair rate of return or cost of capital recommendation for Duke Energy Carolinas, LLC (DEC or Company).[1]

[1] In my testimony, I use the terms "rate of return" and "cost of capital" interchangeably. This is because the required rate of return of investors on a company's capital is the cost of capital.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. First, I summarize my cost of capital recommendation for the Company, and review my primary areas of contention with the Company's position. Second, I discuss the proxy groups that I have used to estimate an equity cost rate for DEC. Third, I review the Company's proposed capital structure and debt cost rate. Fourth, I explain my calculation of my estimate of the appropriate equity cost rate for the Company. Finally, I critique DEC witness Hevert's rate of return analysis and testimony. Appendix A is a summary of my education and business experience.

A. Overview

Q. WHAT IS A UTILITY'S ROE INTENDED TO REFLECT?

A. An ROE is most simply described as the allowed rate of profit for a regulated company. In a competitive market, a company's profit level is determined by a variety of factors, including the state of the economy, the degree of competition a company faces, the ease of entry into its markets, the existence of substitute or complementary products and services, the company's cost structure, the impact of technological changes, and the supply and demand for its services and products. For a regulated monopoly, the regulator determines the level of profit available to the public utility. The United States Supreme Court established the guiding principles for determining an appropriate level of profitability for regulated public utilities in two cases: (1) *Hope*[2] and (2) *Bluefield*.[3] In those cases, the Court recognized that the fair rate of return on equity should be: (1) comparable to returns investors expect to earn on other investments of similar risk; (2) sufficient to assure confidence in the company's financial integrity; and (3) adequate to maintain and support the company's credit and to attract capital.

Thus, calculating the appropriate ROE for a regulated utility requires determining the market-based cost of capital. The market-based cost of capital for a regulated firm represents the return investors could expect from other investments, while assuming no more and no less risk. The purpose of all of the economic models and formulas in cost of capital testimony (including those presented later in my testimony) is to estimate, using market data of similar-risk firms, the rate of return on equity investors require for that risk-class of firms in order to set an appropriate ROE for a regulated firm.

B. Summary of Positions

Q. PLEASE REVIEW THE COMPANY'S PROPOSED RATE OF RETURN.

[2] *Federal Power Commission v. Hope Natural Gas Co*., 320 U.S. 591 (1944) (*Hope*).

[3] *Bluefield Water Works and Improvement Co. v. Public Service Commission of West Virginia*, 262 U.S. 679 (1923) (*Bluefield*).

A. The Company has proposed use of a capital structure of 47.00% long-term debt and 53.00% common equity and a long-term debt cost rate of 4.51% as set out in the testimony of Company witness Newlin. Company witness Hevert has recommended a common equity cost rate of 10.50%. Thus, the Company's overall proposed rate of return is 7.63%.

Q. HOW HAVE YOU CONDUCTED YOUR RATE OF RETURN STUDIES FOR THE COMPANY?

A. I reviewed the Company's proposed capital structure and overall rate of return or cost of capital. The Company's proposed capital structure has a higher common equity component than the capital structure of its parent, Duke Energy Corporation (Duke Energy), as well as the averages of my proxy group of electric utilities (Electric Proxy Group) and Mr. Hevert's proxy group (Hevert Proxy Group). Therefore, as my primary recommendation, I am proposing a capital structure of 50.0% common equity and 50.0% debt, which is more consistent with the capital structures of comparable electric utility companies. To estimate an equity cost rate for the Company, I have applied the Discounted Cash Flow Model (DCF) and the Capital Asset Pricing Model (CAPM) to the Electric Proxy Group. I have also applied the DCF and CAPM to the Hevert Proxy Group for comparison purposes.

Q. WHAT IS YOUR PRIMARY RATE OF RETURN RECOMMENDATION FOR THE COMPANY?

A. My equity cost rate studies indicate that an appropriate ROE for the Company is in the range of 6.90% and 8.40%. I believe that this range accurately reflects current capital market data and the market cost of equity capital. However, I given that I am recommending a capital structure with a lower common equity ratio and higher financial risk than proposed by the Company, as a primary ROE for DEC, I am recommending 9.0%. Given my recommended capitalization ratios and debt cost rate, my rate of return or cost of capital recommendation for the Company is 6.76% and is summarized in Table 1 and Panel A of Exhibit JRW-1.

Table 1

Public Staff's Primary Rate of Return Recommendation

Capital Source	Capitalization Ratios	Cost Rate	Weighted Cost Rate
Long-Term Debt	50.00%	4.51%	2.26%
Common Equity	50.00%	9.00%	4.50%
Total Capitalization	100.00%		6.76%

Q. ARE YOU ALSO PROVIDING AN ALTERNATIVE RATE OF RETURN RECOMMENDATION FOR THE COMPANY?

A. Yes. My alternative rate of return recommendation uses DEC's recommended capital structure consisting of 47.00% long-term debt and 53.00% common equity. With respect to the ROE, as indicated above, I believe that my equity cost rate range, 6.90% to 8.40%, accurately reflects current capital market data. Capital costs in the U.S. remain low, with low inflation and interest rates and very modest economic growth. To reflect these low capital costs, my alternative ROE recommendation is 8.40%, which is at the high end of my equity cost rate range. Given my recommended capitalization ratios and debt capital cost rate, my alternative rate of return or cost of capital recommendation for the Company is 6.57% and is summarized in Table 2 and Panel B of Exhibit JRW-1.

Table 2
Public Staff's Alternative Rate of Return Recommendation

Capital Source	Capitalization Ratios	Cost Rate	Weighted Cost Rate
Long-Term Debt	47.00%	4.51%	2.12%
Common Equity	53.00%	8.40%	4.45%
Total Capitalization	100.00%		6.57%

C. Primary Rate of Return on Equity Issues

Q. PLEASE PROVIDE AN OVERVIEW OF THE PRIMARY ISSUES REGARDING RATE OF RETURN IN THIS PROCEEDING.

A. The primary issues related to the Company's rate of return include the following:

Capital Structure – The Company has proposed a capital structure consisting of 47.00% long-term debt and 53.00% common equity. The Company's proposed capital structure has a higher common equity ratio than the average of the Electric and Hevert Proxy Groups. In my primary rate of return recommendation, I recommend adjusting DEC's proposed capital structure to use a common equity component of 50 percent, as that is more in line with the capital structures of the utilities in both proxy groups as well as DEC's parent, Duke Energy. In my alternative rate of return recommendation, I use DEC's proposed capital structure, but I then employ a lower ROE to reflect the high common equity component in the capital structure and lower financial risk of the Company's proposed capitalization.

<u>Capital Market Conditions</u> – Mr. Hevert's analyses, ROE results, and recommendations reflect an assumption of higher interest rates and capital costs that is inconsistent with current trends. Despite the Federal Reserve's moves to increase the federal funds rate over the 2015-18 time period, interest rates and capital costs remained at low levels. In 2019, interest rates fell dramatically with moderate economic growth and low inflation. The Federal Reserve cut the federal fund rate three times (July, September, and October) and the 30-year yield traded at all-time low levels.

<u>The Company's ROE Analysis is Out-of-Date</u> - The Company's ROE study was prepared in June, 2019, about eight months ago. Since that time, the Federal Reserve has cut the federal funds rate three

times and the 30-year Treasury rate has fallen over seventy basis points. Capital costs are much lower now, not only than when the Company's ROE study was prepared, but also than when the request to increase rates was filed.

DEC's Investment Risk is Below the Averages of the Two Proxy Groups – Mr. Hevert cites the Company's capital expenditures and North Carolina's regulatory environment to imply that DEC is riskier than his proxy group. However, his assessment of DEC's risk is erroneous. The assessment of capital expenditures is part of the credit rating process, and DEC's Standard & Poor's (S&P's) and Moody's credit ratings suggest that the Company's investment risk is below the averages of the proxy groups.

Disconnect Between Mr. Hevert's Equity Cost Rate Studies and his 10.50% ROE Recommendation – There is a disconnect between Mr. Hevert's equity cost rate results and his 10.50% ROE recommendation. Simply stated, the vast majority of his equity cost rate results point to a lower ROE. In fact, the only results that point to an ROE as high as 10.50% are some of his CAPM/Empirical CAPM (ECAPM) results, which, as I explain later in my testimony, are derived from seriously flawed analyses. As a result, Mr. Hevert's ROE recommendation is based on: (1) the results of only one model (the CAPM); and, even more narrowly, (2) primarily *Value Line* data.

Otherwise, Mr. Hevert provides no other equity cost rate studies that support his 10.50% ROE recommendation.

DCF Equity Cost Rate - The DCF Equity Cost Rate is estimated by summing the stock's dividend yield and investors' expected long-run growth rate in dividends paid per share. I have three central issues regarding Mr. Hevert's DCF analysis: (1) Mr. Hevert has given very little weight to his constant-growth DCF results in determining his recommended ROE; (2) he has claimed that the DCF results underestimate the market-determined cost of equity capital due to high utility stock valuations and low dividend yields; and (3) he relies exclusively on the overly optimistic and upwardly biased EPS growth rate forecasts of Wall Street analysts and *Value Line*. By comparison, my DCF growth rate is supported by 13 growth rate measures including historical and projected growth rate measures and my evaluation of growth in dividends, book value, and earnings per share of proxy group companies.

CAPM Approach - The CAPM approach requires an estimate of the risk-free interest rate, the beta, and the market or equity risk premium. There are two primary issues with Mr. Hevert's CAPM analyses: (1) he has employed an ad hoc version of the CAPM, the ECAPM, which is a model untested in academic and profession research, and that makes inappropriate adjustments to the risk-free rate and the market risk premium and; and (2) his market risk premiums of 12.25% and 12.15% are excessive and do not reflect current market fundamentals. Mr. Hevert has employed analysts' three-to-five-year growth-rate projections for EPS to compute an expected market return and market risk premium. These EPS growth-rate projections and the resulting expected market returns and market risk premiums include highly unrealistic assumptions regarding future economic and earnings growth and stock returns.

Alternative Risk Premium Model - Mr. Hevert estimates an equity cost rate using an alternative risk premium model which he calls the Bond Yield Risk Premium (BYRP) approach. The risk premium in his BYRP method is based on the historical relationship between the yields on long-term Treasury yields and authorized ROEs for electric utility companies. There are several issues with this approach including: (1) it is a gauge of commission behavior and not investor behavior; (2) Mr. Hevert's methodology produces an inflated measure of the risk premium he uses historical authorized ROEs and Treasury yields, and applies the resulting risk premium to projected Treasury yields; and (3) the risk premium is inflated as a measure of investor's required risk premium because electric utility companies have been selling at market-to-book ratios in excess of 1.0. This indicates that the authorized rates of return have been greater than the return that investors require.

Expected Earnings Approach - Mr. Hevert also uses the Expected Earnings approach to corroborate his recommended equity cost range for the Company. Mr. Hevert computes the expected ROE as forecasted by *Value Line* for his proxy group as well as for *Value Line*'s universe of electric utilities. Mr. Hevert's Expected Earnings approach does not measure the market cost of equity capital, is independent of most cost of capital indicators, and has several other empirical issues. Therefore, the Commission should ignore Mr. Hevert's Expected Earnings approach in determining the appropriate ROE for DEC.

Other Issues - Mr. Hevert also considers two other factors in arriving at his 10.50% ROE recommendation. Mr. Hevert has cited as risk factors North Carolina's Renewable Energy and Energy Efficiency Portfolio Standard (REPS), the Company's high level of capital expenditures, environmental regulations, and the Company's coal-fired and nuclear generation. However, these risk factors are already considered in the credit-rating process used by major rating agencies. As I noted above, DEC's investment risk as measured by S&P and Moody's is below the average of the proxy groups. Second, Mr. Hevert also considers flotation costs in making his ROE recommendation of 10.50%. However, he has not identified any flotation costs for DEC.[4]

North Carolina Economic Conditions – Mr. Hevert evaluates a number of factors such as employment and income levels and comes to the conclusion that DEC's proposed ROE of 10.50% is fair and reasonable to DEC, its shareholders, and its customers in light of the effect of those changing economic conditions. While I agree economic conditions have improved in North Carolina, the improvements do not necessarily justify such a high rate of return and ROE. Specifically, I highlight the following: (1) DEC's ROE request of 10.50% is almost 100 basis points above the average authorized ROEs for electric utilities over the 2018-19 time period; (2) while the unemployment rates in North Carolina and DEC's service territory have fallen by two-thirds since their peaks in the 2009-2010 period, they are both above the national average of 3.90%; and (3) while North Carolina's residential electric rates are below the national average, North Carolina's median household income is more than 10% below the U.S. norm.

[4] In NC, flotation costs cannot lawfully be recovered when the Company does not expect to issue stock in the near future. Utilities Com. v. Public Staff, 331 N.C. 215; 415 S.E.2d 354 (1992).

II. CAPITAL MARKET CONDITIONS AND AUTHORIZED ROES

Q. PLEASE REVIEW THE FEDERAL RESERVE'S DECISIONS TO RAISE THE FEDERAL FUNDS RATE IN RECENT YEARS.

A. On December 16, 2015, the Federal Reserve increased its target rate for federal funds from 0.25 to 0.50 percent.[5] This increase came after the rate was kept in the 0.00 to 0.25 percent range for over five years in order to spur economic growth in the wake of the financial crisis associated with the Great Recession. As the economy improved, with lower unemployment, steady but slow Gross Domestic Product (GDP) growth, the Federal Reserve has increased the target federal funds rate on eight additional occasions: December 2016; March, June, and December of 2017; and March, June, September, and December of 2018.

Q. HOW HAVE LONG-TERM RATES RESPONDED TO THE ACTIONS OF THE FEDERAL RESERVE?

A. Figure 1, below, shows the yield on 30-year Treasury bonds over the period of 2015-2019. I have highlighted the dates when the Federal Reserve increased the federal funds rate. The 30-year Treasury yield hit its lowest point in the 2015-2016 timeframe in the summer of 2016 and subsequently increased with improvements in the economy.

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[5] The federal funds rate is set by the Federal Reserve and is the borrowing rate applicable to the most creditworthy financial institutions when they borrow and lend funds <u>overnight</u> to each other.

Financial markets moved significantly in the wake of the results of the presidential election on November 8, 2016. The stock market gained more than 10% and the 30-year Treasury yield increased about 50 basis points to 3.2% by year-end 2016. However, over the past three years, even as the Federal Reserve has increased the federal funds rate, the yield on 30-year bonds remained in the 2.8% to 3.4% range through 2018. These yields peaked at 3.48% in November of 2018, shortly before the December 2018 rate increase by the Federal Reserve.

Q. PLEASE REVIEW LONG-TERM TREASURY YIELDS IN 2019.

A. Despite the Federal Reserve's efforts to stimulate the economy, economic growth and inflation remained low, even with record low unemployment levels. The rate increase in December of 2018 was seen by many as maybe too aggressive.[6] Also, with the imposition of trade tariffs aimed at China, economic growth and inflation in the U.S. remained at low levels. This led the Federal Reserve to cut the federal fund rate to the 2.0%-2.25% range in July of 2019. Thirty-year Treasury yields, which began the year in the 3.0% range, declined significantly in the second quarter and, in August, declined to record lows and even traded below 2.0%. As a result, the Federal Reserve cut the discount rate two more times since the July rate cut

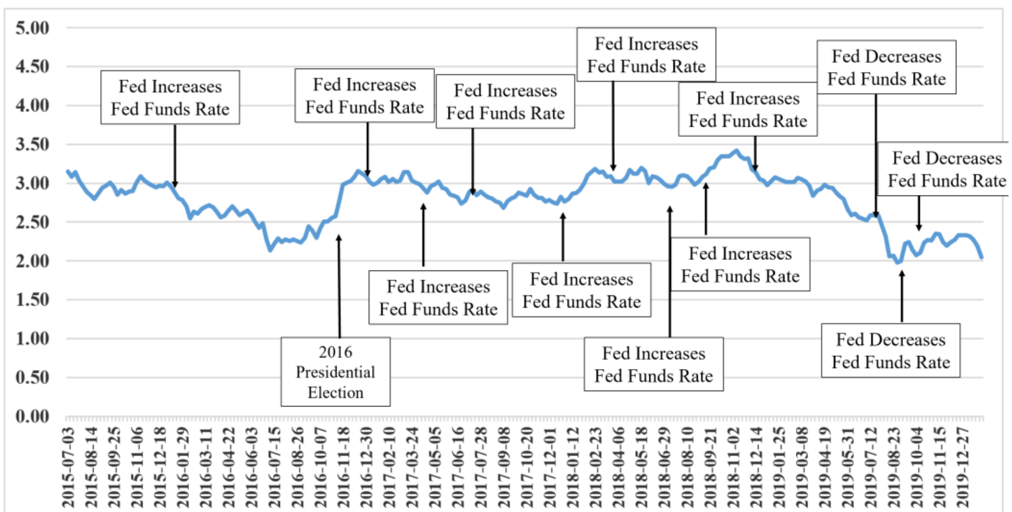
[6] Patti Domm, "Here's What Spooked the Market About the Fed Today,' CNBC Market Insider (December 19, 2018). https://www.cnbc.com/2018/12/19/fed-delivers-.html.

– in September and October. As of year-end, the 30-Treasury yield settled at 2.30% and has declined since that time. The irony is, despite the record low levels in 2019, the 30-year Treasury yield in the U.S. is still somewhat higher than the government bond rates in Japan, the U.K., Germany, and much of the rest of Europe.

Figure 1

Thirty-Year Treasury Yield and Federal Reserve Fed Funds Rate Increases

2015-2020



Q. WHY HAVE LONG-TERM TREASURY YIELDS REMAINED IN THE 2.0%-3.0% RANGE DESPITE THE FEDERAL RESERVE INCREASING THE FEDERAL FUNDS RATE?

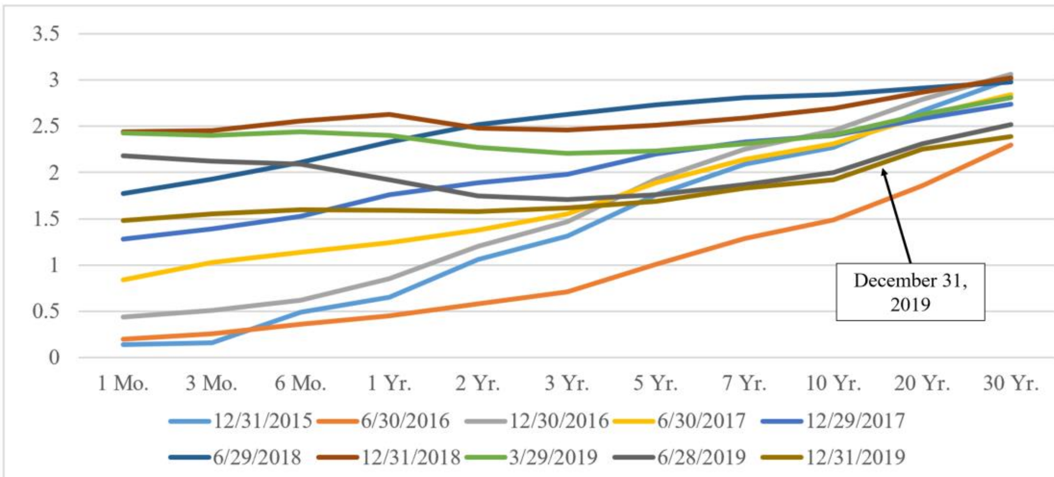
A. While the Federal Reserve can directly affect short-term rates by adjustments to the federal funds rate, long-term rates are primarily driven by expected economic growth and inflation.[7] The relationship between short- and long-term rates is normally evaluated using the yield curve. The yield curve depicts the relationship between the yield-to-maturity and the time-to-maturity for U.S. Treasury bills, notes, and bonds. Figure 2, below, shows the yield curve on a semi-annual basis since the Federal Reserve started increasing the federal funds rate at the end of 2015. It shows that, from the time the Federal Reserve began increasing the federal fund rate in 2015 and until 2018, with the exception of mid-year 2016, the 30-year Treasury yield has remained in the 2.8%-3.4% range over this time frame despite the fact that short-term rates have increased from near 0.0% to about 2.50%. As such, long-term interest rates and capital costs did not increase in any meaningful way even with the Federal Reserve's actions and the increase in short-term rates.

In 2019, with the large decline in long-term Treasury rates, the concern was an "inverted yield curve." An inverted yield curve occurs when short-term Treasury yields are above long-term Treasury yields and is commonly associated with a pending recession. The yield curve did invert a few times in the third quarter of 2019. In Figure

[7] While economic growth picked up in 2018, partly in response to the personal and corporate tax cuts, projected real GDP growth for 2019 and beyond remains in the 2.0% - 2.5% range. In addition, inflation remains low and is also in the 2.0% - 2.5% range.

2, the yield curve for December 31, 2019, is shown in dark orange and is not inverted, due in large part to the three rate cuts.

Figure 2
Semi-Annual Yield Curves
2015-2020



Date Source: https://www.treasury.gov/resource-center/data-chart-center/interest-rates/Pages/TextView.aspx?data=yieldYear&year=2019

Q. WHAT DO YOU RECOMMEND THE COMMISSION DO REGARDING MR. HEVERT'S FORECASTS OF HIGHER INTEREST RATES AND CAPITAL COSTS?

A. I suggest that the Commission disregard Mr. Hevert's forecasts and set an equity cost rate based on current indicators of market-cost rates rather than speculating on the future direction of interest rates.

Economists have been predicting that interest rates would be going up for a decade, and they consistently have been wrong. Several studies in recent years have highlighted the bias in economists' forecasts toward higher interest rates: (1) after the announcement of the end of the Quantitative Easing III (QEIII) program in 2014, all of the economists in Bloomberg's interest rate survey forecasted interest rates would increase in 2014, and 100% of the economists were wrong[8]; (2) *Bloomberg* reported that the Federal Reserve Bank of New York has gone as far as stopping use of interest rate estimates of professional forecasters in its interest rate model[9]; (3) a study entitled "How Interest Rates Keep Making People on Wall Street Look Like Fools," which evaluated economists' forecasts at the beginning of each year of the yield on ten-year Treasury bonds over the last ten years,[10] demonstrated that economists consistently predict that interest rates will go higher, and interest rates have not fulfilled the predictions; and (4) a study that tracked economists' forecasts for the yield on ten-year Treasury bonds on an ongoing basis from 2010 until 2015.[11] The results of this study, which was entitled "Interest Rate Forecasters Are Shockingly Wrong Almost All

[8] Ben Eisen, "Yes, 100% of economists were dead wrong about yields" *Market Watch*, October 22, 2014.https://www.marketwatch.com/story/yes-100-of-economists-were-dead-wrong-about-yields-2014-10-21

[9] Susanne Walker and Liz Capo McCormick, "Unstoppable $100 Trillion Bond Market Renders Models Useless," *Bloomberg.com* (June 2, 2014). http://www.bloomberg.com/news/2014-06-01/the-unstoppable-100-trillion-bond-market-renders-models-useless.html.

[10] Joe Weisenthal, "How Interest Rates Keep Making People on Wall Street Look Like Fools," Bloomberg.com, March 16, 2015. http://www.bloomberg.com/news/articles/2015-03-16/how-interest-rates-keep-making-people-on-wall-street-look-like-fools.

[11] Akin Oyedele, "Interest Rate Forecasters Are Shockingly Wrong Almost All of the Time," *Business Insider*, July 18, 2015. http://www.businessinsider.com/interest-rate-forecasts-are-wrong-most-of-the-time-2015-7.

of the Time," demonstrate how economists continually forecast that interest rates would rise, and they did not.

More recently, in an end-of-decade financial markets review series in the *Wall Street Journal*, Gregory Ip highlighted how economists' forecasts of higher interest rates over the 2010s continued to be erroneous. He provided evidence that economists forecast that short-term and long-term interest rates would go up, and these forecasts were consistently wrong. The article provides insights as to why the longest economic expansion on record that has resulted in a record-breaking stock market run and a 50-year low unemployment rate, was coupled with inflation that consistently ran below the Fed's 2% target and record low interest rates.[12] The bottom line – over the past decade - economists have consistently forecasted higher interest rates, and they have consistently been wrong!

Obviously, investors are aware of the consistently wrong forecasts of higher interest rates, and therefore place little weight on such forecasts. Investors would not be buying long-term Treasury bonds or utility stocks at their current yields if they expected interest rates to suddenly increase, thereby producing higher yields and negative

[12] Gregory Ip, "Economists Got it Wrong for a Decade. They're Trying to Figure Out Why," *Wall Street Journal*, (December 14, 2019). P. C1.

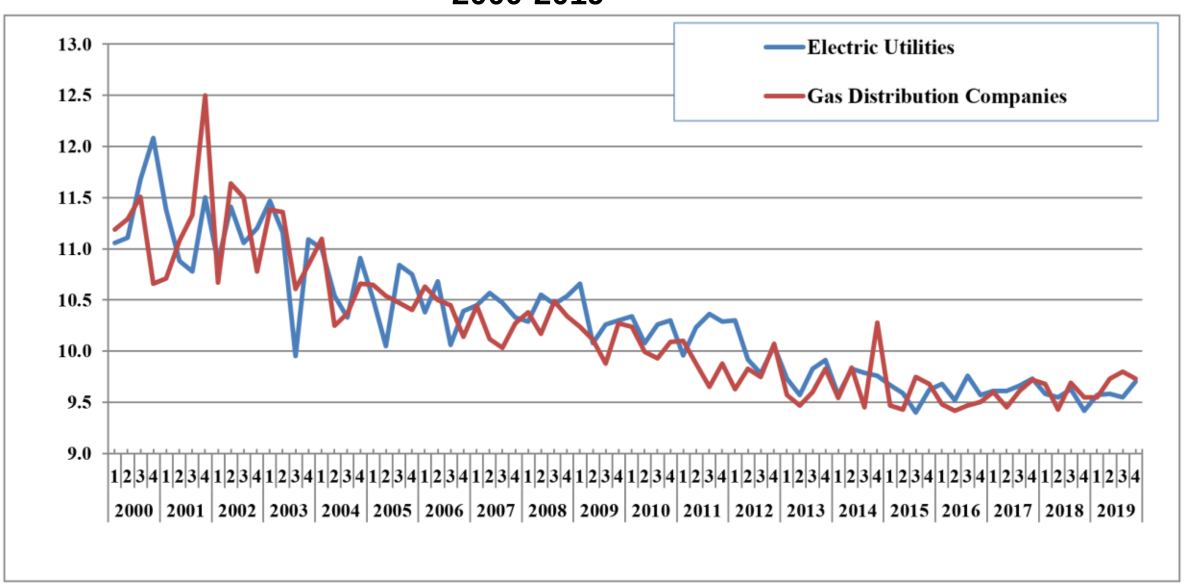
returns. For example, consider a utility that pays a dividend of $2.00 with a stock price of $50.00. The current dividend yield in that example is 4.0%. If, as Mr. Hevert suggests, interest rates and required utility yields increase, the price of the utility stock would decline. In the example above, if higher return requirements led the dividend yield to increase from 4.0% to 5.0% in the next year, the stock price would have to decline to $40, which would be a -20% return on the stock. Obviously, investors would not buy the utility stock with an expected return of -20% due to higher dividend yield requirements.

In sum, it is practically impossible to accurately forecast interest rates and prices of investments that are determined in financial markets, such as interest rates and prices for stocks and commodities. For interest rates, I am not aware of any study that suggests one forecasting service is consistently better than others or that interest rate forecasts are consistently better than just assuming the current interest rate will be the rate in the future. As discussed above, investors would not be buying long-term Treasury bonds or utility stocks at their current yields if they expected interest rates to suddenly increase, thereby producing higher yields and negative returns. Thus, I recommend that the Commission not rely on interest rate forecasts but use current interest rates in estimating the appropriate ROE for the Company.

Q. PLEASE DISCUSS THE TREND IN AUTHORIZED RETURN ON EQUITY FOR ELECTRIC AND GAS COMPANIES.

A. Over the past five years, with historically low interest rates and capital costs, authorized ROEs for electric utility and gas distribution companies have slowly declined to reflect the low capital cost environment. In Figure 3, below, I have graphed the quarterly authorized ROEs for electric and gas companies from 2000 to 2019. There is a clear downward trend in the data. On an annual basis, these authorized ROEs for electric utilities have declined from an average of 10.01% in 2012, 9.8% in 2013, 9.76% in 2014, 9.58% in 2015, 9.60% in 2016, 9.68% in 2017, 9.56% in 2018, and 9.64% in of 2019, according to Regulatory Research Associates.[13]

Figure 3
Authorized ROEs for Electric Utility and Gas Distribution Companies
2000-2019



[13] S&P Global Market Intelligence, RRA *Regulatory Focus*, 2019.

III. PROXY GROUP SELECTION

Q. PLEASE DESCRIBE YOUR APPROACH TO DEVELOPING A FAIR RATE OF RETURN RECOMMENDATION FOR THE COMPANY.

A. To develop a fair rate of return recommendation for DEC, I have evaluated the return requirements of investors on the common stock of a proxy group of publicly-held electric utility companies (Electric Proxy Group). I have also evaluated the group developed by Mr. Hevert (Hevert Proxy Group).

Q. PLEASE DESCRIBE YOUR PROXY GROUP OF COMPANIES.

A. The selection criteria for the companies in Electric Proxy Group include the following:

(1) Received at least 50% of revenues from regulated electric operations as reported in SEC Form 10-K Report;

(2) Is listed as a U.S.-based Electric Utility by *Value Line Investment Survey*;

(3) Has an investment-grade corporate credit and bond rating;

(4) Has paid a cash dividend for the past six months, with no cuts or omissions;

(5) Is not involved in an acquisition of another utility, and not the target of an acquisition; and

(6) Has analysts' long-term EPS growth rate forecasts available from Yahoo or Zack's.

The Electric Proxy Group includes 30 companies. Summary financial statistics for the proxy group are listed in Exhibit JRW-2. The median operating revenues and net plant among members of the Electric Proxy Group are $6,852.0 million and $22,405.5 million, respectively. The group on average receives 81% of its revenues from regulated electric operations, and has a BBB+ bond rating from S&P's and a Baa1 rating from Moody's, a current average common equity ratio of 46.0%, and an earned return on common equity of 9.6%.

Q. PLEASE DESCRIBE THE HEVERT PROXY GROUP.

A. Mr. Hevert's group is smaller (19 companies). Summary financial statistics for Mr. Hevert's proxy group are provided in Panel B of page 1 of Exhibit JRW-2. The median operating revenues and net plant for the Hevert Proxy Group are $4,275.9 million and $18,126.0 million, respectively. The group on average receives 78% of its revenues from regulated electric operations, and has a BBB+ bond rating from S&P's and a Baa1 rating from Moody's, an average common equity ratio of 48.0%, and earned return on common equity of 9.7%.

Q. HOW DOES THE INVESTMENT RISK OF THE COMPANY COMPARE TO THAT OF YOUR ELECTRIC PROXY GROUP AND THE HEVERT PROXY GROUP?

A. I believe that bond ratings provide a good assessment of the investment risk of a company. The S&P and Moody's issuer credit ratings for DEC are A- and A1, respectively. The average S&P and Moody's ratings for the Electric and Hevert Proxy Group are BBB+ and Baa1. Therefore, DEC's S&P rating is one notch above the average of the two groups (A- vs. BBB+), and DEC's Moody's rating is three rating notches above the average of the two groups (A1 vs. Baa1). This indicates that the investment risk of DEC is below the average of the electric utilities in the two proxy groups.

On page 2 of Exhibit JRW-2, I have assessed the riskiness of the two proxy groups using five different risk measures from *Value Line*. These measures are beta, Financial Strength, Safety, Earnings Predictability, and Stock Price Stability.[14] These risk measures indicate that the two proxy groups are similar in risk. The comparisons of the risk measures of the Electric Proxy Group and the Hevert Proxy Group show beta (0.57 vs. 0.56), Financial Strength (A vs. A) Safety (1.8 vs. 1.8), Earnings Predictability (77 vs. 83), and Stock Price Stability (96 vs. 97), respectively. On balance, these measures suggest that the two proxy groups are similar in risk.

Q. WHAT DO YOU CONCLUDE FROM YOUR RISK ANALYSIS?

[14] These risk metrics are described in detail on Page 3 of Exhibit JRW-2.

A. First, based on the credit ratings from S&P and Moody's, I conclude that the Company is less risky than the average of the two proxy groups. Second, the S&P and Moody's credit ratings and the five *Value Line* risk ratings are very similar for the two groups, and therefore I conclude that the two groups are similar in risk. And third, the five *Value Line* risk ratings for the two groups suggest that electric utilities are very low risk. This is indicated by the low betas as well as the high ratings for safety, financial strength, earnings predictability, and stock price stability.

IV. CAPITAL STRUCTURE RATIOS AND DEBT COST RATES

Q. PLEASE DESCRIBE DEC'S PROPOSED CAPITAL STRUCTURE AND SENIOR CAPITAL COST RATES.

A. DEC witness Newlin has proposed a hypothetical capital structure of 47.00% long-term debt and 53.00% common equity and a long-term debt cost rate of 4.51% based on its weighted average cost of long-term debt as of December 31, 2018.

Q. HOW DOES MR. NEWLIN DEVELOP THE COMPANY'S PROPOSED CAPITAL STRUCTURE WITH A COMMON EQUITY RATIO OF 53.0%?

A. Mr. Newlin simply maintains that a capital structure with a common equity ratio of 53.0% is needed to ensure the financial integrity of DEC.

Q. HAS MR. NEWLIN PREPARED ANY STUDIES TO DEFEND HIS PROPOSED CAPITAL STRUCTURE WITH A COMMON EQUITY RATIO OF 53.0%?

A. No. He simply notes that the Company's common equity ratio as of December 31, 2018 was 51.5%.

Q. HAS MR. NEWLIN COMPARED THE COMPANY'S PROPOSED CAPITAL STRUCTURE WITH A COMMON EQUITY RATIO OF 53.0% WITH THE CAPITAL STRUCTURE RATIOS OF OTHER ELECTRIC UTILITY COMPANIES?

A. No.

Q. HAS MR. NEWLIN TAKEN INTO ACCOUNT THE FACT THAT DEC'S S&P AND MOODY'S RATINGS OF A- AND A+ ARE ABOVE THE S&P AND MOODY'S RATINGS OF OTHER ELECTRIC UTILITIES?

A. No.

Q. HOW DO DEC'S PROPOSED CAPITAL STRUCTURE RATIOS COMPARE TO THE AVERAGE CAPITALIZATION RATIOS FOR COMPANIES IN THE PROXY GROUPS?

A. DEC's proposed capital structure ratios include a common equity ratio of 53.00%. As shown on Page 1 of Exhibit JRW-2, the average quarterly common equity ratio for the Electric and Hevert Proxy Groups as of December 31, 2018, was 46.0% and 48.0%, respectively. As such, DEC has proposed a capital structure that includes much more common equity in financing its utility operations than the average of the proxy group.

Q. IS IT APPROPRIATE TO USE THE COMMON EQUITY RATIOS OF THE PARENT HOLDING COMPANIES OR SUBSIDIARY OPERATING UTILITIES FOR COMPARISON PURPOSES WITH DEC'S PROPOSED CAPITALIZATION?

A. It is appropriate to use the common equity ratios of the utility holding companies because the holding companies are publicly-traded and their stocks are used in the cost of equity capital studies. The equities of the operating utilities are not publicly-traded and hence their stocks cannot be used to compute the cost of equity capital for DEC.

Q. IS IT APPROPRIATE TO INCLUDE SHORT-TERM DEBT IN THE CAPITALIZATION IN COMPARING THE COMMON EQUITY RATIOS OF THE HOLDING COMPANIES WITH DEC'S PROPOSED CAPITALIZATION?

A. Yes. I am following North Carolina precedent and not recommending short-term debt in DEC's capital structure. However, in comparing the common equity ratios of the holding companies with DEC's recommendation, it is appropriate to include short-term debt when computing the holding company common equity ratios. That is because short-term debt, like long-term debt, has a higher claim on the assets and earnings of the company and requires timely payment of interest and repayment of principal. In addition, the financial risk of a company is based on total debt, which includes both short-term and long-term debt. This is why credit rating agencies use total debt in assessing the leverage and financial risk of companies.

Q. WHAT IS THE AVERAGE COMMON EQUITY RATIO AUTHORIZED FOR ELECTRIC UTILITIES BY STATE REGULATORY COMMISSIONS?

A. According to S&P Global Market Intelligence, the average authorized common equity ratio for electric utilities in calendar years 2018 and 2019 was 50.98%. This percentage excludes the common equity ratios of utilities in states which include cost-free capital items in authorized capital structures.[15]

Q. HOW DO DEC'S PROPOSED CAPITAL STRUCTURE RATIOS COMPARE TO THE CAPITALIZATION RATIOS OF DEC AND ITS PARENT, DUKE ENERGY?

A. DEC and Duke Energy's quarterly common equity ratio for the eight quarters ending September 30, 2019 (as provided in Panel B on Page 1 of Exhibit JRW-3), were 51.2% and 43.4%, respectively. As a result, the Company's proposed capital structure includes a higher common equity ratio than it has maintained in the past two years and a much

[15] S&P Global Market Intelligence, RRA *Regulatory Focus*, 2018 and 2019.

higher common equity ratio than its parent company, Duke Energy Corporation.

Q. IS DUKE ENERGY'S HIGH DEBT RATIO AND LOW EQUITY RATIO A FACTOR IN THE RISK ASSESSMENT OF DEC?

A. Yes. As previously noted, DEC's Moody's rating of A1 is three rating notches above Duke Energy's rating of Baa1.

Q. PLEASE DISCUSS THE ISSUE OF PUBLIC UTILITY HOLDING COMPANIES SUCH AS DUKE ENERGY USING DEBT TO FINANCE THE EQUITY IN SUBSIDIARIES SUCH AS THE COMPANY.

A. Moody's published an article on the use of low-cost debt financing by public utility holding companies to increase their ROEs. The summary observations included the following:[16]

> US utilities use leverage at the holding-company level to invest in other businesses, make acquisitions and earn higher returns on equity. In some cases, an increase in leverage at the parent can hurt the credit profiles of its regulated subsidiaries.

This financial strategy has traditionally been known as double leverage. Moody's defined double leverage in the following way:[17]

> Double leverage is a financial strategy whereby the parent raises debt but downstreams the proceeds to its

[16] Moody's Investors' Service, "High Leverage at the Parent Often Hurts the Whole Family," May 11, 2015, p.1.

[17] *Ibid.* p. 5.

> operating subsidiary, likely in the form of an equity investment. Therefore, the subsidiary's operations are financed by debt raised at the subsidiary level and by debt financed at the holding-company level. In this way, the subsidiary's equity is leveraged twice, once with the subsidiary debt and once with the holding-company debt. In a simple operating-company / holding-company structure, this practice results in a consolidated debt-to-capitalization ratio that is higher at the parent than at the subsidiary because of the additional debt at the parent.

Moody's goes on to discuss the potential risk to utilities of the strategy, and specifically notes that regulators could take it into consideration in setting authorized ROEs.[18]

> **"Double leverage" drives returns for some utilities but could pose risks down the road.** The use of double leverage, a long-standing practice whereby a holding company takes on debt and downstreams the proceeds to an operating subsidiary as equity, could pose risks down the road if regulators were to ascribe the debt at the parent level to the subsidiaries or adjust the authorized return on capital.

Q. PLEASE DISCUSS THE SIGNIFICANCE OF THE AMOUNT OF EQUITY THAT IS INCLUDED IN A UTILITY'S CAPITAL STRUCTURE.

A. A utility's decision as to the amount of equity capital it will incorporate into its capital structure involves fundamental trade-offs relating to the amount of financial risk the firm carries, the overall revenue

[18] *Ibid.* p. 1.

requirements its customers are required to bear through the rates they pay, and the return on equity that investors will require.

Q. PLEASE DISCUSS A UTILITY'S DECISION TO USE DEBT VERSUS EQUITY TO MEET ITS CAPITAL NEEDS.

A. Utilities satisfy their capital needs through a mix of equity and debt. Because equity capital is more expensive than debt, the issuance of debt enables a utility to raise more capital for a given commitment of dollars than it could raise with just equity. Debt is, therefore, a means of "leveraging" capital dollars. However, as the amount of debt in the capital structure increases, financial risk increases and the risk of the utility, as perceived by equity investors also increases. Significantly for this case, the converse is also true. As the amount of debt in the capital structure decreases, the financial risk decreases. The required return on equity capital is a function of the amount of overall risk that investors perceive, including financial risk in the form of debt.

Q. WHY IS THIS RELATIONSHIP IMPORTANT TO THE UTILITY'S CUSTOMERS?

A. Just as there is a direct correlation between the utility's authorized return on equity and the utility's revenue requirements (the higher the return, the greater the revenue requirement), there is a direct correlation between the amount of equity in the capital structure and the revenue requirements that customers are called on to bear.

Again, equity capital is more expensive than debt. Not only does equity command a higher cost rate, it also adds more to the income tax burden that ratepayers are required to pay through rates. As the equity ratio increases, the utility's revenue requirements increase and the rates paid by customers increase. If the proportion of equity is too high, rates will be higher than they need to be. For this reason, the utility's management should pursue a capital acquisition strategy that results in the proper balance in the capital structure.

Q. HOW HAVE UTILITIES TYPICALLY STRUCK THIS BALANCE?

A. Due to regulation and the essential nature of its output, a regulated utility is exposed to less business risk than other companies that are not regulated. This means that a utility can reasonably carry relatively more debt in its capital structure than can most unregulated companies. Thus, a utility should take appropriate advantage of its lower business risk to employ cheaper debt capital at a level that will benefit its customers through lower revenue requirement.

Q. GIVEN THAT DEC HAS PROPOSED AN EQUITY RATIO THAT IS HIGHER THAN (1) THE AVERAGE COMMON EQUITY RATIOS OF THE ELECTRIC AND HEVERT'S PROXY GROUPS, (2) THE AVERAGE AUTHORIZED COMMON EQUITY RATIO FOR ELECTRIC UTILITY COMPANIES, AND (3) THE COMMON

EQUITY RATIO OF ITS PARENT COMPANY, WHAT SHOULD THE COMMISSION DO IN THIS RATEMAKING PROCEEDING?

A. When a regulated utility's actual capital structure contains a high equity ratio, the options are: (1) to impute a more reasonable capital structure that is comparable to the average of the proxy group used to determine the cost of equity and to reflect the imputed capital structure in revenue requirements; or (2) to recognize the downward impact that an unusually high equity ratio will have on the financial risk of a utility and authorize a common equity cost rate lower than that of the proxy group.

Q. PLEASE ELABORATE ON THIS "DOWNWARD IMPACT."

A. As I stated earlier, there is a direct correlation between the amount of debt in a utility's capital structure and the financial risk that an equity investor will associate with that utility. A relatively lower proportion of debt translates into a lower required return on equity, all other things being equal. Stated differently, a utility cannot expect to "have it both ways." Specifically, a utility cannot maintain an unusually high equity ratio and not expect to have the resulting lower risk reflected in its authorized return on equity. The fundamental relationship between lower risk and the appropriate authorized return should not be ignored.

Q. GIVEN THIS DISCUSSION, PLEASE DISCUSS YOUR PRIMARY CAPITAL STRUCTURE RECOMMENDATION FOR DEC.

A. My primary capital structure recommendation is presented in Panel C of Exhibit JRW-3. As previously noted, DEC's proposed capital structure consists of more common equity and less financial risk than any of the other proxy groups of electric companies. Therefore, in my primary rate of return recommendation, I am proposing a capital structure that includes a common equity ratio of 50.0%. This capital structure includes a common equity ratio that is about halfway between DEC's proposed capital structure of 53.00% and the average common equity ratios of the proxy groups of 46.00% and 48.00%. As shown in Table 3 and Panel C of Exhibit JRW-3, in this capital structure, I have grossed up the percentage amount of long-term debt to 50.0% and reduced the amount of common equity from 53.00% to 50.0%. As noted above, in my primary rate of return recommendation, I am using a ROE of 9.0%.

Table 3

Staff's Primary Capital Structure Recommendation

	DEC Proposed	Adjustment	Staff Proposed	Cost
Long-Term Debt	**47.00%**	**1.063830**	**50.00%**	**4.51%**
Common Equity	**53.00%**	**0.943396**	**50.00%**	**-**
Total Capital	**100.00%**		**100.00%**	

Q. DO YOU BELIEVE THAT YOUR PROPOSED 50% EQUITY CAPITAL STRUCTURE IS FAIR TO DEC?

A. Yes, for two reasons: (1) It includes a common equity ratio that is higher than the average common equity ratio for the Electric and Hevert Proxy Groups and therefore affords DEC with more common equity and less financial risk than other electric utility companies; and (2) it is in line with the average authorized common equity ratios for the proxy groups of electric utility companies.

Q. WHAT IS THE CAPITAL STRUCTURE IN YOUR ALTERNATIVE RATE OF RETURN RECOMMENDATION?

A. In my alternative rate of return recommendation, I am using DEC's proposed capital structure which consists of 47.00% long-term debt and 53.00%. I am also using DEC's proposed long-term debt cost rate of 4.51%. As noted above, in my alternative rate of return recommendation, I am using an ROE of 8.40%. I believe that the 8.40% ROE reflects the current market cost of equity. In addition, if the Commission adopts DEC's proposed capital structure with its high common equity ratio, I believe that the Commission should employ a lower ROE to reflect the lower financial risk associated with a higher common equity ratio.

Table 4

Public Staff's Alternative Capital Structure Recommendation

	Percent of Total	Cost
Long-Term Debt	**47.00%**	**4.51%**
Common Equity	**<u>53.00%</u>**	
Total Capital	**100.00%**	

V. THE COST OF COMMON EQUITY CAPITAL

A. Overview

Q. WHY MUST AN OVERALL COST OF CAPITAL OR FAIR RATE OF RETURN BE ESTABLISHED FOR A PUBLIC UTILITY?

A. In a competitive industry, the return on a firm's common equity capital is determined through the competitive market for its goods and services. Due to the capital requirements needed to provide utility services and the economic benefit to society from avoiding duplication of these services and the construction of utility infrastructure facilities, many public utilities are monopolies. Because of the lack of competition and the essential nature of their services, it is not appropriate to permit monopoly utilities to set their own prices. Thus, regulation seeks to establish prices that are fair to consumers and, at the same time, sufficient to meet the operating and capital costs of the utility, *i.e.*, provide an adequate return on capital to attract investors.

Q. PLEASE PROVIDE AN OVERVIEW OF THE COST OF CAPITAL IN THE CONTEXT OF THE THEORY OF THE FIRM.

A. The total cost of operating a business includes the cost of capital. The cost of common equity capital is the expected return on a firm's common stock that the marginal investor would deem sufficient to compensate for risk and the time value of money. In equilibrium, the expected and required rates of return on a company's common stock are equal.

Normative economic models of a company or firm, developed under very restrictive assumptions, provide insight into the relationship between firm performance or profitability, capital costs, and the value of the firm. Under the economist's ideal model of perfect competition, where entry and exit are costless, products are undifferentiated, and there are increasing marginal costs of production, firms produce up to the point where price equals marginal cost. Over time, a long-run equilibrium is established where price equals average cost, including the firm's capital costs. In equilibrium, total revenues equal total costs, and because capital costs represent investors' required return on the firm's capital, actual returns equal required returns, and the market value must equal the book value of the firm's securities.

In a competitive market, firms can achieve competitive advantage due to product market imperfections. Most notably, companies can gain competitive advantage through product differentiation (adding real or perceived value to products) and by achieving economies of scale (decreasing marginal costs of production). Competitive advantage allows firms to price products above average cost and thereby earn accounting profits greater than those required to cover capital costs. When these profits are in excess of those required by investors, or when a firm earns a return on equity in excess of its cost of equity, investors respond by valuing the firm's equity in excess of its book value.

James M. McTaggart, founder of the international management consulting firm Marakon Associates, described this essential relationship between the return on equity, the cost of equity, and the market-to-book ratio in the following manner:[19]

> Fundamentally, the value of a company is determined by the cash flow it generates over time for its owners, and the minimum acceptable rate of return required by capital investors. This "cost of equity capital" is used to discount the expected equity cash flow, converting it to a present value. The cash flow is, in turn, produced by the interaction of a company's return on equity and the annual rate of equity growth. High return on equity (ROE) companies in low-growth markets, such as Kellogg, are prodigious generators of cash flow, while low ROE companies in high-growth markets, such as Texas Instruments, barely generate enough cash flow to finance growth.
>
> A company's ROE over time, relative to its cost of equity, also determines whether it is worth more or less than its book value. If its ROE is consistently greater than the cost of equity capital (the investor's minimum acceptable return), the business is economically profitable and its market value will exceed book value. If, however, the business earns a ROE consistently less than its cost of equity, it is economically unprofitable and its market value will be less than book value.

[19] James M. McTaggart, "The Ultimate Poison Pill: Closing the Value Gap," *Commentary* (Spring 1986), p.3.

As such, the relationship between a firm's return on equity, cost of equity, and market-to-book ratio is relatively straightforward. A firm that earns a return on equity above its cost of equity will see its common stock sell at a price above its book value. Conversely, a firm that earns a return on equity below its cost of equity will see its common stock sell at a price below its book value.

Q. PLEASE PROVIDE ADDITIONAL INSIGHTS INTO THE RELATIONSHIP BETWEEN ROE AND MARKET-TO-BOOK RATIOS.

A. This relationship is discussed in a classic Harvard Business School case study entitled "Note on Value Drivers." On page 2 of that case study, the author describes the relationship very succinctly:[20]

> For a given industry, more profitable firms – those able to generate higher returns per dollar of equity– should have higher market-to-book ratios. Conversely, firms which are unable to generate returns in excess of their cost of equity should sell for less than book value.

Profitability	*Value*
If ROE > K	*then*
Market/Book > 1	
If ROE = K	*then*
Market/Book =1	
If ROE < K	*then*
Market/Book < 1	

[20] Benjamin Esty, "Note on Value Drivers," Harvard Business School, Case No. 9-297-082, April 7, 1997.

To assess the relationship by industry, as suggested above, I performed a regression study between estimated ROE and market-to-book ratios using *Value Line*'s electric utilities and gas distribution companies. I used all electric utility and gas distribution companies that are covered by *Value Line* and have estimated ROE and market-to-book ratio data. The results are presented in Exhibit JRW-4. The R-square for the regression of estimated ROEs and market-to-book ratios is 0.50.[21] This demonstrates a statistically significant positive relationship between ROEs and market-to-book ratios for electric utilities and gas companies. Given that the market-to-book ratios have been above 1.0 for a number of years, this also demonstrates that utilities have been earnings ROEs above the cost of equity capital for many years.

Q. WHAT ECONOMIC FACTORS HAVE AFFECTED THE COST OF EQUITY CAPITAL FOR PUBLIC UTILITIES?

A. Exhibit JRW-5 provides indicators of public utility equity cost rates.

Page 1 shows the yields on long-term A-rated public utility bonds. These yields decreased from 2000 until 2003, and then hovered in the 5.50%-6.50% range from mid-2003 until mid-2008. The yields peaked in November 2008 at 7.75% during the Great Recession.

[21] R-square measures the percent of variation in one variable (e.g., market-to-book ratios) explained by another variable (e.g., expected ROE). R-squares vary between zero and 1.0, with values closer to 1.0 indicating a higher relationship between two variables.

These yields have generally declined since then, dropping below 4.0% on five occasions - in mid-2013, in the first quarter of 2015, in the summer of 2016, in late 2018, and in 2019. The yields were about 3.5% as of the end of 2019.

Page 2 of Exhibit JRW-5 provides the average dividend yields for electric utility companies over the past 16 years. The dividend yields for the electric group declined from 5.3% to 3.4% between 2001 to 2007, increased to over 5.0% in 2009, and have steadily since that time. The average dividend yield was 3.2% in 2018.

Average earned returns on common equity and market-to-book ratios for electric utilities are on page 3 of Exhibit JRW-5. For the electric group, earned returns on common equity have declined gradually over the years. In the past three years, the average earned ROE for the group has been in the 9.0% to 10.0% range. The average market-to-book ratios for this group declined to about 1.1X in 2009 during the financial crisis and have increased since that time. As of 2018, the average market-to-book for the group was 1.80X. This means that, for at least the last decade, returns on common equity for electric utilities have been greater than the cost of capital, or more than necessary to meet investors' required returns. This also means that customers have been paying more than necessary to support an appropriate profit level for regulated utilities.

Q. WHAT FACTORS DETERMINE INVESTORS' EXPECTED OR REQUIRED RATE OF RETURN ON EQUITY?

A. The expected or required rate of return on common stock is a function of market-wide as well as company-specific factors. The most important market factor is the time value of money as indicated by the level of interest rates in the economy. Common stock investor requirements generally increase and decrease with like changes in interest rates. The perceived risk of a firm is the predominant factor that influences investor return requirements on a company-specific basis. A firm's investment risk is often separated into business risk and financial risk. Business risk encompasses all factors that affect a firm's operating revenues and expenses. Financial risk results from incurring fixed obligations in the form of debt in financing its assets.

Q. HOW DOES THE INVESTMENT RISK OF PUBLIC UTILITIES COMPARE WITH THAT OF OTHER INDUSTRIES?

A. Due to the essential nature of their service as well as their regulated status, public utilities are exposed to a lesser degree of business risk than other, non-regulated businesses. The relatively low level of business risk allows public utilities to meet much of their capital requirements through borrowing in the financial markets, thereby incurring greater than average financial risk. Nonetheless, the overall investment risk of public utilities is below most other industries.

Page 4 of Exhibit JRW-5 provides an assessment of investment risk for 97 industries as measured by beta, which according to modern capital market theory, is the only relevant measure of investment risk. These betas come from the *Value Line Investment Survey.* The study shows that the investment risk of utilities is very low. The average betas for electric, gas, and water utility companies are 0.58, 0.67, and 0.68, respectively.[22] As such, the cost of equity for utilities is among the lowest of all industries in the U.S. based on modern capital market theory.

Q. WHAT IS THE COST OF COMMON EQUITY CAPITAL?

A. The costs of debt and preferred stock are normally based on historical or book values and can be determined with a great degree of accuracy. The cost of common equity capital, however, cannot be determined precisely and must instead be estimated from market data and informed judgment. This return requirement of the stockholder should be commensurate with the return requirement on investments in other enterprises having comparable risks.

According to valuation principles, the present value of an asset equals the discounted value of its expected future cash flows. Investors discount these expected cash flows at their required rate

[22] The beta for the *Value Line* Electric Utilities is the simple average of *Value Line*'s Electric East (0.56), Central (0.61), and West (0.59) group betas.

of return that, as noted above, reflects the time value of money and the perceived riskiness of the expected future cash flows. As such, the cost of common equity is the rate at which investors discount expected cash flows associated with common stock ownership.

Q. HOW CAN THE EXPECTED OR REQUIRED RATE OF RETURN ON COMMON EQUITY CAPITAL BE DETERMINED?

A. Models have been developed to ascertain the cost of common equity capital for a firm. Each model, however, has been developed using restrictive economic assumptions. Consequently, judgment is required in selecting appropriate financial valuation models to estimate a firm's cost of common equity capital, determining the data inputs for these models, and interpreting the models' results. All of these decisions must take into consideration the firm involved, as well as current conditions in the economy and the financial markets.

Q. HOW DO YOU PLAN TO ESTIMATE THE COST OF EQUITY CAPITAL FOR THE COMPANY?

A. I rely primarily on the DCF model to estimate the cost of equity capital. Given the investment valuation process and the relative stability of the utility business, the DCF model provides the best measure of equity cost rates for public utilities. I have also performed a CAPM study; however, I give these results less weight because I believe that risk premium studies, of which the CAPM is one form, provide a less reliable indication of equity cost rates for public utilities.

B. Discounted Cash Flow Analysis

Q. PLEASE DESCRIBE THE THEORY BEHIND THE TRADITIONAL DCF MODEL.

A. According to the DCF model, the current stock price is equal to the discounted value of all future dividends that investors expect to receive from investment in the firm. As such, stockholders' returns ultimately result from current as well as future dividends. As owners of a corporation, common stockholders are entitled to a *pro rata* share of the firm's earnings. The DCF model presumes that earnings that are not paid out in the form of dividends are reinvested in the firm to provide for future growth in earnings and dividends. The rate at which investors discount future dividends, which reflects the timing and riskiness of the expected cash flows, is interpreted as the market's expected or required return on the common stock. Therefore, this discount rate represents the cost of common equity. Algebraically, the DCF model can be expressed as:

$$P = \frac{D_1}{(1+k)^1} + \frac{D_2}{(1+k)^2} + \ldots \frac{D_n}{(1+k)^n}$$

where P is the current stock price, D_1, D_2, and D_n are the dividends in year 1, 2, and the future years n, and k is the cost of common equity.

Q. IS THE DCF MODEL CONSISTENT WITH VALUATION TECHNIQUES EMPLOYED BY INVESTMENT FIRMS?

A. Yes. Virtually all investment firms use some form of the DCF model as a valuation technique. One common application for investment firms is called the three-stage DCF or dividend discount model (DDM). The stages in a three-stage DCF model are presented in Exhibit JRW-6. This model presumes that a company's dividend payout progresses initially through a growth stage, then proceeds through a transition stage, and finally assumes a maturity (or steady-state) stage. The dividend-payment stage of a firm depends on the profitability of its internal investments which, in turn, is largely a function of the life cycle of the product or service.

1. Growth stage: Characterized by rapidly expanding sales, high profit margins, and an abnormally high growth in earnings per share. Because of highly profitable expected investment opportunities, the payout ratio is low. Competitors are attracted by the unusually high earnings, leading to a decline in the growth rate.

2. Transition stage: In later years, increased competition reduces profit margins and earnings growth slows. With fewer new investment opportunities, the company begins to pay out a larger percentage of earnings.

3. Maturity (steady-state) stage: Eventually, the company reaches a position where its new investment opportunities offer, on average, only slightly more attractive ROEs. At that time, its earnings growth rate, payout ratio, and ROE stabilize for the remainder of its life. As I will explain below, the constant-growth DCF model is appropriate when a firm is in the maturity stage of the life cycle.

In using the 3-stage model to estimate a firm's cost of equity capital, dividends are projected into the future using the different growth rates in the alternative stages, and then the equity cost rate is the discount rate that equates the present value of the future dividends to the current stock price.

Q. HOW DO YOU ESTIMATE STOCKHOLDERS' EXPECTED OR REQUIRED RATE OF RETURN USING THE DCF MODEL?

A. Under certain assumptions, including a constant and infinite expected growth rate, and constant dividend/earnings and price/earnings ratios, the DCF model can be simplified to the following:

$$P = \frac{D_1}{k - g}$$

where P is the current stock price, D_1 represents the expected dividend over the coming year, k is investor's required return on equity, and g is the expected growth rate of dividends. This is known as the constant-growth version of the DCF model. To use the constant-growth DCF model to estimate a firm's cost of equity, one solves for k in the above expression to obtain the following:

$$k = \frac{D_1}{P} + g$$

Q. IN YOUR OPINION, IS THE CONSTANT-GROWTH DCF MODEL APPROPRIATE FOR PUBLIC UTILITIES?

A. Yes. The economics of the public utility business indicate that the industry is in the steady-state or constant-growth stage of a three-stage DCF. The economics include the relative stability of the utility business, the maturity of the demand for public utility services, and the regulated status of public utilities (especially the fact that their returns on investment are effectively set through the ratemaking process). The DCF valuation procedure for companies in this stage is the constant-growth DCF. In the constant-growth version of the DCF model, the current dividend payment and stock price are directly observable. However, the primary problem and controversy in applying the DCF model to estimate equity cost rates surrounds estimating investors' expected dividend growth rate.

Q. WHAT FACTORS SHOULD ONE CONSIDER WHEN APPLYING THE DCF METHODOLOGY?

A. One should be sensitive to several factors when using the DCF model to estimate a firm's cost of equity capital. In general, one must recognize the assumptions under which the DCF model was developed in estimating its components (the dividend yield and the expected growth rate). The dividend yield can be measured precisely at any point in time; however, it tends to vary somewhat over time. Estimation of expected growth is considerably more difficult. One must consider recent firm performance, in conjunction with current economic developments and other information available to investors, to accurately estimate investors' expectations.

Q. WHAT DIVIDEND YIELDS HAVE YOU REVIEWED?

A. I have calculated the dividend yields for the companies in the proxy groups using the current annual dividend and the 30-day, 90-day, and 180-day average stock prices. These dividend yields are provided in Panels A and B of page 2 of Exhibit JRW-7. I have shown the mean and median dividend yields using 30-day, 90-day, and 180-day average stock prices. Using both the means and medians, the dividend yields range from 3.1% to 3.2% for the Electric Proxy Group and 2.8% to 3.0% for the Hevert Proxy Group. Therefore, I will use a dividend yields of 3.15% and 2.90% for the Electric Proxy Group and the Hevert Proxy Group, respectively.

Q. PLEASE DISCUSS THE APPROPRIATE ADJUSTMENT TO THE SPOT DIVIDEND YIELD.

A. According to the traditional DCF model, the dividend yield term relates the dividend paid over the coming period to the current stock price. As indicated by Professor Myron Gordon, who is commonly associated with the development of the DCF model for popular use, this is obtained by: (1) multiplying the expected dividend over the coming quarter by 4, and (2) dividing this dividend by the current stock price to determine the appropriate dividend yield for a firm that pays dividends on a quarterly basis.[23]

In applying the DCF model, some analysts adjust the current dividend for growth over the coming year as opposed to the coming quarter. This can be complicated because firms tend to announce changes in dividends at different times during the year. As such, the dividend yield computed based on presumed growth over the coming quarter as opposed to the coming year can be quite different. Consequently, it is common for analysts to adjust the dividend yield by some fraction of the long-term expected growth rate.

Q. GIVEN THIS DISCUSSION, WHAT ADJUSTMENT FACTOR DO YOU USE FOR YOUR DIVIDEND YIELD?

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[23] *Petition for Modification of Prescribed Rate of Return*, Federal Communications Commission, Docket No. 79-05, Direct Testimony of Myron J. Gordon and Lawrence I. Gould at 62 (April 1980).

A. I adjust the dividend yield by one-half (1/2) of the expected growth to reflect growth over the coming year. The DCF equity cost rate (K) is computed as:

$$K = [(D/P) * (1 + 0.5g)] + g$$

Q. PLEASE DISCUSS THE GROWTH RATE COMPONENT OF THE DCF MODEL.

A. There is debate as to the proper methodology to employ in estimating the growth component of the DCF model. By definition, this component is investors' expectation of the long-term dividend growth rate. Presumably, investors use some combination of historical and projected growth rates for earnings and dividends per share and internal or book-value growth to assess long-term potential.

Q. WHAT GROWTH DATA HAVE YOU REVIEWED FOR THE PROXY GROUPS?

A. I have analyzed a number of measures of growth for companies in the proxy groups. I reviewed *Value Line's* historical and projected growth rate estimates for EPS, dividends per share (DPS), and book value per share (BVPS). In addition, I utilized the average EPS growth rate forecasts of Wall Street analysts as provided by Yahoo, Reuters and Zacks. These services solicit five-year earnings growth rate projections from securities analysts and compile and publish the means and medians of these forecasts. Finally, I also assessed prospective growth as measured by prospective earnings retention rates and earned returns on common equity.

Q. PLEASE DISCUSS HISTORICAL GROWTH IN EARNINGS AND DIVIDENDS AS WELL AS INTERNAL GROWTH.

A. Historical growth rates for EPS, DPS, and BVPS are readily available to investors and are presumably an important ingredient in forming expectations concerning future growth. However, one must use historical growth numbers as measures of investors' expectations with caution. In some cases, past growth may not reflect future growth potential. Also, employing a single growth rate number (for example, for five or ten years) is unlikely to accurately measure investors' expectations, due to the sensitivity of a single growth rate figure to fluctuations in individual firm performance as well as overall economic fluctuations (*i.e.*, business cycles). However, one must appraise the context in which the growth rate is being employed. According to the conventional DCF model, the expected return on a security is equal to the sum of the dividend yield and the expected long-term growth in dividends. Therefore, to best estimate the cost of common equity capital using the conventional DCF model, one must look to long-term growth rate expectations.

Internally generated growth is a function of the percentage of earnings retained within the firm (the earnings retention rate) and the rate of return earned on those earnings (the return on equity). The internal growth rate is computed as the retention rate times the return on equity. Internal growth is significant in determining long-run earnings and, therefore, dividends. Investors recognize the importance of internally generated growth and pay premiums for stocks of companies that retain earnings and earn high returns on internal investments.

Q. PLEASE DISCUSS THE SERVICES THAT PROVIDE ANALYSTS' EPS FORECASTS.

A. Analysts' EPS forecasts for companies are collected and published by several different investment information services, including Institutional Brokers Estimate System (I/B/E/S), Bloomberg, S&L Global Market Intelligence FactSet, Zacks, First Call, and Reuters, among others. Thompson Reuters publishes analysts' EPS forecasts under different product names, including I/B/E/S, First Call, and Reuters. S&P, Bloomberg, FactSet, and Zacks each publish their own set of analysts' EPS forecasts for companies. These services do not reveal (1) the analysts who are solicited for forecasts or (2) the identity of the analysts who actually provide the EPS forecasts that are used in the compilations published by the services. S&P, I/B/E/S, Bloomberg, FactSet, and First Call are fee-based services. These services usually provide detailed reports and other data in addition to analysts' EPS forecasts. In contrast, Thompson Reuters and Zacks do provide limited EPS forecast data free-of-charge on the Internet. Yahoo finance (http://finance.yahoo.com) lists Thompson Reuters as the source of its summary EPS forecasts. Zacks (www.zacks.com) publishes its summary forecasts on its website. Zacks estimates are also available on other websites, such as MSN.money (http://money.msn.com).

Q. WHICH OF THE EPS FORECASTS IS USED IN DEVELOPING A DCF GROWTH RATE?

A. I am using the three-to-five- year EPS growth rate forecasts of analysts, which are often referred to as the long-term EPS growth rate forecasts.

Q. WHY DO YOU NOT RELY EXCLUSIVELY ON THE EPS FORECASTS OF WALL STREET ANALYSTS IN ARRIVING AT A DCF GROWTH RATE FOR THE PROXY GROUP?

A. There are several issues with using the EPS growth rate forecasts of Wall Street analysts as DCF growth rates. First, the appropriate growth rate in the DCF model is the dividend growth rate, not the earnings growth rate. Nonetheless, over the very long term, dividend and earnings will grow at a similar growth rate. Therefore, consideration must be given to other indicators of growth, including prospective dividend growth, internal growth, as well as projected earnings growth. Second, a study by Lacina, Lee, and Xu has shown that analysts' three-to-five year EPS growth rate forecasts are not more accurate at forecasting future earnings than naïve random walk forecasts of future earnings.[24] Employing data over a 20-year period, these authors demonstrate that using the most recent year's actual EPS figure to forecast EPS in the next three-to-five years proved to be just as accurate as using the EPS estimates from analysts' three-to-five year EPS growth rate forecasts. In the authors' opinion, these results indicate that analysts' long-term earnings growth-rate forecasts should be used with caution as inputs for valuation and cost of capital purposes. Finally, and most significantly, it is well known that the long-term EPS growth-rate forecasts of Wall Street securities analysts are overly optimistic and upwardly biased. This has been demonstrated in a number of academic studies over the years.[25] Hence, using these growth rates as a DCF growth rate will provide an overstated equity cost rate. On this issue, a study by Easton and Sommers found that optimism in analysts' growth rate forecasts

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[24] M. Lacina, B. Lee & Z. Xu, *Advances in Business and Management Forecasting (Vol. 8),* Kenneth D. Lawrence, Ronald K. Klimberg (ed.), Emerald Group Publishing Limited(2011), pp.77-101.

[25] The studies that demonstrate analysts' long-term EPS forecasts are overly-optimistic and upwardly biased include: R.D. Harris, "The Accuracy, Bias, and Efficiency of Analysts' Long Run Earnings Growth Forecasts," *Journal of Business Finance & Accounting*, pp. 725-55 (June/July 1999); P. DeChow, A. Hutton, and R. Sloan, "The Relation Between Analysts' Forecasts of Long-Term Earnings Growth and Stock Price Performance Following Equity Offerings," *Contemporary Accounting Research* (2000); K. Chan, L., Karceski, J., & Lakonishok, J., "The Level and Persistence of Growth Rates," *Journal of Finance,* pp. 643−684, (2003); M. Lacina, B. Lee, and Z. Xu, *Advances in Business and Management Forecasting (Vol. 8),* Kenneth D. Lawrence, Ronald K. Klimberg (ed.), Emerald Group Publishing Limited, pp.77-101; and Marc H. Goedhart, Rishi Raj, and Abhishek Saxena, "Equity Analysts, Still Too Bullish," *McKinsey on Finance*, pp. 14-17, (Spring 2010).

leads to an upward bias in estimates of the cost of equity capital of almost 3.0 percentage points.[26]

Q. ARE THE PROJECTED EPS GROWTH RATES OF *VALUE LINE* ALSO OVERLY OPTIMISTIC AND UPWARDLY BIASED?

A. Yes. A study by Szakmary, Conover, and Lancaster evaluated the accuracy of *Value Line*'s three-to-five-year EPS growth rate forecasts using companies in the Dow Jones Industrial Average over a 30-year time period and found these forecasted EPS growth rates to be significantly higher than the EPS growth rates that these companies subsequently achieved.[27]

Q. IS IT YOUR OPINION THAT STOCK PRICES REFLECT THE UPWARD BIAS IN THE EPS GROWTH RATE FORECASTS?

A. Yes, I do believe that investors are well aware of the bias in analysts' EPS growth-rate forecasts, and therefore stock prices reflect the upward bias.

Q. HOW DOES THAT AFFECT THE USE OF THESE FORECASTS IN A DCF EQUITY COST RATE STUDY?

A. According to the DCF model, the equity cost rate is a function of the dividend yield and expected growth rate. Because I believe that

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[26] Peter D. Easton & Gregory A. Sommers, *Effect of Analysts' Optimism on Estimates of the Expected Rate of Return Implied by Earnings Forecasts*, 45 J. ACCT. RES. 983–1015 (2007).

[27] Szakmary, A., Conover, C., & Lancaster, C. (2008). "An Examination of *Value Line*'s Long-Term Projections," *Journal of Banking & Finance*, May 2008, pp. 820-33.

investors are aware of the upward bias in analysts' long-term EPS growth rate forecasts, stock prices reflect the bias. Thus, the DCF growth rate must be adjusted downward from the projected EPS growth rate to reflect this upward bias.

Q. PLEASE DISCUSS THE HISTORICAL GROWTH OF THE COMPANIES IN THE PROXY GROUPS, AS PROVIDED BY *VALUE LINE.*

A. Page 3 of Exhibit JRW-7 provides the five- and ten- year historical growth rates for EPS, DPS, and BVPS for the companies in the two proxy groups, as published in the *Value Line Investment Survey.* The median historical growth measures for EPS, DPS, and BVPS for the Electric Proxy Group, as provided in Panel A, range from 4.0% to 5.0%, with an average of the medians of 4.3%. For the Hevert Proxy Group, as shown in Panel B of page 3 of Exhibit JRW-7, the historical growth measures in EPS, DPS, and BVPS, as measured by the medians, range from 4.0% to 6.3%, with an average of the medians of 4.8%.

Q. PLEASE SUMMARIZE *VALUE LINE'S* PROJECTED GROWTH RATES FOR THE COMPANIES IN THE PROXY GROUPS.

A. *Value Line's* projections of EPS, DPS, and BVPS growth for the companies in the proxy groups are shown on page 4 of Exhibit JRW-7. As stated above, due to the presence of outliers, the medians are used in the analysis. For the Electric Proxy Group, as shown in Panel A of page 4 of Exhibit JRW-7, the medians range from 4.5% to 5.8%, with an average of the medians of 5.1%. The range of the medians for the Hevert Proxy Group, shown in Panel B of page 4 of Exhibit JRW-7, is from 4.3% to 5.8%, with an average of the medians of 5.1%.

Also provided on page 4 of Exhibit JRW-7 are the prospective sustainable growth rates for the companies in the two proxy groups as measured by *Value Line*'s average projected retention rate and return on shareholders' equity. As noted above, sustainable growth is a significant and a primary driver of long-run earnings growth. For the Electric and Hevert Proxy Groups, the median prospective sustainable growth rates are 3.6% and 3.4%, respectively.

Q. PLEASE ASSESS GROWTH FOR THE PROXY GROUPS AS MEASURED BY ANALYSTS' FORECASTS OF EXPECTED FIVE-YEAR EPS GROWTH.

A. Yahoo, Zacks, and Reuters collect, summarize, and publish Wall Street analysts' five-year EPS growth-rate forecasts for the companies in the proxy groups. These forecasts are provided for the companies in the proxy groups on page 5 of Exhibit JRW-7. I have reported both the mean and median growth rates for the groups. Since there is considerable overlap in analyst coverage between the three services, and not all of the companies have forecasts from the different services, I have averaged the expected five-year EPS growth rates from the three services for each company to arrive at an expected EPS growth rate for each company. The mean/median of analysts' projected EPS growth rates for the Electric and Hevert Proxy Groups are 4.9%/4.7% and 5.4%/5.4%, respectively.[28]

Q. PLEASE SUMMARIZE YOUR ANALYSIS OF THE HISTORICAL AND PROSPECTIVE GROWTH OF THE PROXY GROUPS.

A. Page 6 of Exhibit JRW-7 shows the summary DCF growth rate indicators for the proxy groups.

The historical growth rate indicators for my Electric Proxy Group imply a baseline growth rate of 4.3%. The average of the projected EPS, DPS, and BVPS growth rates from *Value Line* is 5.1%, and *Value Line*'s projected sustainable growth rate is 3.6%. The projected EPS growth rates of Wall Street analysts for the Electric Proxy Group are 4.9% and 4.7% as measured by the mean and median growth rates. The overall range for the projected growth-rate indicators (ignoring historical growth) is 3.6% to 5.1%. Giving primary weight to the projected EPS growth rate of Wall Street analysts, I believe that the appropriate projected growth rate is 5.0%. This

[28] Given variation in the measures of central tendency of analysts' projected EPS growth rates proxy groups, I have considered both the means and medians figures in the growth rate analysis.

growth rate figure is in the upper end of the range of historic and projected growth rates for the Electric Proxy Group.

For the Hevert Proxy Group, the historical growth rate indicators suggest a growth rate of 4.8%. The average of the projected EPS, DPS, and BVPS growth rates from *Value Line* is 5.1%, and *Value Line*'s projected sustainable growth rate is 3.4%. The projected EPS growth rates of Wall Street analysts are 5.4% as measured by both the mean and median growth rates. The overall range for the projected growth rate indicators is 3.4% to 5.4%. Giving primary weight to the projected EPS growth rate of Wall Street analysts, I believe that the appropriate projected growth rate is 5.4%. This growth rate figure is in the upper end of the range of historic and projected growth rates for the Hevert Proxy Group.

Q. BASED ON THE ABOVE ANALYSIS, WHAT ARE YOUR INDICATED COMMON EQUITY COST RATES FROM THE DCF MODEL FOR THE PROXY GROUPS?

A. My DCF-derived equity cost rates for the groups are summarized on page 1 of Exhibit JRW-7 and in Table 5 below.

Table 5

DCF-Derived Equity Cost Rate/ROE

	Dividend Yield	1 + ½ Growth Adjustment	DCF Growth Rate	Equity Cost Rate
Electric Proxy Group	**3.15%**	**1.02500**	**5.00%**	**8.25%**
Hevert Proxy Group	**2.90%**	**1.02700**	**5.40%**	**8.40%**

The result for the Electric Proxy Group is the 3.15% dividend yield, times the one and one-half growth adjustment factor of 1.02500, plus the DCF growth rate of 5.00%, which results in an equity cost rate of 8.25%. The result for the Hevert Proxy Group is 8.40%, which includes a dividend yield of 2.90%, a growth adjustment factor of 1.0270, and a DCF growth rate of 5.40%.

C. Capital Asset Pricing Model

Q. PLEASE DISCUSS THE CAPM.

A. The CAPM is a risk premium approach to gauging a firm's cost of equity capital. According to the risk premium approach, the cost of equity is the sum of the interest rate on a risk-free bond (R_f) and a risk premium (RP), as in the following:

$$k = R_f + RP$$

The yield on long-term U.S. Treasury securities is normally used as R_f. Risk premiums are measured in different ways. The CAPM is a theory of the risk and expected returns of common stocks. In the CAPM, two types of risk are associated with a stock: firm-specific risk or unsystematic risk, and market or systematic risk, which is measured by a firm's beta. The only risk that investors receive a return for bearing is systematic risk.

According to the CAPM, the expected return on a company's stock, which is also the equity cost rate (K), is expressed as:

$$K = (R_f) + ß * [E(R_m) - (R_f)]$$

Where:

- *K* represents the estimated rate of return on the stock;
- $E(R_m)$ represents the expected rate of return on the overall stock market. Frequently, the S&P 500 is used as a proxy for the "market";
- (R_f) represents the risk-free rate of interest;
- $[E(R_m) - (R_f)]$ represents the expected equity or market risk premium—the excess rate of return that an investor expects to receive above the risk-free rate for investing in risky stocks; and
- *Beta*—(ß) is a measure of the systematic risk of an asset.

To estimate the required return or cost of equity using the CAPM requires three inputs: the risk-free rate of interest (R_f), the beta (ß), and the expected equity or market risk premium $[E(R_m) - (R_f)]$. R_f is the easiest of the inputs to measure – it is represented by the yield on long-term U.S. Treasury bonds. ß, the measure of systematic risk, is a little more difficult to measure because there are different opinions about what adjustments, if any, should be made to historical betas due to their tendency to regress to 1.0 over time. And finally, the most difficult input to measure is the expected equity or market risk premium ($E(R_m)$ - (R_f)). I will discuss each of these inputs below.

Q. PLEASE DISCUSS EXHIBIT JRW-8.

A. Exhibit JRW-8 provides the summary results for my CAPM study. Page 1 shows the results, and the following pages contain the supporting data.

Q. PLEASE DISCUSS THE RISK-FREE INTEREST RATE.

A. The yield on long-term U.S. Treasury bonds has usually been viewed as the risk-free rate of interest in the CAPM. The yield on long-term U.S. Treasury bonds, in turn, has been considered to be the yield on U.S. Treasury bonds with 30-year maturities.

Q. WHAT RISK-FREE INTEREST RATE ARE YOU USING IN YOUR CAPM?

A. As shown on page 2 of Exhibit JRW-8, the yield on 30-year U.S. Treasury bonds has been in the 2.0% to 4.0% range over the 2013–2020 time period. The current 30-year Treasury yield is near the bottom of this range. Given the recent range of yields, I have chosen to use the top end of the range as my risk-free interest rate. Therefore, I am using 3.75% as the risk-free rate, or R_f, in my CAPM.

This is equal to the normalized risk-free interest rate used by the investment advisory firm Duff & Phelps.[29]

Q. DOES YOUR 3.75% RISK-FREE INTEREST RATE TAKE INTO CONSIDERATION FORECASTS OF HIGHER INTEREST RATES?

A. No, it does not. As I stated before, forecasts of higher interest rates have been notoriously wrong for a decade. My 3.75% risk-free interest rate takes into account the range of interest rates in the past and effectively synchronizes the risk-free rate with the market risk premium. The risk-free rate and the market risk premium are interrelated in that the market risk premium is developed in relation to the risk-free rate. As discussed below, my market risk premium is based on the results of many studies and surveys that have been published over time. Therefore, my risk-free interest rate of 3.75% is effectively a normalized risk-free rate of interest.

Q. WHAT BETAS ARE YOU EMPLOYING IN YOUR CAPM?

A. Beta (ß) is a measure of the systematic risk of a stock. The market, usually taken to be the S&P 500, has a beta of 1.0. The beta of a stock with the same price movement as the market also has a beta of 1.0. A stock with price movement greater than that of the market, such as a technology stock, is riskier than the market and has a beta greater than 1.0. A stock with below average price movement, such

[29] https://www.duffandphelps.com/insights/publications/valuation-insights/valuation-insights-first-quarter-2019/us-equity-risk-premium-recommendation.

as that of a regulated public utility, is less risky than the market and has a beta less than 1.0. Estimating a stock's beta involves running a linear regression of a stock's return on the market return.

As shown on page 3 of Exhibit JRW-8, the slope of the regression line is the stock's ß. A steeper line indicates that the stock is more sensitive to the return on the overall market. This means that the stock has a higher ß and greater-than-average market risk. A less steep line indicates a lower ß and less market risk.

Several online investment information services, such as Yahoo and Reuters, provide estimates of stock betas. Usually these services report different betas for the same stock. The differences are usually due to: (1) the time period over which ß is measured; and (2) any adjustments that are made to reflect the fact that betas tend to regress to 1.0 over time. In estimating an equity cost rate for the proxy groups, I am using the betas for the companies as provided in the *Value Line Investment Survey*. As shown on page 3 of Exhibit JRW-8, the median betas for the companies in both the Electric and Hevert Proxy Groups are 0.55.

Q. PLEASE DISCUSS THE MARKET RISK PREMIUM.

A. The market risk premium is equal to the expected return on the stock market (e.g., the expected return on the S&P 500, $E(R_m)$ minus the risk-free rate of interest (R_f)). The market risk premium is the difference in the expected total return between investing in equities and investing in "safe" fixed-income assets, such as long-term government bonds. However, while the market risk premium is easy to define conceptually, it is difficult to measure because it requires an estimate of the expected return on the market - $E(R_m)$. As is discussed below, there are different ways to measure $E(R_m)$, and studies have come up with significantly different magnitudes for $E(R_m)$. As Merton Miller, the 1990 Nobel Prize winner in economics indicated, $E(R_m)$ is very difficult to measure and is one of the great mysteries in finance.[30]

Q. PLEASE DISCUSS THE ALTERNATIVE APPROACHES TO ESTIMATING THE MARKET RISK PREMIUM.

A. Page 4 of Exhibit JRW-8 highlights the primary approaches to, and issues in, estimating the expected market risk premium. The traditional way to measure the market risk premium was to use the difference between historical average stock and bond returns. In this case, historical stock and bond returns, also called *ex post* returns, were used as the measures of the market's expected return (known as the *ex ante* or forward-looking expected return). This type of historical evaluation of stock and bond returns is often called the "Ibbotson approach" after Professor Roger Ibbotson, who

[30] Merton Miller, "The History of Finance: An Eyewitness Account," *Journal of Applied Corporate Finance*, 2000, p. 3.

popularized this method of using historical financial market returns as measures of expected returns. However, this historical evaluation of returns can be a problem because: (1) *ex post* returns are not the same as *ex ante* expectations; (2) market risk premiums can change over time, increasing when investors become more risk-averse and decreasing when investors become less risk-averse; and (3) market conditions can change such that *ex post* historical returns are poor estimates of *ex ante* expectations.

The use of historical returns as market expectations has been criticized in numerous academic studies as discussed later in my testimony. The general theme of these studies is that the large equity risk premium discovered in historical stock and bond returns cannot be justified by the fundamental data. These studies, which fall under the category "*Ex Ante* Models and Market Data," compute *ex ante* expected returns using market data to arrive at an expected equity risk premium. These studies have also been called "Puzzle Research" after the famous study by Mehra and Prescott in which the authors first questioned the magnitude of historical equity risk premiums relative to fundamentals.[31]

[31] Rajnish Mehra & Edward C. Prescott, "The Equity Premium: A Puzzle," *Journal of Monetary Economics,* 145 (1985).

In addition, there are a number of surveys of financial professionals regarding the market risk premium, as well as several published surveys of academics on the equity risk premium. *CFO Magazine* conducts a quarterly survey of CFOs, which includes questions regarding their views on the current expected returns on stocks and bonds. Usually, over 200 CFOs participate in the survey.[32] Questions regarding expected stock and bond returns are also included in the Federal Reserve Bank of Philadelphia's annual survey of financial forecasters, which is published as the *Survey of Professional Forecasters*.[33] This survey of professional economists has been published for almost 50 years. In addition, Pablo Fernandez conducts annual surveys of financial analysts and companies regarding the equity risk premiums used in their investment and financial decision-making.[34]

Q. PLEASE PROVIDE A SUMMARY OF THE MARKET RISK PREMIUM STUDIES.

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[32] DUKE/CFO Magazine Global Business Outlook Survey (https://www.cfosurvey.org).

[33] Federal Reserve Bank of Philadelphia, *Survey of Professional Forecasters* (Mar. 22, 2019), https://www.philadelphiafed.org/-/media/research-and-data/real-time-center/survey-of-professional-forecasters/2019/spfq119.pdf?la=en. The Survey of Professional Forecasters was formerly conducted by the American Statistical Association (ASA) and the National Bureau of Economic Research (NBER) and was known as the ASA/NBER survey. The survey, which began in 1968, is conducted each quarter. The Federal Reserve Bank of Philadelphia, in cooperation with the NBER, assumed responsibility for the survey in June 1990.

[34] Pablo Fernandez, Vitaly Pershin, and Isabel Fernandez Acín, "Market Risk Premium and Risk-Free Rate used for 59 countries in 2019: a survey," *IESE Business School,* (Apr. 2019), available at: https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3358901.

A. Derrig and Orr, Fernandez, and Song completed the most comprehensive reviews of the research on the market risk premium.[35] Derrig and Orr's study evaluated the various approaches to estimating market risk premiums, discussed the issues with the alternative approaches, and summarized the findings of the published research on the market risk premium. Fernandez examined four alternative measures of the market risk premium – historical, expected, required, and implied. He also reviewed the major studies of the market risk premium and presented the summary market risk premium results. Song provided an annotated bibliography and highlighted the alternative approaches to estimating the market risk premium.

Page 5 of Exhibit JRW-8 provides a summary of the results of the primary risk premium studies reviewed by Derrig and Orr, Fernandez, and Song, as well as other more recent studies of the market risk premium. In developing page 5 of Exhibit JRW-8, I have categorized the types of studies as discussed on page 4 of Exhibit JRW-8. I have also included the results of studies of the "Building Blocks" approach to estimating the equity risk premium. The Building

[35] *See* Richard Derrig & Elisha Orr, "Equity Risk Premium: Expectations Great and Small," Working Paper (version 3.0), Automobile Insurers Bureau of Massachusetts, (August 28, 2003); Pablo Fernandez, "Equity Premium: Historical, Expected, Required, and Implied," IESE Business School Working Paper, (2007); Zhiyi Song, "The Equity Risk Premium: An Annotated Bibliography," CFA Institute, (2007).

Blocks approach is a hybrid approach employing elements of both historical and *ex ante* models.

Q. PLEASE DISCUSS PAGE 5 OF EXHIBIT JRW-8.

A. Page 5 of Exhibit JRW-8 provides a summary of the results of the market risk premium studies that I have reviewed. These include the results of: (1) the various studies of the historical risk premium, (2) *ex ante* market risk premium studies, (3) market risk premium surveys of CFOs, financial forecasters, analysts, companies and academics, and (4) the Building Blocks approach to the market risk premium. There are results reported for over 30 studies, and the median market risk premium of these studies is 4.83%.

Q. PLEASE HIGHLIGHT THE RESULTS OF MORE RECENT RISK PREMIUM STUDIES AND SURVEYS.

A. The studies cited on page 5 of Exhibit JRW-8 include every market risk premium study and survey I could identify that was published over the past 15 years and that provided a market risk premium estimate. Many of these studies were published prior to the financial crisis that began in 2008. In addition, some of these studies were published in the early 2000s at the market peak. It should be noted that many of these studies (as indicated) used data over long periods of time (as long as 50 years of data) and so were not estimating a market risk premium as of a specific point in time (e.g., the year

2001). To assess the effect of the earlier studies on the market risk premium, I have reconstructed page 5 of Exhibit JRW-8 on page 6 of Exhibit JRW-8; however, I have eliminated all studies dated before January 2, 2010. The median market risk premium estimate for this subset of studies is 5.13%.

Q. PLEASE SUMMARIZE THE MARKET RISK PREMIUM STUDIES AND SURVEYS.

A. As noted above, there are three approaches to estimating the market risk premium – historic stock and bond returns, ex ante or expected returns models, and surveys. The studies on page 6 of Exhibit JRW-8 can be summarized in the following manners:

Historic Stock and Bond Returns - Historic stock and bond returns suggest a market risk premium in the 4.40% to 6.43% range, depending on whether one uses arithmetic or geometric mean returns.

Ex Ante Models - Market risk premium studies that use expected or ex ante return models indicate a market risk premium in the range of 4.29% to 6.00%.

Surveys - Market risk premiums developed from surveys of analysts, companies, financial professionals, and academics are lower, with a range from 1.85% to 5.70%.

Q. PLEASE HIGHLIGHT THE EX ANTE MARKET RISK PREMIUM STUDIES AND SURVEYS THAT YOU BELIEVE ARE MOST TIMELY AND RELEVANT.

A. I will highlight several studies/surveys.

CFO Magazine conducts a quarterly survey of CFOs, which includes questions regarding their views on the current expected returns on stocks and bonds. In the December 2019 CFO survey conducted by *CFO Magazine* and Duke University, which included approximately 400 responses, the expected 10-year market risk premium was 4.99% (with an expected S&P 500 stock return of 6.81% and a current 10-year Treasury yield of 1.82%).[36] Figure 4, below, shows the market risk premium associated with the CFO Survey, which has been in the 4.0% range in recent years.

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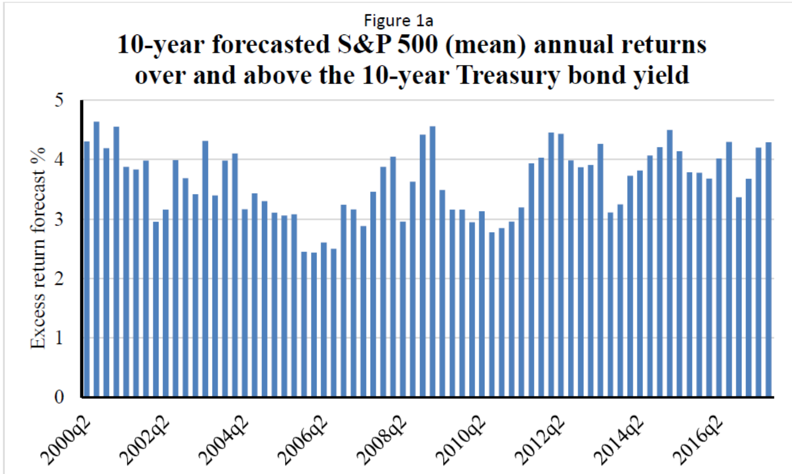
[36] DUKE/CFO Magazine Global Business Outlook Survey, at 38, (December), https://www.cfosurvey.org/wp-content/uploads/2019/12/2019-Q4-US-Toplines.pdf.

Figure 4

Market Risk Premium

CFO Survey



Source:
https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3151162

Pablo Fernandez conducts annual surveys of financial analysts and companies regarding the equity risk premiums used in their investment and financial decision-making.[37] His survey results are included on pages 5 and 6 of Exhibit JRW-8. The results of his 2019 survey of academics, financial analysts, and companies, which included 4,000 responses, indicated a mean market risk premium employed by U.S. analysts and companies of 5.6%.[38] His estimated market risk premium for the U.S. has been in the 5.00%-5.60% range in recent years.

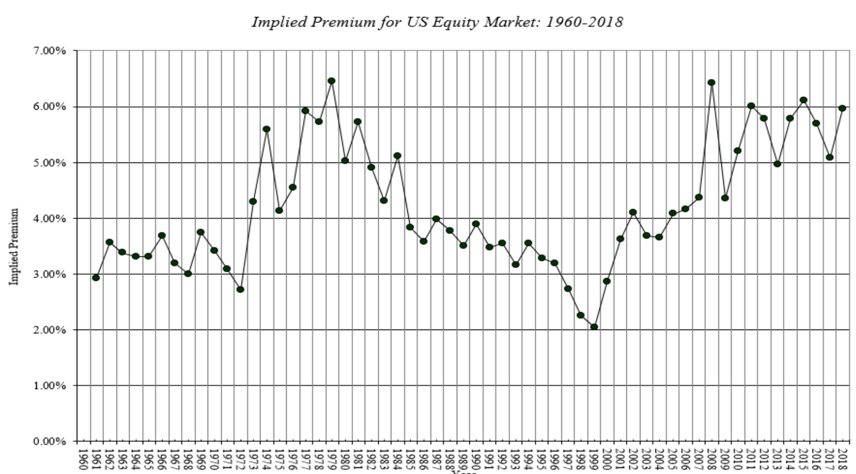
[37] Pablo Fernandez, Vitaly Pershin, and Isabel Fernandez Acín, “Market Risk Premium and Risk-Free Rate used for 59 countries in 2019: a survey,” *IESE Business School,* (Apr. 2019), available at: https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3358901.

[38] *Ibid.* p. 3.

Professor Aswath Damodaran of New York University, a leading expert on valuation and the market risk premium, provides a monthly updated market risk premium based on projected S&P 500 EPS and stock price level and long-term interest rates. His estimated market risk premium, shown graphically in Figure 5, below, for the past 20 years, has primarily been in the range of 5.0% to 6.0% since 2010.

Figure 5

Damodaran Market Risk Premium



Source: http://pages.stern.nyu.edu/~adamodar/

Duff & Phelps, an investment advisory firm, provides recommendations for the risk-free interest rate and market risk premiums to be used in calculating the cost of capital data. Its recommendations over the 2008-2019 time periods are shown on page 7 of Exhibit JRW-8. Duff & Phelps' recommended market risk premium has been in the 5.0% to 6.0% range over the past decade.

Most recently, in the third quarter of 2019, Duff & Phelps increased its recommended market risk premium from 5.0% to 5.50%.[39]

KPMG is one of the largest public accounting firms in the world. Its recommended market risk premium over the 2013-2019 time period is shown in Panel A of page 8 of Exhibit JRW-8. KPMG's recommended market risk premium has been in the 5.50% to 6.50% range over this time period. In the third quarter of 2019, KPMG increased its estimated market risk premium from 5.50% to 5.75%.[40]

Finally, the website *market-risk-premia.com* provides risk-free interest rates, implied market risk premiums, and overall cost of capital for 36 countries around the world. These parameters for the U.S. over the 2012-2019 time period are shown in Panel B of page 8 of Exhibit JRW-8. As of November 30, 2019, *market-risk-premia.com* estimated an implied cost of capital for the U.S. of 5.78%, consisting of a risk-free rate of 1.78% and an implied market risk premium of 4.00.[41]

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[39] Duff & Phelps, "U.S. Equity Risk Premium Recommendation," (Feb. 19, 2019), https://www.duffandphelps.com/insights/publications/cost-of-capital/recommended-us-equity-risk-premium-and-corresponding-risk-free-rates.

[40] KPMG, "Equity Market Risk Premium Research Summary," (September, 2019), https://assets.kpmg/content/dam/kpmg/nl/pdf/2019/advisory/equity-market-risk-premium-research-summary-300919.pdf

[41] Market-Risk-Premia.com, "Implied Market-risk-premia (market risk premium): USA," http://www.market-risk-premia.com/us.html.

Q. GIVEN THESE RESULTS, WHAT MARKET RISK PREMIUM ARE YOU USING IN YOUR CAPM?

A. The studies on page 6 of Exhibit JRW-8, and more importantly the more recent and relevant studies just cited, suggest that the appropriate market risk premium in the U.S. is in the 4.0% to 6.0% range. I will use an expected market risk premium of 5.75%, which is in the upper end of the range, as the market risk premium. I gave most weight to the market risk premium estimates of the KPMG, CFO Survey, Duff & Phelps, the Fernandez survey, and Damodaran. This is a conservatively high estimate of the market risk premium considering the many studies and surveys of the market risk premium.

Q. WHAT EQUITY COST RATE IS INDICATED BY YOUR CAPM ANALYSIS?

A. The results of my CAPM study for the proxy groups are summarized on page 1 of Exhibit JRW-8 and in Table 6 below.

Table 6

CAPM-Derived Equity Cost Rate/ROE

$$K = (R_f) + ß * [E(R_m) - (R_f)]$$

	Risk-Free Rate	Beta	Equity Risk Premium	Equity Cost Rate
Electric Proxy Group	3.75%	0.55	5.75%	7.3%
Hevert Proxy Group	3.75%	0.55	5.75%	7.2%

For the both the Electric and Hevert Proxy Groups, the risk-free rate of 3.75% plus the product of the beta of 0.55 times the equity risk premium of 5.75% results in a 6.9% equity cost rate.

Q. THESE CAPM EQUITY COST RATES SEEM LOW. WHY IS THAT?

A. One major factor is that the riskiness of utilities has declined in recent years, and this lower risk is reflected in their betas. Utility betas have been in the .70 to .75 range in recent years. But they have declined in the past year and are now are primarily in the 0.55 to 0.60 range.

D. Equity Cost Rate Summary

Q. PLEASE SUMMARIZE THE RESULTS OF YOUR EQUITY COST RATE STUDIES.

A. My DCF analyses for the Electric and Hevert Proxy Groups indicate equity cost rates of 8.25% and 8.40%, respectively. The CAPM equity cost rates for both groups are 6.90%. Table 7, below, shows these results.

Table 7

ROEs Derived from DCF and CAPM Models

	DCF	CAPM
Electric Proxy Group	**8.25%**	**6.90%**
Hevert Proxy Group	**8.40%**	**6.90%**

Q. GIVEN THESE RESULTS, WHAT IS YOUR ESTIMATED EQUITY COST RATE FOR THE GROUPS?

A. Given these results, I conclude that the appropriate equity cost rate for companies in the Electric and Hevert Proxy Groups is in the 6.90% to 8.40% range.

Q. WHAT EQUITY COST RATE ARE YOU RECOMMENDING FOR DEC?

A. Given these results, I am recommending an equity cost rate or ROE for DEC of 8.40%. I believe that this equity cost rate accurately reflects the market cost of equity capital currently. As I previously noted, capital costs in the U.S. remain low, with low inflation and interest rates, very modest economic growth, and the stock market at an all-time high. I believe that this range accurately reflects current capital market data. However, given that I am recommending a capital structure with a lower common equity ratio and higher financial risk than proposed by the Company, as a primary ROE for DEC, I am recommending 9.0%. I recognize that this figure is below the authorized ROEs for electric utility companies nationally. Therefore, as a primary ROE for DEC, I am recommending 9.0%. This recommendation gives weight to the higher authorized ROEs for electric utility companies.

Q. PLEASE INDICATE WHY YOUR EQUITY COST RATE RECOMMENDATIONS OF 9.0%/8.40% ARE APPROPRIATE FOR DEC.

A. There are a number of reasons why an equity cost rate of 9.0%/8.40% is appropriate and fair for the Company in this case:

1. DEC's investment risk, as indicated by its S&P and Moody's credit ratings of A- and A1, is below the averages of the Electric and Hevert Proxy Groups;

2. As shown in Exhibits JRW-5, capital costs for utilities, as indicated by long-term utility bond yields, are still at historically low levels. In addition, given low inflationary expectations and slow global economic growth, interest rates are likely to remain at low levels for some time;

3. As shown in Exhibit JRW-5, the electric utility industry is among the lowest risk industries in the U.S. as measured by beta. Most notably, the betas for electric utilities have been declining in recent years, which indicates the risk of the industry has declined. Overall, the cost of equity capital for this industry is the lowest in the U.S., according to the CAPM;

4. I have recommended an equity cost rate at the high end of the range of my ROE outcomes;

5. As shown in Figure 3, the authorized ROEs for electric utility and gas distribution companies have declined in recent years. On an annual basis, these authorized ROEs for electric utilities have declined from an average of 10.01% in 2012, 9.8% in 2013, 9.76% in 2014, 9.58% in 2015, 9.60% in 2016, 9.68% in 2017, 9.56% in 2018, and 9.64% in of 2019, according to Regulatory Research Associates.[42] In my opinion, these authorized ROEs have lagged behind capital market cost rates, or in other words, authorized ROEs have been slow to reflect low capital market cost rates. However, the <u>trend</u> has been towards lower ROEs, and the <u>norm</u> now is below ten percent. Hence, I believe that my recommended ROE reflects the low capital cost rates in today's markets, and these low capital cost rates are finally being recognized by state utility commissions.

Q. DO YOU BELIEVE THAT YOUR ROE RECOMMENDATION MEETS *HOPE* AND *BLUEFIELD* STANDARDS?

A. Yes, I do. As previously noted, according to the *Hope* and *Bluefield* decisions, returns on capital should be: (1) comparable to returns investors expect to earn on other investments of similar risk; (2) sufficient to assure confidence in the company's financial integrity; and (3) adequate to maintain and support the company's credit and to attract capital.

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[42] S&P Global Market Intelligence, RRA *Regulatory Focus*, 2019.

Q. PLEASE ALSO DISCUSS YOUR RECOMMENDATION IN LIGHT OF A MOODY'S PUBLICATION ON ROES AND CREDIT QUALITY.

A. In an article published by Moody's on utility ROEs and credit quality, Moody's recognizes that authorized ROEs for electric and gas companies are declining due to lower interest rates. The article explains:[43]

> The credit profiles of US regulated utilities will remain intact over the next few years despite our expectation that regulators will continue to trim the sector's profitability by lowering its authorized returns on equity (ROE). Persistently low interest rates and a comprehensive suite of cost recovery mechanisms ensure a low business risk profile for utilities, prompting regulators to scrutinize their profitability, which is defined as the ratio of net income to book equity. We view cash flow measures as a more important rating driver than authorized ROEs, and we note that regulators can lower authorized ROEs without hurting cash flow, for instance by targeting depreciation, or through special rate structures.

Moody's indicates that with the lower authorized ROEs, electric and gas companies are earning ROEs of 9.0% to 10.0%, yet this is not impairing their credit profiles and is not deterring them from raising record amounts of capital.

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[43] Moody's Investors Service, "Lower Authorized Equity Returns Will Not Hurt Near-Term Credit Profiles," March 10, 2015.

With respect to authorized ROEs, Moody's recognizes that utilities and regulatory commissions are having trouble justifying higher ROEs in the face of lower interest rates and cost recovery mechanisms:[44]

> Robust cost recovery mechanisms will help ensure that US regulated utilities' credit quality remains intact over the next few years. As a result, falling authorized ROEs are not a material credit driver at this time, but rather reflect regulators' struggle to justify the cost of capital gap between the industry's authorized ROEs and persistently low interest rates. We also see utilities struggling to defend this gap, while at the same time recovering the vast majority of their costs and investments through a variety of rate mechanisms.

Overall, this article further supports the prevailing/emerging belief that lower authorized ROEs are unlikely to hurt the financial integrity of utilities or their ability to attract capital.

Q. ARE UTILITIES ABLE TO ATTRACT CAPITAL WITH THE LOWER ROES?

A. Moody's also highlights in the article that utilities are raising about $50 billion a year in debt capital, despite the lower ROEs.

[44] *Id.*

VI. CRITIQUE OF DEC'S RATE OF RETURN TESTIMONY

Q. PLEASE SUMMARIZE THE COMPANY'S COST OF EQUITY CAPITAL RECOMMENDATION.

A. The Company has proposed a capital structure of 47.00% long-term debt and 53.00% common equity and a long-term debt cost rate of 4.51%. Mr. Hevert has recommended a common equity cost rate of 10.50%. The Company's overall proposed rate of return is 7.83%.

Q. WHAT ISSUES DO YOU HAVE WITH THE COMPANY'S COST OF EQUITY CAPITAL POSITION?

A. I have a number of issues with the Company's ROE position:

<u>Capital Structure</u> – The Company has proposed a capital structure consisting of 47.00% long-term debt and 53.00% common equity. The Company's proposed capital structure has a higher common equity ratio than the average of the Electric and Hevert Proxy Groups. In my primary rate of return recommendation, I am recommending adjusting DEC's proposed capital structure to use a common equity ratio of 50 percent, as that is more in line with the capital structures of the utilities in the proxy group as well as DEC's parent, Duke Energy. In my alternative rate of return recommendation, I am using DEC's proposed capital structure, but I then employ a lower ROE to reflect the high common equity ratio and lower financial risk of the Company's proposed capitalization.

<u>Capital Market Conditions</u> – Mr. Hevert's analyses and ROE results and recommendations reflect the assumption of higher interest rates and capital costs. However, I show that despite the Federal Reserve's moves to increase the federal funds rate over the 2015-18 time period, interest rates and capital costs remained at low levels. In 2019, interest rates fell dramatically with moderate economic growth and low inflation. The Federal Reserve cut the federal fund rate three times (July, September, and October) and the 30-year yield traded at all-time low levels.

<u>The Company's ROE Analysis is Out-of-Date</u> - The Company's ROE study was prepared in June, 2019, about eight months ago. Since that time, the Federal Reserve has cut the federal funds rate three times and the 30-year Treasury rate has fallen over seventy basis points. Capital costs are much lower now not only than when the Company's ROE study was prepared, but also when it filed its request to increase rates.

<u>DEC's Investment Risk is Below the Averages of the Two Proxy Groups</u> – Mr. Hevert cites the Company's capital expenditures and North Carolina's regulatory environment to imply that DEC is riskier than his proxy group. However, his assessment of DEC's risk is erroneous. The assessment of capital expenditures is part of the credit rating process, and DEC's S&P and Moody's credit rating

suggest that the Company's investment risk is below the averages of the proxy groups.

Disconnect Between Mr. Hevert's Equity Cost Rate Studies and his 10.50% ROE Recommendation – There is a disconnect between Mr. Hevert's equity cost rate results and his 10.50% ROE recommendation. Simply stated, the vast majority of his equity cost rate results point to a lower ROE. In fact, the only results that point to an ROE as high as 10.50% are some of his CAPM/ECAPM results, which as I explain later in my testimony are seriously flawed. As a result, Mr. Hevert's ROE recommendation is based on: (1) the results of only one model (the CAPM); and, even more narrowly, (2) and primarily from *Value Line* data. Otherwise, Mr. Hevert provides no other equity cost rate studies that support his 10.50% ROE recommendation.

DCF Equity Cost Rate - The DCF Equity Cost Rate is estimated by summing the stock's dividend yield and investors' expected long-run growth rate in dividends paid per share. There are several errors regarding Mr. Hevert's DCF analyses: (1) he has given very little weight to his constant-growth DCF results; (2) He has claimed that the DCF results underestimate the market-determined cost of equity capital due to high utility stock valuations and low dividend yields; and (3) he has relied exclusively on the overly optimistic and upwardly biased EPS growth-rate forecasts of Wall Street analysts and *Value Line.*

<u>CAPM Approach</u> - The CAPM approach requires an estimate of the risk-free interest rate, the beta, and the market or equity risk premium. There are two primary issues with Mr. Hevert's CAPM analyses: (1) he has Mr. has employed an ad hoc version of the CAPM, ECAPM, which makes inappropriate adjustments to the risk-free rate and the market risk premium and is an untested model in academic and profession research; and (2) his market risk premiums of 12.25% and 12.15% are exaggerated and do not reflect current market fundamentals. Mr. Hevert has employed analysts' three-to-five-year growth-rate projections for EPS to compute an expected market return and market risk premium. These EPS growth-rate projections and the resulting expected market returns and market risk premiums include highly unrealistic assumptions regarding future economic and earnings growth and stock returns.

<u>Alternative Risk Premium Model</u> - Mr. Hevert estimates an equity cost rate using an alternative risk premium model which he calls the BYRP approach. The risk premium in his BYRP method is based on the historical relationship between the yields on long-term Treasury yields and authorized ROEs for electric utility companies. There are several issues with this approach including: (1) this approach is a

gauge of commission behavior and not investor behavior; (2) Mr. Hevert's methodology produces an inflated measure of the risk premium because his approach uses historical authorized ROEs and Treasury yields, and the resulting risk premium is applied to projected Treasury yields; and (3) the risk premium is inflated as a measure of investor's required risk premium, because electric utility companies have been selling at market-to-book ratios in excess of 1.0. This indicates that the authorized rates of return have been greater than the return that investors require.

<u>Expected Earnings Approach</u> - Mr. Hevert also uses the Expected Earnings approach to estimate an equity cost rate for the Company. Mr. Hevert computes the expected ROE as forecasted by *Value Line* for his proxy group as well as for *Value Line*'s universe of electric utilities. The biggest issue is that the so-called "Expected Earnings" approach does not measure the market cost of equity capital, is independent of most cost of capital indicators, and has several other empirical issues. Therefore, the Commission should ignore Mr. Hevert's "Expected Earnings" approach in determining the appropriate ROE for DEC.

<u>Other Issues</u> - Mr. Hevert also considers several other factors in arriving at his 10.50% ROE recommendation. Mr. Hevert has cited North Carolina's REPS, the Company's high level of capital

expenditures, environmental regulations, coal-fired and nuclear generation. However, these are risk factors considered in the credit-rating process used by major rating agencies. As I noted above, DEC's investment risk as measured by S&P and Moody's is below the average of the proxy groups. Second, Mr. Hevert also considers flotation costs in making his ROE recommendation of 10.50%. However, he has not identified any flotation costs for DEC.

North Carolina Economic Conditions – Mr. Hevert evaluates a number of factors such as employment and income levels and comes to the conclusion that DEC's proposed ROE of 10.50% is fair and reasonable to DEC, its shareholders, and its customers in light of the effect of those changing economic conditions. While I agree economic conditions have improved in North Carolina, the improvements do not necessarily justify such a high rate of return and ROE. Specifically, I highlight the following: (1) DEC's ROE request of 10.50% is almost 100 basis points above the average authorized ROEs for electric utilities over the 2018-19 time period; (2) whereas the unemployment rates in North Carolina and DEC's service territory have fallen by two-thirds since their peaks in the 2009-2010 period, they are both above the national average of 3.90%; and (3) whereas North Carolina's residential electric rates are below the national average, North Carolina's median household income is more than 10% below the U.S. norm.

Capital market conditions, the out-of-date ROE study, DEC's proposed capital structure, and the investment risk of DEC were previously discussed. The other issues are addressed below.

A. The Disconnect Between Mr. Hevert's Equity Cost Rate Results and His 10.50% ROE Recommendation

Q. PLEASE REVIEW MR. HEVERT'S EQUITY COST RATE RESULTS AND HIS 10.50% ROE RECOMMENDATION.

A. Page 1 of Exhibit JRW-9 shows Mr. Hevert's equity cost rate results using the DCF, CAPM, and BYRP approaches. There appears to be a disconnect between these results and his 10.50% ROE recommendation. First, it is very difficult to see exactly how he gets to his 10.50% ROE recommendation. He provides no details on how he weighted his equity cost rate results to get to 10.50%.

Second, the vast majority of his equity cost rate results point to a lower ROE. The average of his DCF results is 8.97%, to which he clearly gave no weight. His BYRP results, which are inflated because he has used projected interest rates, average 9.95%. His CAPM results, calculated using data from Bloomberg and *Value Line*, range from 8.73% to 9.81%. These results clearly do not support a ROE of 10.50%.

Finally, the only results that point to a ROE as high as 10.50% are his ECAPM results using *Value Line* betas. As a result, Mr. Hevert's ROE recommendation is based on: (1) the results of only one ad hoc CAPM model (the ECAPM); and, even more narrowly, (2) only one source of financial information for betas (*Value Line*). In addition, as discussed below, there are a number of empirical issues with the *Value Line* projected EPS growth rates which result in an overstated expected market return and market risk premium. Otherwise, Mr. Hevert provides no other credible equity cost rate studies that support his 10.50% ROE recommendation. Therefore, his ROE recommendation is based on not only one model (ECAPM), but also on only one information source (*Value Line*). There are obvious risks to relying on only one approach and information source to estimate the cost of equity capital.

B. DCF Approach

Q. PLEASE SUMMARIZE MR. HEVERT'S DCF ESTIMATES.

A. On pages 74-83 of his testimony and in Exhibit No. RBH-1, Mr. Hevert develops an equity cost rate by applying the DCF model to the Hevert Proxy Group. Mr. Hevert's DCF results are summarized on page 2 of my Exhibit JRW-9. He uses constant-growth and multistage growth DCF models. Mr. Hevert uses three dividend-yield measures (30, 90, and 180 days) in his DCF models. In his constant-growth and quarterly DCF models, Mr. Hevert has relied on the forecasted EPS growth rates of Zacks, IBES, and *Value Line*. For each model, he reports Mean Low, Mean and Mean High results.

Q. WHAT ARE THE ERRORS IN MR. HEVERT'S DCF ANALYSES?

A. The primary errors in Mr. Hevert's DCF analyses are: (1) the low weight he gives to his constant-growth DCF results, and (2) his exclusive use of the overly optimistic and upwardly biased EPS growth rate forecasts of Wall Street analysts and *Value Line.*

1. The Low Weight Given to the DCF Results

Q. HOW MUCH WEIGHT HAS MR. HEVERT GIVEN HIS DCF RESULTS IN ARRIVING AT AN EQUITY COST RATE FOR THE COMPANY?

A. Apparently, very little, if any. The average of his mean constant-growth and multi-stage DCF equity cost rates is only 8.97%. Had he given these results any weight, he would have arrived at a much lower recommendation for his estimated cost of equity.

2. The DCF Model Understates the Cost of Equity Capital

Q. PLEASE EXPLAIN MR. HEVERT'S CLAIM THAT THE DCF MODEL UNDERSTATES THE COST OF EQUITY CAPITAL.

A. At pages 5-11 of his testimony, Mr. Hevert expresses concern with the constant-growth DCF model results in light of current capital market conditions, which include high utility stock valuations and low dividend yields. However, Mr. Hevert's arguments on this issue are without merit for the following reasons: (1) he is saying that utility stocks are overvalued, and their stock prices will decline in the future (and therefore their dividend yield will increase). Hence, Mr. Hevert presumes that he knows more than investors in the stock market. If he believes that utility stock prices will decline in the future, he should be recommending a negative expected return because a decline in utility stock prices would produce negative stock returns in the future; (2) the DCF approach directly measures the cost of equity because it uses dividends, stock prices, and expected growth rates; (3) the CAPM is an indirect method of measuring the cost of equity with the only company-specific input being beta. In addition, it is highly dependent on the market risk premium which, as discussed above, is one of the great mysteries in finance; and (4) as discussed below, Mr. Hevert's CAPM result is grossly inflated due to its unrealistic assumptions on future earnings, economic growth, and future stock returns.

Q. ARE THERE OTHER REASONS WHY UTILITY STOCK STOCKS HAVE PERFORMED SO WELL AND HAVE RELATIVELY HIGH VALUATIONS?

A. Yes. As discussed in a Moody's article, utilities have achieved higher market valuations due to cost recovery mechanisms that have reduced the risk of the utility industry, which have led to higher valuation levels.

> As utilities increasingly secure more up-front assurance for cost recovery in their rate proceedings, we think regulators will increasingly view the sector as less risky. The combination of low capital costs, high equity market valuation multiples (which are better than or on par with the broader market despite the regulated utilities' low risk profile), and a transparent assurance of cost recovery tend to support the case for lower authorized returns, although because utilities will argue they should rise, or at least stay unchanged.[45]

Therefore, Mr. Hevert's suggestion that the constant-growth DCF results provide low equity cost rate results due to current market conditions is incorrect. As indicated by Moody's, the lower risk of utilities has led to higher valuation levels.

3. Wall Street Analysts' EPS Growth Rate Forecasts

Q. PLEASE DISCUSS MR. HEVERT'S EXCLUSIVE RELIANCE ON THE PROJECTED GROWTH RATES OF WALL STREET ANALYSTS AND *VALUE LINE* FOR HIS DCF ANALYSIS.

A. It seems highly unlikely that investors today would rely exclusively on the EPS growth rate forecasts of Wall Street analysts and ignore other growth rate measure in arriving at their expected growth rates

[45] Moody's Investors Service, "Lower Authorized Equity Returns Will Not Hurt Near-Term Credit Profiles," March 10, 2015, p. 3.

for equity investments. As I previously stated, the appropriate growth rate in the DCF model is the dividend growth rate, not the earnings growth rate. Hence, consideration must be given to other indicators of growth, including historical prospective dividend growth, internal growth, as well as projected earnings growth.

Finally, and most significantly, it is well-known that the long-term EPS growth rate forecasts of Wall Street securities analysts are overly optimistic and upwardly biased. In addition, as discussed above, the projected EPS growth rate forecasts have been shown to be overly-optimistic and upwardly biased.

Hence, using these growth rates as a DCF growth rate produces an overstated equity cost rate. A 2007 study by Easton and Sommers found that optimism in analysts' earnings growth rate forecasts leads to an upward bias in estimates of the cost of equity capital of almost 3.0 percentage points.[46]

Q. ON PAGES 77-78 OF HIS TESTIMONY, MR. HEVERT CITES NINE DIFFERENT STUDIES TO SUPPORT HIS USE OF ANALYSTS' EPS GROWTH RATE FORECASTS. PLEASE DISCUSS THESE STUDIES.

[46] Easton, P., & Sommers, G. (2007). "Effect of Analysts' Optimism on Estimates of the Expected Rate of Return Implied by Earnings Forecasts." *Journal of Accounting Research*, 45(5), 983–1015.

A. The studies Mr. Hevert cites to support his exclusive use of analysts' EPS growth rate forecasts are all at least 20 years old. There have been many research studies on this topic over the past 20 years. I reviewed these studies earlier in my testimony. The conclusion from the more recent studies is universal – analysts' three-to-five-year EPS growth rate forecasts are overly optimistic and upwardly biased.

C. CAPM Approach

Q. PLEASE DISCUSS MR. HEVERT'S CAPM.

A. On pages 83-91 of his testimony and in Exhibit Nos. RBH-2-RBH-4, Mr. Hevert develops an equity cost rate by applying the CAPM model to the companies in his proxy group. The CAPM approach requires an estimate of the risk-free interest rate, beta, and the market risk premium. Mr. Hevert uses two different measures of the 30-Year Treasury bond yield: (a) current yield of 2.63% and a near-term projected yield of 2.70%; (b) two different betas (an average Bloomberg beta of 0.498 and an average *Value Line* beta of 0.58); and (c) two market risk premium measures – a Bloomberg, DCF-derived market risk premium of 12.25% and a *Value Line* DCF-derived market risk premium of 12.15%. Based on these figures, he finds a CAPM equity cost rate range from 8.73% to 9.81%. Mr. Hevert also employs an ad hoc version of the CAPM, the ECAPM, which makes inappropriate adjustments to the risk-free rate and the market risk premium and is an untested model in academic and profession research. His ECAPM results range from 10.21% to 11.10%. Mr. Hevert's CAPM/ECAPM results are summarized on page 2 of Exhibit JRW-9.

Q. WHAT ARE THE ERRORS IN MR. HEVERT'S CAPM ANALYSES?

A. As explained further below, there are two issues with Mr. Hevert' CAPM analyses: (1) Mr. Hevert has employed an ad hoc version of the CAPM, the ECAPM; and (2) Mr. Hevert's market risk premiums of 12.25% and 12.15% include highly unrealistic assumptions regarding future economic and earnings growth and stock returns.

1. Market Risk Premiums

Q. PLEASE ASSESS MR. HEVERT'S MARKET RISK PREMIUMS DERIVED FROM APPLYING THE DCF MODEL TO THE S&P 500 AND *VALUE LINE INVESTMENT SURVEY*.

A. For his Bloomberg and *Value Line* market risk premiums, Mr. Hevert computes market risk premiums of 12.25% and 12.15%, respectively, by: (1) calculating an expected market return by applying the DCF model to the S&P 500; and then (2) subtracting the current 30-year Treasury bond yield of 2.63% from his estimate of the expected market return. Mr. Hevert also uses (1) a dividend yield of 2.20% and an expected DCF growth rate of 12.68% for Bloomberg and (2) a dividend yield of 2.08% and an expected DCF growth rate of 12.70% for *Value Line.* The resulting expected annual S&P 500 stock market returns using this approach are 14.78% (using Bloomberg three- to five-year EPS growth rate estimates) and 14.88% (using *Value Line* three- to five-year EPS growth rate estimates). These results are not realistic in today's market.

Q. ARE MR. HEVERT'S MARKET RISK PREMIUMS OF 12.25% AND 12.15% REFLECTIVE OF THE MARKET RISK PREMIUMS FOUND IN STUDIES AND SURVEYS OF THE MARKET RISK PREMIUM?

A. No. These are well in excess of market risk premiums: (1) found in studies of the market risk premium by leading academic scholars; (2) produced by analyses of historic stock and bond returns; and (3) found in surveys of financial professionals. Page 5 of Exhibit JRW-8 provides the results of over 30 market risk premium studies from the past 15 years. Historic stock and bond returns suggest a market risk premium in the 4.5% to 7.0% range, depending on whether one uses arithmetic or geometric mean returns. There have been many studies using expected return (also called *ex ante*) models, and their market risk premium results vary from as low as 2.0% to as high as 7.31%. Finally, the market risk premiums developed from surveys of analysts, companies, financial professionals, and academics suggest lower market risk premiums, in a range of from 1.91% to 5.70%. The bottom line is that there is no support in historic return data, surveys, academic studies, or reports for investment firms for market risk premiums as high as those used by Mr. Hevert.

Q. PLEASE AGAIN ADDRESS THE ISSUES WITH ANALYSTS' EPS GROWTH RATE FORECASTS.

A. The key point is that Mr. Hevert's CAPM market risk premium methodology is based entirely on the concept that analyst projections of companies' three-to-five EPS growth rates reflect investors' expected *long-term* EPS growth for those companies. However, this seems highly unrealistic given the research on these projections. As previously noted, numerous studies have shown that the long-term EPS growth rate forecasts of Wall Street securities analysts are overly optimistic and upwardly biased.[47] Moreover, a 2011 study showed that analysts' forecasts of EPS growth over the next three-to-five years earnings are no more accurate than their forecasts of the next single year's EPS growth.[48] The overly-optimistic inaccuracy

[47] Such studies include: R.D. Harris, "The Accuracy, Bias, and Efficiency of Analysts' Long Run Earnings Growth Forecasts," *Journal of Business Finance & Accounting*, pp. 725-55 (June/July 1999); P. DeChow, A. Hutton, and R. Sloan, "The Relation Between Analysts' Forecasts of Long-Term Earnings Growth and Stock Price Performance Following Equity Offerings," *Contemporary Accounting Research* (2000); K. Chan, L., Karceski, J., & Lakonishok, J., "The Level and Persistence of Growth Rates," *Journal of Finance,* pp. 643‒684, (2003); M. Lacina, B. Lee, and Z. Xu, *Advances in Business and Management Forecasting (Vol. 8),* Kenneth D. Lawrence, Ronald K. Klimberg (ed.), Emerald Group Publishing Limited, pp.77-101.

[48] M. Lacina, B. Lee, & Z. Xu, *Advances in Business and Management Forecasting,* Vol. 8, Kenneth D. Lawrence, Ronald K. Klimberg (ed.), Emerald Group Publishing Limited, pp.77-101.

of analysts' growth rate forecasts leads to an upward bias in equity cost estimates that has been estimated at about 300 basis points.[49]

Q. HAVE CHANGES IN REGULATIONS IMPACTED THE UPWARD BIAS IN WALL STREET ANALYSTS' THREE-TO-FIVE YEAR EPS GROWTH RATE FORECASTS?

A. No. A number of the studies I have cited here demonstrate that the upward bias has continued despite changes in regulations and reporting requirements over the past two decades. This observation is highlighted by a 2010 McKinsey study entitled "Equity Analysts: Still Too Bullish," which involved a study of the accuracy of analysts' long-term EPS growth rate forecasts. The authors conclude that after a decade of stricter regulation, analysts' long-term earnings forecasts continue to be excessively optimistic. They made the following observation:[50]

> Alas, a recently completed update of our work only reinforces this view—despite a series of rules and regulations, dating to the last decade, that were intended to improve the quality of the analysts' long-term earnings forecasts, restore investor confidence in them, and prevent conflicts of interest. For executives, many of whom go to great lengths to satisfy Wall Street's expectations in their financial reporting and long-term strategic moves, this is a cautionary tale worth remembering. This pattern confirms our earlier findings that analysts typically

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[49] Peter D. Easton & Gregory A. Sommers, "Effect of Analysts' Optimism on Estimates of the Expected Rate of Return Implied by Earnings Forecasts," 45, *Journal of Accounting Research*, pp. 983–1015 (2007).

[50] Marc H. Goedhart, Rishi Raj, and Abhishek Saxena, "Equity Analysts, Still Too Bullish," *McKinsey on Finance*, pp. 14-17, (Spring 2010) (emphasis added).

> lag behind events in revising their forecasts to reflect new economic conditions. When economic growth accelerates, the size of the forecast error declines; when economic growth slows, it increases. So as economic growth cycles up and down, the actual earnings S&P 500 companies report occasionally coincide with the analysts' forecasts, as they did, for example, in 1988, from 1994 to 1997, and from 2003 to 2006. *Moreover, analysts have been persistently overoptimistic for the past 25 years, with estimates ranging from 10 to 12 percent a year, compared with actual earnings growth of 6 percent. Over this time frame, actual earnings growth surpassed forecasts in only two instances, both during the earnings recovery following a recession. On average, analysts' forecasts have been almost 100 percent too high.*

This is the same observation made in a *Bloomberg Businessweek* article.[51] The author concluded:

> ***The bottom line:*** *Despite reforms intended to improve Wall Street research, stock analysts seem to be promoting an overly rosy view of profit prospects.*

Q. IS THERE OTHER EVIDENCE THAT INDICATES THAT MR. HEVERT'S MARKET RISK PREMIUMS COMPUTED USING S&P 500 EPS GROWTH RATE ARE EXCESSIVE?

A. Beyond my previous discussion of the upwardly biased nature of analysts' projected EPS growth rates, the fact is that long-term EPS growth rates of 12.68% and 12.70% are inconsistent with both

[51] Roben Farzad, "For Analysts, Things Are Always Looking Up," *Bloomberg Businessweek* (June 10, 2010), https://www.bloomberg.com/news/articles/2010-06-10/for-analysts-things-are-always-looking-up.

historic and projected economic and earnings growth in the U.S for several reasons: (1) long-term EPS and economic growth is about one-half of Mr. Hevert's projected EPS growth rates of 12.68% and 12.70%; (2) as discussed below, long-term EPS and Gross Domestic Product (GDP) growth are directly linked; and (3) more recent trends in GDP growth, as well as projections of GDP growth, suggest slower economic and earnings growth in the future.

Long-Term Historic EPS and GDP Growth have been in the 6%-7% Range - I performed a study of the growth in nominal GDP, S&P 500 stock price appreciation, and S&P 500 EPS and DPS growth since 1960. The results are provided on page 1 of Exhibit JRW-10, and a summary is shown in Table 8, below.

Table 8
GDP, S&P 500 Stock Price, EPS, and DPS Growth
1960-Present

Nominal GDP	**6.46**
S&P 500 Stock Price	**6.71**
S&P 500 EPS	**6.89**
S&P 500 DPS	**5.85**
Average	**6.48**

The results show that the historical long-run growth rates for GDP, S&P EPS, and S&P DPS are in the 6% to 7% range. By comparison, Mr. Hevert's long-run growth rate projections of 12.68% and 12.70% are at best overstated. For Mr. Hevert's estimates to come to fruition, companies in the U.S. would be expected to: (1) increase their growth rate of EPS by 100% in the future, and (2) maintain that growth indefinitely in an economy that is expected to grow at about one-third of his projected growth rates.

<u>There is a Direct Link Between Long-Term EPS and GDP Growth</u> - The results in Exhibit JRW-10 and Table 8 show that historically there has been a close link between long-term EPS and GDP growth rates. Brad Cornell of the California Institute of Technology published a study on GDP growth, earnings growth, and equity returns. He found that long-term EPS growth in the U.S. is directly related to GDP growth, with GDP growth providing an upward limit on EPS growth. In addition, he found that long-term stock returns are determined by long-term earnings growth. He concluded with the following observations:[52]

> The long-run performance of equity investments is fundamentally linked to growth in earnings. Earnings growth, in turn, depends on growth in real GDP. This article demonstrates that both theoretical research and empirical research in development economics suggest relatively strict limits on future growth. In particular, real GDP growth in excess of 3 percent in the long run is highly unlikely in the developed world. In light of ongoing dilution in earnings per share, this finding implies that investors should anticipate real

[52] Bradford Cornell, "Economic Growth and Equity Investing," *Financial Analysts Journal* (January- February 2010), p. 63.

> returns on U.S. common stocks to average no more than about 4–5 percent in real terms.

<u>The Trend and Projections Indicate Slower GDP Growth in the Future</u> - The components of nominal GDP growth are real GDP growth and inflation. Page 3 of Exhibit JRW-10 shows annual real GDP growth rate over the 1961 to 2018 time period. Real GDP growth has gradually declined from the 5.0% to 6.0% range in the 1960s to the 2.0% to 3.0% range during the most recent five-year period. The second component of nominal GDP growth is inflation. Page 4 of Exhibit JRW-10 shows inflation as measured by the annual growth rate in the Consumer Price Index (CPI) over the 1961 to 2018 time period. The large increase in prices from the late 1960s to the early 1980s is readily evident. Equally evident is the rapid decline in inflation during the 1980s as inflation declined from above 10% to about 4%. Since that time, inflation has gradually declined and has been in the 2.0% range or below over the past five years.

The graphs on pages 2, 3, and 4 of Exhibit JRW-10 provide clear evidence of the decline, in recent decades, in nominal GDP as well as its components, real GDP and inflation. To gauge the magnitude of the decline in nominal GDP growth, Table 5, below, provides the compounded GDP growth rates for 10-, 20-, 30-, 40- and 50- years.[53]

[53] Table 5 is also included as Page 5 of Exhibit JRW-10.

Whereas the 50-year compounded GDP growth rate is 6.63%, there has been a monotonic and significant decline in nominal GDP growth over subsequent 10-year intervals. These figures strongly suggest that nominal GDP growth in recent decades has slowed and that a figure in the range of 4.0% to 5.0% is more appropriate today for the U.S. economy.

Table 9

Historical Nominal GDP Growth Rates

10-Year Average		**3.37%**
20-Year Average		**4.17%**
30-Year Average		**4.65%**
40-Year Average		**5.56%**
50-Year Average		**6.36%**

<u>Long-Term GDP Projections also Indicate Slower GDP Growth in the Future</u> - A lower range is also consistent with long-term GDP forecasts. There are several forecasts of annual GDP growth that are available from economists and government agencies. These are listed in Panel B of on page 5 of Exhibit JRW-10. The mean 10-year nominal GDP growth forecast (as of March 2019) by economists in the recent *Survey of Financial Forecasters* is 4.25%.[54] The Energy Information Administration (EIA), in its projections used in preparing *Annual Energy Outlook,* forecasts long-term GDP growth of 4.20%

[54] https://www.philadelphiafed.org/research-and-data/real-time-center/survey-of-professional-forecasters/

for the period 2018-2050.[55] The Congressional Budget Office (CBO), in its forecasts for the period 2019 to 2049, projects a nominal GDP growth rate of 4.40%.[56] Finally, the Social Security Administration (SSA), in its Annual OASDI Report, provides a projection of nominal GDP from 2018-2095.[57] SSA's projected growth GDP growth rate over this period is 4.35%. Overall, these forecasts suggest long-term GDP growth rate in the 4.0% - 4.4% range. The trends and projections indicating slower GDP growth make Mr. Hevert's market risk premiums computed using analysts' projected EPS growth rates look even more unrealistic. Simply stated, Mr. Hevert's projected EPS growth rates of 12.68% and 12.70% are almost three times projected GDP growth.

Q. WHAT ARE THE FUNDAMENTAL FACTORS THAT HAVE LED TO THE DECLINE IN PROSPECTIVE GDP GROWTH?

A. As addressed in a study by the consulting firm McKinsey & Co., two factors drive real GDP growth over time: (a) the number of workers in the economy (employment); and (2) the productivity of those

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[55] U.S. Energy Information Administration, *Annual Energy Outlook 2019*, Table: Macroeconomic Indicators, https://www.eia.gov/outlooks/aeo/pdf/appa.pdf.

[56] Congressional Budget Office, The *2019 Long-Term Budget Outlook*, June 15, 2019 https://www.eia.gov/outlooks/aeo/pdf/appa.pdf.

[57] Social Security Administration, *2019 Annual Report of the Board of Trustees of the Old-Age, Survivors, and Disability Insurance (OASDI) Program*, Table VI.G4, p. 211 (June 15, 2019), https://www.ssa.gov/oact/TR/2019/VI_G2_OASDHI_GDP.html#200732. The 4.35% represents the compounded growth rate in projected GDP from $21,485 trillion in 2019 to $546,311 trillion in 2095.

workers (usually defined as output per hour).[58] According to McKinsey, real GDP growth over the past 50 years was driven by population and productivity growth, which grew at compound annual rates of 1.7% and 1.8%, respectively.

However, global economic growth is projected to slow significantly in the years to come. The primary factor leading to the decline is slow growth in employment (working-age population), which results from slower population growth and longer life expectancy. McKinsey estimates that employment growth will slow to 0.3% over the next 50 years. The study concludes that even if productivity remains at the rapid rate of the past 50 years of 1.8%, real GDP growth will fall by 40% to 2.1%.

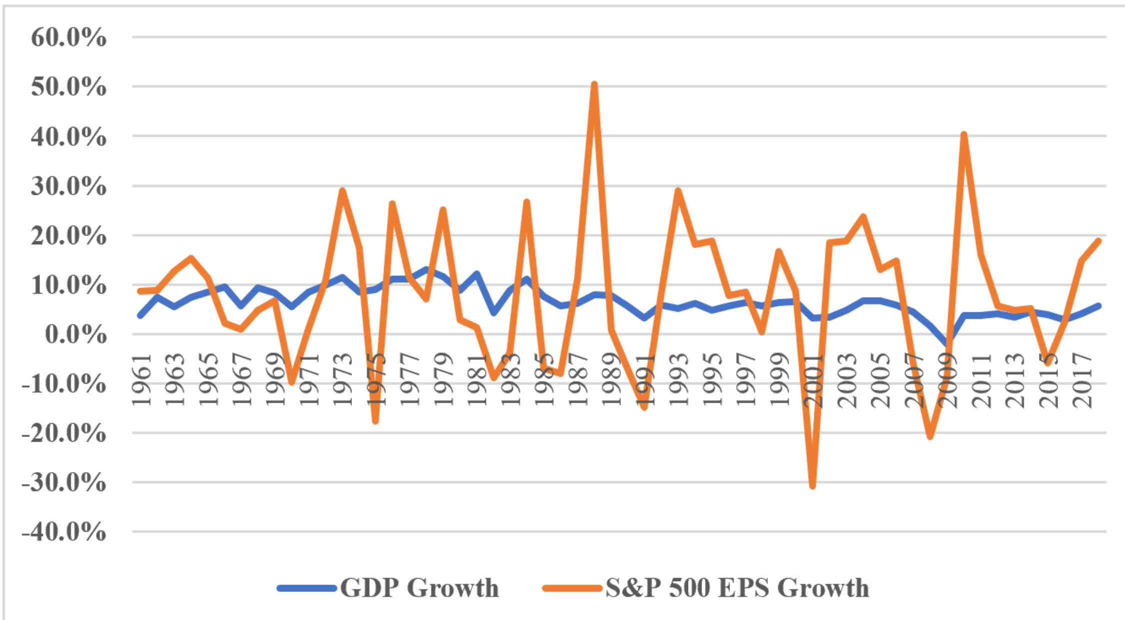
Q. PLEASE PROVIDE MORE INSIGHTS INTO THE RELATIONSHIP BETWEEN S&P 500 EPS AND GDP GROWTH.

A. Figure 6 shows the average annual growth rates for GDP and the S&P 500 EPS since 1960. The one very apparent difference between the two is that the S&P 500 EPS growth rates are much more volatile than the GDP growth rates, when compared using the relatively short, and somewhat arbitrary, annual conventions used in these

[58] McKinsey & Co., "Can Long-Term Growth be Saved?", McKinsey Global Institute, (Jan. 2015).

data.[59] Volatility aside, however, it is clear that over the medium to long run, S&P 500 EPS growth does not outpace GDP growth.

Figure 6
Average Annual Growth Rates
GDP and S&P 500 EPS
1960-2018



Data Sources: GDPA - http://research.stlouisfed.org/fred2/series/GDPA/downloaddata.
S&P EPS - http://pages.stern.nyu.edu/~adamodar/

A fuller understanding of the relationship between GDP and S&P 500 EPS growth requires consideration of several other factors.

[59] Timing conventions such as years and quarters are needed for measurement and benchmarking but are somewhat arbitrary. In reality, economic growth and profit accrual occur on continuous bases. A 2014 study evaluated the timing relationship between corporate profits and nominal GDP growth. The authors found that aggregate accounting earnings growth is a leading indicator of the GDP growth with a quarter-ahead forecast horizon. *See* Yaniv Konchitchki and Panos N. Patatoukas, "Accounting Earnings and Gross Domestic Product," *Journal of Accounting and Economics* 57 (2014), pp. 76–88.

Corporate Profits are Constrained by GDP – Milton Friedman, the noted economist, warned investors and others not to expect corporate profit growth to sustainably exceed GDP growth, stating, "Beware of predictions that earnings can grow faster than the economy for long periods. When earnings are exceptionally high, they don't just keep booming."[60] Friedman also noted in the *Fortune* interview that profits must move back down to their traditional share of GDP. In Table 10, below, I show that currently the aggregate net income levels for the S&P 500 companies, using 2018 figures, represent 6.73% of nominal GDP.

Table 10

S&P 500 Aggregate Net Income as a Percent of GDP

Aggregate Net Income for S&P 500 Companies ($B)	**$1,406,400.00**
2018 Nominal U.S. GDP ($B)	**$20,891,000.00**
Net Income/GDP (%)	**6.73%**

Data Sources: 2018 Net Income for S&P 500 companies – *Value Line* (March 12, 2019).
2018 Nominal GDP – Moody's - https://www.economy.com/united-states/nominal-gross-domestic-product.

Short-Term Factors Impact S&P 500 EPS – The growth rates in the S&P 500 EPS and GDP can diverge on a year-to-year basis due to short-term factors that impact S&P 500 EPS in a much greater way than GDP. As shown above, S&P EPS growth rates are much more

[60] Shaun Tully, "Corporate Profits Are Soaring. Here's Why It Can't Last," Fortune, (Dec. 7, 2017), http://fortune.com/2017/12/07/corporate-earnings-profit-boom-end/.

volatile than GDP growth rates. The EPS growth for the S&P 500 companies has been influenced by low labor costs and interest rates, commodity prices, the recovery of different sectors such as the energy and financial sectors, the cut in corporate tax rates, etc. These short-term factors can make it appear that there is a disconnect between the economy and corporate profits.

The Differences Between the S&P 500 EPS and GDP – In the last two years, as the EPS for the S&P 500 has grown at a faster rate than U.S. nominal GDP, some have pointed to the differences between the S&P 500 and GDP.[61] These differences include: (a) corporate profits are about 2/3 manufacturing driven, while GDP is 2/3 services driven; (b) consumer discretionary spending accounts for a smaller share of S&P 500 profits (15%) than of GDP (23%); (c) corporate profits are more international-trade driven, while exports minus imports tend to be a drag on GDP; and (d) S&P 500 EPS is impacted, not just by corporate profits, but also by share buybacks on the positive side (fewer shares boost EPS) and by share dilution on the negative side (new shares dilute EPS). While these differences may seem significant, it must be remembered that the

[61] *See* the following studies: Burt White and Jeff Buchbinder, "The S&P and GDP are not the Same Thing," LPL Financial, (Nov. 4, 2014), https://www.businessinsider.com/sp-is-not-gdp-2014-11; Matt Comer, "How Do We Have 18.4% Earnings Growth In A 2.58% GDP Economy?," Seeking Alpha, (Apr. 2018), https://seekingalpha.com/article/4164052-18_4-percent-earnings-growth-2_58-percent-gdp-economy; Shaun Tully, "How on Earth Can Profits Grow at 10% in a 2% Economy?," Fortune, (July 27, 2017), http://fortune.com/2017/07/27/profits-economic-growth/.

Income Approach to measure GDP includes corporate profits (in addition to employee compensation and taxes on production and imports) and therefore effectively accounts for the first three factors.[62]

The bottom line is that despite the intertemporal short-term differences between S&P 500 EPS and nominal GDP growth, the long-term link between corporate profits and GDP is inevitable.

Q. PLEASE PROVIDE ADDITIONAL EVIDENCE ON HOW UNREALISTIC THE S&P 500 EPS GROWTH RATES ARE THAT MR. HEVERT USES TO COMPUTE HIS MARKET RISK PREMIUMS.

A. Beyond my previous discussion, I have performed the following analysis of S&P 500 EPS and GDP growth in Table 11 below. Specifically, I started with the 2018 aggregate net income for the S&P 500 companies and 2018 nominal GDP for the U.S. As shown in Table 9, the aggregate profit for the S&P 500 companies represented 6.73% of nominal GDP in 2018. In Table 7, I then projected the aggregate net income level for the S&P 500 companies and GDP as of the year 2050. For the growth rate for the S&P 500 companies, I used the average of Mr. Hevert's Bloomberg and *Value Line* growth

[62] The Income Approach to measuring GDP includes wages, salaries, and supplementary labor income, corporate profits, interest and miscellaneous investment income, farmers' incomes, and income from non-farm unincorporated businesses.

rates, 12.68% and 12.70%, which is 12.69%. As a growth rate for nominal GDP, I used the average of the long-term projected GDP growth rates from CBO, SSA, and EIA (4.0%, 4.4%, and 4.3%), which is 4.23%. The projected 2050 level for the aggregate net income level for the S&P 500 companies is $64.3 trillion. However, over the same period GDP only grows to $78.7 trillion. As such, if the aggregate net income for the S&P 500 grows in accordance with the growth rates used by Mr. Hevert, and if nominal GDP grows at rates projected by major government agencies, the net income of the S&P 500 companies will represent growth from 6.73% of GDP in 2018 to 81.71% of GDP in 2050. Obviously, it is implausible for the net income of the S&P 500 to become such a large part of GDP.

Table 11

Projected S&P 500 Earnings and Nominal GDP

2018-2050

S&P 500 Aggregate Net Income as a Percent of GDP

	2018 Value	Growth Rate	No. of Years	2050 Value
Aggregate Net Income for S&P 500	1,406,400.0	12.69%	32	64,334,063.3
2018 Nominal U.S. GDP	20,891,000.0	4.23%	32	78,735,624.7
Net Income/GDP (%)	6.73%			81.71%

Data Sources: 2018 Aggregate Net Income for S&P 500 companies – *Value Line* (March 12, 2019).
2018 Nominal GDP – Moody's - https://www.economy.com/united-states/nominal-gross-domestic-product.
S&P 500 EPS Growth Rate - Average of Hevert's Bloomberg and *Value Line* growth rates - 12.68% and 12.70%;
Nominal GDP Growth Rate – The average of the long-term projected GDP growth rates from CBO, SSA, and EIA (4.0%, 4.4%, and 4.3%).

Q. PLEASE PROVIDE A SUMMARY ANALYSIS ON GDP AND S&P 500 EPS GROWTH RATES.

A. As noted above, the long-term link between corporate profits and GDP is inevitable. The short-term differences in growth between the two has been highlighted by some notable market observers, including Warren Buffett, who indicated that corporate profits as a share of GDP tend to go far higher after periods where they are depressed, and then drop sharply after they have been hovering at historically high levels. In a famous 1999 *Fortune* article, Mr. Buffet made the following observation:[63]

> You know, someone once told me that New York has more lawyers than people. I think that's the same fellow who thinks profits will become larger than GDP. When you begin to expect the growth of a component factor to forever outpace that of the aggregate, you get into certain mathematical problems. In my opinion, you have to be wildly optimistic to believe that corporate profits as a percent of GDP can, for any sustained period, hold much above 6%. One thing keeping the percentage down will be competition, which is alive and well. In addition, there's a public-policy point: If corporate investors, in aggregate, are going to eat an ever-growing portion of the American economic pie, some other group will have to settle for a smaller portion. That would justifiably raise political problems – and in my view a major reslicing of the pie just isn't going to happen.

[63] Carol Loomis, "Mr. Buffet on the Stock Market," *Fortune*, (Nov. 22, 1999), https://money.cnn.com/magazines/fortune/fortune_archive/1999/11/22/269071/.

In sum, Mr. Hevert's long-term S&P 500 EPS growth rates of 12.68% and 12.70% are grossly overstated and have no basis in economic reality. In the end, the big question remains as to whether corporate profits can grow faster than GDP. Jeremy Siegel, the renowned finance professor at the Wharton School of the University of Pennsylvania, believes that going forward, earnings per share can grow about half a point faster than nominal GDP, or about 5.0%, due to the big gains in the technology sector. But he also believes that sustained EPS growth matching analysts' near-term projections is absurd: "The idea of 8% or 10% or 12% growth is ridiculous. It will not happen."[64]

Q. PLEASE PROVIDE ADDITIONAL INSIGHTS INTO THE CAPM RESULTS.

A. There are several additional issues with the *Value Line* results. Simply put, the 14.78% and 14.88% expected stock market returns (Mr. Hevert's Exhibit RBH-2 at pages 1 and 8) are simply excessive. The compounded annual return in the U.S. stock market is about 10% (9.49% between 1928-2018 according to Damodaran).[65] Mr. Hevert's *Value Line* CAPM results assume that return on the U.S. stock market will be almost 50% higher in the future than it has been

[64] Shaun Tully, "Corporate Profits Are Soaring. Here's Why It Can't Last," *Fortune*, (Dec. 7, 2017), http://fortune.com/2017/12/07/corporate-earnings-profit-boom-end/.

[65] http://pages.stern.nyu.edu/~adamodar/

in the past! The extremely high expected stock market returns, and their resulting market risk premiums and equity cost rate results, are directly related to the 12.69% and 12.70% expected EPS growth rates. Simply put, these projected growth rates do not reflect economic reality. As noted above, it assumes that S&P 500 companies can grow their earnings in the future at a rate that is triple the expected GDP growth rate.

2. ECAPM

Q. WHAT ISSUES DO YOU HAVE WITH MR. HEVERT'S ECAPM?

A. Mr. Hevert has employed a variation of the CAPM which he calls the "ECAPM". The ECAPM, as popularized by rate of return consultant Dr. Roger Morin, attempts to model the well-known finding of tests of the CAPM that have indicated the Security Market Line ("SML") is not as steep as predicted by the CAPM.[66] As such, the ECAPM is nothing more than an ad hoc version of the CAPM and has not been theoretically or empirically validated in refereed journals. The ECAPM uses weighting to adjust the risk-free rate and market risk premium in applying the ECAPM. Mr. Hevert uses 0.25 and 0.75 factors in his ECAPM.

[66] In Modern Capital Market theory, the SML is the relationship between the expected return on common stocks and beta.

Besides the fact that the ECAPM is not a recognized equity cost rate model, Mr. Hevert has already accounted for any empirical issues with the CAPM by using adjusted betas from *Value Line*. Adjusted betas address the empirical issues with the CAPM by increasing the expected returns for low beta stocks and decreasing the returns for high beta stocks.

D. Bond Yield Risk Premium Approach

Q. PLEASE DISCUSS MR. HEVERT'S BYRP APPROACH.

A. On pages 92-96 of his testimony and in Exhibit No. RBH-5, Mr. Hevert develops an equity cost rate using his BYRP approach. Mr. Hevert develops an equity cost rate by: (1) regressing the average quarterly authorized returns on equity for electric utility companies from the January 1, 1992, to May 23, 2019, time period on the 30-year Treasury Yield; and (2) adding the appropriate risk premium established in step (1) to three different 30-year Treasury yields: (a) the current yield of 2.63%; (b) a near-term projected yield of 2.70%; and (c) a long-term projected yield of 3.70%. Mr. Hevert's risk premium results are provided on Exhibit JRW-9. He reports BYRP equity cost rates ranging from 9.90% to 10.06%.

Q. WHAT ARE THE ERRORS IN MR. HEVERT'S BYRP ANALYSIS?

A. The errors include the base yield as well as the measurement and magnitude of the risk premium.

1. Base Yields

Q. PLEASE DISCUSS THE BASE YIELD OF MR. HEVERT'S BYRP ANALYSIS.

A. Mr. Hevert has used current, near-term projected, and long-term projected risk-free rates of 2.63%, 2.70%, and 3.70% in his BYRP analyses. The actual yield on 30-year Treasury bonds has been in the 2.30% range in recent months. As such, Mr. Hevert's current, near-term projected, and long-term projected risk-free rates are 33, 40, and 140 basis points, respectively, above the current yield on long-term Treasury bonds. These current and forecasted yields are excessive for two reasons. First, as discussed previously, economists have been predicting that interest rates are going up for a decade, and yet they are almost always wrong. Obviously, investors are well aware of the consistently wrong forecasts of higher interest rates, and therefore are likely to place little weight on such forecasts. Second, investors would not be buying long-term Treasury bonds at their current yields if they expected interest rates to suddenly increase. If interest rates do increase, the prices of the bonds investors bought at today's yields go down, thereby producing a negative return.

2. Risk Premium

Q. WHAT ARE THE ISSUES WITH MR. HEVERT'S RISK PREMIUM?

A. There are several problems with his approach. First, his BYRP methodology produces an inflated measure of the risk premium because the approach uses historic authorized ROEs and Treasury yields, and the resulting risk premium is applied to projected Treasury yields. Since Treasury yields are always forecasted to increase, the resulting risk premium would be smaller if calculated correctly, which would be to use projected Treasury yields in the analysis rather than historic Treasury yields.

In addition, Mr. Hevert's BYRP approach is a gauge of *commission* behavior and not *investor* behavior. Capital costs are determined in the marketplace through the financial decisions of investors and are reflected in such fundamental factors as dividend yields, expected growth rates, interest rates, and investors' assessment of the risk and expected return of different investments. Regulatory commissions evaluate capital market data in setting authorized ROEs, but also consider other utility- and rate case-specific information in setting ROEs. As such, Mr. Hevert's approach and results reflect factors such as capital structure, credit ratings and other risk measures, service territory, capital expenditures, energy supply issues, rate design, investment and expense trackers, and other factors used by utility commissions in determining an appropriate ROE in addition to capital costs. This may especially be true when the authorized ROE data includes the results of rate cases that are settled and not fully litigated.

Finally, Mr. Hevert's methodology produces an inflated required rate of return because utilities have been selling at market-to-book ratios well in excess of 1.0 for many years. This indicates that the authorized and earned rates of return on equity have been greater than the return that investors require. The relationship between ROE, the equity cost rate, and market-to-book ratios was explained earlier in this testimony. In short, a market-to-book ratio above 1.0 indicates a company's ROE is above its equity cost rate. Therefore, the risk premium produced from the study is overstated as a measure of investor return requirements and produces an inflated equity cost rate.

E. Expected Earnings Approach

Q. PLEASE REVIEW MR. HEVERT'S EXPECTED EARNINGS APPROACH.

A. On pages 96-7 of his testimony and in Exhibit RBH-6, Mr. Hevert develops an equity cost rate using his Expected Earnings approach, which he uses for comparison purposes. Mr. Hevert's approach involves using *Value Line*'s projected ROE for the years 2022-24 for his proxy group and then adjusting this ROE to account for the fact the *Value Line* uses year-end equity in computing ROE. Mr. Hevert reports Expected Earnings results of 10.44% and 10.54%.

Q. PLEASE ADDRESS THE ISSUES WITH MR. HEVERT'S EXPECTED EARNINGS APPROACH.

A. There are a number of issues with this so-called Expected Earnings approach. As such, I strongly suggest that the Commission ignore this approach in setting a ROE for DEC. These issues include:

The Expected Earnings Approach Does Not Measure the Market Cost of Equity Capital – First and foremost, this accounting-based methodology does not measure investor return requirements. As indicated by Professor Roger Morin, a long-term utility rate of return consultant, "More simply, the Comparable (Expected) Earnings standard ignores capital markets. If interest rates go up 2% for example, investor requirements and the cost of equity should increase commensurably, but if regulation is based on accounting returns, no immediate change in equity cost results."[67] As such, this method does not measure the market cost of equity because there is no way to assess whether the earnings are greater than or less than the earnings investors require, and therefore this approach does not measure the market cost of equity capital.

[67] Roger Morin, *New Regulatory Finance* (2006), p. 293.

The Expected ROEs are Not Related to Investors' Market-Priced Opportunities – The ROE ratios are an accounting measure that do not measure investor return requirements. Investors had no opportunity to invest in the proxy companies at the accounting book value of equity. In other words, the equity's book value *to investors* is tied to market prices, which means that investors' required return on market-priced equity aligns with expected return on book equity only when the equity's market price and book value are aligned. Therefore, a market-based evaluation of the cost of equity to investors in the proxies requires an associated analysis of the proxies' market-to-book ("M/B") ratios.

Changes in ROE Ratios do not Track Capital Market Conditions - As also indicated by Morin, "The denominator of accounting return, book equity, is a historical cost-based concept, which is insensitive to changes in investor return requirements. Only stock market price is sensitive to a change in investor requirements. Investors can only purchase new shares of common stock at current market prices and not at book value."[68]

The Expected Earnings Approach is Circular - The proxies' ROEs ratios are not determined by competitive market forces, but instead

[68] *Id.*

are largely the result of federal and state rate regulation, including the present proceeding.

The Proxies' ROEs Reflect Earnings on Business Activities that are not Representative of DEC's Rate-Regulated Utility Activities - The numerators of the proxy companies' ROEs include earnings from business activities that are riskier and produce more projected earnings per dollar of book investment than does regulated electric utility service. These include earnings from: (1) unregulated businesses, including merchant generation; (2) electric generation; and (3) international operations.

Q. PLEASE SUMMARIZE YOUR ANALYSIS OF MR. HEVERT'S EXPECTED EARNINGS APPROACH.

A. In short, Mr. Hevert's Expected Earnings approach does not measure the market cost of equity capital, is independent of most cost of capital indicators and, as shown above, and has a number of other empirical issues. Therefore, the Commission should ignore this approach in determining the appropriate ROE for DEC.

F. Other Issues

1. Other DEC Risk Factors

Q. PLEASE ADDRESS MR. HEVERT'S CONSIDERATION OF OTHER UNIQUE RISK FACTORS FACED BY DEC.

A. Mr. Hevert has a number of risk factors he considered in arriving at his 10.50% ROE recommendation. These include North Carolina's REPS, the Company's high level of capital expenditures, environmental regulations, and its coal-fired and nuclear generation. However, these are risk factors already considered in the credit-rating process used by major rating agencies. In addition, as I noted above, DEC's S&P and Moody's credit ratings of A- and A1 suggest that the Company's investment risk is below the average of the proxy groups.

2. Flotation Costs

Q. PLEASE DISCUSS MR. HEVERT'S ADJUSTMENT FOR FLOTATION COSTS.

A. Mr. Hevert argues that a flotation cost adjustment is appropriate for DEC and he has considered flotation costs in arriving at his 10.50% ROE recommendation.

First and foremost, Mr. Hevert has not identified any flotation cost for DEC. Therefore, he is asking for higher revenues in the form of a higher ROE for expenses that he has not identified.

Second, in North Carolina flotation costs cannot be recovered unless the Company is expected to issue common stock.[69]

Third, it is commonly argued that a flotation cost adjustment (such as that used by the Company) is necessary to prevent the dilution of the investment of the existing shareholders. This is incorrect for several reasons:

(1) If an equity flotation cost adjustment is similar to a debt flotation cost adjustment, the fact that the market-to-book ratios for electric utility companies are over 1.95X actually suggests that there should be a flotation cost reduction (and not an increase) to the equity cost rate. This is because when (a) a bond is issued at a price in excess of face or book value, and (b) the difference between market price and the book value is greater than the flotation or issuance costs, the cost

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[69] In NC, flotation costs cannot lawfully be recovered when the Company does not expect to issue stock in the near future. In State ex rel. Utilities Com. v. Public Staff, 331 N.C. 215; 415 S.E.2d 354 (1992), the Court noted that:

> Prompted by the statement of Duke's chairman, Mr. Lee, that "the company's 'present expectation is that we will be back into the capital markets for new funds in about three to four years,'" the only evidence in the record on the probability of Duke's issuing new stock, we noted the record included no evidence that Duke would issue any new stock sooner than three or four years from the time of the hearing.

Id. at 219. The Court then ruled that,

> In light of the whole record on this issue, particularly the absence of any evidence that Duke intended to issue stock in the immediate future, there is simply no substantial evidentiary support for the Commission's addition of a 0.1% increment to Duke's rate of return on common equity to cover future stock issuance costs.

Id. at 221-222.

of that debt is lower than the coupon rate of the debt. The amount by which market values of electric utility companies are in excess of book values is much greater than flotation costs. Hence, if common stock flotation costs were exactly like bond flotation costs, and one was making an explicit flotation cost adjustment to the cost of common equity, the adjustment would be downward;

(2) If a flotation cost adjustment is needed to prevent dilution of existing stockholders' investment, then the reduction of the book value of stockholder investment associated with flotation costs can occur only when a company's stock is selling at a market price at/or below its book value. As noted above, electric utility companies are selling at market prices well in excess of book value. Hence, when new shares are sold, existing shareholders realize an increase in the book value per share of their investment, not a decrease;

(3) Flotation costs consist primarily of the underwriting spread or fee and not out-of-pocket expenses. On a per-share basis, the underwriting spread is the difference between the price the investment banker receives from investors and the price the investment banker pays to the company. Therefore,

these are not expenses that must be recovered through the regulatory process. Furthermore, the underwriting spread is known to the investors who are buying the new issue of stock, and who are well aware of the difference between the price they are paying to buy the stock and the price that the Company is receiving. The offering price they pay is what matters when investors decide to buy a stock based on its expected return and risk prospects. Therefore, the company is not entitled to an adjustment to the allowed return to account for those costs; and

(4) Flotation costs, in the form of the underwriting spread, are a form of a transaction cost in the market. They represent the difference between the price paid by investors and the amount received by the issuing company. Whereas the Company believes that it should be compensated for these transaction costs, it has not accounted for other market transaction costs in determining its cost of equity. Most notably, brokerage fees that investors pay when they buy shares in the open market are another market transaction cost. Brokerage fees increase the effective stock price paid by investors to buy shares. If the Company had included these brokerage fees or transaction costs in its DCF analysis, the higher effective stock prices paid for stocks would lead to

lower dividend yields and equity cost rates. This would result in a downward adjustment to its DCF equity cost rate.

VII. NORTH CAROLINA ECONOMIC CONDITIONS AND DEC'S RATE OF RETURN RECOMMENDATION

Q. PLEASE DISCUSS MR. HEVERT'S CONSIDERATION OF ECONOMIC CONDITIONS IN NORTH CAROLINA.

A. Mr. Hevert has acknowledged that the North Carolina Utilities Commission must balance the interests of investors and customers in setting the ROE. In addition, Mr. Hevert notes that the Commission's task is to set rates as low as possible consistent with the dictates of the United States and North Carolina Constitutions.[70] On this issue, the ROE should be the minimum amount needed to meet the *Hope* and *Bluefield* standards. Finally, Mr. Hevert also highlights that the North Carolina Supreme Court has indicated that in retail utility service rate cases, the Commission must make findings of fact regarding the impact of changing economic conditions on customers when determining the proper ROE for a public utility.[71]

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[70] State of North Carolina Utilities Commission, Docket No. E-7, Sub 1026, Order Granting General Rate Increase, Sept. 24, 2013 at 24; *see also* DEC Remand Order at 40 ("the Commission in every case seeks to comply with the North Carolina Supreme Court's mandate that the Commission establish rates as low as possible within Constitutional limits.")

[71] *State of North Carolina ex rel. Utilities Commission v. Cooper*, 758 S.E.2d 635, 642 (2014) (Cooper II).

With respect to this latter mandate, Mr. Hevert evaluates a number of factors such as employment and income levels and, based on his review of the data, comes to the conclusion that DEC's proposed ROE of 10.50 percent is fair and reasonable to DEC, its shareholders, and its customers in light of the effect of those changing economic conditions.[72]

Q. DO YOU AGREE WITH MR. HEVERT'S ASSESSMENT OF ECONOMIC CONDITIONS IN NORTH CAROLINA?

A. As highlighted by the correlations between U.S. and North Carolina economic data, I agree with Mr. Hevert that economic conditions in North Carolina have improved with the overall economy over the past decade.

Q. DO YOU AGREE WITH MR. HEVERT'S CONCLUSION THAT THE IMPROVEMENT IN ECONOMIC CONDITIONS IN NORTH CAROLINA AND THE COMPANY'S SERVICE TERRITORY JUSTIFY THE COMPANY'S PROPOSED RATE OF RETURN INCLUDING A 10.50% ROE?

A. No. Whereas economic conditions have improved in North Carolina, it does not necessarily justify such a high rate of return and ROE. I have three observations on Mr. Hevert's assessment of the

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[72] Hevert Testimony, pp. 53-62.

economic conditions in North Carolina and DEC's service territory and its requested ROE:

(1) DEC's ROE request of 10.50% is almost 100 basis points above the average authorized ROEs for electric utilities over the 2018-19 time period;

(2) whereas the unemployment rates in North Carolina and DEC's service territory have fallen by two-thirds since their peaks in the 2009-2010 period, they are both above the national average of 3.90%; and

(3) whereas North Carolina's residential electric rates are below the national average, North Carolina's median household income is more than 10% below the U.S. norm.

Q. WHAT IS YOUR CONCLUSION REGARDING THE ECONOMIC CONDITIONS IN NORTH CAROLINA AND THE COMPANY'S SERVICE TERRITORY?

A. The lower level of household income in the state and the higher level of unemployment in DEC's service territory (relative to the national average) suggest that affordability can be an issue for an essential utility service such as electricity. Certainly, it does not justify an authorized ROE that is almost 100 basis points above the national average. And DEC's overall rate of return request has a significant impact on its overall requested increase in revenues.

Q DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Appendix A
Educational Background, Research, and Related Business Experience
J. Randall Woolridge

J. Randall Woolridge is a Professor of Finance and the Goldman, Sachs & Co. and Frank P. Smeal Endowed Faculty Fellow in Business Administration in the College of Business Administration of the Pennsylvania State University in University Park, PA. In addition, Professor Woolridge is Director of the Smeal College Trading Room and President and CEO of the Nittany Lion Fund, LLC.

Professor Woolridge received a Bachelor of Arts degree in Economics from the University of North Carolina, a Master of Business Administration degree from the Pennsylvania State University, and a Doctor of Philosophy degree in Business Administration (major area-finance, minor area-statistics) from the University of Iowa. He has taught Finance courses including corporation finance, commercial and investment banking, and investments at the undergraduate, graduate, and executive MBA levels.

Professor Woolridge's research has centered on empirical issues in corporation finance and financial markets. He has published over 35 articles in the best academic and professional journals in the field, including the *Journal of Finance,* the *Journal of Financial Economics,* and the *Harvard Business Review*. His research has been cited extensively in the business press. His work has been featured in the *New York Times*, *Forbes*, *Fortune*, *The Economist*, *Barron's*, *Wall Street Journal*, *Business Week*, *Investors' Business Daily*, *USA Today*, and other publications. In addition, Dr. Woolridge has appeared as a guest to discuss the implications of his research on CNN's *Money Line*, CNBC's *Morning Call* and *Business Today*, and Bloomberg's *Morning Call*.

Professor Woolridge's stock valuation book, *The StreetSmart Guide to Valuing a Stock* (McGraw-Hill, 2003), was released in its second edition. He has also co-authored *Spinoffs and Equity Carve-Outs: Achieving Faster Growth and Better Performance* (Financial Executives Research Foundation, 1999) as well as a textbook entitled *Basic Principles of Finance* (Kendall Hunt, 2011).

Professor Woolridge has also consulted with corporations, financial institutions, and government agencies. In addition, he has directed and participated in university- and company-sponsored professional development programs for executives in 25 countries in North and South America, Europe, Asia, and Africa.

Over the past thirty-five years Dr. Woolridge has prepared testimony and/or provided consultation services in regulatory rate cases in the rate of return area in following states: Alaska, Arizona, Arkansas, California, Colorado, Connecticut, Delaware, Florida, Hawaii, Indiana, Kansas, Kentucky, Maryland, Massachusetts, Missouri, Montana, Nebraska, New Hampshire, New Jersey, New Mexico, New York, North Carolina, Ohio, Oklahoma, Pennsylvania, South Carolina, Texas, Utah, Vermont, Virginia, Washington, West Virginia, Wisconsin, and Washington, D.C. He has also testified before the Federal Energy Regulatory Commission.

J. Randall Woolridge

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Academic Experience

Professor of Finance, the Smeal College of Business Administration, the Pennsylvania State University (July 1, 1990 to the present).

President, Nittany Lion Fund LLC, (January 1, 2005 to the present)

Director, the Smeal College Trading Room (January 1, 2001 to the present)

Goldman, Sachs & Co. and Frank P. Smeal Endowed University Fellow in Business Administration (July 1, 1987 to the present).

Associate Professor of Finance, College of Business Administration, the Pennsylvania State University (July 1, 1984 to June 30, 1990).

Assistant Professor of Finance, College of Business Administration, the Pennsylvania State University (September, 1979 to June 30, 1984).

Education

Doctor of Philosophy in Business Administration, the University of Iowa. Major field: Finance.
Master of Business Administration, the Pennsylvania State University.
Bachelor of Arts, the University of North Carolina. Major field: Economics.

Books

James A. Miles and J. Randall Woolridge, *Spinoffs and Equity Carve-Outs: Achieving Faster Growth and Better Performance* (Financial Executives Research Foundation), 1999

Patrick Cusatis, Gary Gray, and J. Randall Woolridge, *The StreetSmart Guide to Valuing a Stock* (2nd Edition, McGraw-Hill), 2003.

J. Randall Woolridge and Gary Gray, *The New Corporate Finance, Capital Markets, and Valuation: An Introductory Text* (Kendall Hunt, 2003).

Research

Dr. Woolridge has published over 35 articles in the best academic and professional journals in the field, including the *Journal of Finance*, the *Journal of Financial Economics*, and the *Harvard Business Review*.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1213 In the Matter of Application of Duke Energy Carolinas, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in 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 Utility Service in North Carolina	)	SUPPLEMENTAL TESTIMONY OF J. RANDALL WOOLRIDGE ON BEHALF OF THE PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUBS 1213 AND 1214

Supplemental Testimony of J. Randall Woolridge

On Behalf of the Public Staff

North Carolina Utilities Commission

March 25, 2020

Q. DR. WOOLRIDGE, WHAT IS THE PURPOSE OF YOUR SUPPLEMENTAL TESTIMONY IN THIS PROCEEDING?

A. The purpose of my supplemental testimony is to update the appropriate embedded cost of debt to be used in this proceeding based on the Public Staff's investigation of the second supplemental filing by Duke Energy Carolinas, LLC (DEC or Company) in this proceeding. On February 14, 2020, DEC filed a second set of supplemental testimony and exhibits supporting a $19,254,000 increase in its request for additional North Carolina retail revenue, for a total supported proposed increase of $464,585,000.

Q. WHAT IS THE COST OF EMBEDDED DEBT USED BY THE COMPANY IN ITS SECOND SUPPLEMENTAL TESTIMONY AND EXHIBITS?

A. As it did in its original filing, DEC used an embedded cost of debt of 4.51% in its second supplemental filing. The Company had a 4.51% cost of embedded debt at the end of its test year, 2018.

Q. WHAT EMBEDDED COST OF DEBT DO YOU RECOMMEND BE USED IN THIS PROCEEDING?

A. I recommend that the Company's embedded cost of debt of 4.29% as of January 31, 2020, be utilized to reflect more current circumstances.

Q. WHAT ARE YOUR UPDATED PRIMARY AND ALTERNATIVE COST OF CAPITAL RECOMMENDATIONS FOR DEC WITH THE COMPANY'S UPDATED LONG-TERM DEBT COST RATE?

A. My updated primary and alternative cost of capital recommendations for DEC, with the updated long-term debt cost rate, are provided in Table 1 and Exhibit JRW-S1. With this update, my primary and alternative cost of capital recommendations for DEC are 6.65% and 6.47%.

Table 1

Public Staff's Update Primary and Alternative Cost of Capital Recommendations

Panel A - Primary Cost of Capital Recommendation

Capital Source	Capitalization Ratios*	Cost Rate	Weighted Cost Rate
Long-Term Debt	50.00%	4.29%	2.15%
Common Equity	50.00%	9.00%	4.50%
Total Capitalization	100.00%		6.65%

* Capital Structure Ratios are developed in Exhibit JRW-3.

Panel B - Alternative Cost of Capital Recommendation

Capital Source	Capitalization Ratios*	Cost Rate	Weighted Cost Rate
Long-Term Debt	47.00%	4.29%	2.02%
Common Equity	53.00%	8.40%	4.45%
Total Capitalization	100.00%		6.47%

* Capital Structure Ratios are developed in Exhibit JRW-3.

Q. DOES THIS COMPLETE YOUR SUPPLEMENTAL TESTIMONY IN THIS PROCEEDING?

A. Yes.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1219
DOCKET NO. E-7, SUB 1214
DOCKET NO. E-7, SUB 1213
DOCKET NO. E-7, SUB 1187

DOCKET NO. E-2, SUB 1219 In the Matter of Application of Duke Energy Progress, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in 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 Utility Service in North Carolina DOCKET NO. E-7, SUB 1213 In the Matter of Petition of Duke Energy Carolinas, LLC, for Approval of Prepaid Advantage Program DOCKET NO. E-7, SUB 1187 In the Matter of Petition of Duke Energy Carolinas, LLC, for an Accounting Order to Defer Incremental Storm Damage Expenses Incurred as a Result of Hurricanes Florence and Michael and Winter Storm Diego	TESTIMONY OF J. RANDALL WOOLRIDGE ON BEHALF OF THE PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION SUPPORTING SECOND PARTIAL STIPULATIONS

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2 SUB 1219

DOCKET NO. E-7, SUBS 1213, 1214, AND 1287

Testimony of J. Randall Woolridge

On Behalf of the Public Staff

North Carolina Utilities Commission

Supporting Second Partial Stipulations

July 31, 2020

Q. PLEASE STATE YOUR FULL NAME, ADDRESS, AND OCCUPATION.

A. My name is J. Randall Woolridge, and my business address is 120 Haymaker Circle, State College, PA 16801. I am a Professor of Finance and the Goldman, Sachs & Co. and Frank P. Smeal Endowed University Fellow in Business Administration at the University Park Campus of the Pennsylvania State University. I am also the Director of the Smeal College Trading Room and President of the Nittany Lion Fund, LLC.

Q. ARE YOU THE SAME J. RANDALL WOOLRIDGE WHO SUBMITTED DIRECT AND SUPPLEMENTAL TESTIMONY ON BEHALF OF THE PUBLIC STAFF-NORTH CAROLINA UTILITIES COMMISSION (“PUBLIC STAFF”) IN DOCKET NO. E-7, SUB 1214 AND DIRECT TESTIMONY IN DOCKET NO. E-2, SUB 1219?

A. Yes, I am.

Q. WHAT IS THE PURPOSE OF YOUR CURRENT TESTIMONY?

A. The purpose of my testimony is to provide my comments on the cost of capital components of the Second Agreement and Stipulation of Partial Settlement filed on July 31, 2020, between Duke Energy Carolinas, LLC (DEC), and the Public Staff (DEC Second Partial Stipulation) and the Second Agreement and Stipulation of Partial Settlement filed on July 31, 2020, between Duke Energy Progress, LLC (DEP), and the Public Staff (DEP Second Partial Stipulation) (together "Second Partial Stipulations") in these proceedings.[1]

Q. WHAT IS YOUR UNDERSTANDING OF THE "TERMS" OF THE COST OF CAPITAL COMPONENTS OF THE PROPOSED SETTLEMENTS?

A. It is my understanding that the following items have been agreed to between DEC, DEP (together "Duke") and the Public Staff on the issues of cost of capital:

Capital Structure – 52% common equity and 48% long-term debt for both companies

[1] An Agreement and Stipulation of Partial Settlement between DEC and the Public Staff was filed on March 25, 2020. An Agreement and Stipulation of Partial Settlement between DEP and the Public Staff was filed on June 2, 2020. These First Partial Stipulations do not involve cost of capital issues.

Cost of Common Equity – 9.6% for both companies

Cost of Long-Term Debt – 4.27% DEC, 4.04% DEP

Q. WHAT IS YOUR EXPERIENCE AND UNDERSTANDING OF SETTLEMENTS IN THE PUBLIC UTILITY PROCEEDINGS IN WHICH YOU HAVE BEEN INVOLVED IN OVER THE YEARS?

A. It is my experience that settlements are generally the result of good faith, "give-and-take," and compromise-related negotiations among the parties of utility rate proceedings, involving the utility, commission staff, and other parties. It is also my understanding that settlements, as well as the individual components of the settlements, are often achieved by the respective parties' agreements to accept otherwise unacceptable individual aspects of individual issues in order to focus on other issues.

Settlements are often the result of agreement on all or a significant portion of the issues that would otherwise be litigated in a rate proceeding; or sometimes are restricted to individual issues.

Q. BESIDES THE COST OF CAPITAL COMPONENTS, WHAT IS YOUR UNDERSTANDING OF THE NATURE OF THE SETTLEMENTS IN THESE PROCEEDINGS?

A. It is my understanding that the proposed settlements cover many of the issues including:

- a return of federal unprotected Excess Deferred Income Tax (EDIT) over five years, North Carolina EDIT over two years, and deferred revenues over two years.
- deferral accounting treatment for certain Grid Improvement programs and withdrawal of deferral requests for the remainder.
- updates of plant (including benefits and executive compensation) through May, but recognition of only 75% of revenues to recognize the uncertainty regarding effects of COVID-19.
- a $19.1 million disallowance for a portion of the costs of the Clemson Combined Heat and Power Project on a system basis.
- Amortization of coal ash capital projects over eight years.
- Acceptance of the Summer Coincident Peak cost of service allocation methodology for purposes of this case only with no precedential effect.
- Duke agreement to conduct a cost of service study.
- In addition to $6 million DEC and DEP have agreed to contribute in their settlement with the North Carolina Justice Center to the Helping Home Fund for energy efficiency , DEC and DEP agree to contribute $5 million each over two years to assist low income customers with payment of their bills.

- Reduction of DEP's annual funding of its Nuclear Decommissioning Fund by $8.7 million.
- There were also a number of accounting issues, including storm securitization, reductions to executive compensation, aviation costs, and employee incentives resolved in the first partial stipulations reached with each company.

The settlements explicitly exclude coal ash costs, depreciation rates, and an adjustment for Hydro Station sales in the DEC proceeding. Additionally, the settlements exclude any revenue or nonrevenue item that has not been specifically addressed in the First or Second Partial Stipulation between DEC and the Public Staff, the First or Second Partial Stipulation between DEP and the Public Staff, or agreed upon in the testimony of the Duke and the Public Staff.

Q. DID YOU PARTICIPATE IN THE NEGOTIATIONS LEADING UP TO THE PROPOSED SETTLEMENTS IN THIS PROCEEDING?

A. No, I was not involved in the negotiations leading up to the proposed settlements.

Q. DO YOU AGREE THAT THE COST OF CAPITAL COMPONENTS OF THE PROPOSED SETTLEMENTS ARE REASONABLE WITHIN THE CONTEXT OF THE OVERALL SETTLEMENTS?

A. Yes I do, for the reasons stated in this testimony. As I have indicated, the proposed settlements reflect the results of good faith negotiations and compromises.

I note that it remains my position that, should this be a fully litigated proceeding, I would continue to recommend as my primary recommendation for each company a capital structure with 50% common equity and 50% long-term debt and an ROE of 9.00%. However, given the benefits associated with entering settlements, it is my view that the cost of capital components of the proposed settlements are reasonable resolutions of otherwise contentious issues.

Q. HOW DO THE COST OF CAPITAL COMPONENTS OF THE PROPOSED SETTLEMENTS BETWEEN THE TWO COMPANIES AND THE PUBLIC STAFF COMPARE TO EACH COMPANY'S REQUESTS?

A. There are three components in the cost of capital issue of the proposed settlements.

The first component is the capital structure. Each company's proposed hypothetical capital structure was comprised of 53% common equity and 47% long-term debt. The proposed settlements utilize a slightly lower common equity ratio (52%) and a slightly higher long-term debt ratio (48%). The second cost of capital component is the cost of equity ("ROE"). Each company's ROE expert recommended an ROE of 10.50%,[2] whereas the proposed settlements contain a 9.6% ROE.

The third cost of capital component is the cost of long-term debt. DEC's proposed cost of long-term debt is 4.29%, as compared to the 4.27% cost of debt in the DEC proposed settlement. DEP's proposed cost of long-term debt is 4.11%, as compared to the 4.04% cost of debt in the DEP proposed settlement.

Q. DO YOU CONSIDER EACH OF THESE COST OF CAPITAL COMPONENTS IN THE PROPOSED SETTLEMENTS AS BEING "REASONABLE" IN THE CONTEXT OF A STIPULATED PROCEEDING?

A. Yes, I do. Each of these components can be considered as reasonable within the context of the proposed settlements. I note that Duke and the Public Staff, in their respective direct testimonies, proposed fundamentally different views on a number of issues, such as current market conditions and related current costs of common equity, as well as the appropriate capital structure. The proposed

[2] While each company found the ROE expert's 10.50% ROE recommendation to be a reasonable and appropriate estimate of its cost of equity capital, as a rate mitigation measure and in recognition of each company's ongoing efforts to keep rates affordable for customers, each company proposed rates to be set with an ROE of 10.30%.

settlements represent a compromise, or middle ground between their respective positions.

Further, the cost of capital components of the proposed settlements can be considered reasonable within a broad negotiation and resolution of most of the issues in this proceeding.

Q. PLEASE FIRST ADDRESS THE CAPITAL STRUCTURE COMPONENT OF THE PROPOSED SETTLEMENTS. WHY DO YOU CONSIDER THIS AS "REASONABLE"?

A. In each application, DEC and DEP both requested a hypothetical capital structure with a common equity ratio of 53% common equity and 47% long-term debt. This proposed capital structure in each case was sponsored by Duke witness Karl Newlin, who described it as the "optimal" capital structure in his direct testimony for each company and, in his rebuttal testimony for each company, described it as "consistent with the Company's financial objectives."

My direct testimony, in contrast, proposed for each company a capital structure with 50% common equity and 50% long-term debt. I note that both DEC's and DEP's actual capital structures were 52% equity / 48% debt as of December 31, 2019, according to discovery provided to the Public Staff.

The 52% common equity ratio in the proposed settlements is reflective of each company's current equity ratio and is also consistent with their currently authorized equity ratios.

Q. PLEASE NOW TURN TO THE COST OF COMMON EQUITY IN THE PROPOSED SETTLEMENTS AND INDICATE WHY THE 9.6% ROE IS REASONABLE FOR EACH COMPANY IN A SETTLEMENT CONTEXT.

A. Both companies requested an ROE of 10.30%, which I indicated in my direct testimony to be well above industry norms in recent years. I, in turn, proposed as my primary recommendation a 9.0% ROE. Whereas, I continue to believe my 9.0% ROE recommendation is appropriate at this time, a 9.6% ROE is 0.60% above my 9.0% recommendation and is 0.70% below Duke’s 10.30% ROE requests and 0.90% below the ROEs recommended by each company's ROE expert. As a result, the 9.6% ROE in the proposed settlements is a “compromise” between Duke’s and the Public Staff’s respective proposals. The 9.6% ROE also reflects a reduction from the 9.9% authorized in each company's last rate proceeding. I also note that the 9.6% ROE is below the 9.67% average authorized ROE for vertically integrated electric utilities during the first half of 2020 as calculated by Regulatory Research Associates. In addition, it is my understanding that this is the lowest ROE for a vertically integrated investor-owned electric utility for at least the last 30 years in North Carolina.

Q. PLEASE NOW DISCUSS THE 4.27% COST OF LONG-TERM DEBT IN THE PROPOSED DEC SETTLEMENT.

A. DEC's application contained a cost of long-term debt of 4.51%. In my supplemental testimony, I proposed an updated cost of long-term debt (as of January 31, 2020) of 4.29%, and DEC updated its cost of debt to 4.29% in supplemental testimony filed July 6, 2020. The proposed settlement recognizes the updated 4.27% cost of long-term debt (i.e., updated cost of debt as of May 2020).

Q. PLEASE NOW DISCUSS THE 4.04% COST OF LONG-TERM DEBT IN THE PROPOSED DEP SETTLEMENT.

A. DEP's application contained a cost of long-term debt of 4.15%. In my testimony, I proposed a cost of long-term debt (as of December 31, 2019) of 4.11%, and DEP updated its cost of debt to 4.11% in second supplemental testimony filed July 10, 2020. The proposed settlement recognizes the updated 4.04% cost of long-term debt (i.e., updated cost of debt as of May 2020).

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

(Whereupon, the prefiled testimony, Appendix A, supplemental and settlement testimony, and testimony supporting second partial settlement of Michelle M. Boswell was copied into the record as if given orally from the stand.)

(Whereupon, Public Staff Boswell Exhibits 1-2, Boswell Supplemental and Stipulation Exhibit 1, and Boswell Supplemental and Settlement Exhibits 2-3 were admitted into evidence.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1213

In the Matter of Application of Duke Energy Carolinas, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina	)	
DOCKET NO. E-7, SUB 1214	)	TESTIMONY OF MICHELLE M. BOSWELL PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION
In the Matter of Application of Duke Energy Carolinas, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina	)	

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1213

DOCKET NO. E-7, SUB 1214

TESTIMONY OF MICHELLE M. BOSWELL
ON BEHALF OF THE PUBLIC STAFF
NORTH CAROLINA UTILITIES COMMISSION

FEBRUARY 18, 2020

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

A. My name is Michelle M. Boswell. My business address is 430 North Salisbury Street, Dobbs Building, Raleigh, North Carolina. I am a Staff Accountant with the Accounting Division of the Public Staff – North Carolina Utilities Commission.

Q. BRIEFLY STATE YOUR QUALIFICATIONS AND DUTIES.

A. My qualifications and duties are included in Appendix A.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to present the accounting and ratemaking adjustments I am recommending, as well as those recommended by other Public Staff witnesses, as a result of the Public Staff's investigation of the revenue, expenses, and rate base presented by Duke Energy Carolinas, LLC (DEC or the Company) in support of its September 30, 2019, request for $445,331,000 in additional North Carolina retail revenue.

Q. WHAT REVENUE DECREASE IS THE PUBLIC STAFF RECOMMENDING?

A. Based on the level of rate base, revenue, and expenses annualized for the test period ended December 31, 2018, with certain updates, the Public Staff is recommending an increase in annual operating revenue of $66,536,000.

Q. MS. BOSWELL, PLEASE DESCRIBE THE SCOPE OF YOUR INVESTIGATION INTO THE COMPANY'S FILING.

A. My investigation included a review of the application, testimony, exhibits, and other data filed by the Company, an examination of the books and records for the test year, and a review of the Company's accounting, end-of-period, and after-period adjustments to test year revenue, expenses, and rate base. The Public Staff has also conducted extensive discovery in this matter, including the review of numerous data responses provided by the Company in response to data requests, participation in conference calls with the Company, and on-site visits to review documents and interview personnel.

Q. PLEASE BRIEFLY DESCRIBE THE PUBLIC STAFF'S PRESENTATION OF THE ISSUES IN THIS CASE.

A. Each Public Staff witness will present testimony and exhibits supporting his or her position and recommend any appropriate adjustments to the Company's proposed rate base and cost of service. My exhibits reflect and summarize these adjustments, as well as the adjustments I recommend.

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

A. Schedule 1 of Boswell Exhibit 1 presents a reconciliation of the difference between the Company's requested increase of $445,331,000 and the Public Staff's recommended increase of $66,536,000.

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

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

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

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

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

Q. MS. BOSWELL, WHAT ADJUSTMENTS TO THE COMPANY'S COST OF SERVICE DO YOU RECOMMEND?

A. I am recommending adjustments in the following areas:

1) Adjust Test Year Revenues
2) Updated Net Plant and Depreciation Expense
3) Update for New Depreciation Rates
4) Removal of Belews Creek Plant and Depreciation Expense
5) Updated Revenues and Non-Fuel Variable Operation and Maintenance (O&M) Expenses
6) Cash Working Capital Under Present Rates
7) Effect of Inflation on Non-Fuel O&M Expenses

8) Payroll
9) Executive Compensation
10) Board of Directors Expenses
11) Incentive Plans
12) Aviation Expenses
13) Outside Services
14) Allocations from DEBS
15) Lobbying Expenses
16) Distribution Vegetation Management
17) Credit Card Fees
18) Advertising Expenses
19) Hydro Station Sale
20) Storm Deferral and Normalization
21) Sponsorships and Donations
22) Rate Case Expense and Amortization
23) O&M Associated with Retired Hydro Plant
24) Severance
25) Interest Synchronization
26) Cash Working Capital Effect of Increase
27) Excess Deferred Income Taxes (EDIT)

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

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

1) The recommendations of Public Staff witness Woolridge regarding the capital structure, embedded cost of long-term debt, and return on common equity;

2) The recommendation of Public Staff witness McLawhorn regarding the Cost of Service Methodology;

3) The recommendations of Public Staff witness Metz regarding project costs included in plant in service and plant retirements;

4) The recommendations of Public Staff witness McCullar of William Dunkel and Associates regarding the Company's depreciation study;

5) The recommendations of Public Staff witnesses Tommy Williamson and David Williamson regarding Vegetation Management and the Grid Improvement Plan (GIP);

6) The recommendations of Public Staff witness Maness regarding ARO and non-ARO environmental costs, reclassification of non-ARO deferred environmental costs, and GIP;

7) The recommendation of Public Staff witness Saillor regarding customer growth, usage, and weather normalization; and

8) The recommendation of Public Staff witness Jeffrey Thomas regarding the GIP.

Q. PLEASE DESCRIBE ITEMS THE PUBLIC STAFF ACCOUNTING DIVISION REVIEWED BUT FOR WHICH IT DID NOT MAKE ADJUSTMENTS.

A. The Public Staff's investigation included procedures to evaluate and review all adjustments proposed by the Company in its initial application and filing. These procedures included a review of the Company's filing, prior Commission orders, and other Company data provided to the Public Staff. As discussed above, the Public Staff conducted extensive discovery of the Company's application including all of the E-1, Item 10 proforma adjustments, as well as other areas identified by the Public Staff where the Company did not make an adjustment. Additionally, we looked at the fluctuations for rate base expenditures, and O&M expenses for one, three, and five-year periods to further review any anomalies that may have surfaced.

Q. PLEASE DESCRIBE YOUR RECOMMENDED ADJUSTMENTS.

A. My adjustments are described below.

ADJUST TEST YEAR REVENUES

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO TEST-YEAR REVENUES.

A. I have adjusted test-year revenues to reflect usage, customer growth, and weather normalization adjustments recommended by Public Staff witness Saillor. I have made a corresponding adjustment for the increase in customer-related O&M expenses that result from the additional customers related to the Company's adjustment to revenues. I have also made corresponding adjustments to fuel and energy-related non-fuel O&M expenses for the change in kilowatt hours resulting from the Company's and the Public Staff's adjustments to revenues.

UPDATED NET PLANT AND DEPRECIATION EXPENSE

Q. PLEASE EXPLAIN HOW PLANT, ACCUMULATED DEPRECIATION, AND DEPRECIATION EXPENSE ARE RELATED.

A. As the Company places new plant into service, it increases its rate base. Upon being placed in service, the plant begins to depreciate, and depreciation expense is recorded each accounting period (and recovered from ratepayers) as the plant is used in providing service. The cumulative amount of depreciation expense is reflected on the balance sheet as accumulated depreciation, which is deducted from the original cost of the plant to determine net plant. Net plant (i.e., total plant, net of accumulated depreciation) is used to calculate the rate base on which the Company is allowed to earn a return, while depreciation expense is an input in the calculation of net operating income.

Q. PLEASE EXPLAIN THE COMPANY'S COMPUTATION OF NET PLANT.

A. The Company began its calculation of net plant with the plant and accumulated depreciation amounts recorded as of December 31, 2018, including the annual level of depreciation on the estimated plant additions as well as the matching amount of estimated accumulated depreciation through January 2020.

Q. PLEASE EXPLAIN HOW YOU HAVE COMPUTED NET PLANT.

A. My calculation begins with plant, accumulated depreciation, and net plant based on the Company's actual per books plant in service and accumulated depreciation amounts as of the update period ending November 30, 2019, which include rate base customer growth-related actual plant additions.

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

A. I have reflected updated net plant for known and actual changes to depreciation expense and non-generation plant retirements that have been recorded between the end of the test year (December 31, 2018) and November 30, 2019. Because I have updated plant and accumulated depreciation to reflect the Company's actual November 30, 2019, per books amounts, I have also considered the effect of normal retirements on the computation of depreciation expense. Pursuant to the FERC Uniform System of Accounts, normal retirements of plant reduce plant and accumulated depreciation by offsetting amounts, and, thus, do not affect the amount of net plant reflected as a component of rate base. If retirements are not properly reflected in the amount of plant used to compute depreciation expense, depreciation expense will be overstated.

Q. BY MAKING THIS ADJUSTMENT TO UPDATE ACCUMULATED DEPRECIATION FOR DEPRECIATION EXPENSE THAT HAS BEEN RECOVERED FROM RATEPAYERS SINCE THE END OF THE TEST PERIOD, IS THE PUBLIC STAFF CHANGING THE TEST PERIOD?

A. No. Consistent with N. C. Gen. Stat. § 62-133, we have used the historic test year to determine the cost of service for DEC. When justified, we have updated expenses, revenues, and investment to reflect the Company's most recent ongoing levels for these items, based on actual known and measurable changes occurring after the test year, just as DEC did in its initial testimony. The costs of the plant additions that the Company included are known and measurable, as are the plant retirements that have occurred and the depreciation that has been recovered from ratepayers, since the end of the test period. The Public Staff updated plant and accumulated depreciation to reflect actual per books amounts as of November 30, 2019, because that date represents the same point in time that the Public Staff used to update customer growth.

While the Public Staff's adjustment to accumulated depreciation is beyond the test year, it recognizes and maintains its relationship with plant and other cost of service items and is permitted by N.C. Gen. Stat. § 62-133(c) and (d). N.C. Gen. Stat. § 62-133(c) provides that the Commission shall consider evidence of changes in costs, revenues, or rate base after the test year, while N.C. Gen. Stat. § 62-133(d) requires the Commission to consider all material facts to allow it to set just and reasonable rates. The changes in plant, depreciation expense, and accumulated depreciation since the test year are exactly the type of changes and material facts that the Commission must consider pursuant to N.C. Gen. Stat. § 62-133(c) and (d).

The adjustment I recommend is consistent with the Commission's past treatment of comprehensive plant updates beyond the end of the test year. Adjustments like this have been consistently approved by the Commission in rate cases for natural gas utilities since the 1990's.[1]

Q. DO YOU HAVE ANY OTHER RECOMMENDATIONS REGARDING PLANT?

A. Yes. In the process of our investigation, I noted the Company has a significant backlog in unitizing plant to the appropriate plant account for depreciation. Unitization is the process of closing plant projects

[1] Per Commission Orders in Public Service Company of North Carolina, Inc., Docket No. G-5, Sub 565; Piedmont Natural Gas Company, Inc., Docket No. G-9, Sub 631; and Dominion North Carolina Power, Docket Nos. E-22, Sub 479 and Sub 532.

into individual FERC plant accounts for appropriate depreciation. Plant retirements related to the plant projects are normally handled simultaneously with unitization of plant projects. My investigation revealed the Company is currently three to four years behind in unitizing plant projects to the appropriate plant accounts. Typically, unitization of plant occurs within three to nine months upon completion of plant, with larger plants comprising the longer time period to unitize. The delay in unitizing plant to the appropriate accounts misstates depreciation expense, because a general depreciation rate is utilized instead of the specific rate for the specific plant accounts. The Company stated it was working with accounting firm, Ernst & Young, to develop a plan for both the generation and power delivery plant categories to begin working on the backlog. The Public Staff recommends the Company file with the Commission its plans to reduce the backlog, within 90 days of the Commission's Order in this case, and implement the proposed plans and procedures to decrease the lag in unitization.

UPDATE FOR NEW DEPRECIATION RATES

Q. PLEASE DESCRIBE YOUR ADJUSTMENT TO DEPRECIATION EXPENSE.

A. Based on the recommendations of Public Staff witness McCullar, I have made an adjustment to depreciation expense to reflect her recommended depreciation rates.

Q. DOES THE PUBLIC STAFF HAVE ANY ADDITIONAL ADJUSTMENTS TO DEPRECIATION RATES?

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

REMOVAL OF BELEWS CREEK PLANT AND DEPRECIATION EXPENSE

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO REMOVE BELEWS CREEK PLANT AND DEPRECIATION EXPENSE.

A. I have incorporated an adjustment to include the recommendation of Public Staff witness Metz to disallow costs related to the Belews Creek Project. I have also made corresponding adjustments to depreciation expense and accumulated depreciation to reflect his recommendation.

UPDATED REVENUES AND NON-FUEL VARIABLE O&M EXPENSES

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO UPDATE REVENUES AND VARIABLE NON-FUEL O&M EXPENSES.

A. As part of my update to plant and related items, I have updated revenues to reflect the effect of usage and customer growth adjustments as of November 30, 2019, based on the recommendation of Public Staff witness Saillor. I have made a corresponding adjustment for the increase in customer-related O&M expenses that result from the additional customers. I have also made corresponding adjustments to fuel and energy-related non-fuel

O&M expenses for the additional kilowatt hours resulting from increased sales.

CASH WORKING CAPITAL UNDER PRESENT RATES

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

A. The Company computed cash working capital using the lead-lag study method and then adjusted it to fully reflect all of the Company's proposed adjustments, before the amount of the proposed rate increase. I have likewise adjusted cash working capital under present rates to reflect all of the Public Staff's adjustments, in accordance with the Commission's Order in Docket No. M-100, Sub 137. Furthermore, through our investigation, the Public Staff discovered several errors in the new lead-lag study filed by the Company. I have incorporated the corrections to these errors in calculating the cash working capital under present rates. This cash working capital adjustment is reflected on Schedule 2-1 and incorporates the effect of the Public Staff's adjustments, before the rate increase, on the lead-lag study.

EFFECT OF INFLATION ON NON-FUEL O&M EXPENSES

Q. WHAT ADJUSTMENT HAVE YOU MADE TO THE COMPANY'S INFLATION ADJUSTMENT?

A. The Company adjusted annual non-labor, non-fuel O&M costs, to reflect the increase in costs during the test year that occurred due to the effect of inflation as of December 31, 2018. I have adjusted the amount to reflect the inflation factor through November 30, 2019, to coordinate with other items updated through that same point in time. I have also modified the Company's inflation adjustment to reflect the Public Staff's adjustment to include variable O&M expenses for changes in customer growth and the removal of aviation expenses, Board of Directors (BOD) expenses, outside services expenses, uncollectibles, sponsorships and donations, and advertising.

PAYROLL

Q. PLEASE EXPLAIN THE PUBLIC STAFF'S ADJUSTMENT TO PAYROLL.

A. I have adjusted the Company's payroll to include the updated payroll amounts and allocation factors through November 2019, as provided by the Company in response to a data request.

EXECUTIVE COMPENSATION AND BENEFITS

Q. WHAT ADJUSTMENT HAVE YOU MADE TO EXECUTIVE COMPENSATION AND BENEFITS?

A. The Company made an adjustment to remove 50 percent of the compensation of the five Duke Energy executives with the highest level of compensation allocated to DEC in the test period. I made an additional adjustment to remove 50 percent of the benefits associated with these top five Duke Energy executives. This adjustment is consistent with the positions taken by the Public Staff and approved by the Commission in past general rate cases involving investor-owned electric utilities serving North Carolina retail customers. The Public Staff believes that it would be inconsistent to remove the compensation of these five executives without also removing the benefits related to that compensation.

Q. IS YOUR RECOMMENDATION BASED ON THE PREMISE THAT THE COMPENSATION AND BENEFITS OF THE EXECUTIVE OFFICERS YOU HAVE SELECTED ARE EXCESSIVE OR SHOULD BE REDUCED?

A. No. This recommendation is based on the Public Staff's belief that it is appropriate and reasonable for the shareholders of the larger electric utilities to bear some of the cost of compensating those individuals who are most closely linked to furthering shareholder interests, which are not always the same as those of ratepayers. Officers have fiduciary duties of care and loyalty to shareholders, but not to customers. Consequently, the Company's executive officers are obligated to direct their efforts not only to minimizing the costs and maximizing the reliability of DEC's service to customers, but also to maximizing the Company's earnings and the value of its shares. It is reasonable to expect that management will serve the shareholders as well as the ratepayers; therefore, a portion of management salary and benefits should be borne by the shareholders.

BOARD OF DIRECTORS (BOD) EXPENSES

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO BOD EXPENSES.

A. I have made an adjustment to remove 50 percent of the expenses associated with the BOD of Duke Energy Corporation that have been allocated to DEC. The expenses allocated to DEC encompass the BOD's compensation, insurance, and other miscellaneous expenses. The premise of this adjustment is closely linked to the premise of the adjustment made by the Public Staff related to executive compensation. We believe that it is appropriate and reasonable for the shareholders of the larger electric utilities to bear a reasonable share of the costs of compensating those individuals who have a fiduciary duty to protect the interests of shareholders, which may differ from the interests of ratepayers. Further, Directors' and Officers' liability insurance, while a necessary expense for a corporation, has been utilized to defend the BOD in suits brought by shareholders regarding issues such as coal ash. It is appropriate for shareholders to share the cost of the insurance with ratepayers.

INCENTIVE PLANS

Q. PLEASE EXPLAIN YOUR ADJUSTMENT FOR THE COMPANY'S LONG AND SHORT-TERM INCENTIVE PLANS.

A. DEC offers two incentive plans to its employees: the Short-Term Incentive Plan (STIP) and the Long-Term Incentive Plan (LTIP). The STIP is offered to all employees, including executives. The LTIP is offered to employees at the Director level and above. Approximately 700 employees of Duke Energy Corporation qualify for the LTIP.

The STIP consists of goals set and approved by the BOD for a one-year term. In 2018, the test year in this case, the goals consisted of Earnings per Share (EPS), Operational Excellence, Customer Satisfaction, and Safety, as well as team and individual goals. The LTIP goals consist of Performance Shares, which are further categorized between EPS, Total Shareholder Return (TSR), and Safety, and Restricted Stock Units (RSU). Both offerings are set and approved by the BOD for a three-year period.

The Company's payout of STIP is based on the achievement of targets at minimum, target, and maximum levels. During the test year, the Company included an adjustment to reduce the STIP from the 2018 payout level to the 2018 target level. With regard to LTIP, the Company made an adjustment to remove the 2018 accruals and replace them with 2019 target accruals.

I have adjusted the allowable costs of STIP to exclude the incentive accruals that were based on the EPS metric. The Public Staff believes that the incentives related to EPS should be excluded, because they provide a direct benefit to shareholders rather than to ratepayers.

I have also adjusted the allowable LTIP costs to exclude the Performance Shares related to the EPS and TSR metrics. The Public Staff believes that the incentives related to EPS and TSR should be excluded, because they provide a direct benefit to shareholders rather than to ratepayers. The Company's BOD minutes depict a direct link and benefit between the Company's goals and shareholder's interests. Therefore, these costs should be borne by shareholders.

AVIATION EXPENSES

Q. WHAT ADJUSTMENT DO YOU RECOMMEND RELATED TO AVIATION EXPENSES?

A. The Company made an adjustment to O&M expenses to remove an amount for corporate aviation. The Public Staff made a further adjustment after investigating the aviation expenses charged to DEC during the test year. The aviation expenses are incurred by Duke Energy Corporation, and then a portion is allocated to DEC through the use of a corporate allocation factor. Based on the Public Staff's review of flight logs, the corporate aircraft are available for use by Duke Energy Corporation's Chief Executive Officer (CEO) and her staff. I recommend that certain expenses allocated to DEC be removed due to the nature of the flights involved. In the course of our investigation, the Public Staff determined that some of these flights appear to be either unrelated to the provision of utility service; or the costs of the flights were incorrectly allocated to DEC. Additionally, I removed the DEC-allocated portion of commercial international flights due to the Public Staff's determination the international flights included were unrelated to the provision of utility service.

OUTSIDE SERVICES

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO OUTSIDE SERVICES.

A. The Public Staff reviewed costs for outside services associated with expenses that were indirectly charged to DEC by DEBS as well as those incurred by DEC directly. Our investigation found certain expenses related to legal and non-legal invoices, which the Public Staff believes should not be charged to ratepayers. Based on our understanding, the Company agrees that these items should be removed based on the Public Staff's review.

LOBBYING EXPENSES

Q. PLEASE EXPLAIN YOUR ADJUSMTENT TO LOBBYING EXPENSES.

A. The Company assigned some lobbying expenses from the test year to below-the-line accounts, and therefore were not included in the cost of service. I have further adjusted O&M expenses to remove additional lobbying costs. In determining what costs should be removed, I applied the "but for" test for reporting lobbying costs as used in a Formal Advisory Opinion of the State Ethics Commission dated February 12, 2010. The Commission recognized at pages 70-71 of its 2012 Dominion North Carolina Power Order in Docket No. E-22, Sub 479, that lobbying included not only employees' direct contact with legislators, but also other activities preparing for or surrounding lobbying that would not have been conducted but for the lobbying itself. In applying this test, I removed O&M expenses associated with stakeholder engagement, state government affairs, and federal affairs that were recorded above the line.

DISTRIBUTION VEGETATION MANAGEMENT

Q. PLEASE EXPLAIN THE PUBLIC STAFF'S ADJUSTMENT TO DISTRIBUTION VEGETATION MANAGEMENT.

A. I have made an adjustment to correct the test year cost per mile to reflect the actual costs incurred for distribution vegetation management during the test year, as provided by the Company in response to a data request. The correction also had an impact on the adjusted cost per mile, as the Company's adjusted amount is calculated utilizing the actual test year amount and actual cost increase of 3%. Vegetation management for distribution and transmission is further discussed in the testimony of Public Staff witness David Williamson.

CREDIT CARD FEES

Q. WHAT ADJUSTMENT HAVE YOU MADE FOR CREDIT CARD FEES?

A. In the present case, the Company has made a proforma adjustment to include credit card transaction fees for residential customers in its revenue requirement. The fees for other forms of payments such as checks, ACH payments[2], and bank drafts are currently included in the Company's cost of service. The Public Staff does not have an issue regarding the inclusion of credit card fees in the cost of service. However, in its adjustment, the Company did not calculate any impacts to late payments or uncollectibles associated with the request to include credit card fees. The Company included the 2019 credit card transactions in the adjustment, but has not removed the

[2] ACH payments are electronic payment that are created when the customer gives an originating institution, corporation, or other customer (originator) authorization to debit directly from the customer's checking or saving account for the purpose of bill payment.

expenses related to the forms of payment that were utilized in the 2018 cost of service. I have made an adjustment to remove the O&M expenses included in the cost of service for 2018 associated with the increase in credit card transactions from the 2018 to 2019 period, so as to avoid a double counting of costs associated with the same payments.

Q. DO YOU HAVE ANY RECOMMENDATIONS REGARDING THE ALLOWANCE OF CREDIT CARD FEES FOR RESIDENTIAL CUSTOMERS INTO THE COST OF SERVICE?

A. Yes. I recommend the Company track the impact, of the credit cards that no longer have a separate fee associated with the payment, on the late payment and uncollectible accounts, and report the quantitative impact in testimony in the Company's next general rate case.

ADVERTISING

Q. PLEASE EXPLAIN THE PUBLIC STAFF'S ADJUSTMENT TO ADVERTISING EXPENSES.

A. I have adjusted O&M expenses to remove amounts charged to O&M expense to exclude items incorrectly booked to advertising; amounts the Company could not provide advertisement support for, as well image and promotional advertising, in accordance with Commission Rule R12-13 and prior Commission orders.

HYDRO STATION SALE

Q. WHAT ADJUSTMENT HAVE YOU MADE REGARDING THE HYDRO STATION SALE?

A. I have adjusted the amortization period for the loss on the sale of the hydro units to the overall remaining depreciable life of the assets of 20 years. In the present case, the Company has recommended an amortization period of 7 years, with the purpose of keeping the overall revenue requirement for the units the same as before the sale occurred. In its filing for deferral accounting in E-7, Sub 1181 (Sub 1181), the Company asserted that, through the transaction, the facilities would continue to serve the customers with clean renewable energy, but at a lower cost. Additionally, the cost benefit analysis provided by the Company in the above referenced docket was based on 20-year costs to maintain and operate.

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

STORM EXPENSE AND DEFERRAL

Q. PLEASE EXPLAIN THE PUBLIC STAFF'S ADJUSTMENT TO THE COMPANY'S PROPOSED STORM DEFERRAL.

A. I have made an adjustment to remove all capital and O&M costs associated with Hurricane Florence, Hurricane Michael, and Winter Storm Diego in the present case; because the Company indicated it would seek to recover the costs of the foregoing storms through securitization if this method of financing were authorized by the North Carolina Legislature. In his initial testimony, Company witness DeMay stated that, "If, however, North Carolina law is amended to allow for the securitization of these storm costs, the Company would pursue securitization if it provided a savings to its customers and would cease the recovery of the remaining storm costs in current rates and instead begin recovering the remaining unrecovered storm costs as provided for in a securitization financing order." On November 6, 2019, Senate Bill 559, which authorized a public utility to seek recovery of storm costs through securitization, was signed into law.

Q. ARE THE COSTS RELATED TO HURRICANE FLORENCE, HURRICANE MICHAEL, AND WINTER STORM DIEGO AS PRESENTED IN THE CURRENT CASE PRUDENTLY INCURRED?

A. Based upon our review of the costs the Company has included in the present case, the Public Staff believes the costs associated with these storms were prudently incurred.

Q. DO YOU HAVE ANY OTHER ADJUSTMENTS RELATED TO STORM EXPENSE?

A. I have included an adjustment to reflect a 10-year normalized level of storm expense for storms that would not otherwise be large enough for the Company to seek securitization of the costs.

<u>RATE CASE EXPENSE AND AMORTIZATION</u>

Q. WHAT ADJUSTMENT HAVE YOU MADE TO RATE CASE EXPENSE AND AMORTIZATION?

A. I have adjusted rate case expense to reflect the actual costs through the current update period of November 30, 2019. Furthermore, I have removed the Company's adjustment to include the unamortized portion of rate case expense in rate base. I have removed the Company's adjustment to include the unamortized balance in rate base, because the amortization of rate case expense should reflect a normalization of the costs associated with the filing of a rate case, based on a historical average of the number of years between rate case filings. It is the Public Staff's position that rate case expense does not rise to the level of being extraordinary in nature, and, therefore, does not require rate base treatment.

RETIRED HYDRO STATIONS

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO THE O&M ASSOCIATED WITH THE RETIRED HYDRO STATIONS.

A. In May and December of 2018, the Company retired several hydro units at Rocky Creek, Great Falls, and 99 Islands. In the present case, the Company did not remove the O&M related to these retired units from the cost of service. I have made an adjustment to remove all non-payroll related O&M related to these retired hydro units.

SPONSORSHIPS AND DONATIONS

Q. WHAT ADJUSTMENT HAVE YOU MADE FOR SPONSORSHIPS AND DONATIONS?

A. I have adjusted O&M expenses to remove amounts charged to O&M expense for sponsorships and charitable donations. Specifically, I have excluded from expenses amounts paid to the chambers of commerce, the NC Chamber, and other donations. These expenses should be disallowed because they do not represent actual costs of providing electric service to customers.

SEVERANCE

Q. PLEASE DESCRIBE THE PUBLIC STAFF'S ADJUSTMENTS TO SEVERANCE COSTS.

A. The Company made an adjustment to remove atypical severance and retention costs included in the test period. The Company is also requesting to establish a regulatory asset and defer the NC retail amount and to amortize the regulatory asset over a three-year period.

I have adjusted severance costs to reflect a normalized level over a five-year period. This is consistent with how the Public Staff has treated severance program costs in other utility rate cases.[3] The costs that the Company has incurred correlate with the savings reflected in the Company's update. There is a relationship between the savings generated by a severance program and the costs incurred for the severance program. The more employees who leave under a severance program, the greater the savings, and the greater the cost.

With regard to the Company's request to establish a regulatory asset, the Public Staff has established a normalized level to include in rates, and, as a result, has removed the Company's requested amount from rate base. The Company did not state a rationale for establishing a regulatory asset in its testimony. This is also consistent with how the Public Staff has treated severance program costs as stated above.

[3] Dominion Energy North Carolina Docket No. E-2, Subs 532 and 562.

INTEREST SYNCHRONIZATION ADJUSTMENT

Q. PLEASE EXPLAIN YOUR INTEREST SYNCHRONIZATION ADJUSTMENT.

A. The Company adjusted income tax expense to reflect interest synchronization with its proposed capital structure, cost of debt, and rate base. I have also adjusted income tax expense to reflect the deduction of the pro forma level of interest resulting from the application of the Public Staff's recommended return and capital structure to its recommended rate base.

CASH WORKING CAPITAL EFFECT OF INCREASE

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

A. The cash working capital lead-lag effect of the proposed revenue increase as recommended by the Public Staff has been calculated on Boswell Exhibit 1.

EXCESS DEFERRED INCOME TAXES (EDIT)

Q. PLEASE EXPLAIN THE COMPANY'S ADJUSTMENT RELATED TO EDIT.

A. In this case, the Company has proposed an EDIT Rider that contains the following categories of refunds for customers:

(1) Federal EDIT – Protected

(2) Federal EDIT – Unprotected (PP&E and non PP&E related)

(3) State EDIT

(4) Deferred Revenue from Tax Act Overcollections

DEC did not make an adjustment to exclude any EDIT from rate base, but instead proposes to handle each of the categories above in a single Rider, with rate changes occurring each year based on the proposed amortizations for these categories, which range from 39.6 years to 5 years. The Public Staff believes that the four categories of refunds listed above should be handled separately, due to the differing natures of the amounts and the amortization periods. We believe that this provides a more transparent means of tracking the Tax Act and state tax-related refunds to customers for each year.

Based upon the foregoing, I recommend several adjustments regarding federal EDIT.

Q. PLEASE EXPLAIN THE PUBLIC STAFF'S RECOMMENDATIONS REGARDING EDIT.

The federal EDIT consists of two categories of amounts, protected and unprotected. The protected EDIT are deferred taxes related to timing differences arising from the utilization of accelerated depreciation for tax purposes and another depreciation method for book purposes. These deferred taxes are deemed protected because the Internal Revenue Service (IRS) does not permit regulators to flow back the excess to ratepayers immediately, but instead requires that the excess be flowed back to ratepayers ratably over the life of the timing difference that gave rise to the excess. Unprotected EDIT are those taxes that result from all other timing differences, and can be flowed back to ratepayers however quickly regulators deem reasonable.

Federal Protected EDIT

I have made an adjustment to remove the federal protected EDIT from the EDIT Rider proposed by the Company, and instead leave the amount in base rates. I recommend this treatment since the Company's calculation of the net remaining life of the timing differences (average rate assumption method or ARAM) results in an extremely long life due to the timing differences that gave rise to the excess. The Public Staff proposes to amortize the protected EDIT balance over 39.6 years in base rates and to remove the first year of amortization from the deferral amount for purposes of this proceeding.

Federal Unprotected EDIT

The Company has artificially created two categories of unprotected EDIT for purposes of its proposal: "unprotected PP&E" (Property Plant & Equipment) and "unprotected other," and has proposed to return EDIT to ratepayers over periods of 20 years and 5 years, respectively. The Company asserts that, since the unprotected PP&E EDIT is similar in nature to protected EDIT (which is also related to PP&E), it is reasonable to flow it back to the ratepayers over the same time period that it would have been paid to the IRS had the Tax Cuts and Jobs Act not been enacted. However, the Company acknowledges the Commission has the discretion to flow back all of the unprotected EDIT over any time period it finds appropriate.

The tax normalization rules are very clear - either EDIT is protected, or it is not. The EDIT that the Company designates as "PPE-related" is still clearly unprotected, a fact conceded by the Company. The Company's assertion that it should only return this PP&E-related unprotected EDIT over the same period of time it would have paid the funds to the IRS had the tax law not been passed,

Is not supportable by any logical accounting or ratemaking principle, and should not dictate this Commission's decision as to what is a reasonable amount of time within which to return these funds to ratepayers. These funds rightfully belong to the ratepayers and should be returned to them as soon as reasonably possible. It should be noted that the Company will continue to collect accumulated deferred income taxes (ADIT) at a tax rate sufficient to meet its tax obligations.

Based on the forgoing, for unprotected EDIT, I recommend removing the EDIT regulatory liability associated with the unprotected differences from rate base, and placing it in a rider to be refunded to ratepayers over five years on a levelized basis, with carrying costs. The immediate removal of unprotected EDIT from rate base increases the Company's rate base, and mitigates regulatory lag that might occur from refunds of unprotected EDIT not contemporaneously reflected in rate base. Additionally, refunding the unprotected EDIT over five years allows the Company to properly plan for any future credit needs while refunding ratepayer dollars in a reasonable time. The Public Staff has provided the Company with the benefit of removing the total amount of the unprotected EDIT credit from rate base in the current case, thus providing the Company with an increase in rates to moderate any cash flow issues, to the extent they would exist. The financing cost to the Company will be imposed ratably over the period that the EDIT is returned through the levelized rider.

<u>Overcollection of Federal Taxes</u>

I have made an adjustment to remove, from the Company's single rider, the overcollection of federal taxes, which resulted from the reduction in tax rates from 35% to 21%, and placed it in a separate levelized rider amortized over a one-year period. Furthermore, I have removed the balance from the working capital schedules, since

I am recommending a refund over one year. The one-year amortization period is consistent with the period approved by the Commission in the most recent rate cases of: Aqua North Carolina, Inc. in Docket No. W-218, Sub 497 (December 18, 2018), Carolina Water Service, Inc. of North Carolina in Docket No. W-354, Sub 360 (February 21, 2019), and Piedmont Natural Gas Company, Inc. in Docket No. G-9, Sub 743 (October 31, 2019).

State EDIT

I recommend removing the entire state EDIT balance from rate base, as the Company has in adjustment NC-0600, and placing it in a separate rider, and recommend a one-year levelized return on the balance. The change in the state tax rate represents one year's worth of tax difference, much like the overcollection of federal taxes, and, to avoid intergenerational issues, should be flowed back over the same time. This period is also consistent with the Commission's Order in Dominion Energy North Carolina, Docket No. E-22, Sub 532, in which the Commission approved a one-year flowback.

ADDITIONAL COMMENTS

Q. DO YOU HAVE ADDITIONAL COMMENTS?

A. Yes. I have additional comments with regard to the Company's February 14, 2020, supplemental filing.

Q. WHAT ARE YOUR ADDITIONAL COMMENTS REGARDING THE COMPANY'S FEBRUARY 14, 2020, SUPPLEMENTAL FILING?

A. The Public Staff is aware of the supplemental filing; however, given the timing of the supplemental filing and the due date of the Public Staff's testimony, the Public Staff could not reasonably perform its investigation on the Company's updated information in the short amount of time before it was due to file testimony. The Public Staff reserves the right to file its own supplemental testimony related to the Company's February 14, 2020, supplemental filing once its investigation of the updated information is completed.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Appendix A

MICHELLE M. BOSWELL

Qualifications and Experience

I graduated from North Carolina State University in 2000 with a Bachelor of Science degree in Accounting. I am a Certified Public Accountant.

I joined the Public Staff in September 2000. I have performed numerous audits and/or presented testimony and exhibits before the Commission addressing a wide range of electric, natural gas, and water topics. I have performed audits and/or presented testimony in Duke Energy's 2010 REPS Cost Recovery Rider; the 2008 REPS Compliance Reports for North Carolina Municipal Power Agency 1, North Carolina Eastern Municipal Power Agency, GreenCo Solutions, Inc., and EnergyUnited Electric Membership; four recent Piedmont rate cases; PSNC's 2016 rate case, DNCP's 2012 rate case, DEP's 2013 rate case, several Piedmont, NUI, and Toccoa annual gas cost reviews; Piedmont and NUI's merger; and Piedmont and NCNG's merger.

Additionally, I have filed testimony and exhibits in numerous water rate cases and performed investigations addressing a wide range of topics and issues related to the water, electric, and telephone industries.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1213 In the Matter of Application of Duke Energy Carolinas, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in 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 Utility Service in North Carolina	)	SUPPLEMENTAL AND SETTLEMENT TESTIMONY OF MICHELLE M. BOSWELL PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUBS 1213 AND 1214

Supplemental and Settlement Testimony of Michelle M. Boswell

On Behalf of the Public Staff

North Carolina Utilities Commission

March 25, 2020

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

A. The purpose of my supplemental and settlement testimony is to (1) support the Agreement and Stipulation of Partial Settlement (Stipulation) between Duke Energy Carolinas, LLC (DEC or the Company) and the Public Staff (Stipulating Parties); (2) present the non-settled accounting and ratemaking adjustments, which I have updated from my original testimony; (3) recommend adjustments as a result of information provided by the Company, subsequent to the filing of my original testimony; and (4) make updates and corrections recommended by other Public Staff witnesses, as a result of the Public Staff's investigation of the second supplemental filing by DEC in this proceeding. On February 14, 2020, DEC filed supplemental testimony and exhibits supporting a $19,254,000 increase in its request for additional North Carolina retail revenue, for a total supported proposed increase of $464,585,000. However, the Company did not provide customers notice of an increase beyond the initial $445,331,000 filed for on September 30, 2019.

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

A. Based on the level of rate base, revenue, and expenses annualized at December 31, 2018, with certain updates, the Public Staff is recommending an increase in annual base rate operating revenue of $126,710,000.

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

A. Schedule 1 of Boswell Supplemental and Stipulation Exhibit 1 presents a reconciliation of the difference between the Company's requested increase of $464,585,000 and the Public Staff's recommended increase of $126,710,000, including all adjustments included in the Partial Stipulation.

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

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

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

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

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

Boswell Supplemental and Stipulation Exhibit 3 sets forth the calculation of the difference in allocation methodologies from the Company filed SCP to SWPA based on the recommendation of Public Staff witness McLawhorn.

Q. MS. BOSWELL, WHAT UPDATED OR CORRECTED ADJUSTMENTS TO THE COMPANY'S COST OF SERVICE DO YOU RECOMMEND?

A. I am recommending updated, corrected, or new adjustments in the following areas:

1) Change in allocation methodology from SCP to SWPA
2) Updated Net Plant and Depreciation Expense
3) Update for New Depreciation Rates
4) Belews Creek plant and depreciation expense
5) Clemson CHP plant and depreciation expense
6) Hydro Station Sale
7) Cash Working Capital under Present Rates
8) Interest Synchronization
9) Cash Working Capital Effect of Increase
10) Excess Deferred Income Taxes (EDIT)

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

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

1) The recommendations of Public Staff witness Woolridge regarding the capital structure, embedded cost of long-term debt, and return on common equity.

2) The recommendations of Public Staff witness Maness regarding ARO and non-ARO environmental costs, as well as the reclassification of non-ARO deferred environmental costs.

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

4) The recommendation of Public Staff witness McLawhorn regarding the Cost of Service Methodology.

5) The recommendations of Public Staff witness McCullar of William Dunkel and Associates regarding the Company's depreciation study.

Q. PLEASE BRIEFLY DESCRIBE THE STIPULATION.

A. The Stipulation sets forth agreement between the Stipulating Parties regarding the following revenue requirement issues:

(1) Adjustment of weather normalization to January 31, 2020.
(2) ADIT for retired meters.
(3) Update of revenues to January 31, 2020.
(4) Outside services.
(5) Salaries and wages expense.
(6) Advertising expense.
(7) Retired hydro O&M.
(8) Protected federal excess deferred income taxes (EDIT) due to Tax Cuts and Jobs Act.
(9) Aviation expenses.
(10) Executive compensation.
(11) Rate case expense.
(12) Incentives.
(13) Sponsorships and donations.
(14) Severance.
(15) Lobbying expense.
(16) Board of Directors expense.

(17) Credit card fees.
(18) Inflation to January 31, 2020.
(19) Storm deferral.
(20) Storm expense.

The details of the agreements in these areas are set forth in the Stipulation.

Q. WHAT BENEFITS DOES THE STIPULATION PROVIDE FOR RATEPAYERS?

A. From the perspective of the Public Staff, the most important benefits provided by the Stipulation are as follows:

(a) An aggregate reduction in the increase of the specific expense items listed above requested in the Company's application, resulting from the adjustments agreed to by the Stipulating Parties.

(b) The avoidance of protracted litigation between the Stipulating Parties before the Commission and possibly the appellate courts.

Based on these ratepayer benefits, as well as the other provisions of the Stipulation, the Public Staff believes the Stipulation is in the public interest and should be approved.

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

A. Yes. The attached Boswell Supplemental and Stipulation Exhibit 1 sets forth the accounting and ratemaking adjustments to which DEC and the Public Staff have agreed. I note that not until the Commission makes a determination regarding the yet unresolved issues (including but not limited to rate of return, cost of capital, allocation methodologies, federal income taxes, and coal ash disposal costs) can the settled accounting and ratemaking adjustments be finalized, and the resulting rate base, net operating income, return, and rate increase be calculated.

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

A. My adjustments are described below.

<u>UPDATE FOR CHANGE IN ALLOCATION METHODOLOGIES</u>

Q. PLEASE EXPLAIN THE ADJUSTMENT TO UPDATE FOR THE CHANGE IN ALLOCATION METHODOLOGIES.

A. In my initial testimony, I applied the SWPA allocation factors to adjustments I recommended and replaced the Company's SCP allocation factors. However, I did not recalculate the Company's pro forma rate base, revenues, and expenses from the Company's proposed SCP factors and amounts to the Public Staff's proposed SWPA factors and amounts. Boswell Supplemental and Settlement Exhibit 3 corrects this oversight by making this recalculation, and the revenue requirement impact is shown on Exhibit 1. All remaining adjustments shown on Exhibit 1 have been recalculated to reflect only SWPA allocations.

<u>UPDATE FOR PLANT AND ACCUMULATED DEPRCIATION</u>

Q. PLEASE EXPLAIN HOW YOU HAVE COMPUTED NET PLANT.

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

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

A. I have reflected updated net plant for known and actual changes to depreciation expense and non-generation plant retirements that have been recorded between the end of the test year (December 31, 2018) and January 31, 2020, utilizing the depreciation rates reflected in Public Staff witness McCullar's exhibits. The Company has reflected updated net plant for known and actual changes to depreciation expense and non-generation plant retirements that have been recorded between the end of the test year and January 31, 2020, utilizing the depreciation rates recommended by Company witnesses.

UPDATE FOR NEW DEPRECIATION RATES

Q. PLEASE DESCRIBE YOUR ADJUSTMENT TO DEPRECIATION EXPENSE.

A. Based on the recommendations of Public Staff witness McCullar, I have made an adjustment to depreciation expense to reflect her recommended depreciation rates.

REMOVAL OF BELEWS CREEK PLANT AND DEPRECIATION EXPENSE

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO REMOVE BELEWS CREEK PLANT AND DEPRECIATION EXPENSE.

A. I have incorporated an adjustment to reverse the adjustment in my original schedules based upon the recommendation of Public Staff witness Metz.

REMOVAL OF CLEMSON CHP PLANT AND DEPRECIATION EXPENSE

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO REMOVE BELEWS CREEK PLANT AND DEPRECIATION EXPENSE.

A. I have incorporated an adjustment to remove Clemson CHP from plant in service, and made corresponding adjustments to depreciation expense and accumulated depreciation, based on the recommendation of Public Staff witness Metz.

HYDRO STATION SALE

Q. WHAT ADJUSTMENT HAVE YOU MADE REGARDING THE HYDRO STATION SALE?

A. I have updated my adjustment to hydro station sales to reflect the Company's January 31, 2020 updated adjustment, adjusting the amortization period for the loss on the sale of the hydro units to the overall remaining depreciable life of the assets of 20 years.

CASH WORKING CAPITAL UNDER PRESENT RATES

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

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

INTEREST SYNCHRONIZATION ADJUSTMENT

Q. PLEASE EXPLAIN YOUR INTEREST SYNCHRONIZATION ADJUSTMENT.

A. The Company adjusted income tax expense to reflect interest synchronization with its proposed capital structure, cost of debt, and rate base. I have also adjusted income tax expense to reflect the deduction of the pro forma level of interest resulting from the application of the Public Staff's recommended return and capital structure to its recommended rate base.

CASH WORKING CAPITAL EFFECT OF INCREASE

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

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

EXCESS DEFERRED INCOME TAXES (EDIT)

Q. PLEASE EXPLAIN THE ADJUSTMENTS RELATED TO EDIT.

A. First, I have separated the unprotected federal EDIT, unprotected federal "PP&E" EDIT, federal deferred EDIT, and State EDIT into individual line items. I have updated the amount of each EDIT category to reflect the amounts on McManeus Supplemental Exhibit 4, Line 8. In my initial schedules, I reflected the incorrect amount due to the inclusion of an incorrect line item. The error has been corrected in these adjustments.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

NORTH CAROLINA
PUBLIC STAFF
UTILITIES COMMISSION

July 31, 2020

Ms. Kimberley A. Campbell, Chief Clerk
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, North Carolina 27699-4300

Re: Docket No. E-7, Sub 1213 – Petition of Duke Energy Carolinas, LLC for Approval of Prepaid Advantage Program; and Docket No. E-7, Sub 1214 – Application of Duke Energy Carolinas, LLC for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina

Dear Ms. Campbell:

In connection with the above-referenced dockets, I transmit herewith for filing on behalf of the Public Staff the testimony of Michelle M. Boswell, Acting Manager, Electric Section, Accounting Division, supporting a second partial settlement.

By copy of this letter, we are forwarding copies to all parties of record.

Sincerely,

/s/ Dianna W. Downey
Chief Counsel
dianna.downey@psncuc.nc.gov

DWD/cla

Attachment

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1214
DOCKET NO. E-7, SUB 1213
DOCKET NO. E-7, SUB 1187

In the Matter of Application of Duke Energy Carolinas, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina In the Matter of Petition of Duke Energy Carolinas, LLC, for Approval of Prepaid Advantage Program In the Matter of Petition of Duke Energy Carolinas, LLC, for an Accounting Order to Defer Incremental Storm Damage Expenses Incurred as a Result of Hurricanes Florence and Michael and Winter Storm Diego	))))))))))))))))))	TESTIMONY OF MICHELLE M. BOSWELL PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION SUPPORTING SECOND PARTIAL STIPULATION

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1214
DOCKET NO. E-7, SUB 1213
DOCKET NO. E-7, SUB 1187

Testimony of Michelle M. Boswell Supporting Second Partial Stipulation

On Behalf of the Public Staff

North Carolina Utilities Commission

July 31, 2020

Q. MS. BOSWELL, WHAT IS THE PURPOSE OF YOUR TESTIMONY IN SUPPORT OF SECOND PARTIAL STIPULATION IN THIS PROCEEDING?

A. The purpose of my testimony is to support the Second Agreement and Stipulation of Partial Settlement (Second Partial Stipulation) filed on July 31, 2020 between Duke Energy Carolinas, LLC (DEC or the Company) and the Public Staff (Stipulating Parties) regarding certain issues related to the Company's pending application for a general rate increase.

Q. PLEASE BRIEFLY DESCRIBE THE SECOND PARTIAL STIPULATION.

A. The Second Partial Stipulation sets forth agreement between the Stipulating Parties regarding the following revenue requirement and rate issues:

(1) Return on Equity, Capital Structure, and Debt Cost.

(2) Update of revenues, rate base, and expenses to May 31, 2020 (subject to further Public Staff investigation).

(3) Return of unprotected federal excess deferred income taxes (EDIT) due to the Tax Cuts and Jobs Act to customers.

(4) Return of North Carolina state EDIT due to reduction in state tax rates.

(5) Treatment of federal deferred revenue due to the Tax Cuts and Jobs Act.

(6) Amortization period for Non-Asset Retirement Obligation (ARO) coal ash costs.

(7) The Company's Grid Improvement Plan (GIP) (revenue requirement effects only in future cases).

(8) Cost of service allocation methodology.

(9) Rate design.

(10) The process to be used to determine the base fuel factor in this proceeding.

In addition to the settled issues having a revenue requirement impact in the present case, the Second Partial Stipulation also settles non-revenue requirement issues involving additional cost of service studies, a rate design study, the Prepaid Advantage Program, affordability, and audit and reporting obligations.

The details of the agreements in these areas are set forth in the Second Partial Stipulation.

Q. WHAT BENEFITS DOES THE SECOND PARTIAL STIPULATION PROVIDE FOR RATEPAYERS?

A. From the perspective of the Public Staff, the most important benefits provided by the Second Partial Stipulation are as follows:

(a) A significant reduction in the Company's proposed revenue increase in this proceeding.

(b) The avoidance of protracted litigation between the Stipulating Parties before the Commission and possibly the appellate courts.

Based on these ratepayer benefits, as well as the other provisions of the Second Partial Stipulation, the Public Staff believes the Second Partial Stipulation is in the public interest and should be approved.

Q. ARE THERE ANY AREAS ABOUT WHICH THE STIPULATING PARTIES DID NOT REACH AGREEMENT?

A. Yes. The Stipulating Parties did not reach agreement regarding recovery of ARO-related coal ash costs; depreciation rates, including the Company's proposal to shorten the lives of certain coal-fired generating facilities; the amortization period for the loss on the sale of hydro facilities, and any other revenue requirement or non-revenue requirement issue not specifically addressed in the Stipulations, or agreed upon in the testimony of the Stipulating Parties. The Public Staff fully supports its filed positions on these particular issues, and intends to demonstrate the appropriateness and reasonableness of its positions through litigation in this case.

Q. WILL THE PUBLIC STAFF BE PRESENTING ITS CALCULATION OF THE REVENUE REQUIREMENT INCLUDING THE IMPACTS OF THE SECOND PARTIAL STIPULATION?

A. Yes. Once the Public Staff has completed the audit of all revenue, rate base, and expense updates through May 31, 2020, the Public Staff will file schedules supporting the Public Staff's recommended revenue requirement. I note that it is not until the Commission makes a determination regarding the yet unresolved issues, and the results of the Public Staff's audit, that the settled accounting and ratemaking adjustments can be finalized, and the resulting rate base, net operating income, return, and rate increase be calculated.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

(Whereupon, the prefiled joint testimony and Appendices A, B, and C of David Williamson and Tommy Williamson, Jr. was copied into the record as if given orally from the stand.)

(Whereupon, Public Staff T and D Williamson Exhibits 1-5 were admitted into evidence.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1213 In the Matter of Application of Duke Energy Carolinas, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in 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 Utility Service in North Carolina	))))))))))))))))	JOINT TESTIMONY OF DAVID WILLIAMSON AND TOMMMY WILLIAMSON, JR. PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1213

AND

DOCKET NO. E-7, SUB 1214

JOINT TESTIMONY OF
DAVID WILLIAMSON AND TOMMY WILLIAMSON, JR.
ON BEHALF OF THE PUBLIC STAFF
NORTH CAROLINA UTILITIES COMMISSION

FEBRUARY 18, 2020

Q. MR. DAVID WILLIAMSON, PLEASE STATE YOUR NAME AND ADDRESS FOR THE RECORD.

A. My name is David Williamson. My business address is 430 North Salisbury Street, Raleigh, North Carolina.

Q. WHAT IS YOUR POSITION WITH THE PUBLIC STAFF?

A. I am an engineer in the Electric Division of the Public Staff.

Q. WOULD YOU BRIEFLY DISCUSS YOUR EDUCATION AND EXPERIENCE?

A. Yes. My education and experience are summarized in Appendix A to my testimony.

Q. MR. TOMMY WILLIAMSON, PLEASE STATE YOUR NAME AND ADDRESS FOR THE RECORD.

A. My name is Tommy Williamson. My business address is 430 North Salisbury Street, Raleigh, North Carolina.

Q. WHAT IS YOUR POSITION WITH THE PUBLIC STAFF?

A. I am an engineer in the Electric Division of the Public Staff.

Q. WOULD YOU BRIEFLY DISCUSS YOUR EDUCATION AND EXPERIENCE?

A. Yes. My education and experience are summarized in Appendix B to my testimony.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of our testimony is to present to the Commission the Public Staff's recommendations with regard to Duke Energy Carolinas, LLC's (DEC or the Company): (1) Quality of Service; (2) Vegetation Management (VM) Plan; and (3) Grid Improvement Plan (GIP or the Plan).

Q. PLEASE STATE A SUMMARY OF YOUR RECOMMENDATIONS.

A. The Public Staff makes the following recommendations to the Commission:

1. That the Company's current overall Quality of Service is adequate.
2. That it should approve the Company's 3% increase in VM expenses and current progress toward eliminating backlogged miles.
3. That it should find the following GIP programs are extraordinary in type: Self-Optimizing Grid (SOG) subcomponents – Automation and Advanced Distribution Management System (ADMS); Integrated Volt/Var Control (IVVC); Transmission System Intelligence;

Underground Automation; and Integrated System Operation Planning (ISOP).[1]

Q. ARE YOU PROVIDING ANY EXHIBITS WITH YOUR TESTIMONY?

A. Yes. We have five total exhibits, described below:

- Exhibit 1: Data response by the Company on the performance of its distribution vegetation management practice.
- Exhibit 2: Data response by the Company providing a timeline of actual and forecasted Company spend for both Distribution and Transmission expenses.
- Exhibit 3: Company reliability data broken down by category.
- Exhibit 4: Public Staff's Evaluation Matrix.
- Exhibit 5: Summary of Public Staff Electric Division's final evaluation, including the costs associated with the programs.

I. QUALITY OF SERVICE

Q. WHAT FACTORS DID YOU CONSIDER IN YOUR EVALUATION OF DEC'S OVERALL QUALITY OF SERVICE?

A. We reviewed the System Average Interruption Duration Index (SAIDI) and the System Average Interruption Frequency Index (SAIFI) reliability scores filed by DEC with the Commission in Docket No. E-100, Sub 138A; informal complaints and inquiries from DEC customers received by the Public Staff's

[1] Appendix C contains a list of abbreviations used in this testimony.

Consumer Services Division; and the Consumer Statements of Position filed in Docket No. E-7, Sub 1214CS. We also considered what we know from our individual interactions with DEC and its customers.

Q. WHAT HAS BEEN THE COMPANY'S SAIDI AND SAIFI PERFORMANCE SINCE 2010?

A. SAIDI and SAIFI are measured and provided to the Commission on a system level. For the period 2010 through 2019, Company reports show that the SAIDI and SAIFI indices have been worsening over the years. However, there has been some realized improvement for calendar year 2019. This improvement is primarily from a reduction in Vegetation and Equipment Failure related outages, compared to the previous year.

We present a more in depth analysis of the Company's reliability scores and how they are being addressed by the Company's efforts later in our testimony pertaining to DEC's GIP.

Q. WHAT TYPES OF COMPLAINTS AND INQUIRIES HAS THE PUBLIC STAFF'S CONSUMER SERVICES DIVISION RECEIVED FROM DEC'S CUSTOMERS?

A. For the period January 2018 through January 2020, the Public Staff's Consumer Services Division received approximately 8,378 contacts from DEC customers. Of those contacts, 88% dealt with financial related issues. The largest single issue was the establishment or modification of payment arrangements (69%). Approximately 4% of contacts dealt with service administrative issues (facilities relocation, easements, street lighting, service theft, etc.) and less than 2% of contacts were related to power reliability issues. The remaining 6% of direct contacts were classified as miscellaneous "other" inquires.

Q. WHAT TYPE OF CONCERNS WERE DISCUSSED IN THE CONSUMER STATEMENTS OF POSITION FILED IN DOCKET NO. E-7, SUB 1214CS?

A. As of February 6, 2020, approximately 628 individuals had filed consumer statements in this docket. Approximately 30% of these did not provide a physical address so it is unclear if they are DEC customers. However, of the 628 statements filed, 96% were related to two primary topics: the cleanup of coal ash (52%) and opposition to an increase in rates (44%).

Q. WHAT IS YOUR CONCLUSION REGARDING THE COMPANY'S QUALITY OF SERVICE?

A. We conclude that the overall Quality of Service provided by DEC to its North Carolina retail customers is adequate at this time.

II. VEGETATION MANAGEMENT

Q. PLEASE DESCRIBE THE COMPANY'S CURRENT DISTRIBUTION VEGETATION MANAGEMENT PLAN?

A. The Company initiated its current vegetation management work cycle, referred to as the "5-7-9" Plan, in 2013. At the time, the 5-7-9 Plan represented a change from a reliability-based approach, to a cyclical approach to vegetation management (VM). The 5-7-9 Plan classifies DEC's distribution circuit-miles into three categories, maintained on three independent maintenance cycle periods: “Old-urban” – five years; “Mountain” – seven years; and “Other” – nine years. The categories and cycles were based on a vegetation growth study conducted by DEC.

Q. HAVE THERE BEEN ANY CHANGES TO THE VM COMPLIANCE PLAN FILING SINCE THE LAST RATE CASE?

A. No, there have not been any changes to the VM Compliance Plan[2] since the Company’s December 14, 2015 filing. All changes to the VM Compliance Plan are required to be filed with the Commission in Docket No. E-7, Sub 1014.

Q. DID THE COMPANY PROPOSE AN INCREASE IN ITS VEGETATION MANAGEMENT COSTS IN ITS 2017 GENERAL RATE CASE?

A. Yes. In its 2017 general rate case, the Company proposed to increase its VM Plan costs due to an increase in the frequency of trimming and herbicide application, the continuation of other vegetation management practices such as hazard tree cutting, and a 7% increase in contractor VM production labor costs. Additionally, the Company requested an increase of approximately $8.5 million annually to address its existing backlog miles. As of December 31, 2017, the Company identified 13,467 miles of existing backlog (the 2017 backlog).

[2] The Company’s Compliance Plan covers the Company’s standard practice with regard to policies of trimming of its electrical system and its customer engagement policies.

Q. PLEASE BRIEFLY DESCRIBE THE OUTCOME OF THE 2017 GENERAL RATE CASE WITH RESPECT TO THE COMPANY'S VM COSTS.

A. In Docket No. E-7, Sub 1146, *Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction* (Sub 1146 Final Order), issued on June 22, 2018, the Commission approved the stipulation between the Company and the Public Staff. Regarding the Company's VM costs, the stipulation provided the expense level for vegetation management for maintaining the Company's distribution circuits would be $62.6 million on an annual basis. The stipulation did not provide additional funds to address the backlog. The stipulation also provided that the Company committed to eliminating the 2017 backlog within five years of the date of the final order for that proceeding.

Q. PLEASE DESCRIBE THE COMPANY'S PERFORMANCE EXECUTING ITS DISTRIBUTION VEGETATION MANAGEMENT PLAN SINCE 2014.

A. During the discovery process in this case, the Company provided the Public Staff with both the actual and budgeted performance of its VM Plan for calendar years 2014 through 2019. This data is attached as T&D Williamson Exhibit 1. This Exhibit provides an assessment of the Company's activities with regard to trimming miles and costs, herbicide application and costs, and inspections.

Q. WHAT IS YOUR ASSESSMENT AS TO HOW THE COMPANY IS PROGRESSING TOWARDS ITS COMMITMENT TO ELIMINATE ITS 2017 BACKLOG MILES?

A. During the discovery process, the Company stated that as of December 7, 2019, there were approximately 6,608 miles of the 2017 backlog remaining on the DEC system. In other words, the Company has eliminated 6,859 miles, or a little more than 50%, of the 2017 backlog. If the Company maintains its current pace, it should eliminate the 2017 backlog within the five-year period as stipulated in Docket No. E-7, Sub 1146 (the Sub 1146 Proceeding).

Q. WHAT RECOMMENDATIONS DO YOU PROPOSE GOING FORWARD FOR TRACKING EXPENDITURES TO ELMINATE DISTRIBUTION BACKLOG MILES?

A. Although the Company is currently on track to eliminate the 2017 backlog, we recommend that the Commission continue to require the Company to file semi-annual VM Plan reports as outlined in the Commission's Orders in Docket Nos. E-7, Subs 1146 and 1182. The Public Staff will continue to monitor the reports and inform the Commission if there are any issues with the report or if it appears the Company is no longer on track to eliminate the 2017 backlog.

Q. HAS THE COMPANY INCREASED ITS TARGETED MILES PER YEAR UNDER THE 5-7-9 PLAN?

A. Yes. Under the 5-7-9 Plan, the Company sets a target number of miles to cut each year to stay on plan. In response to a Public Staff data request, the Company reported that its distribution VM targeted plan miles under the 5-7-9 Plan has increased to 6,187 to account for growth in the total number of distribution miles subject to the plan. The number of target miles in the last rate case was 6,177.

Q. HAS THE COMPANY PROPOSED AN INCREASE TO VEGETATION MANAGEMENT PROGRAM COSTS IN THIS APPLICATION?

A. Yes. The Company proposes to increase its VM plan costs as a result of the increase in the miles targeted per year, as well as for the continuation of other vegetation management practices such as hazard tree cutting. The Company has also requested an increase to reflect a 3% increase in contractor VM production labor costs.

Q. PLEASE DESCRIBE THE PUBLIC STAFF'S ASSESSMENT OF THE PROPOSED INCREASES IN THE VM PRODUCTION LABOR COSTS.

A. Similar to the process of validating the Company's request toward contractor rate increases in the last rate case, the Public Staff reviewed the labor costs contained in the contracts of the various VM companies hired by the Company to perform VM management. The Public Staff believes that the 3% increase requested by the Company in contractor production labor cost rates is reasonable.

Q. DID THE COMPANY ACCURATELY CALCULATE THE COST PER MILE FOR THE TEST PERIOD?

A. No, the Company did not calculate the test period cost per mile dollar value correctly. The Company utilized the wrong dollar amount per mile trimmed for the test period. T&D Williamson Exhibit 1 shows the actual test dollar amount as provided by the Company. The Public Staff's correction to this adjustment is to match the dollar amount to the actual miles trimmed during the test period. We provided our calculation to Public Staff witness Boswell for incorporation in her Exhibit 1.

Q. DO YOU AGREE WITH PUBLIC STAFF WITNESS BOSWELL'S ADJUSTMENT TO THE COMPANY'S VEGETATION MANAGEMENT PROGRAM BUDGET?

A. Yes. We agree with her adjustment as shown in Boswell Exhibit 1, Schedule 3-1(e). The Public Staff's adjustment corrects the dollar amount per mile trimmed, and allows the 3% increase in contractor VM production labor costs.

III. GRID IMPROVEMENT PLAN (GIP)

Q. PLEASE DESCRIBE THE ORGANIZATION OF YOUR GIP TESTIMONY.

A. Our testimony is organized as follows:

A. Public Staff's approach to evaluating the deferral request;

B. Evolution of the Grid Improvement Plan;

C. Overview and Comparison of Power Forward and the Company's GIP Proposal;

D. Discussion of the current state of DEC's North Carolina electrical grid;

E. Drivers behind the Company's proposal;

F. Cost Benefit Analysis of the Company's plan;

G. The Public Staff's Evaluation Guidelines;

H. Individual program evaluation; and

I. Final program considerations.

A. Public Staff's approach to evaluating the deferral request

Q. PLEASE DESCRIBE THE PUBLIC STAFF'S APPROACH IN EVALUATING THE COMPANY'S REQUEST FOR SPECIAL RATEMAKING TREATMENT OF ITS GRID IMPROVEMENT PLAN COSTS IN THE FORM OF AN ACCOUNTING DEFERRAL IN THIS CASE.

A. The Public Staff assessed the deferral request in two steps. First, the Electric Division reviewed the proposal to assess which, if any, programs in the request should be considered extraordinary in type and outside the scope of DEC's normal course of business. Second, the Accounting Division assessed the costs associated with any identified extraordinary type activities to determine whether or not such costs are of a magnitude that justifies deferral.

Q. HAS THE PUBLIC STAFF REVIEWED THE COMPANY'S PROPOSAL FOR A DEFERRAL OF ITS GIP COSTS?

A. Yes. We will discuss the review process and results of our technical assessment. Our testimony also incorporates the detailed assessment of the Company's cost-benefit analyses presented by Public Staff witness Thomas. At this time, the Accounting Division is continuing to work with the Company to determine the magnitude of the recommended deferral. In supplemental testimony, Public Staff witness Maness will discuss the magnitude of the costs and recommend whether special ratemaking treatment is appropriate.

Q. PLEASE DESCRIBE THE PUBLIC STAFF'S REVIEW PROCESS FOR EVALUATING THE GIP.

A. The Public Staff participated in Company workshops and webinars related to grid improvement planning in North Carolina. Additionally, the Public Staff submitted numerous discovery requests to the Company in order to gain a better understanding of the proposed Plan and participated in in-person meetings with the Company's technical personnel.

The Public Staff also relied on the following in our evaluation of the Company's proposal:

- The Commission's decision in the Sub 1146 Proceeding;
- Previous Smart Grid filings made by the Company in the Company's Integrated Resource Planning (IRP) Docket, Docket No. E-100, Sub 157;

- Analysis of the current state of the Company's grid;
- Current drivers behind the need for grid investments;
- The proposed pace of GIP work proposed by the Company;
- The Company's reliability indices;
- Evaluation of the Company's Cost-Benefit Analyses;
- Perceived customer expectations; and
- Other utility grid investment/modernization proposals and investigations from around the country.

B. Evolution of the Grid Improvement Plan

Q. PLEASE PROVIDE AN OVERVIEW OF THE BACKGROUND OF THE GIP IN NORTH CAROLINA.

A. As a precursor plan to the GIP, the Company first presented its Power/Forward Carolinas (Power Forward) proposal in 2017, in its most recent general rate case. Subsequently, the Company presented similar proposals for transmission and distribution related improvements in other dockets, including the 2018 Smart Grid Technology Plans in the IRP Docket, Docket No. E-100, Sub 157.

Additionally, as directed by the Commission, the Company held a series of grid improvement workshops following the Sub 1146 Proceeding to engage and collaborate with stakeholders. We provide a short history of the Power Forward proposal, and the evolution of the GIP to date, below.

Q. PLEASE SUMMARIZE POWER FORWARD AND THE KEY COMPONENTS OF THE PROPOSAL.

A. In the Sub 1146 Proceeding, the Company proposed various transmission and distribution related programs it designated as Power Forward. DEC and Duke Energy Progress, LLC (DEP) stated that collectively they planned to spend an estimated $13 billion over a 10-year period on Power Forward programs across their North Carolina territories.[3]

As presented by the Company in the Sub 1146 Proceeding,[4] transmission system upgrades would be focused on: (1) replacing equipment before it failed; (2) installing equipment and processes that would notify the Company of issues that could lead to failure or outage; (3) decreasing the Companies' environmental footprint; (4) increasing physical and cyber security defenses; and (5) adding new system intelligence capabilities.

Distribution system upgrades would be focused on: (1) targeting problematic circuits for undergrounding; (2) installing or replacing equipment to harden and improve resiliency and provide back feed capabilities; (3) adding systems to self-optimize circuits in order to identify and resolve issues automatically; (4) improving the communications assets of key facilities; and (5) installing smart metering technologies.

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[3] Docket No. E-7, Sub 1146, Power Forward Carolinas Executive Technical Overview at 2, November 2017.

[4] Docket No. E-7 Sub 1146, Direct Testimony of DEC witness Simpson, at 25-32.

Q. WHAT WAS THE PUBLIC STAFF'S POSITION REGARDING POWER FORWARD AND ITS ASSOCIATED PROGRAMS?

A. The Public Staff was not opposed to any particular Power Forward program as presented by the Company in the Sub 1146 Proceeding. In general, the Public Staff recognized that the Company has a continuing obligation to make reasonable and prudent investments in the grid as a part of ensuring reliable service to its customers. However, the Public Staff had significant concerns regarding the substantial uncertainty with the details of the Power Forward initiative, as the Company's descriptions of the programs were broad and open-ended. The Public Staff argued, and the Commission agreed, that additional information was needed to allow the Commission and Public Staff to better understand the Power Forward initiative and to assess its benefits.[5]

Based on the information available in Sub 1146 Proceeding, the Public Staff was not persuaded that the components of the Power Forward initiative would result in modernizing the grid, but rather involved customary, routine spend not outside of the scope of normal business to meet its responsibility

[5] Sub 1146 Final Order, at 149:
The Commission finds and concludes that several of the intervening parties have raised valid concerns regarding the need for additional transparency and detailed information regarding Power Forward. Although the Commission concluded in this proceeding that Power Forward costs do not warrant special ratemaking treatment, the Commission finds and concludes that additional information would be helpful to the Commission, the Public Staff, and to other intervening and interested parties to better understand Power Forward projects, grid modernization in general, and the cost-effectiveness of such programs.

to provide adequate and reliable service to its customers. As witness Simpson stated, much of the Power Forward initiative was projected to improve DEC's outage frequency and duration, which should be part of DEC's everyday planning and operations. [6]

Q. WHAT INDIVIDUAL PROGRAMS WERE INCLUDED IN POWER FORWARD?

A. Power Forward was comprised of seven programs:

1. Targeted Undergrounding (TUG);
2. Distribution Hardening & Resiliency;
3. Transmission Improvements;
4. Self-Optimizing Grid (SOG);
5. Advanced Metering Infrastructure (AMI);
6. Communications Network Upgrades; and
7. Advanced Enterprise Systems.

Q. WHAT CIRCUMSTANCES DID THE COMPANY IDENTIFY AS DRIVING THE NEED FOR POWER FORWARD?

A. The Company cited four areas of concern: (1) increased customer expectations for more options, greater reliability, and perfect power; (2) increasing severe weather events; (3) increasing threats to physical and

[6] Docket No. E-7, Sub 1146, Direct Testimony of DEC witness Simpson, at 12.

cyber security; and (4) technology availability that enables a transition from a mechanical grid that is aging to a more modern, digitized grid.[7]

In response to these drivers, in its Sub 1146 Final Order, the Commission stated:

> …the Commission finds and concludes that the reasons DEC says underlie the need for Power Forward are not unique or extraordinary to DEC, nor are they unique or extraordinary to North Carolina. Weather, customer disruption, physical and cyber security, DER, and aging assets are all issues the Company (and all utilities) have to confront in the normal course of providing electric service.[8]

Q. DID THE COMPANY REQUEST SPECIAL RATEMAKING TREATMENT OF POWER FORWARD COSTS IN THE SUB 1146 PROCEEDING?

A. Yes. The Company requested approval of a Grid Resiliency and Reliability Rider (GRR) or, in the alternative, a deferral.

Q. DID THE COMMISSION GRANT THE COMPANY'S REQUEST FOR SPECIAL RATEMAKING TREATMENT IN THE PRIOR RATE CASE?

A. No. The Commission did not grant approval of either the GRR or the deferral request.[9] In general, the Commission found that Power Forward Carolinas programs did not represent new work or grid modernization and were part of the Company's normal or routine operations.[10]

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[7] Docket No. E-7, Sub 1146, Power/Forward Carolinas Executive Technical Overview, at 2.

[8] Sub 1146 Final Order at 146.

[9] *Id.* at 146-48

[10] *Id.*

Specifically, with regard to the request for deferral accounting, the Commission concluded that:

> …DEC has not satisfied the criteria for deferral accounting treatment of Power Forward costs. In order for the Commission to grant a request for deferral accounting treatment, the utility first must show that the cost items at issue are adequately extraordinary, in both type of expenditure and in magnitude, to be considered for deferral and the Commission is unpersuaded that the entirety of Power Forward programs as proposed are unique or extraordinary.[11]

Q. DID THE COMMISSION PROVIDE GUIDANCE IN THE SUB 1146 FINAL ORDER FOR A FUTURE DEFERRAL REQUEST?

A. Yes. The Commission found that for a deferral to be granted, "…the utility first must show that the cost items at issue are adequately extraordinary, in both type of expenditure and in magnitude, to be considered for deferral."[12]

Q. HOW DID YOUR INVESTIGATION EVALUATE DEC'S REQUEST FOR A DEFERRAL IN THIS CASE?

A. This testimony reflects our technical investigation and evaluation of the Company's various GIP programs and our recommendation regarding whether each program meets the "extraordinary type of expenditure" requirement set forth by the Commission in its Sub 1146 Final Order. The "extraordinary magnitude" requirement is discussed further by Public Staff witness Maness.

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[11] *Id.* at 148.
[12] *Id.*

Q. SINCE THE COMMISSION'S SUB 1146 FINAL ORDER, HAS THE COMPANY CONTINUED ITS PLANS FOR GRID IMPROVEMENT ACTIVITIES?

A. Yes. On October 1, 2018, the Company filed with the Commission in Docket No. E-100, Sub 157 its 2018 Smart Grid Technology Plans (Smart Grid Plans) for both DEC and DEP.[13] The Smart Grid Plans are a collection of activities that both DEC and DEP are evaluating, designing, or implementing as they project how the Companies are making smart grid investments in the near term and leverage emerging technologies for the future. Some of the activities included in the Smart Grid Plans by DEC include the following:

- Physical and Cyber Security;
- Self-Optimizing Grid (SOG), including Advanced Distribution Management System (ADMS);
- Integrated Voltage/VAR Control (IVVC);
- Distribution System Modernization, Automation and Intelligence;
- Transmission System Modernization, Automation and Intelligence;
- Upgrades to Communication Networks;
- Energy Storage;

[13] As of November 13, 2019, the requirement for the Companies to file smart grid plans has been eliminated from Commission Rule R8-60.1.

- Advanced Metering Infrastructure; and
- Customer Programs.[14]

Based on their filings and the comments provided by other parties in the docket, the Commission accepted the Companies' positions in its Order, stating:

> The Company has determined those smart-thinking, self-optimizing grid technologies, as well as certain transmission improvements, physical and cyber security upgrades, and the advanced monitoring and communication capabilities required to enable a smart grid, meet the criteria for the SGTP [Smart Grid Technology Plan] and will be outlined within the Plans each year as applicable.[15]

Q. IS THE COMPANY'S SMART GRID PLAN COMPARABLE TO THE GRID IMPROVEMENT PLAN?

A. Yes, the two filings share many of the same programs and concepts. The Smart Grid Plans can be characterized as a precursor to the Company's GIP.

Q. IN ADDITION TO ITS SMART GRID PLAN, HAS THE COMPANY PROCEEDED WITH ANY OTHER GRID IMPROVEMENT ACTIVITIES?

A. Yes. Following the Sub 1146 Proceeding, the Company held three technical workshops and a series of webinars beginning May of 2018 through June

[14] Customer Programs included Outage notifications, a Smart Meter Usage App, and Prepaid Advantage.

[15] Docket No. E-100, Sub 157, Order Accepting Smart Grid Technology Plans and Requiring Additional Information, at 22 (July 22, 2019).

of 2019. The Company's hosted events are summarized in detail as part of DEC witness Oliver exhibits 11 through 18.

These webinars and workshops were informational sessions that the Public Staff, and many of the other stakeholders, used to inform our understanding of the Company's proposed programs and the need for those programs. Members of the Public Staff that attended, including the two of us, neither supported nor opposed any of the items presented by the Company; however, we did ask questions to gain a better understanding of the Company's approach to each program.

Q. THE COMPANY STATES ON PAGE 50 OF WITNESS OLIVER'S TESTIMONY, THAT IT ATTEMPTED TO HELP THE STAKEHOLDERS "GAIN A BETTER CONSENSUS AND UNDERSTANDING OF OUR PROPOSED THREE-YEAR PLAN." WAS CONSENSUS REACHED ON THE COMPANY'S PLAN?

A. No. It did not appear to us, during any part of the Company's webinars or workshops, that there was global consensus on any items presented by the Company.

C. Overview and Comparison of Power Forward and the Company's GIP Proposal

Q. HOW DOES THE COMPANY'S SPEND ON GIP COMPARE WITH ITS PREVIOUS POWER FORWARD PROPOSAL?

A. The Power Forward initiative proposed to spend $13 billion total between DEC and DEP over a ten-year period in the Companies' North Carolina service territories. In contrast, DEC and DEP propose to spend a combined $2.3 billion over a three-year period on the GIP in their North Carolina territories. The Company proposes to spend approximately $1.33 billion in DEC and approximately $0.98 billion in DEP.

Q. ARE THERE PROGRAMS THAT WERE INCLUDED IN POWER FORWARD THAT ARE ALSO INCLUDED IN GIP?

A. Yes. Six of the seven original Power Forward programs are included in the Company's GIP proposal in this case. Only the AMI program was not included in GIP. The AMI component was partially addressed in the Sub 1146 Proceeding and the costs were approved through November of 2017. As noted by Public Staff witness Floyd, the Company has completed its deployment of AMI meters and is including the remainder those costs in this case to be recovered through its base rates.

Q. HOW DO THE PROGRAMS THAT WERE CARRIED OVER FROM POWER FORWARD TO GIP COMPARE?

A. The table below, which was provided by the Company in response to NCSEA Data Request 3, compares the total program and annual average program spending of these programs for Power Forward and GIP.

Table 1: Power Forward Carolinas and GIP Comparison of Spending

CURRENT

Grid Improvement Plan Carolinas (NC)

dollars in (000's)	NC 2020-2022
Compliance: Cost Effectiveness Justified	**$134**
Physical Security	$111
Cyber Security	$23
Cost Benefit & Cost Effectiveness Justified	**$1,649**
SOG	$722
Incremental Distribution H&R	$145
IVVC	$217
Incremental Transmission H&R	$134
TUG	$115
Energy Storage	$129
Transmission Bank Replacement	$116
OIL Breaker Replacements	$200
Rapid Technology Advancement: Cost-Effectivenes	**$536**
T&D Communications	$212
Distribution System Automation	$194
Transmission System Intelligence	$86
T&D Enterprise Systems	$28
ISOP	$7
DER Dispatch Tool	$7
Electric Vehicle Charging	$63
Power Electronics for volt/var control	$2
Total	**$2.3 billion**

PREVIOUS

Power/Forward (NC)

dollars in (000's)	NC 2018-2027	
Compliance: Cost Effectiveness Justified		
Physical Security	$0	*new program*
Cyber Security	$0	*new program*
Cost Benefit & Cost Effectiveness Justified	**$11,804**	
SOG	$1,267	
Incremental Distribution H&R	$3,379	↓ 96%
IVVC DEC	$0	*new program*
Transmission	$2,195	
TUG	$4,962	↓ 98%
Energy Storage	$0	*new program*
Transmission Bank Replacement		
OIL Breaker Replacements		
Rapid Technology Advancement: Cost-Effectivene	**$926**	
T&D Communications	$447	
Distribution System Automation	$140	
Transmission System Intelligence		
T&D Enterprise Systems	$339	
ISOP	$0	*new program*
DER Dispatch Tool	$0	*new program*
Electric Vehicle Charging	$0	*new program*
Power Electronics for volt/var control	$0	*new program*
Total NC	**$13 billion**	

D. Discussion of the current state of North Carolina's electrical grid

Q. PLEASE PROVIDE YOUR UNDERSTANDING OF THE CURRENT STATE OF DEC'S ELECTRICAL GRID IN NORTH CAROLINA.

A. As stated in the Quality of Service section of our testimony, DEC's current service is adequate at this time. We analyzed the state of the Company's electrical grid by comparing the Company's spending on its distribution and transmission grid over time, with the overall grid reliability trends to determine a baseline for assessing the GIP proposal going forward.

Q. HOW HAS TOTAL SPENDING ON DISTRIBUTION AND TRANSMISISON INCREASED OVER TIME?

A. As shown in T&D Williamson Exhibit 2, spending for both distribution and transmission has increased since 2010 and is projected to continue to increase over the next four years.

Q. HAS THE COMPANY MADE ANY INVESTMENTS IN PROGRAMS THAT IT INCLUDES IN THE GIP PRIOR TO THE BEGINNING OF THE DEFERRAL REQUESTED IN THIS PROCEEDING?

A. Yes. The Company has made investments in several, but not all, of the programs that are listed as part of GIP. Of the 19 programs that the Company has proposed for the Plan, work is currently ongoing for 12 of them.

Q. WHAT HAS THE COMPANY SPENT TO DATE ON GRID IMPROVEMENT PLAN RELATED COSTS?

A. The Company spent approximately $52 million (system basis) for calendar year 2018 (the Company's test year). For calendar year 2019, the Company spent approximately an additional $273 million (system basis).

Q. PLEASE DESCRIBE THE PROGRAM INVESTMENTS THAT THE COMPANY HAS MADE WITH REGARD TO GIP.

A. The table below shows the total dollars spent for each of the 12 programs.

Table 2: GIP System Spend in 2018 and 2019

Program	System Total 2018	System Total 2019
Self Optimizing Grid	$ 7,423,411	$ 31,848,375
Advanced DMS	$ 1,051,369	$ 12,778,829
Transformer Retrofit	$ 1,274,362	$ 4,259,845
LDI	$ 654,750	$ 7,178,554
Targeted Undergrounding	$ 3,456,524	$ 26,632,618
Transmission H&R	$ -	$ 19,152,971
Oil Breaker Replacement	$ -	$ 7,495,456
Enterprise Applications	$ 313,100	$ 13,497,638
Enterprise Communications	$ 5,820,044	$ 49,315,999
Transmission System Intelligence	$ 16,280,677	$ 4,862,377
Distribution Automation	$ 1,754,853	$ 13,621,067
Physical and Cyber Security	$ 14,116,559	$ 82,649,198
TOTAL	**$ 52,145,650**	**$ 273,292,925**

Q. ARE THESE INVESTMENTS NEW TO THE COMPANY?

A. No. As mentioned earlier in our testimony, the Company has been planning these GIP-related investments since 2016 as part of its Power Forward proposal, as well as part of its 2018 Smart Grid Technology Plans.

Q. ARE ANY OF THE COSTS FOR GIP PROGRAMS THAT WERE INCURRED DURING 2018 AND 2019 INCLUDED IN THE COMPANY'S BASE RATE INCREASE REQUEST IN THIS PROCEEDING?

A. Yes. All used and useful investments placed into service prior to November 30, 2019[16] are included in the Company's rate base in this case.

[16] The update period in this case.

Q. DO YOU TAKE ISSUE WITH ANY OF THE GIP COSTS FOR WHICH DEC HAS REQUESTED RECOVERY IN THIS CASE?

A. No. We have not found any of the GIP programs to be unreasonable or imprudent at this time. However, many of the programs are made up of discrete activities and projects and require continuous evaluation. As noted by Public Staff witness Jeff Thomas, and discussed in more detail later in our testimony, the cost benefit analyses that DEC has relied upon for many of the programs contain weaknesses and significant uncertainties and should be subject to future review. As a result, the Public Staff reserves the right to challenge the prudence of any future investments in any GIP programs for which the Company requests rate recovery.

E. Drivers behind the Company's proposal

Q. WHAT DOES THE COMPANY SAY ARE THE DRIVERS BEHIND THE GIP AND ITS DEFERRAL REQUEST?

A. The Company asserts that the "megatrends" require efforts to deal with the changing needs of the electrical grid for its customers, and adapting its grid to provide customers with safe and reliable power.

Likewise, the Company asserts that "reliability" issues and customer expectations require it to take certain actions to maintain a level of confidence by its customers in their power provider. However, the Company also acknowledges that it must recognize that "a certain level of outages and interruptions is acceptable to avoid making the system too costly."[17]

The Company's pace of GIP implementation is what is driving the need for deferral in this proposal. The pace the Company has set is a function of its assessment of the looming impacts of megatrends and worsening reliability.

Q. THE COMPANY ASSERTS THAT THERE ARE MEGATRENDS TAKING PLACE ACROSS THE COUNTRY, AND THAT THESE SAME MEGATRENDS ARE HAPPENING HERE IN THE CAROLINAS. PLEASE DISCUSS THE COMPANY'S RECOGNITION OF THESE MEGATRENDS.

A. The Company has been discussing the topic of "megatrends" for several years, beginning during the stakeholder process following the Sub 1146 Final Order, and now included in its GIP as the primary justification for the Company's proposed programs. These megatrends, as identified by the Company, are as follows:

I. Threats to Grid Infrastructure;
II. Technology Advancements – Renewables and DER;
III. Environmental Trends;
IV. Impacts of Weather Events;
V. Grid Improvements;
VI. Concentrated Population Growth; and
VII. Customer Expectations.

[17] Docket No. E-7, Sub 1214 DEC witness Oliver Direct Testimony, Exhibit 1, at 4.

Q. DOES THE PUBLIC STAFF GENERALLY AGREE WITH THE MEGATRENDS IDENTIFIED BY DEC?

A. Yes. However, the Public Staff would not characterize a number of these trends as new, novel, or outside the scope of normal business.

The Public Staff agrees that DEC should continue to address these trends by making the necessary grid infrastructure investments to ensure safety and reliability, ensure proper security measures are in place to protect those investments, address customer migration trends, ensure the investments take advantage of the latest technological advancement to provide the increased levels of customer service required, and cost effectively protect against weather events.

Q. PLEASE DESCRIBE THE COMPANY'S USE OF RELIABILITY INDICES TO JUSTIFY THE INVESTMENTS IT HAS IDENTIFIED IN ITS GIP.

A. In addition to the reliability indices that electric utilities have traditionally used to evaluate its reliability performance, SAIDI and SAIFI, the Company has begun to utilize the Customers Experiencing Multiple Interruptions (CEMI-6) index over the last few years.

Q. PLEASE DESCRIBE THE THREE RELIABILITY INDICES.

A. <u>SAIDI:</u> System Average Interruption Duration Index – This scoring metric represents the average duration of sustained customer interruptions per customer occurring during the analysis period. It is the average time customers are without power for the entire system. It is determined by dividing the sum of all sustained customer interruption durations, in minutes, by the total number of customers served.

SAIFI: System Average Interruption Frequency Index - This scoring metric represents the average frequency of sustained interruptions[18] per customer for the entire system occurring during the analysis period. It is calculated by dividing the total number of sustained customer interruptions by the total number of customers served.

CEMI-6: Customers Experiencing Multiple Interruptions - This scoring metric represents the percentage of customers experiencing six or more sustained interruptions in a 12-month period. This metric is a good indicator of the worst performing circuits, which would allow for better targeting of resources to the most critical needs.

Q. DOES THE COMPANY REPORT THESE RELIABILITY INDEX SCORES TO THE COMMISSION?

A. In accordance with Commission Rule R8-40A(d),[19] the Company files twelve-month trailing reliability scores for both SAIDI and SAIFI, on a quarterly basis, in Docket No. E-100, Sub 138A (Sub 138A). The Company does not report CEMI-6 scores to the Commission. The Company also does

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[18] Sustained interruptions refers to those interruptions lasting longer than five minutes.

[19] Adopted by the Commission in its November 25, 2013 Order Adopting Rule Establishing Electric Utility Service Quality Metrics and Requiring Filing of Quarterly Reports and Requesting Further Comments.

not report the individual categories that make up the total SAIDI and SAIFI scores.

We recommend that if the Company is going to utilize additional indices to analyze its level of reliability, the Commission should require the Company to update the filing requirements of Sub 138A to include these new indices. Additionally, we recommend that the Commission require the Company to file the full breakdown of individual categories for all index calculations, so that the Public Staff and Commission is aware of the drivers of both positive and negative contributors to reliability.

Table 3 below provides the year-end twelve-month trailing SAIDI and SAIFI scores, excluding Major Event Days (MED), that have been filed with this Commission in the Sub 138A docket. The Company reports SAIDI and SAIFI scores for both MEDs and non-MEDs in these filings.

Table 3: SAIDI and SAIFI Scores as filed by the Company

	Duke Energy Carolinas (excluding MEDs)	
Year	**DEC_SAIFI**	**DEC_SAIDI**
2yr_Avg	1.08	190.00
3yr_Avg	1.10	190.33
5yr_Avg	1.07	176.80
10yr_Avg	1.03	161.30
Year	**DEC_SAIFI**	**DEC_SAIDI**
2019	1.07	175
2018	1.09	205
2017	1.13	191
2016	1.07	170
2015	0.99	143
2014	0.94	138
2013	0.92	133
2012	1.03	147
2011	1.03	160
2010	1.02	151

Q. PLEASE DISCUSS HOW THESE SCORES ARE CALCULATED.

A. The Company uses Customer Interruption (CI) and Customer Minutes of Interruption (CMI) data, along with customer population, to calculate the SAIDI and SAIFI reliability scores. CI and CMI data is derived from various contributing categories such as vegetation related outages, public accidents, wildlife, equipment failure, lightning, etc. T&D Williamson Exhibit 3 shows the classification of these scores by category.

Q. HAS THE COMPANY BEEN ABLE TO PROVIDE SCORES FOR THE CEMI-6 RELIABILITY INDEX FOR THE PUBLIC STAFF'S REVIEW?

A. Yes. Through the discovery process, the Company has been able to provide these scores to the Public Staff, but only for the last three years.

Q. ARE YOU CONCERNED THAT THE CEMI-6 RELIABILITY INDEX SCORES CAN ONLY BE PROVIDED FOR THIS LIMITED PERIOD OF TIME?

A. Yes. Having only three years of scores makes it difficult to establish a meaningful baseline reference. Thus, CEMI-6, as a newly utilized reliability metric, will provide only limited value in assessing the need to make changes to the status quo. Analytical trend data over a number of years is needed to provide an adequate baseline that allows the Company to better asses the reliability score that it should be targeting.

Q. DEC WITNESS OLIVER PROVIDES THE COMPANY'S SAIDI AND SAIFI TRENDS THROUGH 2018. HAS THE COMPANY PROVIDED THE PUBLIC STAFF WITH SCORES FOR CALENDAR YEAR 2019?

A. Yes. As shown in T&D Williamson Exhibit 3, the Company's reliability scores for both SAIDI and SAIFI have been updated to include 2019.

Q. ARE THERE ANY NOTICEABLE CHANGES TO THE SCORES?

A. Yes. The Company's SAIFI score improved from 1.09 in calendar year 2018 to 1.07 in calendar year 2019. The Company's SAIDI score improved from 205 in calendar year 2018 to 175 in calendar year 2019.

Q. PLEASE EXPLAIN WHAT CAUSED THE IMPROVEMENT IN THE SAIDI SCORE FOR 2019.

A. The improvement was primarily driven by a reduction in vegetation related outages from the previous year. As seen in T&D Williamson Exhibit 3, the net decrease in the SAIDI score from 2018 to 2019 was approximately 27.8 minutes on a system average basis. Of those 27.8 minutes, 17.4 (63%) were directly related to a reduction in vegetation related outages. The vegetation related outages totaled 76.3 minutes (44%) of the total 174.66 minutes on a system average basis. The vegetation related outage category has not been below 80 minutes for DEC since 2016, when it was at 67.58 minutes.

While this category has shown improvement, the Public Staff acknowledges that while an electric utility cannot reach zero outage minutes for this category, there is more room for improvement based on the Company's efforts to optimize its VM strategies along with eliminating its backlogged miles.

Q. WHY DID THE COMPANY EXPERIENCE A REDUCTION IN VEGETAION RELATED OUTAGES?

A. The Company has placed an increased emphasis on its Vegetation Management related activities since the Sub 1146 Proceeding. This is primarily attributable to the Company's focus on reducing, and eventually eliminating, its backlogged miles that were addressed in the last rate case. The Company has made significant improvements to its number of backlogged trim miles. This improvement is significant as it shows the direct benefits to customers from properly maintaining the vegetated miles of the Company's overhead assets, as required by the 5-7-9 Plan.

F. Cost Benefit Analysis of the Company's plan

Q. DID THE PUBLIC STAFF INVESTIGATE THE COMPANY'S COST BENEFIT ANALAYSES?

A. Yes. The Company's Cost Benefit Analyses (CBA) for its various GIP programs are discussed in detail by Public Staff witness Thomas in his testimony in this case.

Q. HOW DOES WITNESS THOMAS' ANALYSES OF THE GIP CBAS INFLUENCE YOUR EVALUATION?

A. Witness Thomas makes several recommendations regarding the quantification of the costs and benefits included in the Company's CBAs as they relate to GIP. Table 4 below summarizes the impacts to the benefit-cost ratios as a result of the recommendations witness Thomas was able to quantify for programs that the Company had calculated a CBA,[20] as well as the percent of total benefits that are customer reliability benefits. It is important to note that the impact of other recommendations may change the benefit-cost ratios of other programs not shown below.

In our evaluation, we reviewed the conclusions in witness Thomas' testimony to understand (1) whether each GIP program would be cost beneficial and (2) what proportion of the claimed benefits were attributable to customer reliability benefits. This second consideration was important

[20] Witness Thomas estimated the impact of implementing the following recommendations to the IVVC and SOG CBAs: (1) removal of CO_2 benefits; (2) reduction of avoided capacity benefits; (3) inclusion of momentary outages in SOG; and (4) reduction in the faults per mile used in SOG.

because customer reliability benefits are difficult to quantify and will not lead to a reduction in customer rates that offsets the increase in rate base proposed in the GIP. We viewed programs with high levels of reliability benefits with skepticism, as we agree with DEC witness Oliver that "a certain level of outages and interruptions is acceptable to avoid making the system too costly."[21]

Table 4: Cost Benefit Analyses with Public Staff Adjustment

	DEC – As Filed		DEC – Thomas Recommendations	
Description	**BCR**	**% Customer Reliability Benefits**	**BCR**	**% Customer Reliability Benefits**
SOG Capacity & Connectivity	2.5	93%	**1.5**	**89%**
SOG Connectivity				
SOG Automation + Control				
SOG ADMS				
Dist Tx Retrofit	1.5	96%	1.5	96%
IVVC	1.2	0%	**0.9**	0%
Trans Line H&R	14.4	100%	14.4	100%
TX Bank Replacements	1.2	51%	1.2	51%
Oil Breaker Replacements	1.6	67%	1.6	67%
TUG	12.1	92%	12.1	92%
Long Duration / High Impact	29.4	100%	29.4	100%

[21] See Oliver Exhibit 1, at 4.

Q. BASED ON THE RESULTS OF WITNESS THOMAS' EVALUATION, ARE YOU RECOMMENDING ANY PROGRAMS NOT BE IMPLEMENTED?

A. No. At this time, we recognize that the quantification of costs and benefits from GIP programs is challenging, particularly with regard to customer reliability. While the GIP proposal includes significant costs, only about 10% of the benefits are considered operational and would be expected to lead to future rate reductions. IVVC, one of the only GIP programs that derives a majority of its benefits from operational cost savings to the utility, is therefore an important component of GIP because it has the potential to offset GIP costs. While witness Thomas estimates that the IVVC benefit-cost ratio will fall below 1.0 if his recommendations are implemented, the importance of IVVC, its interdependency with SOG, and the general difficulty in estimating benefits from GIP leads us to include it in the portfolio of projects we are recommending as extraordinary type.

G. Public Staff's Evaluation Guidelines

Q. PLEASE DESCRIBE HOW THE PUBLIC STAFF DEVELOPED ITS MATRIX FOR EVALUATING THE COMPANY'S GIP PROPOSAL.

A. Determining whether a program meets the definition of grid modernization requires an understanding of the current state of the utility's grid, the role the proposed programs play within both the existing and future grid, how they interact with legacy devices, and how the programs meet the objectives of interested stakeholders. We recognize that any evaluation of programs will necessarily have some level of subjectivity, but we attempted to assess each program with as much objectivity as reasonably possible.

To do so, we followed a two-step approach. First, we reviewed each GIP program to determine whether it exhibited characteristics of a grid modernization program. Second, we created an evaluation matrix, which we used to rank each GIP program proposal on metrics we consider important in defining grid modernization. The combined results of these two review processes were used to inform our final determination of whether each GIP program meets the "extraordinary type" test discussed earlier in our testimony. The results of this two-step approach are discussed below.

Q. PLEASE DESCRIBE THE FIRST STEP OF YOUR EVALUATION PROCESS.

A. In determining whether each program should be considered grid modernization, the Public Staff relied upon several information sources, as discussed below. Consistent with our position on the Company's previous Power Forward proposal, we sought to identify those programs that would "bring the current grid up to new standards of operation and reliability," as opposed to "investments needed to maintain or restore the grid to historic levels of operation and reliability."[22] Investments that reflect an expansion or acceleration of existing programs could be classified as grid

[22] Docket No, E-7, Sub 1146, Direct Testimony of Public Staff witness Tommy C. Williamson, Jr, at 8.

improvement, but not necessarily grid modernization. This type of characterization would not meet our threshold for "unique and extraordinary."

We were also cognizant of the Commission's conclusions in the Sub 1146 Final Order that rejected grid modernization programs that are the "kinds of activities in which the Company engages or should engage on a routine and continuous basis."[23] In its Sub 1146 Final Order, the Commission defined the requirements that it would examine before determining that a proposed investment would meet the "extraordinary expenditure" test and be authorized for deferral. The Order states that the Company would need to demonstrate that the costs "can be properly classified as Power Forward and grid modernization."[24]

Q. WHAT OTHER RESOURCES DID THE PUBLIC STAFF RELY UPON IN MAKING ITS GRID MODERNIZATION DETERMINATION?

A. We reviewed the U. S. Department of Energy's (DOE) Modern Distribution Grid Project (DOE Project), and found it to be useful in our evaluation. Also referred to as the "next generation distribution system platform" (DSPx), the DOE Project is a collaboration with state regulators, utility companies, energy services companies, and technology developers across several

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[23] Sub 1146 Final Order, at 146.

[24] *Id.* at 148.

states (including NY, CA, HI, MN, and DC) with the goal of developing guidance to assist in the development and evaluation of distribution grid modernization.[25]

The DOE Project is intended to "develop a consistent understanding of requirements to inform investments in grid modernization," and consists of three volumes.

- Volume I - Customer and State Policy Driven Functionality defines the functional scope for a modern grid platform.
- Volume II - Advanced Technology Market Assessment presents a survey of grid modernization technologies and their functions.
- Volume III - Decision Guide provides a user guide for the application of the first two volumes.

Figure 1 below summarizes the three volumes, as well as showing at what stage of the grid modernization process they should be applied.

[25] The Modern Distribution Grid Project report can be found on the Pacific Northwest National Laboratory (PNNL) website: https://gridarchitecture.pnnl.gov/modern-grid-distribution-project.aspx

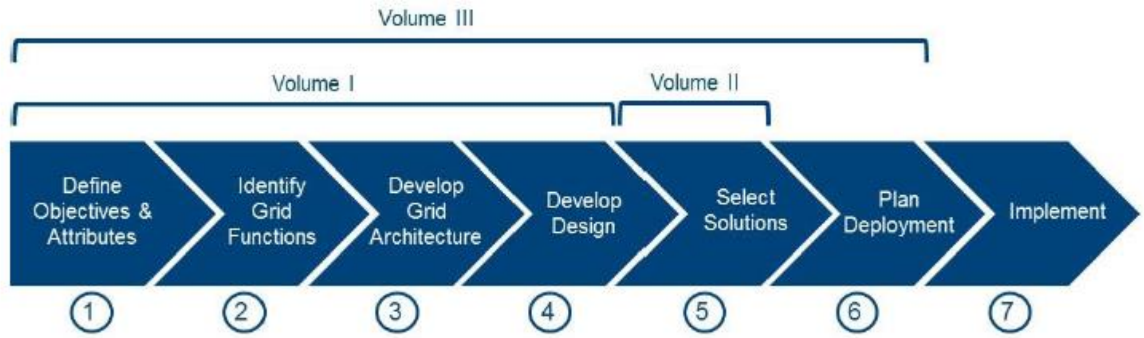

Figure 1: Modern Grid Decision Process. Source: DOE Project, Volume III, at 11.

Q. HOW DID THE DOE PROJECT ASSIST THE PUBLIC STAFF IN EVALUATING THE GIP PROPOSAL?

A. The three volumes offer a detailed look at how grid modernization programs should be orientated, how to define desired grid attributes, what functions are necessary, how grid modernization should be structured, and how the appropriate devices and technologies should be selected. The DOE Project is primarily a guidance document, and as such, we applied the findings and considerations to our state's grid needs and policy. Overall, the DOE Project helped us to put DEC's GIP proposal in context, and helped in our evaluation of whether each GIP program should be considered grid modernization under the definitions provided. We relied primarily on Volume III when reviewing GIP Programs.

Q. DID YOU RELY ON ANY OTHER EXTERNAL DATA SOURCES?

A. Yes. We looked to other states that are considered to be further along than North Carolina in their evaluation of grid modernization efforts to see if any of their work might inform our evaluation. During our investigation, we discovered a document developed by the California Public Utilities Commission (CPUC) Staff titled Staff White Paper on Grid Modernization (CPUC Framework), which was largely an adaptation of the DOE Project.[26] The CPUC Framework was created to help identify and prioritize grid modernization investments for California's electrical grid by understanding the function of each identified technology and the integration challenges they are designed to solve. The CPUC Framework provides a list of requirements for future grid modernization filings by California utilities as well as a matrix that details how various technology categories: (1) interact with specific use cases; (2) provide certain grid functions; (3) support certain grid management activities; and (4) address certain system or integration challenges.

Q. IS THE CPUC FRAMEWORK APPLICABLE TO THE ONGOING GRID IMPROVEMENT/MODERNIZATION EFFORTS IN NORTH CAROLINA?

A. Yes. Because the principles that the CPUC used in determining its CPUC Framework are derived from the DOE Project, North Carolina could use a variation of the CPUC Framework to help guide our improvement and modernization efforts. However, as a point of clarification, the CPUC, beginning in 2015, developed rules for distribution resource planning (DRP)

[26] See California Public Utilities Commission Rulemaking 14-08-013. Decision 18-03-023, issued March 22, 2018, adopted the grid modernization classification framework proposed by CPUC Staff.

that are currently not required in North Carolina. The CPUC Framework was largely a means of evaluating programs to be considered in its DRP.

Q. BASED UPON THE FIRST STEP OF YOUR EVALUATION PROCESS, WERE THERE ANY PROGRAMS THAT DID NOT ADEQUATELY MEET THE DEFINITION OF GRID MODERNIZATION?

A. Yes. The following DEC GIP programs failed our First Step evaluation: (1) Distribution H&R; (2) Transmission H&R; (3) Transformer Bank Replacements; (4) TUG; and (5) Long Duration Interruption/High Impact Sites (LDI/HIS). In addition, these programs did not meet any of the technology categories considered in the DOE Project or the CPUC Framework. This evaluation supports our determination that these programs are customary grid investments and not of an extraordinary type. It is important to note that we used the CPUC Framework as a guide, but that North Carolina and California are at different stages of grid modernization. Thus, we classify programs that met at least one grid modernization technology category definition, which we then labeled in our evaluation as “possible grid modernization.”

Q. PLEASE DESCRIBE THE SECOND STEP OF YOUR EVALUATION PROCESS.

A. The second step consisted of creating and applying an evaluation matrix. We determined a set of metrics on which to evaluate each program, based upon our experience with grid modernization in North Carolina and our research into grid modernization efforts across the country.

Q. WHICH METRICS DID YOU CONSIDER IMPORTANT TO INCLUDE?

A. We considered three primary metrics in our evaluation: (1) the transformative impact of the program; (2) timing of the deployment; and (3) how the program fits in grid modernization architecture. Together, these three metrics help inform what we consider to be an "extraordinary type" activity, which would meet the first prong of the two pronged deferral test.

Q. HOW DID YOU SCORE THE GIP PROGRAMS USING THESE METRICS?

A. Each program was given a score by metric, with the available scores ranging from one (the lowest ranking score) to three (the highest ranking score). In order to bring as much objectivity to this process as possible, we assigned a description to each metric. Each program of GIP was then given a score from one to three by metric, based upon the best-fit description. Finally, a weighted score was calculated based upon the weights for each metric, as described further below. The higher the score, the more likely we viewed the program as an "extraordinary type."

Q. PLEASE DESCRIBE THE TRANSFORMATIVE METRIC.

A. The "transformative" metric is the primary driver for determining whether or not a proposed program has characteristics of grid modernization. We assigned each program or component[27] to one of the following three categories:

1. The program or component is providing no new capabilities, or current procedures and initiatives provide similar benefits;
2. The program or component is providing some limited new capabilities; or,
3. The program or component is providing significant new capabilities.

Because of the importance of classifying a project as a transformative project with regard to grid improvement or modernization, we assigned this metric a weight of 2.0 in our evaluation. The weighting of this metric is designed to reflect whether the Company is proposing programs that will bring the grid up to new standards of operation and reliability rather than providing for investments that are needed to maintain or restore the grid to historic levels of operation and reliability.

Q. PLEASE DESCRIBE THE TIMING METRIC.

A. The "timing" metric assigns each program or component to one of the following three categories:

1. The program or component is ongoing work, but the proposed 3-year timeline for implementation is not critical to grid operations;
2. The program or component is new work, but the proposed 3-year timeline for implementation is not critical to grid operations; or,

[27] Several programs are comprised of distinct individual initiatives, which are referred to as components.

3. The program or component is urgent work and the proposed 3-year implementation is critical to grid operations.

We assigned this metric a weight of 1.0 in our evaluation.

The DOE Project provides guidance on the timing of grid modernization rollouts, which assisted us in evaluating the timing of each GIP program.[28]

Q. PLEASE DESCRIBE THE GRID ARCHITECTURE METRIC.

A. The "grid architecture" metric is based upon the concept of an overarching grid architecture, which the DOE Project considers an important guiding principle in deploying coordinated gird modernization efforts. Based upon our review of the DOE Project Volume III, we have defined three levels of "grid architecture" which we used to rank GIP programs:

1. This program is standalone and operates outside grid modernization architecture.
2. This program is an application dependent upon core components.[29]
3. This program is a core component of grid modernization (foundational).

We assigned this metric a weight of 1.0 in our evaluation. It is important to differentiate between a core component of grid modernization architecture

[28] See DOE Project Volume III at 14-18, 27-31.

[29] *Id.*at 24-26. Core Components include: Physical infrastructure (wires, transformers, switches, etc.); Advanced protection and controls; Sensing and situational awareness; Operational communications; and Planning tools and models (DER & Load forecasting, power flow analysis, etc.).

(such as an intelligent grid sensing or switching device, which enables other grid modernization programs and would be scored 3.0) and a physical grid component which does not interact or enable other grid modernization programs (such as animal mitigation infrastructure, which would be scored 1.0). Software applications which build upon core grid components would generally be scored 2.0.

Q. PLEASE DESCRIBE HOW YOU SCORED EACH OF THESE PROJECTS FOR THE SECOND STEP OF THE EVALUATION.

A. The scores of 1.0, 2.0, and 3.0 have been previously defined for each metric, but generally, a higher score indicates a higher ranking. After we scored each program on each metric, we then calculated the weighted score by multiplying each metric's score by the weight assigned to each metric and summing the results. Because we assigned a weight of 2.0 to the transformative metric, projects could score a maximum score of 12 and a minimum score of 4. The spreadsheet for this calculation is provided as T&D Williamson Exhibit No. 4. The main considerations for each GIP program or component is described in more detail later in our testimony.

Q. IF THE PUBLIC STAFF'S EVALUATION ELIMINATES SPECIFIC PROGRAMS FROM "EXTRAORDINARY TYPE" CONSIDERATION, DOES THE PUBLIC STAFF ALSO BELIEVE THOSE PROGRAMS SHOULD BE COMPLETELY ELIMINATED FROM THE COMPANY'S WORK PLAN?

A. No. The Company should be undertaking all activities that are necessary and prudent to ensure safe, reliable, and economical power delivery to its customers. The Public Staff's evaluation is focused on the individual GIP programs and an assessment of their qualification as an "extraordinary type" activity for consideration for deferral accounting.

Q. DOES THE PUBLIC STAFF HAVE ANY CONCERNS ABOUT WHAT ACTIVITES QUALIFY FOR SPECIAL RATEMAKING TREATMENT?

A. Yes. The Public Staff believes that under the current construct of the Company's GIP, any item that provides a benefit or "improvement" to the grid could ultimately be considered for special ratemaking treatment such as deferral, whether in this initial phase of GIP, or in potential later phases.

Based on the information provided by DEC during our investigation, we believe that each program that has been proposed by the Company will likely improve the performance of the grid; however, the same can be said about any equipment placed into service, assuming that a utility is only placing or replacing needed equipment that is used and useful. This reality creates a certain tension between "business as usual" activities and activities involving the installation of new technologies that can elevate the electrical grid to a new operational standard. In our evaluation, we have attempted to distinguish between these two characteristics that are in tension.

We believe that merely applying the term "grid improvement" is too generic and overly broad for this purpose. Our evaluation process attempts to identify programs that are extraordinary in type and will transform the Company's day-to-day grid operations and planning toward a business model of the future prior to consideration for special ratemaking deferral treatment.

H. Individual GIP Program Evaluation

Q. BASED ON THE EVALUATION METRICS YOU DISCUSSED ABOVE, PLEASE PROVIDE YOUR FINAL EVALUATION RESULTS FOR EACH GIP PROGRAM YOU DETERMINED TO QUALIFY AS AN EXTRAORDINARY TYPE.

A. We applied the information mentioned throughout our testimony to aid in our evaluation and understanding of each GIP program proposed by the Company. The table below summarizes the programs or components identified as an extraordinary type of activity. These identified programs or components are listed in T&D Williamson Exhibit 5.

Table 5: GIP Programs Classified as Extraordinary Type

Focus	Description	Program Currently Exists?	Possible Grid Mod?	PS Rubric Weighted Score	Extraordinary TYPE?	Total Capital ($M) - DEC NC
Modernize	ISOP	No	Yes	12	Yes	$4.2
Optimize	SOG Automation + Control	Yes	Yes	11	Yes	$176.6
Modernize	Transmission System Intelligence	No	Yes	11	Yes	$62.7
Optimize	SOG ADMS	No	Yes	11	Yes	$29.6
Modernize	UG System automation	Yes	Yes	11	Yes	$12.1
Optimize	IVVC	No	Yes	10	Yes	$206.7
					TOTAL	**$491.8**

Q. PLEASE DESCRIBE ANY THEMES SHARED IN COMMON BY THESE PROGRAMS.

A. In reviewing our evaluation results, we observed the following with regard to the programs classified as extraordinary type:

- In the transformative metric, all six programs were considered to provide significant new capabilities to the grid;
- In the grid architecture metric, five of the six programs were considered a core component of grid modernization. Only IVVC was considered to be dependent on core components.
- In the timing metric, five of the six programs were determined to be programs that could begin implementation, but that the 3-year timeframe proposed by the Company was not critical to grid operations.

Q. PLEASE DESCRIBE EACH OF THESE SIX QUALIFYING PROGRAMS.

A. <u>SOG automation and ADMS</u> – SOG automation projects provide intelligence and control capability for the self-optimizing grid. The grid intelligence captured by circuit protective devices will be utilized by the new Advanced Distribution Automation System (ADMS) to optimize power flow and reduce the impact of faults experienced by customers. The combination of the automation equipment and the ADMS will allow DEC's grid to operate in a new manner and at an additional level of reliability. Data collected by the Company will allow for a greater level of distribution planning. It is the new capabilities provided by the ADMS and the automated devices that led us score it 3.0 on the transformative metric. The ADMS will also allow greater functionality of the IVVC system, and is interdependent with IVVC – earning it a score of 3.0 on the grid architecture metric. The Company indicated that a SOG circuit will be designed to pick up 70% of the companion circuit's load during 90% of the annual hours. On the timing metric, we believe that customers on SOG circuits will see improved reliability, but that a 3-year timeline is not critical for deployment of the entire SOG proposal.

<u>IVVC</u> – This program enables the distribution system to optimize voltage and reactive power needs by coordinating and configuring the intelligent devices on the grid using a management control system, ADMS. IVVC is a program that is dependent upon ADMS, and we scored it 2.0 on the grid architecture metric. The ADMS utilizes the data collected to operate the grid more efficiently while maintaining distribution voltages within acceptable operating limits. IVVC allows grid operators to lower system voltage in order to reduce peak demand and energy. This real-time adjustment of grid

devices to save energy is a new capability not currently employed on the DEC grid, and as such, was scored 3.0 in the transformative metric. While we believe the Company should make all reasonable investments to reduce its operating costs, we do not believe it is critical to deploy IVVC in the 3-year timeframe envisioned by the Company.

<u>Transmission System Intelligence</u> – The focus of this program is reduce the impacts on the transmission system through better protection and monitoring of system equipment. This program has four main components: (1) replacement of electro-mechanical relays with remotely operated digital relays; (2) deployment of intelligence and monitoring technology to provide asset health data for use in predictive maintenance programs; (3) deployment of remote monitoring and control functionality for substation and transmission line devices; and (4) resiliency projects that will leverage capabilities of this program, along with existing equipment capabilities to more rapidly respond to system outages and disturbances. These components have the potential to be utilized by other programs as DEC improves its grid management practices, and as such we scored it 3.0 in the grid architecture metric.

The combination of these four components will allow DEC to operate its grid in a way it had not previously been able to do, earning it a 3.0 score on the transformative metric. The new capabilities are summarized as follows:

- Health and Risk Monitoring (HRM) will extend asset life by identifying issues before failure.
- Digital relay design will enable quicker recovery from fault events.
- Remote control transmission switches will enable faster identification and isolation of system faults and trouble spots leading to faster service restoration.
- This technology will allow more data to be collected and analyzed to better operate the transmission system.
- The data collected through this program will help inform future planning efforts.

This program has meaningful interdependencies with the IVVC program, as well as transformative effects that will increase the amount of data to be utilized by the Company in developing more detailed transmission planning. As with many of the GIP programs, we encourage the utility to invest in ways that make its system more efficient, but we believe the 3-year timeline is not critical, so we scored it 2.0 on the timing metric.

Underground System Automation – This component of the Company's Distribution Automation program seeks to upgrade the protection and control of underground distribution systems serving customers in high-density locations (urban downtown areas, business districts, airports, entertainment venues), earning it a score of 3.0 on the grid architecture metric. This component will give the Company the ability to automatically reconfigure underground systems in order to isolate faults, reduce the effect of outages similar to SOG, and operate in a new, more efficient manner, earning it a score of 3.0 on the transformative metric. Similar with the previous programs, we continue to encourage the utility to invest in ways that make its system more efficient, but we believe the 3-year timeline is not critical, so we scored it 2.0 on the timing metric.

ISOP – This program is a planning tool that takes a holistic approach to integrate planning for the Company's generation, transmission, and distribution systems. ISOP is a multi-year program that takes into account operational and economic concerns.

For example, ISOP may focus on developing a methodology to determine the combined value of DER and customer programs. This effort would consider the benefit of delaying or deferring traditional deployment of wires solutions and how non-traditional alternatives may assist in meeting the bulk generation needs: regulating reserves, balancing reserves, and capacity reserves. Because of these methodology impacts, we scored it 3.0 on both the transformative and grid architecture metrics.

The ISOP program also scored 3.0 in the timing metric because we believe the improved modeling and analytical tools and processes expected to be developed through ISOP will be a critical core component of grid modernization in the Carolinas. Key elements of ISOP provide significant capabilities that can aid in the grid modernization process. The Company describes these elements as improved forecasting, advanced distribution planning, non-traditional grid solutions, and integrated planning from generation to distribution that feeds into the IRP.[30] These modeling tools and themes are recurrent in the DOE Project literature.

Q. FOR THE GIP PROGRAMS THAT YOU DETERMINED DID NOT QUALIFY AS AN EXTRAORDINARY TYPE OF ACTIVITY, PLEASE DESCRIBE ANY COMMON THEMES SHARED BY THESE PROGRAMS.

A. In reviewing our evaluation results, we observed the following common themes among the 32 programs or components that did not qualify as extraordinary in type:

- For the transformative metric, none of these 32 programs or components, for which deferral is requested, were considered as adding significant new capabilities to the grid.[31]
- For the timing metric, for 31 of the 32 programs or components, it was determined that the three-year time period was not critical to grid operations. Only Next Generation Cellular, a component of the Enterprise Communications program, has a three-year time period deemed critical due to the end of 2G/3G vendor support in 2022.

[30] *See* Joint Report of DEC, DEP and Public Staff on ISOP Workshop in Docket No. E-100, Sub 157 (January 21, 2020).

[31] The Energy Storage program was considered to contribute significant new capabilities, however; it is not included in this deferral request by the Company. The Electric Transportation program was also not included in this deferral request by the Company.

- Thirteen of the programs or components not recommended did not meet any of the grid modernization technology categorizations found in the CPUC Framework.

Q. PLEASE PROVIDE YOUR ANALYSIS OF EACH PROGRAM NOT CATEGORIZED AS AN "EXTRAORDINARY TYPE."

Self-Optimizing Grid (SOG) Capacity and Connectivity – SOG capacity projects focus on increasing substation transformer and distribution line capacity. SOG connectivity projects create ties between different distribution circuits. These two SOG components represent traditional technologies and utilize material and equipment that are current industry standards and are activities that have occurred, and continue to occur, as a normal part of operations; therefore, we scored these programs 1.0 for both the transformative and timing metrics. These components will be installed to complement other components of the SOG program, which is why we scored these two components 3.0 on the grid architecture metric.

Distribution Hardening and Resiliency (H&R) – Flood Hardening – This program seeks to mitigate the effects to at-risk equipment from flooding. Work includes: (1) creating alternate power feeds for radial distribution lines and substations that reside in or cross flood-prone areas; (2) hardening facilities at river crossings where distribution lines are vulnerable during extreme flooding events; and (3) improved guy-wire support for equipment in identified flood zones. These types of activities are not providing new or innovative capabilities to the grid, and so we scored this program 1.0 on the transformative metric. This program is a standalone program that is part of the normal and on-going mitigation planning process with distribution lines, and so we scored this program 1.0 on both the timing and grid architecture metrics.

Long Duration Interruption/High Impact Sites (LDI/HIS) – This program seeks to reduce the frequency and duration of outages in areas that may have a higher duration outage than average. The majority of this program will: (1) reconductor distribution lines with larger wire; (2) relocate distribution lines; and (3) install ties between distribution circuits. This type of distribution work has been historically performed by DEC. Similar to the Flood Hardening mentioned above, these types of activities are not providing new or innovative capabilities to the grid, and as such, we scored this program 1.0 on the transformative metric. This program is also a standalone program that is part of the normal and on-going planning process with distribution lines, and as such, we scored this program 1.0 on both the timing and grid architecture metrics.

Distribution Transformer Retrofit – This program focuses on overhead transformers currently in service. The work at most of these locations involves adding fused disconnect switches, lightning arrestors, and animal protection to the existing transformer. These additions should improve the power reliability of customers by: (1) reducing the risk of outages due to animal interference and lightning, and (2) limiting the effect of faults that occur on the customer side of the transformer to that particular segment only. These types of additions are not providing new capabilities to the Company's grid, and as such, we scored this program 1.0 on the transformative metric. However, we considered this program a core component to the Company's ability to update the design of the distribution system, which is why we scored this program 3.0 on the grid architecture metric.

The equipment used for this program has been standard in the electric utility industry for decades. This program has been in place for DEC since 2009 and the Company indicated inclusion in the GIP in order to accelerate this program to completion, which is why we scored this program 1.0 on the timing metric.

Transformer Bank Replacement – This program will work together with the Health and Risk Management (HRM) software.[32] The focus of this program is to accelerate the replacement of substation transformers prior to their failure. The combination of the two programs will formalize what had been an informal collection/review of transformer health status. The program will analyze transformer health and rank units for replacement consideration based on their measured risk of failure. Based on review of this risk ranking, an annual replacement plan will be developed by the Company. Because

[32] HRM is deployed for DEC transmission transformers as of January 2020.

of this new ability to manage the health of the transformer bank, we scored this program 3.0 on the grid architecture metric.

DEC has initially developed a "watch list" that contains 488 substation transformer units to be monitored under this program. The Public Staff, through the discovery process, requested the capacity rating (MVA) of all units being monitored. The Company did not provide transformer capacity ratings for 212 (43%) out of 488 units on the Watch List. The table below provides a summary of the units being monitored as part of the Company's watch list.

Table 6 Transformer Bank Replacement Program - Watch List

Capacity (MVA)	<20	21-50	51-200	201-500	>500	No Rating	Total
Quantity	160	75	26	13	2	212	488

DEC has identified 43 substation transformer units that they consider priorities for replacement.

Table 7: Transformer Bank Replacement Program - Priority List

Capacity (MVA)	<20	>50	Total
Quantity	40	3	43

DEC has historically been replacing 1-2 of these units annually. DEC's proposal is to accelerate this initiative to 5-10 units annually; however, budget limitations prohibit them from doing so at this time. Substation transformer units up to 50 MVA are widely used throughout the DEC service territory. DEC states that the normal procurement period for these units ranges from 12-24 months. In the event an emergency replacement is required, DEC has access to multiple layers of substation transformer inventory, including: DEC, DEP, Duke Energy Enterprise, and the Regional Equipment Sharing for Transmission Outage Restoration (RESTORE) program.[33]

The Public Staff supports the monitoring activities of the Transformer Bank Replacement program and encourages the Company to continue this effort in order to minimize potential customer outages caused by transformer failure. However, because it is a pre-existing initiative and DEC has access to multiple inventories of substation transformers in the event of an actual emergency, we scored this program 1.0 on both the transformative and timing metrics. In addition, Oliver Exhibit 1 specifically identifies "proactive replacement of pad mount transformers" and preventing load service events with "high consequences with adverse occurrences" (which a transformer bank failure would fall under) as part of its base maintenance work.

Distribution Automation – This program consists of four primary components that seek to minimize the effects of outages on the distribution system. We found one component, Underground Distribution Automation, to qualify as extraordinary type and the remaining three components are discussed below.

[33] RESTORE is a national program for the sharing of substation and transmission equipment between member utilities. DEC is a RESTORE member.

The Hydraulic to Electronic Recloser component will replace oil-filled reclosers with current industry standard electronic reclosers. These electronic units allow for remote operation and provide ongoing and continuous monitoring of distribution system health.

The System Intelligence and Monitoring component is a pilot seeking to replace an existing feeder management system. It seeks to build a distribution diagnostic tool to give grid operators the ability to troubleshoot developing problems as they occur.

The Fuse Replacement component involves replacing single-use fuses with an Automatic Lateral Device (ALD). Typically, these fuses are installed on a distribution line at a point that then creates a downstream distribution lateral section. Currently when a single-use fuse operates, there is the need for a technician to be dispatched to replace the fuse. The ALD has the capability of resetting itself without need of a technician site visit.

All three components scored 3.0 on the grid architecture metric because they are core components. The program, as a whole, was determined to provide limited new capabilities and as such was scored 2.0 on the transformative metric. These components were determined to be ongoing work and should continue at normal pace and, because of this, they scored 1.0 on the timing metric.

Transmission Hardening and Resiliency (H&R) – This program has three main components: (1) line hardening and resiliency; (2) flood hardening; and (3) animal mitigation.

DEC has not identified any substations that qualify for flood hardening work under this program; however, through the discovery process, the Company has indicated that it has modified its station site selection criteria to use the higher of: (1) the 100-year flood elevation plus 2 feet for non-critical facility, or plus 3 feet for a critical facility; (2) the 500-year flood elevation plus 1 foot; or, (3) the Design Flood Elevation adopted by the community.

DEC has approximately 2,815 miles of 44-KV lines. This program seeks to rebuild 80 of those miles to bring them up to the 100-KV construction standards including larger wire, taller and stronger structures, and increased spacing between phases. This rebuild will provide the foundation to connect more load or generation in the future; however, after the rebuild is complete, the lines will continue to operate at the 44-KV level until the Company determines it is appropriate to increase to the 100-KV rating. When the Company makes that determination, then the substation transformers will need to be upgraded to convert it to the 100-KV class. These rebuilds also seek to eliminate radial circuits by adding circuit miles in order to connect radial ends together to form a networked circuit.

The animal mitigation component installs protective equipment in an attempt to decrease the risk and impact of outages caused by animal interference.

The Public Staff finds that the three components of this program provide no new capabilities; represent ongoing work that should be continued at a normal pace; and are standalone and not part of grid modernization architecture.

Oil Breaker Replacement – This program seeks to replace oil-filled circuit breakers (OCB) in the DEC transmission and distribution fleet. OCBs have been in operation throughout the electric utility industry and in DEC's service territory for over a century. OCBs use oil as the medium to extinguish electrical arcs created during the opening of the breaker contacts. Circuit breaker technology has continued to evolve in the electric utility industry leading to technologies available for the replacement of OCBs, and we find that no new capabilities are readily available from these technologies, which is why we scored these programs 1.0 on the transformative metric.

According to discovery responses provided by DEC, the Company began installing both the gas and vacuum breaker technologies in the 1970-1971 period. Transmission OCBs are being replaced primarily with breakers that utilize gas (Sulfur-hexafluoride) and distribution OCBs are being replaced primarily with breakers that utilize vacuum technology to extinguish electrical arcs. These replacement breaker types will allow for two-way communications and remote operation capability, which provide a core component to grid modernization architecture. For this reason, we scored these components 3.0 on the grid architecture metric.

The table below shows the approximate number of circuit breakers currently in operation in the DEC transmission and distribution fleet.

Table 8: DEC Transmission and Distribution Fleet Breaker Types

Oil	Gas	Vacuum	Total
3,398	2,051	2,679	8,128

According to discovery responses provided by DEC, the installation of new gas and vacuum breakers (combined) exceeded new OCB installations in approximately 1988, and has been the predominant replacement strategy ever since. Since 1997, DEC has installed 2,681 gas or vacuum breakers and only 10 OCB's. For these reasons, we scored these components 1.0 on the timing metric.

We believe that this is ongoing work that should be continued, and the Company should continue to monitor and evaluate existing OCB installations and make decisions to replace those units based on established criteria and field observations.

<u>Physical and Cyber Security</u> continues to be a major area of concern for all electric utilities in the country. This program is comprised of multiple components that seek to improve security of the transmission and

distribution system. DEC is generally using North American Reliability Corporation (NERC) Critical Infrastructure Protection (CIP) standards to guide and inform its actions in this program.

We believe that the need for physical and cyber security will be continually present and will evolve to address emerging threats. DEC has indicated that none of the planned expenditures in GIP are required for CIP compliance. In addition, no component of this program is required to be completed due to any industry or regulatory mandate For these reasons, we scored all components of this program 1.0 on the timing metric.

We also believe that for the transformative metric, while the Device Entry Alert System, Secure Access Device Management, and the Line Device Protection programs provide limited additions beyond the current capabilities that are available to the Company for physical and cyber security, programs like the Substation Physical Security and Windows Based Unit Change Outs are standard types of physical security upgrades.

For the grid architecture metric, the Device Entry Alert System and Line Device Protection programs are both core components of grid architecture, and as such, they scored 3.0 on this metric. The Secure Access Device Management program is an application that is dependent upon core grid components and was scored 2.0 on this metric. Lastly, the Substation Physical Security and the Windows Based Unit Change Outs are standalone programs and operate outside of the grid modernization architecture, which is why we scored them 1.0 on the grid architecture metric.

Targeted Undergrounding (TUG) – DEC has been undergrounding distribution lines for decades, including conversions of overhead to underground, which is why we scored it 1.0 on the timing metric. According to discovery responses provided by DEC, the Company currently has approximately 20,737 miles (35% of total distribution miles) of underground primary distribution lines out of 58,621 total miles in their primary distribution system. The materials and technology used today for TUG are also used throughout the industry and are not new, which is why we scored it 1.0 on the transformative metric. However, because of the future planning and operations aspect of this program, we believe that this program is a core component of grid architecture, resulting in a score of 3.0 for this metric.

Enterprise Communications – This program consists of nine components. Most of these components replace equipment or infrastructure that have been part of normal operations for recent history. Only Vehicle Area Network and Network Asset Systems are new platforms the Company plans to deploy.

The Next Generation Cellular component replaces obsolete 2G/3G modems with the current 4G/5G standard modems. The Company currently has the 2G/3G[34] version of cellular communications equipment installed on some substation and line equipment. The Company has negotiated with its current cellular communications vendor to support the existing 2G/3G standard until the end of 2022. After that date, the 2G/3G modems will not communicate and this will isolate the Company's equipment.

Mission Critical Voice replaces radios used by field personnel to communicate between and within the field of operations. The current system of radios used by DEC is not compatible with other Duke Energy jurisdictions and does not allow communications between personnel from those different jurisdictions. This program will deploy a common platform of radios that is compatible throughout all Duke Energy jurisdictions.

Mission Critical Transport replaces existing fiber cable, optical and microwave systems that are at end-of-life. This component seeks to expand the capacity and reliability of the existing DEC communications network.

The components of this program offer no new capabilities and, with the exception of Next Generation Cellular, are part of normal ongoing work. Next Generation Cellular is deemed an urgent need due to its specific deadline for completion.

[34] 2G/3G refers to the standard used for cellular communicants. The 2G/3G standard is obsolete and is being replaced by the 4G/5G standard.

Enterprise Applications – This program seeks to provide enterprise-wide software for transmission, distribution, enterprise systems, and grid analytics.

The Health Risk Management (HRM) tool gathers and analyzes transmission system data for use in predictive and preventative maintenance efforts. The Enterprise Distribution System Health (EDSH) tool seeks to provide a platform to improve planning, governance, and customer delivery of power quality.

The Public Staff finds that this program, as a whole, provides some limited new capabilities and was scored 2.0 on the transformative metric. This program is dependent upon core components of grid modernization architecture and as such, was scored 2.0 on the grid architecture metric. The program will provide some limited new capabilities and represents ongoing work that should be continued at a normal pace.

DER Dispatch Enterprise Tool – As of 2018, North Carolina is the state with the second highest amount of interconnected solar DER in the United States, with over 3,000 MW of installed solar capacity. To assist in managing this level of DER, DEP (where most of the solar capacity has been deployed) implemented a rudimentary dispatch tool. The current tool allows DEP to interrupt DER in 50 MW blocks in certain conditions, as needed, and requires phone calls between DEP dispatchers and DER sites to coordinate and execute the process. DEC, with far less solar capacity, did not deploy the same tool. With the Competitive Procurement of Renewable Energy program seeking solar capacity in DEC's territory, a single coordinated tool was designed for both jurisdictions.

The proposed DER Dispatch Tool will be deployed in both DEC and DEP, replacing the existing tool in DEP. It will allow the Company to curtail DER in blocks as small as 1 MW, and allow for more automation of the process by eliminating the need for a DEC dispatcher to place a call to DER sites for execution to be completed. However, the Company has indicated that the DER Dispatch Tool as implemented will only be used in emergency situations for curtailment of solar facilities. DEC does not currently plan to use the DER Dispatch Tool to manage energy storage or for the forecasting of solar facilities. As such, we scored it 2.0 for transformative metric, as the program only provides limited new capabilities. Due to the existing tools and the lack of solar capacity in DEC, we also scored it 1.0 in the timing metric. Finally, this software application is dependent on core components of grid architecture, and thus receives a 2.0 on this metric.

<u>Power Electronics for Volt/VAR Control</u> –This program is a pilot and is in the infancy stages of research. It seeks to assist grid operators to better manage power quality issues associated with the high level of DER expected on the DEC system.

The Public Staff finds that this program provides limited new capabilities; represents new work that is not critical to core grid operations; and is a core component to other programs that are part of grid modernization architecture. We encourage the Company to continue learning how to better operate their grid through this pilot.

Q. ARE THERE PROGRAMS THAT THE COMPANY PRESENTED IN THE GIP PROPOSAL BUT DID NOT INCLUDE IN THE DEFERRAL REQUEST?

A. Yes. The Company included the Electric Transportation (ET) and Energy Storage programs in its presentations and final proposal; however, the costs for these programs are not included in the GIP deferral request.

Q. IS THE PUBLIC STAFF MAKING A RECOMMENDATION FOR THE ELECTRIC TRANSPORTATION AND ENERGY STORAGE PROGRAMS?

A. No, not at this time. The Company's ET proposal is currently being addressed in a separate proceeding, Docket No. E-7, Sub 1195. The Public Staff has filed comments in that docket.

As discussed in DEC's 2018 IRP, energy storage continues to evolve as a resource in the electric industry.[35] DEC states that the candidates for storage projects will be designed and assessed on a case-by-case basis. Currently, the number and location of sites that qualify for assessment are in the planning stages and are operating as potential pilots. We believe that

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[35] *See* Chapter 6 of DEC's 2018 IRP - INTEGRATED SYSTEMS AND OPERATIONS PLANNING (ISOP) AND BATTERY STORAGE.

energy storage should be evaluated as part of the ISOP process to inform the Company as to its best uses and business cases.

While no program costs have been included for consideration in the Company's GIP proposal for ET or energy storage, we encourage the Company to continue its evaluations of these programs to identify reasonable and prudent applications. The Public Staff will evaluate any future requests involving these programs, should they arise.

I. Final program considerations for a deferral

Q. BASED ON YOUR EVALUATION, WHICH GIP PROGRAMS QUALIFY AS AN EXTRAORDINARY TYPE OF ACTIVITY FOR FURTHER CONSIDERATION FOR DEFERRAL ACCOUNTING?

A. A summary of the final evaluation and recommendation of certain programs that we provided to the Public Staff's Accounting Division is presented as T&D Williamson Exhibit 5.

Q. WITH YOUR EVALUATION OF GIP PROGRAMS COMPLETED FOR THIS CASE, WILL THE PUBLIC STAFF MAKE THE SAME DETERMINATIONS IN FUTURE CASES?

A. No. We evaluated the programs in this case based on the specifics as presented by the Company. Company proposals may change over time and as such, we will continue to evaluate those proposals in each case on their own merits. In addition, the methods and inputs used to inform our evaluation in this case are based on the current information and resources available to us at the time of this filing. Our decisions may change over time as new information becomes available, and we will modify our evaluation process as necessary. As stated earlier in our testimony, our agreement with the recovery of costs for GIP programs in this proceeding should not be interpreted as implying continual approval of the costs of these same programs in the future. The Public Staff reserves the right to challenge the recovery of future costs associated with any of the GIP programs in future proceedings before the Commission.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes.

APPENDIX A

QUALIFICATIONS AND EXPERIENCE

DAVID WILLIAMSON

I am a 2014 graduate of North Carolina State University with a Bachelor of Science Degree in Electrical Engineering. I began my employment with the Public Staff's Electric Division in March of 2015. My current responsibilities within the Electric Division include reviewing applications and making recommendations for certificates of public convenience and necessity of small power producers, master meters, and resale of electric service; reviewing applications and making recommendations on transmission proposals for certificates of environmental compatibility and public convenience and necessity; and interpreting and applying utility service rules and regulations. Additionally, I am currently serving as a co-chairman on the National Association of State Utility and Consumer Advocates' (NASUCA) DER and EE Committee.

I have filed testimony in various DEC, DEP, and DENC's Demand Side Management/Energy Efficiency rider proceedings, as well as recently in DENC's most recent general rate case in Docket No. E-22, Sub 562.

APPENDIX B

QUALIFICATIONS AND EXPERIENCE

TOMMY WILLIAMSON, JR.

I am an Engineer with the Public Staff's Electric Division. I graduated from North Carolina State University with a Bachelor in Science in Electrical Engineering. I have approximately 3 years of electrical distribution design and construction experience with Florida Power & Light Company. During that time I designed distribution circuits for overhead and underground services from the substation through to end users. This was inclusive of but not limited to; customer load analysis, feeder line loading analysis, facilities construction and installation. I then served 11 years as an Engineer with General Electric Company. In this role at General Electric Company, I represented the company with electrical design engineers, industrial and commercial end customers, and installation contractors to develop technical specifications for the procurement and use of electrical distribution equipment.

Since my employment with the Public Staff, I have reviewed customer quality of service complaints, transmission and distribution construction projects, vegetation management, small generator interconnection procedures, and filed testimony in general rate cases and North Carolina Interconnection Procedures.

Abbreviations List

AACE	American Association of Cost Engineering
ADMS	Advanced Distribution Management System
ALD	Automatic Lateral Device
AMI	Advanced Metering Infrastructure
BCR	Benefit Cost Ratio
C&I	Commercial and Industrial
CBA	Cost Benefit Analysis
CEMI-6	Customers Experiencing Multiple Interruptions
CI	Customer Interruptions
CIP	Critical Infrastructure Protection
CMI	Customer Minutes Interrupted
COSS	Cost of Service Study
CPUC	California Public Utilities Commission
DEC	Duke Energy Carolinas, LLC
DEP	Duke Energy Progress, LLC
DER	Distributed Energy Resource
DOE	Department of Energy
DR	Data Request
DRP	Distribution Resource Planning
DSM	Demand Side Management
DSPx	Next Generation Distribution System Platform
DTR	Distribution Transformer Retrofit
EDSH	Enterprise Distribution System Health
EE	Energy Efficiency
ET	Electric Transportation
GIP	Grid Improvement Plan
GRR	Grid Reliability and Resiliency (Rider)
H&R	Hardening and Resiliency
HRM	Health and Risk Monitoring
ICE	Interruption Cost Estimator
IRP	Integrated Resource Plan
ISOP	Integrated System Operations Planning
IVVC	Integrated Volt Var Control
LBNL	Lawrence Berkeley National Laboratory
LDI / HIS	Long Duration Impact / High Impact Sites
M&S	Materials and Supplies
MED	Major Event Day
NC	North Carolina

NERC	North American Reliability Corporation
O&M	Operations and Maintenance
OCB	Oil-filled Circuit Breakers
PFC	Power Forward Carolinas
PNNL	Pacific Northwest National Laboratory
PRMR	Planning Reserve Margin Requirement
PURPA	Public Utilities Regulatory Policies Act
QF	Qualified Facility
RESTORE	Regional Equipment Sharing for Transmission Outage Restoration
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCP	Summer Coincident Peak
SOG	Self-Optimizing Grid
SWPA	Summer/Winter Peak and Average
T&D	Transmission and Distribution
TMT	Targeted Management Tool
TUG	Targeted Undergrounding
UCT	Utility Cost Test
VEPCO	Virginia Electric and Power Company
VM	Vegetation Management
WTA	Willingness to Accept
WTP	Willingness to Pay

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

(Whereupon, Public Staff Thomas Exhibits 1-7 were admitted into evidence.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1213 In the Matter of Application of Duke Energy Carolinas, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in 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 Utility Service in North Carolina	))))))))))))))))	TESTIMONY OF JEFF THOMAS PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1213

AND

DOCKET NO. E-7, SUB 1214

TESTIMONY OF JEFF THOMAS
ON BEHALF OF THE PUBLIC STAFF
NORTH CAROLINA UTILITIES COMMISSION

FEBRUARY 18, 2020

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

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

Q. BRIEFLY STATE YOUR QUALIFICATIONS AND DUTIES.

A. My qualifications and duties are included in Appendix A.

Q. BRIEFLY EXPLAIN THE SCOPE OF YOUR INVESTIGATION REGARDING THE COMPANY'S APPLICATION.

A. In this proceeding, I investigated Duke Energy Carolinas, LLC's (DEC or the Company) proposed Grid Improvement Plan (GIP),[1] and in particular the associated Cost-Benefit Analyses (CBAs) that support certain GIP programs, as provided in Oliver Exhibit 7 and then summarized in Oliver

[1] Appendix B contains a list of abbreviations used in this testimony.

Exhibit 8. Specifically, the programs which had CBAs conducted are listed below, along with brief descriptions of each program.[2]

- Self-Optimizing Grid (SOG) – segmentation of and interconnection between distribution circuits, enabling automatic isolation of faults and reducing the number of affected customers.
- Integrated Volt/Var Control (IVVC) – voltage regulators and capacitor banks installed on distribution circuits to enable a lower voltage at the substation, reducing both demand and energy consumption.
- Transmission Transformer Bank Replacements – accelerated proactive replacements of transformers in an effort to reduce unexpected failures and the associated outages.
- Distribution Transformer Retrofits (DTR) – accelerated proactive retrofits of distribution transformers with devices enabling segmentation, as well as additional protective features.
- Transmission Hardening and Resiliency (H&R), consisting of:
    - Substation flood mitigation – relocating and reinforcing substations prone to flooding during major storms.
    - Transmission Line Projects – targeted line rebuilds to withstand extreme weather as well as accelerated upgrades of the 44 kV system.

[2] For a more detailed description of each program, please refer to the joint testimony of Public Staff witnesses Tommy Williamson and David Williamson and DEC witness Jay Oliver, Exhibit 10.

- Oil Breaker replacement (Distribution and Transmission) – accelerated replacements of oil circuit breakers with gas circuit breakers (transmission) or vacuum circuit breakers (distribution).
- Long Duration Impact / High Impact Sites (LDI / HIS) – extreme hardening, circuit relocations, new circuit ties, and undergrounding of distribution lines to improve reliability to sites with high potential for long-duration outages.
- Targeted Underground (TUG) projects – burying distribution lines in areas with a history of unusually high outages.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to provide an analysis of GIP CBAs in support of the joint testimony of Public Staff witnesses Tommy Williamson and David Williamson. I present to the Commission the results and recommendations of the Public Staff's investigation into the reasonableness of the GIP CBAs provided by DEC. I will summarize how the CBAs were performed, what benefit categories were included and how the benefits were estimated, and how costs were estimated. In addition, I will highlight the Public Staff's concerns with the CBAs, present some relevant sensitivity analyses performed by the Public Staff, and share our conclusions regarding the cost-effectiveness of the selected programs. While I do not recommend that any GIP programs be rejected based upon their CBA, I do share the Public Staff's findings and recommendations so that the

Commission can view the CBA results in the appropriate light and require revisions as it deems appropriate.

The importance of accurate and realistic quantification of benefits and costs is critical when assessing large-scale grid improvement investments such as those included within the GIP. The estimated benefits from the Company's GIP proposal are massive, equal to nearly three times the total fuel and fuel-related expenses incurred across DEC's and Duke Energy Progress, LLC's (DEP) <u>entire system</u> in the twelve months ending November 2019.[3] A key point that I will elaborate on later in my testimony is that a majority (87%) of these benefits are categorized as customer reliability benefits, which are not derived from the operation of the electricity system, but rather they reflect estimates of reduced economic activity caused by interruptions. In light of the significant implications to ratepayers of the GIP proposal, it is critical that benefit estimations – and particularly customer reliability benefits – be as realistically and accurately evaluated, quantified, and allocated as possible. In addition, this is important to the ratepayers as well as to the utility; the cost to customers from poor service quality can influence the rate of return authorized by the Commission, and

[3] See DEC's November Monthly Fuel Report, Docket No. E-7, Sub 1198 and DEP's November Monthly Fuel Report, Docket No. E-2, Sub 1201.

may one day be used to determine a utility's rate of return, under a theoretical performance-based ratemaking structure.[4]

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized as follows:

I. Overview of GIP CBAs;

II. Discussion of GIP program benefits;

III. Discussion of GIP program costs; and,

IV. Recommendations to the Commission.

Q. ARE YOU PROVIDING ANY EXHIBITS WITH YOUR TESTIMONY?

A. Yes. I am including seven exhibits, described below:

Exhibit 1. 2015 *Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States*, by Lawrence Berkeley National Laboratory (LBNL).

Exhibit 2. DEC response to Public Staff Data Request (DR) 133-7.

Exhibit 3. DEC response to Public Staff DR 133-13.

Exhibit 4. DEC response to Public Staff DR 179-4.

Exhibit 5. LBNL guidance document on estimating outage costs associated with self-healing grids.

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[4] See National Renewable Energy Laboratory, *Next-Generation Performance-Based Regulation*, NREL Report No. NREL/TP-6A50-68512 (September 2017), at 14, *available at* https://www.nrel.gov/docs/fy17osti/68512.pdf.

Exhibit 6. 2009 *Estimated Value of Service Reliability Estimates for Electric Utility Customers in the United States*, by LBNL.

Exhibit 7. DEC response to Public Staff DR 14 in Docket No. E-7, Sub 1164.

Q. BASED ON YOUR REVIEW OF THE COMPANY'S COST-BENEFIT ANALYSES, CAN YOU SUMMARIZE YOUR RECOMMENDATIONS?

A. Yes. I recommend several changes to the CBAs that justify GIP programs, and I recommend that the Company take steps to improve its interruption cost estimates. I discuss these recommendations in more detail at the end of my testimony, but I summarize them here:

1. Future expenditures on GIP should be tracked and reported.
2. The Company should perform CBAs for some GIP programs that were not evaluated for cost-effectiveness, such as Distribution Automation, DER Dispatch, and any others that the Commission deems appropriate.
3. The Company should be required to file sensitivity analyses of its CBAs, which should include, at a minimum, variance in capital costs, O&M costs, fuel and related benefits, and customer interruption costs, along with any other parameters the Commission deems appropriate.

4. The Company should consider if there is value in conducting an interruption cost study in the Carolinas that would more accurately reflect interruption costs experienced by its customers.
5. The Company should remove or modify certain benefits from its CBAs, including long-term reliability benefits; CO_2 emission savings; avoided capacity Planning Reserve Margin Requirements (PRMR) gross-up; and avoided capacity in years where no capacity need is identified.
6. The Company should revise its Transmission H&R Line Projects CBA to assign customer reliability benefits to customer classes.
7. The Company should revise its SOG CBAs to include the effect of momentary outages as a result of automatic circuit reconfiguration.
8. The Company should revise its SOG CBA to take into account the expected reduction in vegetation-related outages resulting from the increased pace of vegetation management proposed in this proceeding.
9. The Company should consider the impact of GIP programs on costs not considered, such as materials and supplies (M&S) inventory and deferral costs, and factor those impacts (if any) into its CBAs.
10. The Commission and the Company should consider if changes to GIP cost allocations are warranted.

I. Summary of GIP CBAs

Q. WHAT IS A COST-BENEFIT ANALYSIS?

A. A cost-benefit analysis is a comparative analytical tool used to evaluate whether or not a certain investment is cost-effective. Typically, a CBA compares two or more options, is performed over a fixed time period, and considers periodic expenditures and benefits throughout the time period studied. CBAs must consider the time value of money, escalation rates, and other factors that influence costs and benefits over time. Replacement costs for capital assets that have lives shorter than the CBA analysis period must also be included. Typically, estimating the costs is a relatively straightforward exercise; the challenge often lies in the quantification of benefits to offset costs. Key variables and assumptions such as capital and labor costs, escalation rates, and prices for energy and capacity underpin the calculations performed. Once the net present value of the costs and benefits has been calculated, the benefit-cost ratio (BCR) is derived by dividing total benefits by total costs.[5]

Q. YOU REFER TO COST-BENEFIT ANALYSIS AS A COMPARATIVE ANALYSIS. TO WHAT ALTERNATIVES DOES DEC COMPARE ITS GIP PROJECTS?

[5] The use of a CBA for GIP programs is not unlike the costs and benefits contemplated under Commission Rule R8-68(c)(2)(iv). The results of the CBA, including the BCR, are not unlike the cost-effectiveness test contemplated under Commission Rule R8-68(c)(2)(v).

A. In its CBAs, the Company compares the cost of its chosen GIP programs to a "business as usual" scenario – in other words, it evaluates its selection of GIP projects relative to no new action. I do have some concerns that GIP projects were not compared to other possible actions – for example, the reliability benefits of SOG were compared to the grid as it is today, instead of other reliability improvements (such as microgrids, onsite generation, or targeted undergrounding). It is possible that more cost-effective solutions exist that would provide similar reliability benefits.

Q. PLEASE PROVIDE A HIGH-LEVEL SUMMARY OF THE PUBLIC STAFF'S PROCESS FOR REVIEWING GIP CBAs.

A. The Public Staff reviewed each CBA spreadsheet provided as part of Oliver Exhibit 7. We reviewed the costs and benefits that were included in each CBA, and sent numerous discovery requests for supporting documentation, particularly focusing on obtaining a better understanding of the quantified benefits. In addition, the Public Staff met with Duke's technical subject matter experts to review the CBAs and operational aspects of the GIP programs. We questioned each benefit calculation to ensure that the assumptions underpinning the benefits were reasonable. In addition, we looked at capital cost assumptions and estimates to determine reasonableness.

Q. DID YOU FIND THE CBAs TO BE GENERALLY REASONABLE?

A. I believe the Company made a good faith effort to quantify the costs and benefits of the GIP programs. The reliability benefits, which make up a large portion of the overall GIP benefits, are difficult to quantify accurately, particularly without direct customer surveys performed by the Company. However, I have several concerns regarding the assumptions made for the CBAs that may influence the final cost-effectiveness of each program, and indeed, the entire GIP proposal. In our evaluation of the Company's deferral request, discussed in the testimony of witnesses David Williamson and Tommy Williamson, the Public Staff reviewed the cost-effectiveness of each GIP program, taking into account the impact of several of my recommendations.

Q. CAN YOU SUMMARIZE YOUR CONCERNS FROM A COST-BENEFIT PERSPECTIVE?

A. Yes. These concerns will be discussed in more detail later in my testimony, but can be generally summarized as follows:

- Direct benefits from GIP programs are primarily customer reliability benefits, which make up approximately 87% of total GIP benefits. Customer reliability benefits are very difficult, if not impossible, to verify.
- The study supporting the reliability benefits may not accurately reflect outage costs incurred in North Carolina.

- Further, where these reliability benefits were broken out by customer class, approximately 97% were attributed to commercial and industrial customers, with the remaining 3% attributed to residential customers.
- Capital cost estimates were of a high-level nature with wide expected accuracy ranges, and the CBAs did not include any sensitivity analysis of capital costs.
- No sensitivity analysis of any key variables appear to have been conducted as part of the CBA process.
- Some CBAs appear to have ignored or minimized the unfavorable effects of momentary outages, as well as future investments in traditional grid maintenance programs, such as vegetation management (VM).

Q. WAS A CBA CONDUCTED FOR EVERY GIP PROGRAM?

A. No. Detailed quantitative CBAs were performed for the projects within the "Optimize" category of GIP investments.[6] No CBAs were performed for any programs within the "Modernize" or "Protect" categories.

Q. WHY DID SOME PROGRAMS NOT HAVE A CBA CONDUCTED?

A. Oliver Exhibit 6 provides a protocol for the level of study programs must undergo and provides a process for determining whether or not a CBA is

[6] These programs include SOG, IVVC, Transmission H&R, TUG, DTR, LDI/HIS, Transmission Transformer Bank Replacements, and Oil Breaker Replacements.

required. For example, programs that are required for compliance and that are non-discretionary are exempted from a CBA. This generally covers the "Protect" category of GIP investments.[7]

In addition, there are certain factors, such as objective or subjective qualitative or quantitative benefits to the customer, Company, or third parties that may not be quantifiable but "nonetheless justify the activity",[8] which can lead to a project being considered presumptively justified. In this case, the project would not require the detailed cost-benefit analysis. This may include work that is not technically compliance work, but is essential for modern system operations.[9] These generally apply to the programs under the "Modernize" category.[10]

Finally, no CBA was filed in this proceeding for the Energy Storage or Electric Transportation programs, as the Company did not request deferral for these programs in this proceeding.

Q. ARE THERE ANY GIP PROGRAMS THAT YOU BELIEVE SHOULD HAVE HAD A CBA CONDUCTED AND DID NOT?

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[7] These programs are also referred to as Physical and Cyber Security, representing approximately $133 million over three years, of which $65 M is allocated to DEC (NC capital budget).

[8] See Oliver Exhibit 6, at 2.

[9] See Oliver Exhibit 5, at 2.

[10] These programs include Enterprise Communications, Distribution Automation, Transmission System Intelligence, Enterprise Applications, Integrated Systems Operations Planning, DER Dispatch Tool, and Power Electronics for Volt/VAR Control. They represent $536 million over three years, of which $308 million is allocated to DEC (NC capital budget).

A. Yes. I believe the Company should have conducted a CBA for several of the programs within the "Modernize" category. Specifically, I recommend that the Company perform CBAs for the DER Dispatch Tool and the Distribution Automation program (including hydraulic to electronic reclosers, fuse replacement, and underground system automation). The DER Dispatch Tool will allow the Company more control over curtailment of third-party owned and operated solar facilities, and has an estimated cost of $4.5 million in DEC. The Distribution Automation programs I am recommending for a CBA consist of an accelerated deployment of certain automated devices that allow the Company more control over distribution system power flows. The three components of the program have estimated capital costs of approximately $110 million in DEC's North Carolina jurisdiction. While a CBA may not necessarily change the conclusions reached by Public Staff witnesses Tommy Williamson and David Williamson regarding the Company's deferral request, they are important in determining whether these programs are reasonable and prudent in future cost recovery proceedings.

Q. DID THE COMPANY ANALYZE THE SENSITIVITY OF ITS CBAs TO CHANGES IN KEY VARIABLES?

A. No. The CBAs provided in Oliver Exhibit 7 did not include or discuss any sensitivity analyses. I am concerned that lack of sensitivity analyses included in the CBAs masks the significant uncertainty in key underlying assumptions.

Q. WHAT IS A SENSITIVITY ANALYSIS AND WHY ARE THEY IMPORTANT?

A. Each CBA performed by the Company includes many assumptions, such as discount and escalation rates, capital costs, interruption cost estimates, etc. Many are subject to significant uncertainty. A sensitivity analysis would select key assumptions and present a range of CBA results based upon varying those assumptions, identifying the risks to ratepayers of cost overruns or benefit shortfalls. Sensitivity analyses are useful for the utility, regulators, and stakeholders, in that they can show how robust a GIP program's CBA is to changes in key variables. The lack of sensitivity analysis was identified by Commission Staff in Virginia as a shortcoming of Virginia Electric and Power Company's (VEPCO) grid transformation proposal.[11]

Q HAS THE PUBLIC STAFF TRADITIONALLY REQUIRED SENSITIVITY ANALYSES FOR PROPOSED INVESTMENTS?

A. The use of sensitivity analyses is required by Commission Rule R8-60(g) for Integrated Resource Plans (IRPs) when evaluating resource options, indicating its importance to the Commission. In some cases, the Public Staff has identified the need for additional analysis of key assumptions.[12] In this

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[11] See VA Docket No. PUR-2019-00154, Prefiled Staff Testimony, Volume II, Part B, Testimony of Curt Volkmann, at 26-27.

[12] For example, in the Public Staff's comments on the 2016 IRPs, we recommended the utilities evaluate the risks and required costs for subsequent license renewals at their nuclear

proceeding, the scale of the proposed benefits from GIP is almost without precedent, and we believe more analysis is necessary to ensure that the risks to ratepayers are fully explored.

II. GIP Program Benefits

A. Overview of GIP Benefits

Q. PLEASE DESCRIBE WHAT BENEFITS WERE CONSIDERED IN THE CBAs.

A. The Public Staff divided benefits within the CBAs into two broad categories: operational benefits and customer benefits. In this context, operational benefits describe benefits which accrue to DEC and have the potential to reduce future operating costs. Thus, benefits in this category can be expected to reduce future customer bills. The subcategories of operational benefits include:

1. Outage restoration – cost savings attributable to a reduction in outage repair costs (i.e., truck rolls) as a result of fewer outages occurring.
2. Vegetation management – lower costs due to less vegetation management required (in the Targeted Undergrounding CBA only).

plants. See Docket No. E-100, Sub 147, Comments of the Public Staff, at 34-35. We also request sensitivity analyses as part of our discovery and investigation process.

3. Asset management – these benefits reflect that for some programs, assets already deployed are replaced before they would typically be scheduled for replacement. Thus, the avoided cost of replacing these devices in the future is considered a program benefit.
4. Fuel and related – these benefits include avoided fuel, reagent, and emission costs (excluding CO_2), reduced variable O&M, and avoided start-up costs as a result of GIP programs.
5. Avoided capacity – reflects the reduced need for future capacity, generally a result of a reduction in peak load, as a result of GIP programs.

<u>Customer benefits</u> accrue to the customer but are generally difficult to quantify and are not expected to reduce future utility operating expenses, which means these benefits will not directly cause future rate reductions. The subcategories of customer benefits include:

1. Reliability – these are monetized estimates of the benefits customers realize by having more reliable power. The reliability improvement estimates have been quantified using a 2015 Lawrence Berkeley National Laboratory (LBNL) report entitled *Updated Value of Service Reliability Estimates for Electric Utility Customers in the United*

States[13] (LBNL Report, attached as Exhibit 1), which will be discussed in more detail later in my testimony.

2. CO_2 – DEC uses its projections of a future carbon price from its 2019 IRP to quantify the cost savings from reduced CO_2 emissions. This benefit is directly proportional to the reduction in carbon-emitting generation.[14]

3. Distributed Energy Resource (DER) Enablement – the benefit of enabling additional DER to be added compared to the base case, primarily due to increased distribution line capacity in the SOG program.

These benefits, and their inclusion in each program's CBA, are summarized in Table 1 below. The Public Staff did not review the Company's claimed IMPLAN benefits, which are indirect and societal benefits estimated through economic modeling.[15]

[13] Sullivan, M.J., J. Schellenberg, and M. Blundell. (2015). *Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States*. Lawrence Berkeley National Laboratory Report No. LBNL-6941E.

[14] CO_2 benefits have been separated from utility operational fuel and fuel related benefits because, unlike SO_2 and NO_X, there currently are no costs associated with CO_2 emissions.

[15] IMPLAN is an economic input-output model that estimates the economic impact to communities based upon interdependencies between economic sectors. The Public Staff did not review these benefits because indirect benefits such as those estimated from IMPLAN are not traditionally considered in cost benefit analyses for prudence review and program approval.

Table 1: Benefit Categories of GIP CBAs. "Yes" indicates this benefit is quantified in the GIP CBA.

GIP Program	Operational					Customer		
	Outage Restore	Veg Mgmt	Asset Mgmt	Fuel + Related	Avoided Capacity	Reliability	CO_2	DER Enablement
SOG				Yes	Yes	Yes	Yes	Yes
IVVC				Yes	Yes		Yes	
DSDR				Yes			Yes	
T-Transformer Bank Replacement			Yes			Yes		
DTR	Yes					Yes		
Transmission H&R	Yes		Yes			Yes		
Oil Breaker Replacements			Yes			Yes		
Transmission Line Projects (DEC)						Yes		
Transmission Line Projects (DEP)						Yes		
LDI / HIS						Yes		
TUG	Yes	Yes	Yes			Yes		

Q. WHY HAVE YOU DIVIDED BENEFITS INTO OPERATIONAL AND CUSTOMER CATEGORIES?

A. We performed this analysis to better understand which GIP programs would be likely to pass a utility cost test (UCT),[16] if all cost and benefit estimates are accurate. A program that still had a BCR greater than one even after removing the customer benefits would be indicative that it would reduce customer rates over the long term, which is an important consideration to the Public Staff for such large utility investments.

In addition, operational benefits from GIP programs are measurable and can generally be validated after GIP program implementation with the proper monitoring and reporting requirements. However, I do not believe it is possible for DEC to verify their estimates of customer benefits. While reliability improvements can and should be measured following GIP implementation, quantifying those benefits in terms of cost savings to customers is extremely difficult, if not impossible.

Q. WOULD ANY OF THE GIP PROGRAMS PASS A UTILITY COST TEST?

A. Yes. DEC witness Oliver's Exhibit 8 shows that when all benefits are included, the total "Optimize" portfolio of projects claims a combined BCR of 4.7; only one project, the Transformer Bank Replacements, has a BCR

[16] This test is commonly used in energy efficiency program evaluations, and reflects the program costs and benefits from the utility's perspective. The UCT is used for evaluating the cost effectiveness of Energy Efficiency and Demand Side Management programs under Commission Rule R8-68(c)(2)(v).

less than 1.0. However, if only the operational benefits are considered, the combined BCR of the "Optimize" portfolio falls to 0.48, and the only programs that pass a UCT test with a BCR greater than 1.0 are IVVC, DSDR,[17] and Transmission H&R (substation flood mitigation). The inclusion of customer benefits in the GIP CBAs, and particularly customer reliability benefits, significantly influence their cost-effectiveness.

Q. PLEASE SUMMARIZE THE MAGNITUDE AND DISTRIBUTION OF GIP CBA BENEFITS.

A. Figure 1 below visually summarizes the program costs, operational benefits, and customer benefits for all GIP CBAs in DEC's and DEP's North Carolina territories.[18] These figures were drawn from the individual CBAs filed in Oliver Exhibit 7 and were validated against the summary provided in Oliver Exhibit 8. Total CBA program costs are estimated to be $1.98 billion. Total CBA program benefits are estimated at $9.24 billion, consisting of approximately $8.3 billion in customer benefits and $942 million in operational benefits.

Several conclusions can be drawn from reviewing the costs and benefits split out in this way: first, the total program costs are twice as large as the operational benefits, indicating that as a whole, the GIP proposal would not pass a UCT for cost-effectiveness. Second, operational benefits only

[17] DSDR is a DEP program, but was included in the joint DEC/DEP analysis.

[18] All figures in NPV, 2019 dollars.

account for approximately 10% of the total benefits claimed. Finally, the vast majority (approximately 87%) of all benefits from the proposed GIP program are attributed to customer reliability.

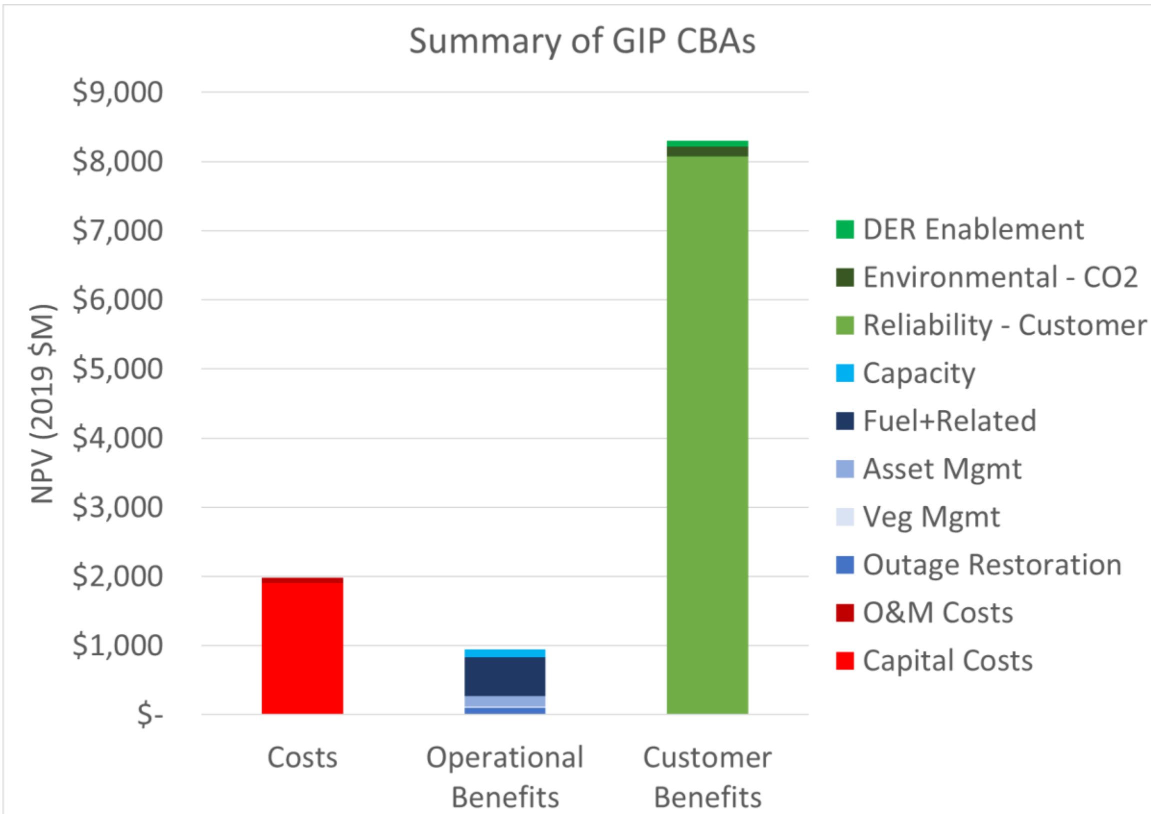

Figure 1: Summary of GIP CBA Costs and Benefits

B. Customer Reliability Benefits

Q. CAN YOU ELABORATE ON THE METHOD USED TO QUANTIFY CUSTOMER RELIABILITY BENEFITS?

A. Yes. These benefits have been quantified in two steps: first, the reduction in outages as a result of the GIP program (quantified as Customer Interruptions, or CI) is estimated. The methodology for doing so varies by CBA, but generally this process relies on reviewing historical outage data to establish a 'baseline' CI, and then attempting to determine what types and quantities of outages might be avoided if the GIP program is successful.

Next, the cost per outage is quantified using the LBNL Report, specifically Table ES-1, which is presented below as Table 2. In every CBA but for the Integrated Volt-VAR Control (IVVC) (which does not include reliability benefits), the Company uses the "Cost per Event" figures from this table, adjusted for inflation, to quantify the benefits from the estimated improvement in CI caused by the GIP program being studied. The customer classes studied in the LBNL Report are residential, small commercial and industrial (C&I), and medium and large C&I.[19] This LBNL report will be addressed in detail later in my testimony.

Table 2: Estimated Interruption Cost per Event from the LBNL Report, page xii.

Interruption Cost	Interruption Duration					
	Momentary	30 Minutes	1 Hour	4 Hours	8 Hours	16 Hours
Medium and Large C&I (Over 50,000 Annual kWh)						
Cost per Event	$12,952	$15,241	$17,804	$39,458	$84,083	$165,482
Cost per Average kW	$15.9	$18.7	$21.8	$48.4	$103.2	$203.0
Cost per Unserved kWh	$190.7	$37.4	$21.8	$12.1	$12.9	$12.7
Small C&I (Under 50,000 Annual kWh)						
Cost per Event	$412	$520	$647	$1,880	$4,690	$9,055
Cost per Average kW	$187.9	$237.0	$295.0	$857.1	$2,138.1	$4,128.3
Cost per Unserved kWh	$2,254.6	$474.1	$295.0	$214.3	$267.3	$258.0
Residential						
Cost per Event	$3.9	$4.5	$5.1	$9.5	$17.2	$32.4
Cost per Average kW	$2.6	$2.9	$3.3	$6.2	$11.3	$21.2
Cost per Unserved kWh	$30.9	$5.9	$3.3	$1.6	$1.4	$1.3

[19] Small C&I represents C&I customers with less than 50 MWh of annual usage; medium and large C&I represent C&I customers with 50 MWh or more of annual usage.

Q. BEFORE ADDRESSING THE LBNL REPORT, DO YOU HAVE ANY CONCERNS WITH HOW THE COMPANY HAS QUANTIFIED THE REDUCTION IN OUTAGES AS A RESULT OF GIP?

A. Yes, I have identified two main problems: (1) certain CBAs appear to lack a consideration of the impact of VM, and (2) the SOG CBA appears to ignore the costs of increased momentary outages during SOG events.

Q. PLEASE DESCRIBE HOW VEGETATION MANAGEMENT AFFECTS OVERALL SYSTEM RELIABILITY.

A. Witness Oliver describes the Company's VM plan, which is designed to "eliminate the 13,467 miles of existing tree trimming backlog within five years, while still ensuring that all miles previously trimmed with their 5-, 7-, or 9-year timeframe … are trimmed on schedule per the Company's 5/7/9 Plan."[20] The Company proposes an increase of $7.4 million to its rates in this proceeding to address contractor rate increases, as well as adjusting test year revenues to allow for appropriate revenues under the Company's 5/7/9 plan.[21] While the Company has not quantified expected improvement in system reliability metrics as a result of reducing its VM backlog, vegetation-related outages have accounted for 44% and 37% of DEC's 2019 North Carolina SAIDI and SAIFI metrics, respectively. The Public Staff expects that increased VM spend over the next five years will result in some

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[20] Direct testimony of Oliver, at 25.

[21] See Direct testimony of McManeus, Pro forma Adjustment NC-2702.,

level of reduced vegetation-related outages; however, we do acknowledge that there is not a realistic amount of VM work that can be done to reduce these numbers to zero.

As discussed in the joint testimony of Public Staff Witnesses Tommy Williamson and David Williamson, there are various components that contribute to the calculation of the Company's reliability trends. Each of these components will necessarily vary from year to year, meaning that some years' contributions from individual components will be greater or lesser than other years. Assuming that the trends of these various components will remain constant is not a realistic approach to reliability planning.

Q. HOW COULD OUTAGE REDUCTION BENEFITS BE IMPACTED BY VEGETATION MANAGEMENT?

A. I believe it is likely that the Company's VM plan will reduce the number of avoided outages that the Company is currently projecting from its GIP programs. The estimated reduction in CI from each GIP program is largely derived from the difference between historical outage rates (the 'baseline') and assumptions about how a particular GIP program will reduce outages. If outage rates decline over the next five years due to increased VM, then the 'baseline' used in the GIP CBAs will be overstated, causing the projected CI reduction, and the estimated benefits, to similarly be overstated.

Q. HAS THE COMPANY ATTEMPTED TO MITIGATE THE INFLUENCE OF THIS FACTOR?

A. Yes. In some instances, the Company made efforts to control for this by only including historical outages of a certain type in its baseline (for example, the Transformer Bank Replacement CBA only looked at historical outages initiated by a failed transmission transformer equipment). The outage history database maintained by the Company includes comments and outages that are classified by cause. It appears that good faith efforts were made, in some of the CBAs, to remove vegetation-related outages from estimates of outage reductions due to GIP.

Q. ARE THERE ANY CBAs THAT MAY NOT HAVE APPROPRIATELY INCLUDED THE IMPACT OF FUTURE VEGETATION MANAGEMENT IMPROVEMENTS?

A. Yes. For some programs, the mitigation process required some subjectivity or was not done, and a high baseline bias cannot be ruled out. One example is the Distribution Transformer Retrofit (DTR) CBA, in which the baseline outage information required a complex series of steps to scrub the data, including a "contextual search of comments" to determine if the outage was due to an un-retrofitted transformer.[22] Errors in entering or searching the comments could lead to a high (or low) bias in baseline reliability if vegetation-related outages were inadvertently included in (or excluded

[22] See DEC response to PS DR 133-7, attached as Exhibit 2.

from) the baseline. Another example is TUG, which also uses historical outage data to estimate customer reliability benefits of $1.9 billion. CBAs are comparative analyses, looking at the merits of one course of action over another. The TUG CBAs compare undergrounding to no action; instead, they should compare undergrounding to the impact of reduced outages from improved VM practices to avoid overstating customer reliability benefits.

Of particular concern are the outage reduction estimates from SOG. A key factor in the calculations supporting estimated CI and Customer Minutes Interrupted (CMI)[23] reductions on SOG circuits is the "faults per mile" on the DEC distribution system; this factor divides the total number of outages on the distribution system greater than five minutes, regardless of cause, by the total number of feeder backbone[24] miles. As <u>all</u> vegetation-related outages are included in the faults per mile calculation (including those outages that might be avoided through increased VM activity over the next five years as the Company reduces its VM backlog), it is likely that this figure is biased high, leading to inflated estimates of reliability benefits from SOG.

Q. WHAT IMPACT WOULD AN OVERSTATED FAULTS-PER-MILE FIGURE HAVE ON THE OUTAGE REDUCTION BENEFITS ESTIMATED IN SOG?

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[23] CI is generally used to quantify the reduction in the number of outages. CMI is used to determine the typical duration of outages, which allows the Company to select the appropriate Cost per Event from the LBNL Study.

[24] Duke describes the feeder backbone of a circuit as: "3-phase, unfused line sections, <u>not</u> protected by a reclosing device of 200 amps per phase or less." See DEC response to PS DR 133-13, attached as Exhibit 3.

A. Table 3 below presents the results of the Public Staff's sensitivity analysis of the faults per mile factor performed on six of the 432 circuits selected for SOG in DEC's North Carolina territory. Because, as stated above, all vegetation-related outages are included in the faults per mile calculation (including those outages that might be avoided through increased VM spend over the next five years), I have reduced this factor to 0.22, from the 0.24 used in the Company's CBA.[25] The potential CI Reduction, a key input into the SOG CBA, is reduced proportionately. Due to the similarities in how per-circuit reliability improvements are calculated, this proportional reduction of CI and CMI is assumed to hold for all circuits.

Table 3: Effect of changes to the Faults per Mile factor on six (6) selected SOG circuits in DEC.

Metric	Faults Per Mile = 0.24	Faults Per Mile = 0.22	Delta (%)
Baseline CI	34,296	31,438	-8.3%
Potential CI Reduction	30,049	27545	-8.3%
Potential CMI Reduction	4,179,595	3,898,146	-6.7%

Q. HOW ARE THE ESTIMATED BENEFITS AND THE OVERALL SOG CBA AFFECTED BY CHANGES TO THE FAULTS PER MILE FACTOR?

[25] The selection of 0.22 faults per mile is for illustrative purposes only. Based on 2018 outages on the DEC North Carolina system, the 0.22 faults per mile factor roughly reflects a 30% reduction in the number of vegetation-related outages.

A. With nearly $2 billion in customer reliability benefits attributed to SOG deployment (DEC and DEP, North Carolina only), even a slight error in calculating faults per mile could lead to significantly overstated benefits. Adjusting the CI and CMI estimates according to the analysis above, Table 4 shows that the total SOG CBA is sensitive to changes in CI and CMI - reducing the faults per mile to 0.22 measurably impacts the BCR of the entire program.

Table 4: Sensitivity analysis of CI and CMI benefits in the DEC-NC SOG CBA.

% Change to Projected CI and CMI Improvements	BCR	Reliability Benefits ($M)	% Change to Total Benefits
No Change (as filed)	2.5	$1,050	-
-8% CI and -7% CMI	2.3	$972	-6.9%

Q. DO YOU HAVE ANY RECOMMENDATIONS TO REDUCE THE IMPACT OF FUTURE VEGETATION MANAGEMENT ON GIP CBAs?

A. Yes. With respect to SOG, the Company should recalculate its faults per mile metric by removing a reasonable percentage of vegetation-related distribution outages from its baseline. The percentage of such outages removed should reflect anticipated reliability benefits from reducing VM backlog; if the Company does not anticipate that its VM plan will lead to a reduction in vegetation-related distribution outages, it should plainly state as such and provide an explanation to the Commission.

Regarding DTR and TUG, the Company should carefully review the sources of outage data and the methods utilized to mitigate this issue for each CBA, along with the estimated reliability impacts of improved VM. It should then be required to update the Commission and GIP stakeholders on the process and results of its review, including a revised CBA.

Q. PLEASE EXPLAIN YOUR CONCERNS REGARDING MOMENTARY OUTAGES IN THE SOG CBA.

A. To begin, I will briefly explain how SOG improves reliability. First, it splits a circuit into segments that are separated with automatic switches or reclosers (SOG Automation). Next, it interconnects with an alternate feeder, creating a “loop” where power can now come from both ends of the line (SOG Connectivity); capacity of the distribution lines, the original feeder, and the alternate feeder substations are increased so that either substation can supply power to the majority[26] of the combined circuit in the event of a fault (SOG Connectivity).[27] Figure 2 below illustrates a SOG circuit with three segments, tied into an alternate substation with a normally open line.

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[26] The increased capacity of SOG circuits is designed so that up to 70% of the companion circuit’s load can be carried during 90% of the annual hours.

[27] SOG Automation, SOG Connectivity, and SOG Capacity are three components of SOG. The fourth is Advanced Distribution Management System, which coordinates the other components.

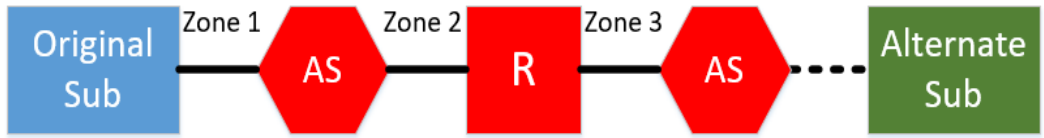

Figure 2: Illustration of a SOG circuit. AS = automatic switch; R = recloser. The dotted line represents an intertie to an alternative substation that is normally open unless a fault occurs.

In a hypothetical scenario, assume a fault occurs in Zone 2, which causes a sustained outage. The automatic sensing and switching devices detect the segment of the circuit where the fault occurred, isolate it from the remainder of the circuit, and begin feeding power in from the alternate feeder. In its CBA, the Company assumes that customers in Zone 2 experience a sustained outage, and customers in Zones 1 and 3 experience no outage. I believe the Company has correctly quantified these benefits for Zone 2 customers; however, while customers in Zones 1 and 3 avoid a sustained outage, they will experience a momentary outage. This is because it can take up to two minutes for the SOG system to locate and isolate the fault and connect the alternate substation in a way that will ensure adequate paths for power flows.[28] During this time, customers in Zones 1 and 3 may experience a series of momentary outages. The costs of these momentary outages are not included in the Company's CBA.

[28] DEC Response to PS DR 179-4, attached as Exhibit 4.

Similar concerns were expressed by Virginia Commission Staff in its recent comments on the VEPCO Grid Transformation Plan.[29]

Q. DO CUSTOMERS INCUR COSTS FOR MOMENTARY OUTAGES?

A. Yes. The LBNL Report quantifies these costs. In fact, the SOG CBA includes $275 million in customer reliability benefits attributed to a reduction in the number of momentary outages, based upon a Company assumption that for every one sustained outage, there are 1.5 momentary outages. It is not reasonable for the Company to include the benefits of avoided momentary outages, while at the same time ignoring the costs of increased momentary outages.

Q. DO THE AUTHORS OF THE REPORT IDENTIFY THIS ISSUE OF MOMENTARY OUTAGES?

A. Yes. The Interruption Cost Estimator (ICE) Calculator[30] website, under the documentation tab, has published a guide, "Using the ICE Calculator for FLISR [Fault Location Isolation and Service Restoration] Reliability Improvement Value", attached as Thomas Exhibit 5. FLISR is the automatic reconfiguration of distribution circuits, and is similar to the Company's proposed SOG program. Within this document is a discussion of how the

[29] *See* VA Docket No. PUR-2019-00154, Prefiled Staff Testimony, Volume II, Part B, Testimony of Curt Volkmann, at 12-15.

[30] The ICE Calculator is an online tool that uses the econometric model from the LBNL Report to generate interruption cost data using specified input parameters. It can be accessed at www.icecalculator.com.

outage benefit estimates generated for FLISR / SOG must be adjusted to account for momentary outages. In the example provided, failing to account for momentary outages could overstate benefits by about 50%.

Q. HOW SIGNIFICANT ARE THESE EFFECTS?

A. It depends on the circuit. Generally, the Company assumes that the reduction in CI relative to the baseline is equal to the inverse of the number of segments; in other words, three segments reduce the CI by 33% and ten segments reduce the CI by 90%, reflecting the ability of SOG to confine a sustained outage to a single segment. As the number of segments increases, the number of customers affected by each interruption (CI) decreases; yet not all customers avoid an interruption, as the Company assumes. The customers who do not experience a sustained outage due to SOG will nonetheless experience a momentary outage.

Q. DO YOU HAVE ANY RECOMMENDATIONS REGARDING MOMENTARY OUTAGES IN THE SOG CBA?

A. Yes. The customer reliability benefits associated with SOG should account for momentary outages that occur during circuit reconfiguration events. The CBA should reflect that for some customers, sustained outages are not eliminated entirely, but rather become momentary outages. Because the Company made the same assumptions when it quantified momentary outage benefits, these should be similarly reduced.

Q. HAS THE PUBLIC STAFF ATTEMPTED TO ESTIMATE THE IMPACT OF ITS PROPOSED CHANGES?

A. Yes, I have, although a full recalculation of the per-circuit CI and CMI savings should be performed by the Company to verify. Using the SOG CBA spreadsheet, I first estimated the cost of the momentary outages that were not included by the Company, assuming that the customers who avoid a sustained outage experience a momentary one. Because the LBNL Report estimates that the cost of a sustained outage is greater than the cost of a momentary outage, there is still a net benefit to customer reliability. Next, I eliminated the avoided momentary outage benefit that was included by the Company to reflect that all customers experience some momentary outages during circuit reconfiguration.[31] Finally, I subtracted the estimated cost of momentary outages from the remaining outage benefit. Based upon my analysis, I believe that accounting for the effect of momentary outages could reduce the reliability benefits of SOG by approximately 44%, or $459 million, which is in line with the LBNL FLISR document. The Company should revise its SOG CBA to validate this result.

C. <u>The LBNL Report and Interruption Cost Estimates</u>

Q. TURNING NOW TO THE LBNL REPORT, PLEASE PROVIDE A GENERAL OVERVIEW OF REPORT'S METHODOLOGY.

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[31] The LBNL Report considers all outages under 5 minutes to be "momentary."

A. The LBNL report was an update to a similar 2009 report,[32] which was a meta-analysis performed by the consulting group Nexant for LBNL (2009 LBNL Report, attached as Thomas Exhibit 6). The 2009 LBNL Report analyzed the results from "28 customer value of service reliability studies conducted by 10 major U.S. electric utilities over the 16-year period from 1989 to 2005." Because these studies utilized very similar methodologies to estimate interruption costs (including direct cost estimation[33] or willingness-to-pay (WTP) / willingness-to-accept (WTA) surveys[34]), these results were integrated into a single econometric dataset that was used to create an econometric regression model to estimate outage costs to customers.[35]

The 2015 LBNL Report updates this work with two additional interruption cost studies (one each from a southeastern and a western electric utility), which improves the ability of the ICE Calculator to estimate the cost of outages longer than eight hours, a limitation of the 2009 LBNL Report. It also makes refinements to the econometric model and the associated ICE

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[32] Sullivan, M.J., M. Mercurio, and J. Schellenberg (2009). *Estimated Value of Service Reliability for Electric Utility Customers in the United States*. Lawrence Berkeley National Laboratory Report No. LBNL-2132E.

[33] Direct cost estimation surveys (also known as direct worth) typically ask respondents to quantify the economic losses due to a hypothetical power outage using a worksheet. These are more typically sent to non-residential customers.

[34] Willingness-to-pay surveys typically ask customers questions designed to understand what they would be willing to pay to avoid a hypothetical outage. Willingness-to-accept surveys typically ask customers questions designed to understand how much they would be willing to accept to be indifferent to an outage. These are more typically sent to residential customers.

[35] The authors of the 2009 LBNL Report discuss the various survey methodologies in Appendix B.

Calculator, such as reducing the number of variables needed, thus easing data burdens associated with using the ICE Calculator.

Q. ARE THERE ANY CAVEATS NOTED IN THE LBNL REPORT?

A. Yes, there are several caveats either explicitly stated or implied in both the 2009 LBNL Report and the 2015 LBNL Report, some of which highlight the Public Staff's concerns with the $8 billion in customer reliability benefits claimed in DEC's and DEP's North Carolina CBAs. Broadly, these concerns include: (1) limitations when quantifying outages longer than 16 hours; (2) possible high bias on outage cost data due to the nature of the studies used; and, (3) the lack of DEC-specific outage surveys used to create the LBNL Report. These issues highlight the Public Staff's primary concern with the quantification of these benefits, which is the Company's direct application of the national level outage costs. I would also note that some of these issues have been raised in other jurisdictions where the LBNL Report has been used to quantify customer reliability benefits, most recently in Virginia.[36]

Q. BEFORE YOU DETAIL THE PUBLIC STAFF'S CONCERNS WITH THE COMPANY'S DIRECT APPLICATION OF THE LBNL BENEFITS, DO YOU HAVE ANY THOUGHTS ON HOW THEY MIGHT BE RESOLVED?

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[36] See VA Docket No. PUR-2019-00154, Prefiled Staff Testimony, Volume II, Part B, Testimony of Curt Volkmann, at 6-27.

A. Yes. I will summarize them here, with additional explanation to follow. Broadly, my concerns center around the fact that the interruption cost estimates are not certain enough, not region-specific enough, and are not sufficiently verifiable to be considered in a prudence evaluation of proposed GIP investments.[37] DEC can improve the accuracy and reliability of these results in a few ways.

First, I would recommend that the Company reach out to LBNL to see how their work might be furthered to resolve some of the concerns, some of which I will describe shortly. For example, the researchers may highlight how the Company could design an efficiently conducted, targeted interruption cost study in its jurisdictions to provide new region-specific data, which could be used in a new Southeastern interruption cost model.

In the interim, I recommend that DEC coordinate with other Southeastern utilities that provided interruption surveys to LBNL (e.g., Southern Company) to see if they will share the interruption cost surveys they provided to LBNL. DEC could then adjust the LBNL figures to take into account nearby utilities' experience. DEC could also conduct limited direct cost estimation surveys of its C&I customers to validate against the LBNL Report.

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[37] This concern as also raised in Virginia by the Attorney General in the Dominion Grid Transformation plan. See VA Docket No. PUR-2019-00154, Direct Testimony and Exhibits of D. Scott Norwood, at 10.

I also recommend that the Company reduce or remove the benefits associated with outages over 24 hours until these costs can be better understood. The Company also should perform sensitivity analyses on the cost per event figures in order to demonstrate to the Commission how the CBA results are influenced by outage cost estimates.

Q. CAN THE OUTAGE DATA IN THE LBNL REPORT BE USED TO QUANTIFY LONGER TERM OUTAGES?

A. The authors of the report caution against using the outage cost data to estimate longer-term outages. While the LBNL Report does attempt to better quantify the costs of outages lasting longer than 8 hours with the addition of new outage cost surveys, the report warns that "the estimates in this report are not appropriate for resiliency planning."[38] The results in the LBNL Report are truncated at 16 hours due to the relatively few number of observations beyond 12 hours. The LBNL Report states that for consideration of "long duration outages of 24 hours or more, the nature of costs change and the indirect, spillover effects to the greater economy must be considered."[39]

Q. DESPITE THESE CAVEATS, DOES THE COMPANY USE THE LBNL REPORT TO ESTIMATE THE VALUE OF LONGER OUTAGES?

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[38] LBNL Report at 48.

[39] *Id.* at 49.

Yes. The Company linearly extrapolates the LBNL Report outage costs for outages lasting longer than 16 hours. Linear extrapolation describes the process of using the outage cost dataset (outage cost as a function of duration) to estimate outage costs for durations longer than the maximum provided in the dataset, assuming that outage costs increase linearly with duration. This was typically done to quantify the benefits of reduced Major Event Day (MED) outages.[40]

For example, the Long Duration Interruptions / High Impact Sites (LDI/HIS) and the Transformer Hardening and Resiliency (Transformer H&R) CBAs quantify the costs of outages of up to 96 hours. The Distribution Transformer Retrofit (DTR) CBA quantifies MED outages up to 20 hours. Some of the Targeted Undergrounding (TUG) CBAs quantify avoided MED outages significantly longer than 12 hours, in some cases as long as 30 or more hours.

Q. DOES THE PUBLIC STAFF HAVE CONCERNS WITH THE COMPANY'S LINEAR EXTRAPOLATION METHODOLOGY?

A. Yes, I have concerns that the customer reliability benefits associated with long-duration MED outages may be overstated. Figure 3 from the LBNL Report below illustrates the risks in quantifying outage durations longer than 16 hours.

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[40] MED outages are typically the result of major events, such as hurricanes, ice storms, severe thunderstorms, and other events.

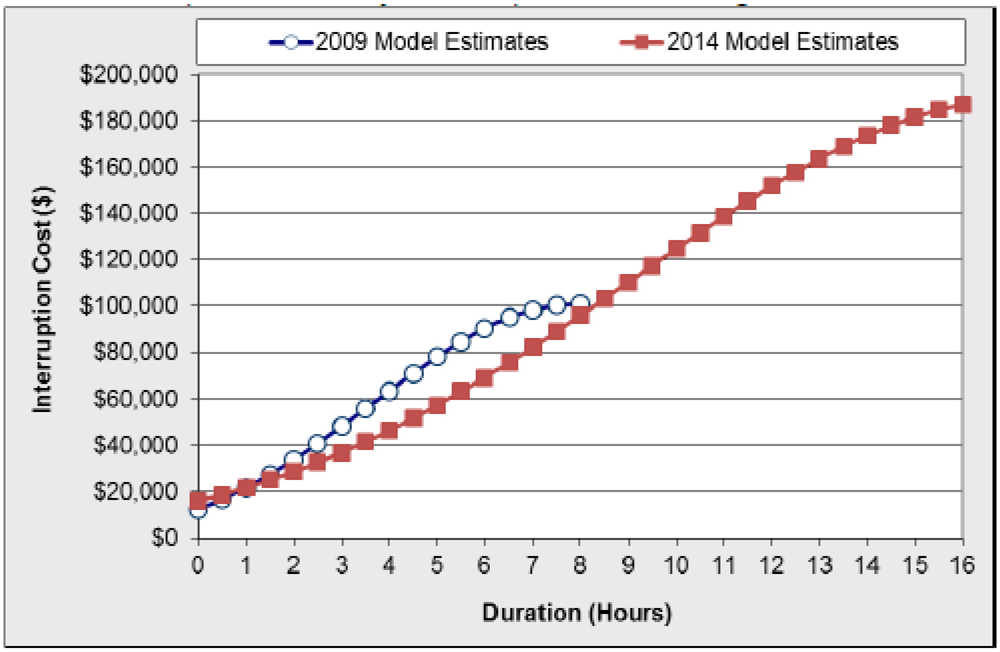

Figure 3: Estimated Customer Interruption Costs (2013 $) by Duration and Model - Summer Weekday Afternoon, Medium and Large C&I. Source: Figure 3-1 from LBNL Report.

The outage cost curve for Medium and Large C&I customers in the summer weekday afternoon, as a function of outage duration, exhibits S-curve characteristics, with outage costs appearing to increase at a slower rate after outage durations of approximately 12 hours.[41] A linear interpolation such as that used by the Company could potentially overstate outage costs for long-duration outages, which could have a significant impact on the CBA results. For example, $1.56 billion in customer reliability benefits in the LDI/HIS CBA come from quantifying long-term MED outages, representing

[41] The same trend is exhibited by Small C&I customers (see LBNL Report, figure 4-1) and, to a lesser extent, Residential customers (see LBNL Report, figure 5-1).

84% of the total benefits quantified in the LDI/HIS CBA and 20% of the total benefits quantified across all GIP CBAs.

Q. IS IT THE PUBLIC STAFF'S POSITION THAT OUTAGES LONGER THAN 16 HOURS DO NOT HAVE A COST TO CUSTOMERS?

A. No. Clearly, outages of a sustained duration have costs imposed on customers. However, I have concerns that the methodology used by the Company to estimate those costs, which the authors of the LBNL Report decline to estimate, may actually overstate the cost to customers. I recommend that outage costs for events lasting longer than 24 hours should be either validated by the Company through surveys, or reduced by some reasonable factor.

Q. IS IT POSSIBLE THAT THE OUTAGE COSTS IN THE LBNL REPORT COULD BE INACCURATE DUE TO THE UNDERLYING DATA?

A. Yes. The authors of the report acknowledge that the data used in their analysis came from interruption cost data studies performed by individual utilities; these utilities performed their study in such a way as to "focus on periods of time when interruptions were more problematic for that region."[42] Since each region has different outage distributions (by season and time of day), a bias in the timing of outages studied from a particular region could skew the results. For example, a southwestern utility might structure its

[42] 2009 LBNL Report at 48, Thomas Exhibit 6.

WTP surveys to focus on outages during the hot summer months when customers are most likely to highly value reliable power; or a Midwestern utility facing pressure to keep C&I rates low might focus on the cost of outages to those customers at the expense of residential customers.

Q. WHAT IMPACT MIGHT THIS HAVE ON OUTAGE COSTS IN THE LBNL REPORT?

A. In both cases, the WTP surveys might return higher outage costs than if they had been structured to cover all customers and all times of day. The effects of this bias could be reduced if a significant portion of the utility study data was provided from utilities with customer and regional characteristics similar to the Company's jurisdictions; but without the underlying studies, it is impossible to understand how this bias might affect the results.

In addition, the model uses national averages that include significant manufacturing customers, which are "more likely to incur costs than non-manufacturing industry customers."[43] DEC reported a significantly lower share of its C&I customers as manufacturing than the ICE Calculator default values. Thus, high interruption cost estimates for C&I customers in the LBNL Report may be influenced by the costs reported by manufacturing customers in other areas of the country.

[43] LBNL Report at 28.

Q. WHICH UTILITIES PROVIDED INTERRUPTION COST SURVEY DATA TO LBNL FOR PURPOSES OF THIS STUDY?

A. The LBNL Report does not provide details on individual utilities that conducted each study, but classifies them into regions. The LBNL Report includes 34 different datasets, from 15 interruption cost surveys, fielded by 10 different utility companies between 1989 and 2012.[44] Of the 10 utility companies, three were from the Southeast, one was from the Midwest, and five were from the southwest, west, or northwest. No studies from the mid-Atlantic or northeast were included, which the authors flag as a limitation of the study.

Q. DID DEC PROVIDE ANY INTERRUPTION COST DATA TO THE LBNL STUDY?

A. Interestingly, the 2009 LBNL Report lists some utilities that provided interruption cost surveys, which includes Duke Energy (the jurisdiction is not mentioned) and Cinergy (now Duke Energy Ohio).[45] Based upon discovery requests in this proceeding, the Public Staff has confirmed that DEC provided data in 1997 as Duke Energy, prior to the Cinergy and Progress mergers; however, the Company does not have access to the data that was provided to LBNL. The Company stated that due to the existence

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[44] *Id.* at 16.

[45] Other contribution electric utilities include Bonneville Power Administration, Mid America Power, Pacific Gas and Electric Company, Puget Sound Energy, Salt River Project, Southern California Edison, and Southern Company. See 2009 LBNL Report at i.

of the ICE Calculator and the LBNL Reports, it does not see value in conducting its own interruption cost study. It should be noted that of all the individual observations in the dataset, approximately 33% come from the southeastern utility studies (although southeastern is not explicitly defined in the LBNL Report).[46]

Q. YOU PREVIOUSLY MENTIONED THAT THE INTERRUPTION COST DATA USED BY THE COMPANY IS A NATIONAL AVERAGE. IS IT POSSIBLE TO ESTIMATE INTERRUPTION COSTS SPECIFIC FOR DEC, USING THIS STUDY'S REGRESSION MODELS?

A. Yes. Using the previously mentioned ICE Calculator, I was able to estimate the outage costs using input variables specific to DEC's North Carolina territory.[47] Generally, the input of DEC-specific values yielded higher outage costs per event, indicating that some characteristics of DEC's North Carolina service territory may result in outage costs that are higher than the national average. These differences were particularly large for Medium and Large C&I customers; for example, the LBNL Report estimates a per-event cost of $17,804 for a 1-hour outage; plugging in DEC-specific data to the

[46] Based on an analysis of Table 1-1 in the LBNL Report, at 16.

[47] These variables include the breakdown of customers among the three classes; daily outage distributions (morning, afternoon, evening, and night); seasonal outage distributions (summer and non-summer); and C&I sector breakdown (manufacturing, construction, and all other).

ICE Calculator yields an estimate of $61,686 for a 1-hour outage (2013 dollars).

Q. DO YOU KNOW WHAT IS DRIVING THIS VARIANCE?

A. It appears that the primary driver behind these significant differences lies in the usage per customer and the outage distribution for DEC's territory. DEC provided data indicating that the annual usage was significantly higher for its Small C&I and Medium and Large C&I customers than the averages used in the LBNL Report. When this variable was changed in the ICE Calculator, it significantly increased the cost per outage for Medium and Large C&I customers (from approximately $8,000 per outage to $77,000 per outage). In addition, DEC's outage distribution appears more skewed towards morning and afternoon than the national average, which increases Small C&I costs.

Q. HOW DOES THE PROPORTION OF C&I CUSTOMERS WITH BACKUP GENERATION AFFECT THEIR INTERRUPTION COSTS?

A. For Medium and Large C&I customers, it does not. The backup generation variable was removed from the final model,[48] and therefore even if 100% of the 72 Medium and Large C&I customers in DEC's North Carolina service

[48] See the final model interruption cost equation for Medium and Large C&I Customers, LBNL Report at 27.

territory had backup generation and power conditioning, it would not reduce the outage costs from the LBNL Report.[49]

Q. DOES THIS IMPLY THAT THE INTERRUPTION COST ESTIMATES THE COMPANY IS USING ARE ACTUALLY UNDERSTATED?

A. No. I do not believe this discovery indicates that DEC should be using higher interruption costs in its CBAs than it currently is. In fact, the enormous variance in interruption costs based upon the changes to certain input variables may indicate the model is extraordinarily sensitive, calling the C&I outage costs into question. It may be the case that characteristics specific to DEC's NC service territory yield slightly higher than average outage costs; it may also be the case that the model is overly sensitive to changes in outage distribution and annual energy usage variables. Without an updated interruption cost data survey that specifically covers the Company's territories, it is difficult to make a conclusion regarding the applicability of the ICE Calculator results.

Q. REGARDING THE CUSTOMER COSTS IN THE LBNL REPORT DATASET, DO YOU HAVE CONCERNS REGARDING THE NATURE OF THE CLAIMED CUSTOMER RELIABILITY BENEFITS?

A. Yes. As I have stated before, these customer reliability benefits are based on estimated economic losses, and are impossible for the Company to

[49] DEC indicated in discovery that it did not have this information, thus it is impossible to tell if there is more or less backup generation for C&I customers than the LBNL Report assumes.

validate. Some of the interruption cost surveys that underpin the LBNL Report are from WTP or WTA surveys. While there has been significant work over the years to improve WTP survey design, particularly in the marketing sector, one challenge is the so-called "hypothetical bias." [50] This bias refers to the difference between the survey respondent's answer and what they would actually pay in a real-life scenario. The authors of the 2009 LBNL report refer to this: "[we] cannot determine, prima facie, the biases inherent in such self-reports of cost estimates associated with hypothetical interruption scenarios."[51]

The 2009 LBNL Report states that all of the C&I interruption cost estimates were based upon direct cost estimation surveys, and all residential interruption cost estimates used in their meta-analysis were based upon WTP surveys.[52] It is impossible to gauge the extent or direction of the potential hypothetical bias in the LBNL Report's data. While the use of direct cost estimation surveys for C&I customers may reduce the hypothetical bias, it is unclear to what extent. I appreciate that these types of surveys have been used for decades to evaluate much more than electric reliability, and significant research has been done into improving the accuracy of the

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[50] There is significant controversy in the literature about the validity of the various WTP survey methods, and the relationship between WTP and WTA surveys. See the 2009 LBNL Report, at xviii, fn 3. Several academic papers are cited.

[51] 2009 LBNL Report at 6, Thomas Exhibit 6.

[52] *Id*. at 8. Some residential surveys include direct cost estimation or WTA surveys, but these were excluded from the meta-analysis.

response for intangible goods through clever questionnaire design. However, the fact remains that the actual reliability benefits customers realize are not likely to match those used in the GIP CBAs.

Q. HOW ARE CUSTOMER RELIABILITY BENEFITS ALLOCATED AMONG CUSTOMER CLASSES?

A. North Carolina customer reliability benefits are heavily skewed towards C&I customers. In all CBAs but for the Transmission H&R Line Projects,[53] customer reliability benefits are broken out by Residential, Small C&I, and Medium and Large C&I. For the $6 billion in reliability benefits, in DEC and DEP, that are assigned by class, $163 million (2.7%) accrue to Residential, $2.7 billion (43.8%) accrue to Small C&I, and $3.3 billion (53.5%) accrue to Medium and Large C&I. Reliability benefits for the two C&I classes alone comprise 64% of <u>all</u> GIP benefits, customer and operational.

Q. WHAT AMOUNT OF RELIABILITY BENEFITS WERE NOT ASSIGNED TO CUSTOMER CLASSES?

A. Approximately $2 billion in reliability benefits from Transmission H&R Line Projects were not assigned to customer classes. I recommend that the

[53] The reliability benefits for Transmission H&R Line Projects are broken into three categories depending on their source, as opposed to their beneficiary. These sources of transmission reliability benefits are: structure replacement, static line replacement, and conductor replacement. While it is reasonable that these benefits would be allocated among customer classes in a similar manner as other reliability benefits, I do not make that assumption for my calculations here.

Company modify its CBA to appropriately assign these reliability benefits to the customer classes benefitting from them.

Q. IS THE MAGNITUDE OF THE CLAIMED CUSTOMER RELIABILITY BENEFITS REALISTIC?

A. At first glance, the amount of reliability benefits claimed strains credulity. The Company provided data indicating that the GIP proposal will result in incremental improvements to SAIDI and SAIFI of approximately 16% and 15%, respectively.[54] DEC and DEP estimate $8 billion in reliability benefits across their North Carolina system, consisting of nearly $6 billion in C&I benefits, resulting from these improvements. The C&I benefits alone, if accurate, represents approximately 1% of North Carolina's 2018 gross domestic product.[55] For context, from 2014 to 2019, DEC saw SAIDI and SAIFI worsen by 34% and 22%, respectively. No evidence has been presented that this has had an impact on the North Carolina economy.

Q. DOES THE ALLOCATION OF THE CLAIMED CUSTOMER RELIABILITY BENEFITS RAISE ANY CONCERNS?

A. The allocation of GIP reliability benefits raises serious questions about equity in cost allocation and rate design. Claimed customer reliability

[54] Measured relative to DEC's 2019 North Carolina service quality. SAIDI was 174.7 minutes per customer and SAIFI was 1.0697 interruptions per customer.

[55] Department of Commerce, North Carolina Annual Economic Report: A Year in Review, 2018. Accessed at https://www.nccommerce.com/blog/2019/11/04/nc-annual-economic-report-gross-domestic-product

benefits for C&I customers are estimated at approximately $6 billion, representing over 97% of customer reliability benefits broken out by class, 73% of total customer reliability benefits,[56] and 64% of all GIP program benefits. Residential reliability benefits only comprise 1.8% of all GIP program benefits. While it can be assumed that all customers benefit equally from the other benefit categories (particularly operational benefits), customer reliability benefits comprise the vast majority of all claimed benefits and their allocation has an enormous impact on the allocation of total GIP benefits.

In addition, certain programs, such as SOG, have the potential to provide significant reliability benefits, but only to those selected circuits on which it is deployed; nevertheless, costs will be recovered from all ratepayers. This was a concern identified by the Commission when it rejected the Company's proposed Grid Reliability and Resiliency Rider.[57]

Q. HOW DOES THE ALLOCATION OF RELIABILITY BENEFITS COMPARE TO HOW GIP COSTS WILL BE ALLOCATED?

A. If there is no new allocation factor proposed for GIP investments, all GIP costs are expected to be allocated among customer classes according to the allocation factors that have historically been used for T&D expenditures.

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[56] This includes the approximately $2 billion in customer reliability benefits that the Company has not assigned to customer classes.

[57] See the Commission's *Order Accepting Stipulation, Deciding Contested Issues, And Requiring Revenue Reduction* in Docket No. E-7 Sub 1146, at 147.

Figure 4 below presents the allocation of customer reliability benefits next to the traditional cost allocation of T&D investments from DEC's Cost of Service Study (COSS). Public Staff witness McLawhorn discusses COSS methodologies in his direct testimony.

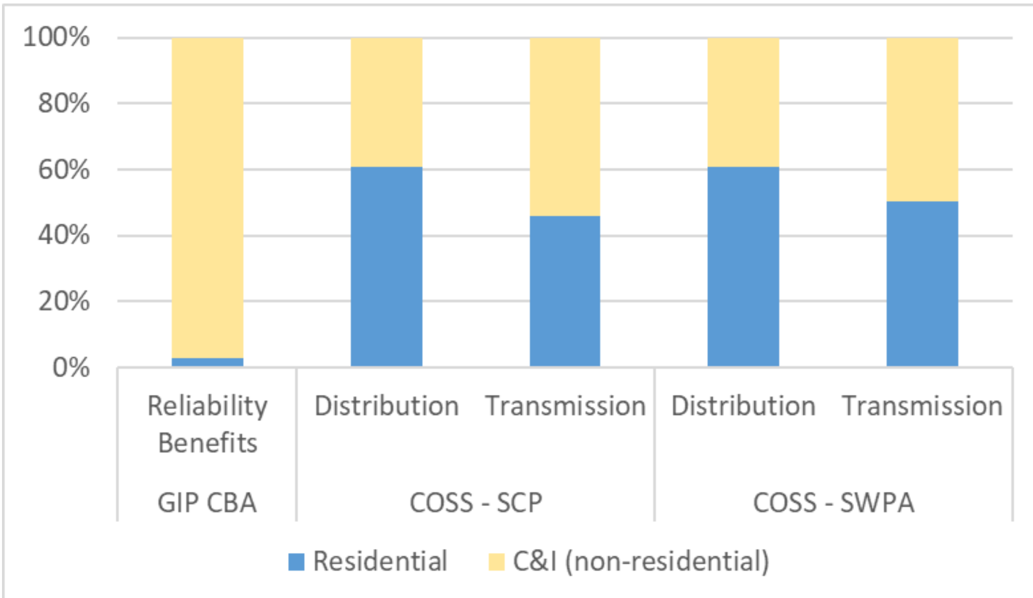

Figure 4: Allocation of assigned customer reliability benefits and T&D class factors for cost allocation.

Distribution investments are typically allocated using a non-coincident peak allocation factor; for residential customers, the jurisdictional factor is approximately 45% and the class factor is approximately 61%.[58] Transmission investments are allocated on a transmission demand

[58] This number reflects the primary distribution allocation factor found in DEC's Cost of Service Study (See E-1 Item 45a).

allocation factor; for residential customers, the jurisdictional factor is approximately 24% and the class factor is approximately 46%.[59]

Q. DO YOU HAVE ANY RECOMMENDATIONS REGARDING THE ALLOCATION OF GIP COSTS?

A. At this time, I am not recommending that GIP costs be allocated differently than traditional T&D investments. However, I do believe the issue is ripe for Commission consideration, particularly in light of the Commission's *Order Approving Revised Interconnection Standard and Requiring Reports and Testimony* in Docket No. E-100 Sub 101, which requires the Company to "file testimony in [its] next general rate case application[] regarding the benefits that distributed generators are receiving from the Utility's System, estimating their share of related costs, and providing options for recovering those costs from distributed generators." If the Commission agrees that this issue merits further study, DEC's and DEP's planned study of the impact of distributed generation could be expanded to require an evaluation of possible alternative methods of allocating GIP investments that provide primarily reliability benefits.

[59] This number reflects the transmission demand allocation factor found in DEC's Cost of Service Study (See E-1 Item 45a). Public Staff witness McLawhorn has proposed utilizing a different cost allocation methodology (SWPA); the corresponding residential jurisdictional transmission allocation factor is 26.7%; the residential retail transmission allocation factor is 50.5%.

D. Other Customer Benefits

Q. STEPPING BACK FROM THE LBNL REPORT, CAN YOU SPEAK TO THE OTHER CATEGORIES OF CUSTOMER BENEFITS THAT THE COMPANY HAS QUANTIFIED?

A. Yes. The other two categories are CO_2 emission reductions and DER Enablement. The former is included in programs such as IVVC and SOG, which lead to reduced overall generation and thus lower CO_2 emissions. However, it is important to note that CO_2 emissions currently do not have a real cost to the utility, and while DEC typically includes a future CO_2 price in its IRPs, it does not include CO_2 prices when it calculates its avoided energy rates for the purpose of paying PURPA contracts. The CO_2 emission reduction benefits are relatively minor ($135 million, or 1.5% of total GIP program benefits), and the effects of removing them from the three programs which include them are shown below in Table 5. It should be noted that the BCR for the IVVC program is reduced to 1.0 from 1.2 after removing the CO_2 benefit.

Table 5: Effect of removing CO2 emission reduction benefits from select GIP CBAs

Program (NC only)	**Total Benefits ($M)**	**CO_2 Benefits ($M)**	**BCR w/ CO_2**	**BCR w/o CO_2**
IVVC (DEC)	$ 546	$ 86.0	1.2	1.0
DSDR (IVVC in DEP)	$ 232	$ 49.7	35.3	27.8
SOG (DEC and DEP)	$ 2,088	$ 0.056	2.7	2.7
Total	**$ 2,868**	**$ 135.8**		

E. <u>Operational Benefits</u>

Q. LET'S TURN NOW TO THE OPERATIONAL BENEFITS THAT THE COMPANY HAS QUANTIFIED. CAN YOU DESCRIBE THEIR SOURCES AND MAGNITUDE?

A. Yes. Generally, I do not have significant concerns with the claimed operational benefits of each program. Total operational benefits from all GIP CBAs are estimated at $942 million, summarized in Figure 5 below (all figures are NPV over the program life, for DEC and DEP, North Carolina only). The majority of these benefits (59%) fall into the fuel and related category, benefits which largely are derived from lower overall electricity consumption due to lower distribution circuit voltages enabled by IVVC and SOG. A related benefit is avoided capacity, comprising approximately 12% of total operational benefits, which reflects the reduced need for future capacity due to IVVC and SOG, both of which enable emergency voltage reductions in peak periods.

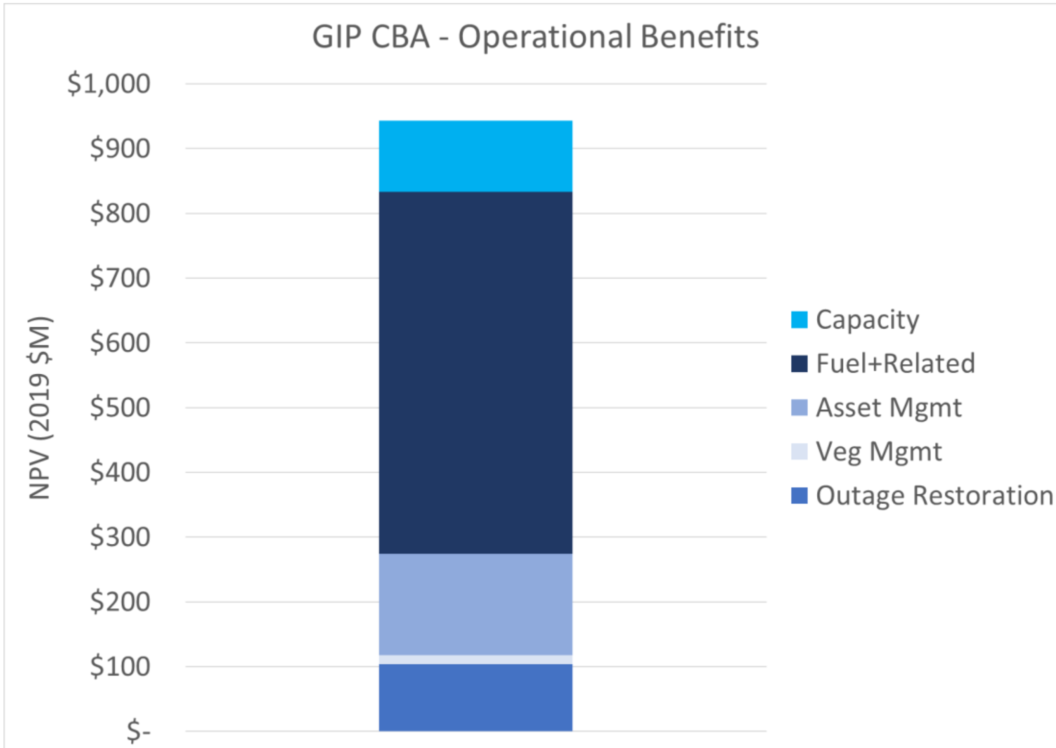

Figure 5: Operational Benefits from GIP CBAs (DEC and DEP, NC Only)

The next largest benefit category is the asset management benefit. This benefit reflects lower future asset replacement costs due to accelerated replacement planned by certain GIP programs, primarily Transmission H&R, Transmission Transformer Bank Replacements, T&D Oil Breaker replacements, and TUG. This benefit is estimated at $156 million, comprising 17% of total operational benefits. While other jurisdictions have raised concerns about this benefit category,[60] I believe that the Company's CBA takes into account both the time value of money and escalation rates of capital costs, two opposing factors that determine this benefit.

The reduction in outage restoration costs is an ancillary benefit to the reduction in outages projected from GIP; at $103 million, it comprises 11% of total operational benefits. The only programs that included this benefit are TUG and DTR, as other programs that increase reliability (SOG, T&D Oil Breaker Replacement, Transformer Bank Replacements) do not necessarily reduce the number of times the Company must dispatch a repair crew. These estimates are based upon historical costs of outage repairs divided by the number of outages requiring repair crews.

Finally, the TUG CBA includes a reduction in vegetation management of $13 million, reflecting the reduced need to trim vegetation where distribution lines have been buried. This is a minor benefit, comprising only 1% of total GIP operational benefits and only 1% of total TUG benefits.

Q. IF REALIZED, WOULD THESE BENEFITS BE LIKELY TO CAUSE LOWER RATES FOR RATEPAYERS?

A. Generally, yes. With the exception of avoided capacity, all of these benefit categories directly reflect reductions in operating expenses or rate base

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[60] Virginia Commission Staff testified that the analogous benefit claimed by VEPCo should be removed. See VA Docket No. PUR-2019-00154, Prefiled Staff Testimony, Volume II, Part B, Testimony of Curt Volkmann, at 18-19.

because of GIP programs. Avoided capacity has been quantified similarly to the method that is used for setting the avoided capacity rate for small power producers selling their output to the Company under avoided cost rates pursuant to N.C. Gen Stat § 62-156; as such, it reflects the programs' contribution to reducing the need for future capacity additions.

Q. DO YOU HAVE ANY CONCERNS WITH THE OPERATIONAL BENEFITS?

A. Yes, I have concerns with the addition of avoided capacity benefits. First, the Company calculates the avoided capacity due to peak reduction from GIP programs. In the SOG CBA, this avoided capacity is 'grossed up' twice: by 4% to account for system losses; and again by 6%, which the Company claims reflects the additional capacity avoided due to Planning Reserve Margin Requirements (PRMR). The Company includes the PRMR gross up to account for the fact that they must build more capacity than peak demand due to uncertainty in load forecasts and weather.

Q. DO YOU AGREE WITH THE COMPANY'S GROSS UP FACTORS FOR AVOIDED CAPACITY?

A. I believe that the system loss gross-up is appropriate, as the avoided capacity payments to Qualified Facilities (QFs) calculated in Docket No. E-

100, Sub 158 (Sub 158) also includes a gross-up factor for system losses.[61] However, I believe the PRMR gross-up factor is inappropriate, for two reasons. First, in the IRP process, the Company already includes the reserve margin in determining the amount and timing of new generation additions. Thus, including it here effectively double-counts the impact of the reserve margin. Second, QFs who provide capacity to the utility do not receive a similar PRMR gross-up factor; I believe that the same Commission approved avoided costs should be used by DEC when evaluating new programs as is paid to QFs. Removing the PRMR factor would reduce avoided capacity benefits of SOG by approximately $4.7 million, or 19%.

Q. DO YOU BELIEVE THAT THE COMPANY HAS OVERSTATED AVOIDED CAPACITY BENEFITS IN OTHER WAYS?

A. Yes. The Company includes avoided capacity benefits in the first year following program deployment, despite the fact that DEC's 2019 IRP shows the first year of capacity need as 2026.[62] This is contrary to the Company's approved practice of awarding avoided capacity payments only beginning in the year where the Company's IRP shows a demonstrated capacity need.

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[61] The gross up factor for distribution-connected QFs on the DEC system is less than 4%. The small difference is relatively minor and likely reflects system losses that may not be included in the avoided cost calculations (i.e., losses between transmission and generation).

[62] See Docket No. E-100 Sub 157, Duke Energy Carolinas 2019 Integrated Resource Plan Update Report at 69. While this IRP has not yet been accepted by the Commission, the Public Staff notes it is the first to include a specific statement of need, and is thus an appropriate benchmark. The Public Staff believes that the Company should utilize the most recently accepted IRP in determining avoided capacity benefits in future program evaluations.

Including avoided capacity benefits in years 2019 through 2025, where no capacity is actually avoided, overstates the avoided capacity benefit by approximately $25 million in IVVC and $5.4 million in SOG. The effect of removing capacity in years 2019 through 2025, and removing the PRMR gross-up factor, is shown below in Table 6. This has a small effect on each program's BCR; however, taken in conjunction with removing the CO_2 benefit as previously discussed, the IVVC BCR falls to 0.9.

Table 6: Avoided Capacity in SOG and IVVC

Program	**Metric**	**As Filed**	**'19-'25 Capacity Removed**	**'19-'25 Capacity Removed, No 6% Gross-Up**
IVVC (DEC-NC)	Avoided Capacity Benefits ($M)	$83.9	$58.7	$58.7
	BCR	1.2	1.1	1.1
SOG (DEC-NC)	Avoided Capacity Benefits ($M)	$25.2	$19.9	$16.2
	BCR	2.49	2.48	2.47
Total Avoided Capacity Benefits ($M)		$109.1	$78.6	$74.9
Total Recommended Reduction in Avoided Capacity Benefits (M$)			**($30.6)**	**($34.3)**

Q. HAS THE PUBLIC STAFF TAKEN A SIMILAR POSITION ON AVOIDED CAPACITY BENEFITS IN ANY OTHER PROCEEDING?

A. Yes. In past avoided cost proceedings, the Public Staff has taken the position that "it is appropriate for utilities to make a capacity payment to QFs only when additional capacity is needed on the system."[63] In past Demand Side Management (DSM) and Energy Efficiency (EE) cost recovery proceedings, we have taken the position that an avoided capacity benefit should not be included in years without a need for capacity.[64] Generally, our position has been that capacity (from new generation or capacity reductions) provided in years in which there is no capacity need cannot provide avoided capacity benefits to ratepayers. The Commission has declined to adopt the Public Staff's recommendations with respect to avoided capacity benefits from legacy DSM and EE programs.[65]

Q. ARE THERE ANY DIFFERENCES BETWEEN GIP PROGRAMS AND DSM AND EE PROGRAMS?

A. Yes. For one, the energy and capacity savings from GIP programs are not currently included in the Company's long-term resource plan. GIP programs are new, incremental programs, and do not have the same characteristics

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[63] See Docket No. E-100, Sub 148, Testimony of John R. Hinton at 13.

[64] See Docket No. E-7, Sub 1164, Testimony of Eric Williams, at 7. See also Docket No. E-2, Sub 1174, Testimony of John R. Hinton, at 6.

[65] See Docket No. E-2, Sub 1174, *Order Approving DSM/EEE Rider and Requiring Filing of Customer Notice*, Finding of Fact 12. See also Docket No. E-7, Sub 1164, *Order Approving DSM/EEE Rider and Requiring Filing of Customer Notice*, Finding of Fact 16.

as legacy DSM and EE programs. This is a significant difference, because in arguing for avoided capacity benefits in all years for legacy DSM and EE programs, DEC argues that existing DSM and EE programs are embedded in their resource plans, stating, "if the Company's legacy DSM programs were closed tomorrow, there would be an immediate need for new capacity."[66] For new programs not embedded in the resource plans, DEC stated that

> [T]he incremental impacts from those programs could be treated the same as the incremental QF resources in the IRP. This means that, consistent with how "new" QFs with LEOs after November 15, 2016 are treated, the Company would ascribe a zero value of capacity for the years 2019 to 2022 for these other EE programs.[67]

All of the GIP programs will be introduced after the implementation of House Bill 589, which established the calculation of avoided capacity in years without a projected capacity need in N.C.G.S. § 62-156(b)(3). Thus, these programs will be "incremental" rather than "embedded' in the resource plans and should not be ascribed capacity benefits in years when the utility does not need capacity. The utility has supported this position in the past, stating that "[it] is wholly consistent to treat avoided capacity value for existing EE the same way existing QFs are treated with respect to capacity valuation,

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[66] See Docket No. E-7, Sub 1164, Rebuttal Testimony of witnesses Timothy J. Duff and Richard G. Stevie, Ph.D, at 20.

[67] *Id*.

while treating incremental EE capacity value in the same manner which incremental solar QF capacity value is treated."[68]

Q. DOES THE PUBLIC STAFF RECOMMEND REMOVING AVOIDED CAPACITY BENEFITS FOR GIP PROGRAMS THAT REDUCE PEAK DEMAND IN YEARS PRIOR TO THE FIRST YEAR IN WHICH DEC'S IRP INDICATES A PROJECTED CAPACITY NEED?

A. Yes. The Public Staff believes the proposed GIP programs and DSM and EE programs are distinguishable, and we recommend that any avoided capacity benefits quantified in years prior to the first capacity need be removed from the GIP CBAs. Notably, the investments in GIP that are estimated to provide avoided capacity benefits are new programs that are not included in the IRP. As such, the capacity reductions provided by these programs are not able to reduce capacity in years in which there is no capacity need to avoid.

III. GIP Program Costs

Q. WHAT COSTS ARE CONSIDERED IN THE GIP CBAs?

A. The CBAs include capital costs and operations and maintenance (O&M) costs for certain projects. Capital costs describe electronic devices, equipment, hardware, and software systems that would generally be included in the Company's rate base. For devices that have an assumed

[68] See DEC response to PS DR 14-3 in Docket No. E-7, Sub 1164, attached as Exhibit 7.

life of less than the CBA evaluation period, replacement costs are included in future years. O&M costs are those costs associated with maintaining the equipment or systems that have been deployed, and would be booked as expenses by the Company.

As illustrated in Figure 1, the vast majority (96%) of costs in the GIP CBAs are capital, with the remaining 4% consisting of O&M. Table 6 below summarizes the costs included in the individual GIP CBAs, along with reasons why certain programs had O&M costs are excluded. When O&M costs are not expected to change as a result of a GIP program, these costs are excluded from the comparative analysis.

Table 6: Cost categories included in the GIP CBAs. "Yes" indicates this cost is quantified in the GIP CBA.

GIP Program	Capital Costs	O&M Costs
Self-Optimizing Grid	Yes	Yes
Integrated Volt/VAR Control	Yes	Yes
DSDR	Yes	Yes
T-Transformer Bank Replacement	Yes	No – no change in O&M expected due to accelerated replacements
Distribution Transformer Retrofit	Yes	Yes
Transmission H&R	Yes	No – O&M costs assumed to be the same before and after project
Oil Breaker Replacements	Yes	No – O&M costs assumed to be similar for oil breakers and gas / vacuum breakers
Transmission Line Projects (DEC)	Yes	No – O&M costs assumed to be the same before and after project
Transmission Line Projects (DEP)	Yes	No – O&M costs assumed to be the same before and after project
LDI / HIS	Yes	No – O&M costs assumed to be the same before and after project
Targeted Undergrounding	Yes	Yes

Q. HOW DOES THE COMPANY ESTIMATE CAPITAL COSTS?

A. The methodology for estimating capital and O&M costs vary by CBA; some cost estimates are likely to be more accurate than others. As described in the joint testimony of Public Staff witnesses Tommy Williamson and David Williamson, some of the GIP programs consist of accelerated deployments of programs already underway. For example, DEC and DEP are both already proactively[69] replacing oil circuit breakers with gas and vacuum circuit breakers at an average of 70-100 replacements each per year. The T&D Oil Breaker Replacement program proposed in GIP would enable DEC and DEP to each proactively replace 120-160 circuit breakers per year.[70] This is true for several other GIP programs, including Transformer Bank Replacements, DTR, TUG, and Transmission H&R. For these CBAs, the cost estimates are expected to be relatively accurate, as the Company utilizes actual cost data from historical projects in its jurisdiction.

Q. HOW DOES THE COMPANY ESTIMATE CAPITAL COSTS FOR NEW PROGRAMS?

A. For new programs that are not currently being deployed, such as SOG, IVVC, and the DSDR conversion in DEP, the Company uses cost estimation methods. Generally, the Company has indicated it uses cost estimate methodologies defined by the American Association of Cost Engineering (AACE), which recommends practices for estimating engineering,

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[69] A proactive replacement is a replacement completed before the unit in the field fails, avoiding the outages associated with an unexpected failure.

[70] The CBA for the Oil Breaker Replacement program anticipates an average of 164 breakers replaced per year in DEC; thus, the CBA appears to analyze the entire program, not the incremental acceleration proposed in GIP.

procurement, and construction processes. Depending on factors such as the development stage of the project, the purpose of the estimate, and the estimating methodology used, AACE defines five estimate classes from Class 1 (most accurate) to Class 5 (least accurate).[71]

SOG capital costs include four components: (1) switch automation and circuit segmentation, (2) circuit capacity and connectivity, (3) substation bank capacity, and (4) control devices and advanced distribution management systems. DEC has indicated that the SOG CBA costs are Class 4 and were generated without cost estimators visiting actual sites for SOG deployment. Capital costs were calculated by first generating a high-level estimate of the number of devices to be deployed and the number of circuit miles to be upgraded at the circuit level; per-unit costs based on a combination of historical costs (i.e., for upgrading circuit capacity) and known or quoted (i.e., for automated switches) were then applied to those estimates. The AACE standard states that the expected accuracy range of a Class 4 estimate is -15% to -30% on the low side, and +20% to +50% on the high side. These costs are expected to change as engineers visit the field and project scope is refined.

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[71] A sample copy of AACE International standard "18R-97: Cost Estimate Classification System – As Applied in Engineering, Procurement, and Construction for the Process Industries" was shared with the Public Staff as part of discovery.

IVVC (and the DSDR conversion in DEP) capital costs are broken into several broad categories, including transmission, telecom, information technology, distribution, and staff support. DEC states that these are Class 5 estimates, supported by a detailed evaluation of materials, labor, overhead, and contingencies. The AACE standard states that the expected accuracy range of a Class 5 estimate is -20% to -50% on the low side, and +30% to +100% on the high side.

Q. ARE YOU AWARE OF ANY CHANGES TO CAPITAL COST ESTIMATES SINCE THE COMPANY FILED ITS APPLICATION?

A. No. To the Public Staff's knowledge, DEC has not performed any updated cost estimates for any GIP programs since September 30, 2019. However, DEC has closed several Transmission H&R Line Projects to Plant in Service. As shown in Table 7 below, of the four projects closed to plant and included in this proceeding, capital cost overruns reached 20%.

Table 7: CBA capital cost estimates compared to actual capital expenditures for Transmission Line Projects closed to plant.

Project Name	CBA Cost Estimate ($M)	Actual Capital Closed to Plant	Delta
Duke Univ 44kV Undergnd System	$ 3.06	$ 4.79	56%
Rockford Level Cr 44 kV Ln Rbld	$ 5.19	$ 5.73	10%
Cabin Creek – Stevens Tap Rebld	$ 4.08	$4.63	14%
Capps–Hendersonville Line Rbld	$ 7.37	$ 8.52	16%
Total	**$19.7**	**$23.7**	**20%**

Q. YOU MENTIONED EARLIER THAT THE COMPANY DID NOT PROVIDE ANY SENSITIVITY ANALYSES. HAS THE PUBLIC STAFF PERFORMED SUCH AN ANALYSIS OF CAPITAL COSTS ON ANY GIP CBAs?

A. Yes. Presented below are capital cost sensitivities for the two most capital intensive GIP programs, SOG and IVVC. Table 8 summarizes a sensitivity analysis of the SOG program (considered over both DEC and DEP), showing that the program retains a net benefit even if capital costs double from initial estimates (refer to the “Benefits as Filed” columns). However, to demonstrate how sensitivity analyses must consider multiple assumptions, I also show the same capital cost sensitivity results for SOG if momentary outages are accounted for, as I have discussed previously in my testimony. It that situation, capital cost increases can quickly eliminate net benefits to ratepayers (refer to the "Momentary Outages Accounted For" columns).

Table 8: Sensitivity Analysis of SOG (DEC-NC). Class estimates from American Association of Cost Engineering standard 18R-97. Higher classes indicate lower estimate maturity level.

Capital Cost Variance	Benefits As Filed		Momentary Outages Accounted For	
	BCR	Capital Cost NPV ($M)	BCR	Capital Cost NPV ($M)
-50%	4.9	$ 222.5	2.9	$ 222.5
-30%	3.5	$ 311.5	2.1	$ 311.5
0% (Baseline)	**2.5**	**$ 445.0**	**1.5**	**$ 445.0**
50%	1.7	$ 667.5	1.0	$ 667.5
100%	1.3	$ 890.0	0.7	$ 890.0

The CBA for IVVC is highly influenced by capital cost increases. Table 9 below shows the same capital cost sensitivities as were performed for SOG for two scenarios: as originally filed and without CO_2 benefits, per my recommendations discussed herein. If CO_2 benefits are included, a 50% increase to capital costs will result in a 0.8 BCR; capital costs could increase by approximately 25% without the program BCR falling below 1.0. However, if CO_2 benefits are removed, any increase to costs will cause the BCR to fall below 1.0. If costs are not kept under control, the deployment of IVVC will not be to the ratepayers' benefit. As IVVC represents approximately 50% of the GIP portfolio's total operational benefits, a reduction in program scope or significant cost overruns threatens the future rate reductions that customers may actually realize from GIP.

Table 9: Sensitivity Analysis of Capital Costs with and without CO_2 benefits for IVVC (DEC-NC).

Capital Cost Variance	Benefits As Filed		CO_2 Benefits Removed	
	BCR	**Capital Cost NPV ($M)**	**BCR**	**Capital Cost NPV ($M)**
-50%	2.1	$ 209.7	1.8	$ 209.7
-30%	1.6	$ 293.5	1.3	$ 293.5
0% (Baseline)	**1.2**	**$ 419.3**	**1.0**	**$ 419.3**
50%	0.8	$ 629.0	0.7	$ 629.0
100%	0.6	$ 838.6	0.5	$ 838.6

Q. ARE THERE ANY COSTS FROM GIP THAT MAY NOT BE INCLUDED IN THESE ANALYSES?

A. Possibly. One area that was not considered in the GIP CBAs was the potential impact on materials and supplies (M&S) inventory and the associated carrying costs. To illustrate how a GIP program may impact M&S inventory, consider the Oil Breaker Replacement program. If gas and vacuum circuit breakers are more expensive to carry on the Company's books than oil circuit breakers, holding the same number of spare circuit breakers will increase M&S inventory, assuming similar reliability and lifetime characteristics.[72] This could impact customer rates and the cost-effectiveness of certain CBA programs. However, I have not quantified this potential impact and expect that it is relatively minor compared to the costs of the entire GIP proposal.

V. Recommendations

Q. ARE YOU MAKING ANY RECOMMENDATIONS TO THE COMMISSION?

A. Yes. I have several recommendations, based upon my review of the Company's CBAs.

1. To assist in the evaluation of GIP program benefits and cost recovery, the Company should be required to track and annually report the progress of GIP implementation throughout the 3-year plan and beyond, including actual expenditures, changes in program scope, and Evaluation, Measurement, and Verification of claimed benefits.[73] In addition, costs related to GIP should be booked, tracked, and reported separately from other T&D investments.
2. The Company should perform CBAs for some GIP programs that were not evaluated for cost-effectiveness, such as Distribution

[72] The Company, in its CBAs, assumed that gas and vacuum breakers have similar lifetimes and failure rates as oil breakers.

[73] These reports might take a similar format as the annual reports DEP files for its DSDR program in Docket No. E-2, Sub 926.

Automation, DER Dispatch, and any others that the Commission deems appropriate.

3. The Company should be required to file sensitivity analyses of its CBAs, which should explore variations in multiple input variables. These sensitivity analyses should include, at a minimum, capital costs, O&M costs, fuel and related benefits, and customer interruption costs, along with any other parameters the Commission deems appropriate. These analyses should discuss the risk of benefit shortfalls and cost overruns, and provide plans on how GIP implementation will be modified if either occurs.

4. In light of the limitations of the LBNL Report, the Company should consider if there is value in conducting an interruption cost study in the Carolinas that would more accurately reflect interruption costs experienced by its customers than the LBNL Report. This study could be conducted with the cooperation of LBNL, with a new region-specific interruption cost model being the ultimate goal.

5. The Company should remove or modify certain benefits from its CBAs, including long-term reliability benefits; CO_2 emission savings; avoided capacity PRMR gross-up; and avoided capacity in years where no capacity need is identified.

6. The Company should revise its Transmission H&R Line Projects CBAs to assign customer reliability benefits to customer classes.

7. The Company should revise its SOG CBAs to include the effect of momentary outages as a result of automatic circuit reconfiguration.
8. The Company should revise its SOG CBA to adjust the faults per mile variable, taking into account the expected reduction in vegetation-related outages resulting from the increased pace of vegetation management proposed in this proceeding.
9. The Company should consider the impact of GIP programs on costs not considered, such as M&S inventory, and factor those impacts (if any) into its CBAs.
10. The Commission and the Company should consider if changes to GIP cost allocations are warranted, in light of the benefit allocation discussed herein.

Q. CAN YOU SUMMARIZE THE IMPACT OF YOUR RECOMMENDATIONS ON THE COMPANY'S CBAs?

A. I have been able to estimate the impact of the following recommendations: (1) removal of CO_2 benefits; (2) reduction of avoided capacity benefits; (3) inclusion of momentary outages in SOG; and (4) reduction in the faults per mile used in SOG. I was unable to estimate the impact of other changes I have recommended, such as modifying baseline reliability to reflect the impact of VM in DTR and TUG, or modifying the cost per outage for outages longer than 24 hours. I have summarized the cumulative impact of four recommendations enumerated above in Table 10 below (only SOG and IVVC were changed).

Table 10: Summary of the impact of PS Recommendations.

Description	Benefits As Filed		Benefits with PS Recommendations	
	BCR	**% Customer Reliability Benefits**	**BCR**	**% Customer Reliability Benefits**
SOG	2.5	93%	**1.4**	**88%**
DTR	1.5	96%	1.5	96%
IVVC	1.2	0%	**0.9**	**0%**
Trans Line H&R	14.4	100%	14.4	100%
Transformer Bank Replacements	1.2	51%	1.2	51%
Oil Breaker Replacements	1.6	67%	1.6	67%
TUG	12.1	92%	12.1	92%
LDI / HIS	29.4	100%	29.4	100%

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

APPENDIX A

QUALIFICATIONS AND EXPERIENCE

JEFFREY T. THOMAS

I graduated from the University of Illinois Champaign-Urbana in 2009, earning a Bachelor of Science in General Engineering. Afterwards, I worked in various operations management roles for General Electric, United Technologies Corporation, and Danaher Corporation. Originally, a manufacturing and process engineer in GE's Operations Management and Leadership program, I eventually became a production supervisor, where I was responsible for the safety and productivity of a team of employees. I left manufacturing in 2015 to attend North Carolina State University, earning a Master of Science degree in Environmental Engineering. At NC State, I performed cost-benefit analysis evaluating smart grid components, such as solid-state transformers and grid edge devices, at the Future Renewable Energy Electricity Delivery and Management Systems Engineering Research Center. My master's thesis focused on electric power system modeling, capacity expansion planning, linear programming, and the effect of various state and national energy policies on North Carolina's generation portfolio and electricity costs. After obtaining my degree, I joined the Public Staff in November 2017. In my current role, I have filed testimony in avoided cost proceedings, general rate cases, and CPCN applications, and have been involved in the implementation of HB 589 programs, utility cost recovery, renewable energy program management, customer complaints, and other aspects of utility regulation.

Abbreviations List

AACE	American Association of Cost Engineering
ADMS	Advanced Distribution Management System
ALD	Automatic Lateral Device
AMI	Advanced Metering Infrastructure
BCR	Benefit Cost Ratio
C&I	Commercial and Industrial
CBA	Cost Benefit Analysis
CEMI-6	Customers Experiencing Multiple Interruptions
CI	Customer Interruptions
CIP	Critical Infrastructure Protection
CMI	Customer Minutes Interrupted
COSS	Cost of Service Study
CPUC	California Public Utilities Commission
DEC	Duke Energy Carolinas, LLC
DEP	Duke Energy Progress, LLC
DER	Distributed Energy Resource
DOE	Department of Energy
DR	Data Request
DRP	Distribution Resource Planning
DSM	Demand Side Management
DSPx	Next Generation Distribution System Platform
DTR	Distribution Transformer Retrofit
EDSH	Enterprise Distribution System Health
EE	Energy Efficiency
ET	Electric Transportation
GIP	Grid Improvement Plan
GRR	Grid Reliability and Resiliency (Rider)
H&R	Hardening and Resiliency
HRM	Health and Risk Monitoring
ICE	Interruption Cost Estimator
IRP	Integrated Resource Plan
ISOP	Integrated System Operations Planning
IVVC	Integrated Volt Var Control
LBNL	Lawrence Berkeley National Laboratory
LDI / HIS	Long Duration Impact / High Impact Sites
M&S	Materials and Supplies
MED	Major Event Day

NC	North Carolina
NERC	North American Reliability Corporation
O&M	Operations and Maintenance
OCB	Oil-filled Circuit Breakers
PFC	Power Forward Carolinas
PNNL	Pacific Northwest National Laboratory
PRMR	Planning Reserve Margin Requirement
PURPA	Public Utilities Regulatory Policies Act
QF	Qualified Facility
RESTORE	Regional Equipment Sharing for Transmission Outage Restoration
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCP	Summer Coincident Peak
SOG	Self-Optimizing Grid
SWPA	Summer/Winter Peak and Average
T&D	Transmission and Distribution
TMT	Targeted Management Tool
TUG	Targeted Undergrounding
UCT	Utility Cost Test
VEPCO	Virginia Electric and Power Company
VM	Vegetation Management
WTA	Willingness to Accept
WTP	Willingness to Pay

(Whereupon, the prefiled testimony of John R. Hinton and Appendix A was copied into the record as if given orally from the stand. The confidential testimony was filed under seal.)

(Whereupon, Public Staff Hinton Exhibits 1-5 were admitted into evidence. Public Staff Hinton Exhibits 3 and 5 are corrected exhibits filed 2/24/2000. Public Staff Hinton Exhibit 1-2 were filed under seal.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1214

In the Matter of		TESTIMONY OF
Application of Duke Energy Carolina,	)	JOHN R. HINTON
for Adjustment of Rates and Charges	)	PUBLIC STAFF – NORTH
Applicable to Electric Utility Service in	)	CAROLINA UTILITIES
North Carolina	)	COMMISSION

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-7, SUB 1214

Testimony of John R. Hinton
On Behalf of the Public Staff
North Carolina Utilities Commission
February 18, 2020

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

A. My name is John R. Hinton. I am Director of the Economic Research Division of the Public Staff of the North Carolina Utilities Commission. My business address is 430 North Salisbury Street, Raleigh, North Carolina 27603.

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

A. The purpose of my testimony is to address concerns raised by Company witnesses Stephen De May and Karl W. Newlin with regards to the credit metrics and the risk of a downgrade of Duke Energy Carolinas' (Company or DEC) debt rating. Furthermore, I address how the Public Staff's proposals on the Company's flowback of unprotected excess deferred income taxes (EDIT) impacts the Company's credit metrics.

Q. HAS THE COMPANY PROVIDED THE PUBLIC STAFF WITH THE PROJECTED CREDIT METRICS UNDER FUTURE SCENARIOS: A SCENARIO WITH THE PUBLIC STAFF'S TAX REFUND PROPOSAL FOR UNPROTECTED EDIT OVER A 20-YEAR PERIOD AS PROPOSED IN THIS PROCEEDING?

A. Yes. The Company provided confidential data for seven years of historical and projected Cash Funds from Operations over total debt (FFO/Debt)[1] ratios (2017 and 2018 are based on historical data; whereas, 2019-2023 are based on projected data) where the EDIT is assumed to be returned over a twenty-year period as originally proposed by the Company. The FFO/Debt credit metrics are attached as Confidential Exhibit JRH-1. The Exhibit also reflects a 3-year moving average of the FFO/Debt metric as employed by Moody's with **[BEGIN CONFIDENTIAL]** [redacted]. **[END CONFIDENTIAL]**

Q. DID THE COMPANY ALSO PREPARE CREDIT METRICS OVER AN ALTERNATIVE FIVE-YEAR PERIOD?

A. Yes. In response to a confidential data request, attached as Confidential Exhibit JRH-2, the Company provided the Public Staff with a requested FFO/Debt analysis assuming the EDIT is refunded

[1] The actual credit metric by Moody's is referred to as Cash Flow from Operations excluding changes in working capital over total debt.

over a five-year period. The rest of my testimony is based on a five-year refund period for the EDIT.

Q. WAS THE PUBLIC STAFF PROVIDED WITH SUPPORT FOR THE PROJECTED CASH FLOW AND DEBT DATA INCORPORATED IN THE CREDIT METRICS?

A. Yes. The Public Staff was provided with several assumptions that are somewhat general in nature; such as, **[BEGIN CONFIDENTIAL]** [redacted]. **[END CONFIDENTIAL]**

Q. WHAT DID YOU CONCLUDE FROM THE PROJECTED FFO/DEBT RATIOS THAT REFLECT A FIVE-YEAR FLOWBACK OF EDIT AS RECOMMENDED BY THE PUBLIC STAFF?

A. The three-year moving average of DEC's FFO/Debt ratio shown in Confidential Exhibit JRH-2 is expected to be **[BEGIN CONFIDENTIAL]** [redacted]. **[END CONFIDENTIAL]** As expected, the 20-year flowback of unprotected EDIT results in a higher average projected FFO to debt ratios of approximately 42 basis points. As noted in Moody's October 31, 2019 Credit Opinion, an FFO to Debt ratio that is between 24% and 26% qualifies for an

"A" rating, as shown in Exhibit JRH-3. Given that the FFO/Debt metric is only below 24% in 2021 and the other metrics are 24% or 25% through 2023, I believe that unexpected financial developments would have to occur that reduced DEC's cash flow from operations or cause the Company to issue more debt to trigger a downgrade.

Q. WILL A TEMPORARY DECREASE IN FFO/DEBT LIKELY LEAD TO A DOWNGRADE OF THE COMPANY'S "Aa2" RATING ON ITS FIRST MORTGAGE BONDS OR ITS "A1" SENIOR UNSECURED BONDS?

A. No. Moody's, like Standard & Poor's, focuses on net income and cash flow metrics from ongoing and continued operations over time. As such, Moody's averages its financial metrics over three years. Furthermore, Moody's October 31, 2019 Credit Opinion notes that a **sustained** decline in cash flow metrics below 25% could lead to a downgrade.

Q. HOW MUCH WEIGHT DOES MOODY'S PLACE ON CREDIT METRICS?

A. Moody's places 40% weight on financial strength as measured by its quantitative financial metric, 50% weight on the utility regulation, and 10% weight on utility diversification. The 50% weight on regulation focuses on two areas: the regulatory framework and the ability to recover costs and earn returns. The regulatory framework relates to rate setting by the governing body, credit supportive legislation that is responsive to the needs of the utility, and the manner in which the utility manages the political and regulatory process. The ability to recover costs and earn returns on its investments relates to the assurance that the regulated rates will be based on prescriptive and clear ratemaking methods. While awarding the least weight in its rating methodology to diversification, Moody's positively views utilities with multinational and regional diversity in terms of regulatory regimes and diversity in the economics of its service territories.

Q. DOES DEC HAVE OTHER MEANS TO FINANCE THE EDIT OVER A FIVE-YEAR PERIOD?

A. Yes, I believe there are other sources of capital available to DEC that would not deteriorate their FFO/Debt metrics. The filed E-1, Item 23 contains the Company's financial forecast, which indicates that DEC will continue every year to be financed with 48% to 47% long-term debt and 52% to 53% common equity through 2023. From 2020 through 2023, the Item indicates that the Company plans to issue a total of $2.40 billion in long-term debt and infuse $4.05 billion to Duke Energy Corporation (parent). Thus, indicating that an option may exist for DEC to offset some of its debt issuances through a reduction in its planned contributions to its parent which would allow DEC to maintain its credit ratings or, in the event of a downgrade, the ability to restore its current credit ratings. The Company witnesses DeMay, and Newlin stress the importance of maintaining DEC's credit quality, which Moody's Investor Services places as the highest-rated among Duke Energy Corporation and its other five electric utility subsidiaries as shown below:

Moody's Credit Ratings

	Long-Term Issuer Rating	First Mortgage Bonds
Duke Energy Corporation	Baa1	NA
Duke Energy Carolinas	A1	Aa2
Duke Energy Progress	A2	Aa3
Duke Energy Florida	A3	A1
Duke Energy Indiana	A2	Aa3
Duke Energy Kentucky	Baa1	NA
Duke Energy Ohio	Baa1	A2

In addition, Duke Energy Corporation[2] said it will issue approximately 29 million shares in common stock which will result in approximately $2.5 billion of net proceeds. This additional equity could allow DEC to decrease its projected equity infusions up to the parent company, which would alleviate the need to issue the amount of new debt and reduce the possibility of a downgrade.

[2] Duke Energy Press Release, "Duke Energy announces closing of common equity stock offering with a forward component", November 21, 2019.

Q. IF THE COMPANY'S FIRST MORTGAGE BONDS WERE DOWNGRADED TO "Aa3", DO YOU HAVE AN ESTIMATE OF THE INCREASE IN THE COST OF DEBT CAPITAL?

A. Yes, the Company believes that it is reasonable to expect that a one-notch downgrade by Moody's to Aa3 would increase the investor-required bond yield by 5-basis points. The Company noted that this estimate was based on market conditions associated with the January 7, 2020 issue of 2.45%, 10-year bonds. The Company noted that the differential would be greater than 5-basis points if the bond market was under dramatic volatile periods. Following the Company's acknowledgment of the current bond market, it is worth noting that Moody's A-rated long-term utility bond yields are the lowest in over thirty years. In light of the Company's financial forecasts, it is my opinion that the added cost of debt capital from a downgrade to an "Aa3" rating will not be burdensome on the Company.

Q. IF DEC IS DOWNGRADED, IS IT LIKELY THAT DEC WILL REMAIN AT THAT LEVEL FOR AN EXTENDED PERIOD?

A. No. While a downgrade to "Aa3" is not likely, recent history indicates that if it did occur, it would probably last less than five years. Since 1973, DEC has had six upgrades and four downgrades as identified in Exhibit JRH-4. Furthermore, it does not appear that any downgrade resulted from the 1986 change in the federal income tax rate.

Q. IN VIEW OF YOUR REVIEW OF THE FFO/DEBT CREDIT METRICS, DO YOU SUPPORT THE REFUND OF EDIT OVER FIVE YEARS?

A. Yes, I believe it is unlikely that spreading the EDIT over five years will result in a debt rating downgrade and it is reasonable and fair to the DEC's ratepayers and the Company.

Q. HOW DO THE CREDIT RATING AGENCIES VIEW SECURITIZATION OF DEC'S STORM COSTS?

A. I understand that credit rating agencies positively view securitization of utility costs with the prompt and certain recovery from the net proceeds from the sale of the bonds. As identified in the Credit Opinion on Duke Energy Corporation by Moody's in Exhibit JRH-5, the reduction in regulatory lag with DEC's securitization of its storm costs is viewed as a credit positive.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Appendix A
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QUALIFICATIONS AND EXPERIENCE

JOHN ROBERT HINTON

I received a Bachelor of Science degree in Economics from the University of North Carolina at Wilmington in 1980 and a Master of Economics degree from North Carolina State University in 1983. I joined the Public Staff in May of 1985. I filed testimony on the long-range electrical forecast in Docket No. E-100, Sub 50. In 1986, 1989, and 1992, I developed the long-range forecasts of peak demand for electricity in North Carolina. I filed testimony on electricity weather normalization in Docket Nos. E-7, Sub 620, E-2, Sub 833, and E-7, Sub 989. I filed testimony on customer growth and the level of funding for nuclear decommissioning costs in Docket No. E-2, Sub 1023. I filed testimony on the level of funding for nuclear decommissioning costs in Docket Nos. E-7, Sub 1026 and E-7, Sub 1146. I have filed testimony on the Integrated Resource Plans (IRPs) filed in Docket No. E-100, Subs 114 and 125, and I have reviewed numerous peak demand and energy sales forecasts and the resource expansion plans filed in electric utilities' annual IRPs and IRP updates.

I have been the lead analyst for the Public Staff in numerous avoided cost proceedings, filing testimony in Docket No. E-100, Subs 106, 136, 140, 148, and Sub 158. I have filed a Statement of Position in the arbitration case involving EPCOR and Progress Energy Carolinas in Docket No. E-2, Sub 966. I have filed testimony in avoided cost related to the cost recovery of energy efficiency programs and demand side management programs in Dockets Nos. E-7, Sub 1032, E-7, Sub 1130, E-2, Sub 1145, and E-2, Sub 1174.

I have filed testimony on the issuance of certificates of public convenience and necessity (CPCN) in Docket Nos. E-2, Sub 669, SP-132, Sub 0, E-7, Sub 790, E-7, Sub 791, and E-7, Sub 1134.

I filed testimony on the merger of Dominion Energy, Inc. and SCANA Corp. in Docket Nos. E-22, Sub 551 and G-5, Sub 585.

I have filed testimony on the issue of fair rate of return in Docket Nos.: E-22, Sub 333; E-22, Sub 412; E-22, Sub 532; P-26, Sub 93; P-12, Sub 89; P-31, Sub 125; P-100, Sub 133b; P-100, Sub 133d (1997 and 2002); G-21, Sub 293; G-5, Sub 327; G-5, Sub 386; G-9, Sub 351; G-21, Sub 442; G-9, Sub 743; W-778, Sub 31; W-218, Sub 319, W-218, Sub 497, W-354, Sub 360; W-354, Sub 364, and in several smaller water utility rate cases. I have filed testimony on credit metrics and the risk of a downgrade in Docket No. E-7, Sub 1146.

I have filed testimony on the hedging of natural gas prices in Docket No. E-2, Subs 1001 and 1018. I have filed testimony on the expansion of natural gas in Docket No. G-5, Subs 337 and 372. I performed the financial analysis in the two audit reports on Mid-South Water Systems, Inc., Docket No. W-100, Sub 21. I testified in the application to transfer of the CPCN from North Topsail Water and Sewer, Inc. to Utilities, Inc., in Docket No. W-1000, Sub 5. I have filed testimony on rainfall normalization with respect of water sales in Docket No. W-274, Sub 160.

With regard to the 1996 Safe Drinking Water Act, I was a member of the Small Systems Working Group that reported to the National Drinking Water Advisory Council of the U.S. Environmental Protection Agency. I have published an article in the National Regulatory Research Institute's Quarterly Bulletin entitled Evaluating Water Utility Financial Capacity.

CHAIR MITCHELL: All right. With that, we will proceed with the next witness. My notes indicate that it would be Mr. O'Donnell, but I assume you all have made arrangements as to the order of witnesses?

MR. CRYSTAL: Chair Mitchell, this is Howard Crystal for Center for Biological Diversity and Appalachian Voices.

CHAIR MITCHELL: Okay, Mr. Crystal.

MR. CRYSTAL: Greer Ryan is next on the list, and she's here and prepared to testify. DEC had listed that they had cross examination questions for her, but indicated to us this morning that if we treat her as an excused witness for efficiency sake, that they'll waive cross examination. So I can -- I can introduce her testimony as an excused witness if the Commission is so inclined or she can go ahead with her testimony today if the Commission wants to ask her questions.

CHAIR MITCHELL: All right. Let me check in with my colleagues to see if any of the Commissioners has a question for witness Ryan.

COMMISSIONER HUGHES: No.

CHAIR MITCHELL: All right. Hearing none, Mr. Crystal, you may proceed.

MR. CRYSTAL: Thank you, Chair Mitchell. I move the admission of Ms. Ryan's testimony, filed on February 18, 2020, consisting of 40 pages, along with five exhibits identified as GR-1 through GR-5. I'd ask that the testimony be entered into the record in this proceeding and copied into the record as if given orally from the stand.

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

MR. CRYSTAL: Thank you, Chair Mitchell. Thank you.

CHAIR MITCHELL: All right. Thank you.

(Whereupon, the prefiled direct testimony of Greer Ryan, Ph.D., stricken by Commission Order of 3/3/2020, was copied into the record as if given orally from the stand.)

(Whereupon, Exhibits GR-1 through GR-5 were admitted into evidence.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

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

In the Matter of:	)	
	)	**DIRECT TESTIMONY OF**
Application of Duke Energy Carolinas, LLC	)	**GREER RYAN FOR**
For Adjustment of Rates And Charges	)	**CENTER FOR BIOLOGICAL**
Applicable to Electric Service	)	**DIVERSITY AND**
in North Carolina	)	**APPALACHIAN VOICES**

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I. INTRODUCTION

Q: PLEASE STATE YOUR FULL NAME, OCCUPATION, AND BUSINESS ADDRESS.

A: My name is Greer Ryan. I am the Energy Policy Analyst at the Center for Biological Diversity. My business address is P.O. Box 11374, Portland, Oregon 97211.

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

A: I hold a B.S. in Molecular Environmental Biology from the University of California, Berkeley and an M.S. in Environmental Science from the School of Public and Environmental Affairs at Indiana University. I am the Energy Policy Analyst of the Energy Justice Program at the Center for Biological Diversity, a national non-profit conservation organization dedicated to using expertise in law, policy, and advocacy to protect the planet and people and promote the just transition from a fossil fuel economy to a 100 percent clean and renewable energy system to address the climate crisis.

For the past five years in my role at the Center, I have reviewed and analyzed local, state and federal energy policies and regulations regarding the deployment of clean and renewable energy resources, with a particular emphasis on distributed solar and other distributed energy resources. My work includes analyzing how rate structures, in conjunction with state-level policies, encourage or discourage the adoption of distributed clean energy, particularly for integrated monopoly utilities. For the past two years, I have focused in large part on North

Carolina's policy and regulatory landscape to provide analysis in support of the Energy Justice North Carolina coalition and for a variety of Center work. My relevant publications include:

- Hernandez R.R., A. Armstrong, J. Burney, **G. Ryan,** K. Moore-O'Leary, I. Diedhiou, S.M. Grodsky, L. Saul-Gershenz, R. Davis, D. Mulvaney, G.A. Heath, S.B. Easter, B. Beatty, M.K. Allen, D.M. Kammen. (2019). Techno-ecological synergies of solar energy for global sustainability. *Nature Sustainability*. 2: 560-568.
- "Throwing Shade: 10 Sunny States Blocking Distributed Solar Development," a report for the Center for Biological Diversity, first edition published in 2016 and second edition published in 2018.

My resume, attached as Greer Ryan Exhibit ("GR-1"), presents a summary of my professional and educational experience.

Q: HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE NORTH CAROLINA UTILITIES COMMISSION OR OTHER UTILITY COMMISSIONS?

No, I have not testified before the North Carolina Utilities Commission ("the Commission") or other utility commissions.

Q: ON WHOSE BEHALF ARE YOU TESTIFYING?

A: I am testifying on behalf of the Center for Biological Diversity ("the Center") and Appalachian Voices (collectively, "Intervenors").

Q. WHAT MATERIALS DID YOU REVIEW IN PREPARING THIS TESTIMONY?

A. I have reviewed Duke Energy Carolinas' ("DEC") application ("Application"), all testimony and exhibits of DEC Witnesses Jackson, McManeus, Newlin, Oliver, and Spanos, Duke Energy's Power/Forward proposal as related to DEC's 2018 rate case,[1] the Commission's Order in DEC's 2018 rate case,[2] DEC's documents concerning storm damages related to Hurricanes Florence and Michael and Winter Storm Diego,[3] North Carolina Governor Cooper's Executive Order 80,[4] the North Carolina Clean Energy Plan,[5] DEC's 2019 Integrated Resources Plan Update ("2019 IRP Update"),[6] and all responses to Intervenors' discovery requests.

Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A: The purpose of my testimony is to discuss my assessment of several impacts that DEC's rate proposal, including capital expenditures related to fossil fuel infrastructure, ~~have on North Carolina's necessary energy transition away from fossil fuels to clean and renewable energy, and further address why I believe these impacts contravene the public interest as embodied in Governor Cooper's~~

~~1 NCUC E-7, Sub 1146. Direct testimony of Duke Energy witness David B. Fountain.~~

~~2 NCUC E-7, Sub 1146. Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction at 19.~~

~~3 NCUC E-7, Sub 1187.~~

~~4 E.O. 80 is available at https://files.nc.gov/ncdeq/climate-change/EO80--NC-s-Commitment-to-Address-Climate-Change---Transition-to-a-Clean-Energy-Economy.pdf.~~

~~5 The North Carolina Clean Energy Plan, issued in 2019, is available at: https://files.nc.gov/ncdeq/climate-change/clean-energy-plan/NC_Clean_Energy_Plan_OCT_2019_.pdf.~~

~~6 2019 IRP Update is available at https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=40bbb323-936d-4f06-b0ba-7b7683a136de~~

~~Executive Order 80 ("E.O. 80")~~[7]~~, the state's Clean Energy Plan~~[8]~~, and climate science, as detailed in the Testimony of Shaye Wolf.~~[9] My testimony also discusses concerns regarding the grouping of already-incurred Grid Improvement Plan-related costs with customary T&D expenditures and the request for accounting deferral of future GIP costs. Additionally, my testimony discusses concerns regarding the inclusion of storm damage costs as part of the rate base. Finally, my testimony addresses DEC's recovery of lobbying and other political expenses as part of the cost of service.

Q: PLEASE SUMMARIZE YOUR PRIMARY RECOMMENDATIONS.

A: I recommend the following:

- The Commission should postpone this rate case until after the completion of the 2020 Integrated Resource Plan ("IRP") proceeding to allow for the Commission to consider the prudency of these costs in light of likely adjusted IRP goals.
- In lieu of postponing the rate case, I recommend the Commission:
  - Reject the rate increase associated with new fossil fuel capital expenditures and certain fossil power-related Grid Improvement Plan costs; and
  - Reject the request for accounting deferral of GIP costs until after

[7] E.O. 80 is available at https://files.nc.gov/ncdeq/climate-change/EO80--NC-s-Commitment-to-Address-Climate-Change---Transition-to-a-Clean-Energy-Economy.pdf.

[8] The North Carolina Clean Energy Plan, issued in 2019, is available at: https://files.nc.gov/ncdeq/climate-change/clean-energy-plan/NC_Clean_Energy_Plan_OCT_2019_.pdf.

[9] Testimony of Shaye Wolf at 4-36.

DEC's upcoming 2020 IRP proceeding; and

- Remove all storm damage costs from the rate base and move these costs to operating expenses; and
- Disallow cost recovery for DEC payments to groups that engage in political advocacy or lobbying.

II. COSTS ASSOCIATED WITH FOSSIL FUEL GENERATION AND CLEAN AND RENEWABLE ENERGY GENERATION IN THE CLIMATE CHANGE CONTEXT.[10]

Q: DESCRIBE DEC'S PAST AND PROPOSED ENERGY PORTFOLIO.

A: During the Test Period of 2018, DEC's solar generation accounted for less than 1% of the utility's total generation. [11] In contrast, nuclear power provided 59%, coal provided 22%, gas provided 16%, and hydropower provided less than 2%.[12]

With respect to 2020, according to the 2019 IRP Update, DEC projects that fossil fuels and nuclear power will still supply the vast majority—78%—of its energy capacity: nuclear power at 25%, coal at 30%, and gas facilities at 23%.[13] In contrast, DEC has planned for clean and renewable energy to make up only 5% of capacity, with pumped and battery storage providing another 9%. *Id.*

Over a fifteen-year horizon, that energy portfolio is expected to further

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[10] "Clean and renewable" energy is defined in this testimony as solar and wind energy. As in DEC's 2019 IRP Update, hydropower and nuclear are carved out separately from renewable energy.

[11] NCUC E-7, Sub 1214, DEC Witness Immel Testimony at 11; NCUC E-7, Sub 1214, DEC Witness Capps Testimony at 14.

[12] *Id.*

[13] 2019 IRP Update at 9.

change, but still toward a majority fossil-powered portfolio. By 2034, DEC plans for clean and renewable energy to generate only 13% of total electricity capacity, in contrast to gas and coal which together will generate 50% and nuclear 20%. *Id.* In short, under DEC's current resource plans, clean and renewable energy and distributed energy resources are substantially outweighed by fossil fuel and nuclear resources for the upcoming fifteen-year horizon.

Q: DESCRIBE PAST AND PROPOSED CAPITAL EXPENDITURES WITH REGARDS TO FOSSIL FUEL GENERATION IN RELATION TO CLEAN AND RENEWABLE ENERGY GENERATION.

A: Mirroring DEC's proposed energy portfolio, the capital expenditure funded by ratepayers has historically been majority dedicated to fossil fuels rather than clean and renewable energy. For the period of 2013-2018, the capital expenditure on clean and renewable generation resources amounted to $163 million, which is 1.4% of the capital expenditure on non-renewable resources of $11 billion.[14] Put another way, for every dollar expended on clean and renewable energy, DEC has spent $72 on non-renewable energy. *Id.* Moreover, DEC made zero expenditures on energy storage and micro-grid technology from 2005 to date.[15] DEC did expend $493 million on energy efficiency programs and $120 million on demand side management programs from 2015-2018.

For 2019 through 2023, DEC has proposed a total capital expenditure of

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[14] The renewable generation capital expenditures consisted of Mockville, Monroe, and Woodleaf solar facilities. DEC Response to CBD & AV Request No. DR-1-II.8.

[15] DEC Response to CBD & AV DR 2-37.

$13.83 billion, with $3 billion dedicated to new electric generation.[16] Specifically with respect to this rate proceeding, DEC has provided that capital investments justifying the rate increase will be directed to (i) upgrading and maintaining active coal plants to meet environmental regulations, as well as (ii) completing work to allow for DEC's Cliffside Units 5 and 6 generators to burn fossil gas as well as coal.[17] To the best of my knowledge, nowhere in the application does DEC include the addition of renewable energy generation as part of the capital costs associated with the rate increase.

Q: ~~**EXPLAIN YOUR CONCERN WITH NON-RENEWABLE CAPITAL EXPENDITURES AS RELATED TO E.O. 80, THE CLEAN ENERGY PLAN, AND CLIMATE SCIENCE AND WHY THAT IS RELEVANT TO THIS PROCEEDING.**~~

~~A: In my professional opinion, and based on the accompanying testimony of Shaye Wolf, DEC's current energy portfolio and related capital expenditures contravene the demands of E.O. 80, the Clean Energy Plan, and climate science.[18] As discussed in Intervenors' Witness Shaye Wolf's testimony, Governor Cooper's landmark E.O. 80 calls for the rapid reduction in greenhouse gas emissions across North Carolina, including a 2025 deadline to reduce statewide greenhouse gas emissions to 40% below 2005 levels.[19] Moreover, North Carolina's inaugural Clean Energy Plan, which was mandated as part of~~

~~16 DEC Response to CBD & AV DF 1-IV.7.~~
~~17 NCUC E-7, Sub 1214, DEC App. at 5, 7.~~
~~18 Testimony of Shaye Wolf at 4-36.~~
~~19 *Id* at 5.~~

~~E.O. 80, specifically calls on the electricity sector to reduce greenhouse gas emissions by 70% below 2005 levels by 2030.[20] This last mandate is consistent with the recent 2018 report of the Intergovernmental Panel on Climate Change, the international scientific body for the assessment of climate change, which calls for the vast majority of electricity to be supplied by clean and renewable resources by 2030 in order to avoid the worst impacts of climate change.[21]~~

~~As outlined in Intervenors' Witness Shaye Wolf's testimony, E.O. 80 and the Clean Energy Plan represent the public interest as relates to the climate emergency and should play a foundational role in the Commission's proceedings that are grounded in service to the public interest, including rate cases.[22]~~

~~Moreover, in light of the fact that both EO 80 and the more detailed Clean Energy Plan were issued and released in 2018 and 2019, the Commission has not yet had the opportunity to thoroughly evaluate DEC's resource planning and accompanying rate proposals and take into account these state policies in a comprehensive manner. Significantly, in accepting DEC's 2018 IRP, the Commission recognized that the public staff and Intervenors had raised a host of issues that DEC must address going forward, including matters related to climate change and clean energy investments, and the Commission's IRP approval was premised on assumption that the utilities would be addressing these matters going forward, including thorough analyses~~

~~20 *Id.* at 6-9.~~
~~21 *Id.* at 11-16.~~
~~22 *Id.* at 5-11.~~

~~comparing its plans with E.O. 80's greenhouse gas emissions reduction goals.~~[23]

~~In addition, DEC's last Integrated Resource Plan updated was completed in October, 2019.~~[24] ~~It outlines an atrophied plan to transition to clean energy resources. For example, the IRP Update plans for only 13% renewable energy generation in 2034, and that at that time, DEC will still be obtaining 50% of its electricity from fossil fuels. *Id.* at 9. Moreover, the IRP Update projects that fossil fuel resources will account for more than 40% of the capacity additions DEC will acquire between now and 2034, more than the anticipated capacity additions in renewables. *Id.* This approach is woefully inadequate to meet the needs of climate science, as detailed in Intervenors' Witness Shaye Wolf's testimony.~~[25]

~~Q: EXPLAIN THE IMPACTS OF CAPITAL EXPENDITURES IN FOSSIL FUEL INFRASTRUCTURE ON THE PUBLIC INTEREST.~~

~~First, as a threshold matter, based on Intervenors' Witness Shaye Wolf's testimony, in light of the climate emergency DEC customers can no longer afford DEC's energy system to continue with business as usual, expending~~

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[23] ~~Commission Order of August 27, 2019, "In the Matter of the Biennial Integrated Resources Plan and Related 2018 REPS Compliance Plans," NCUC Docket E-100, Sub 157. We note that DEC claimed that its plans were consistent with E.O. 80, id. at 69-70, but neither has this claim been tested by the Commission and public, nor has the Commission had the opportunity to discuss the consistency of DEC's plans with the Clean Energy Plan.~~

[24] ~~The 2019 Integrated Resource Plan Update Report is available at https://starw1.ncuc.net/NCUC/PSC/PSCDocumentDetailsPageNCUC.aspx?DocumentId=dd4e7e15-257a-4f00-8dd0-8b3beb975a31&Class=Filing~~

[25] ~~Testimony of Shaye Wolf at 9-17.~~

~~ratepayer funds to sustain an energy system largely powered by fossil fuels.~~[26] ~~DEC's failure to decarbonize its electricity portfolio in line with E.O. 80, the Clean Energy Plan, and climate science fundamentally contravenes the public interest.~~

~~Second, it is my professional opinion that permitting ratepayer funds to be invested in building new and perpetuating existing fossil fuel infrastructure now, as opposed to new renewable energy infrastructure, exacerbates the climate crisis—and public harm—because of the lock-in effect of fossil infrastructure. DEC offers the following common life spans for its fossil production facilities: (i) 36 to 69 years for most steam, base-load units combusting coal and (ii) 40-41 years for combustion turbines and combined cycle units using gas.~~[27] ~~Thus, ratepayer funds that are spent on fossil generation lock DEC into multiple decades of combusting polluting gases—a result that both the climate and the public cannot afford to avoid the worst consequences of climate change.~~[28]

~~**Q: WHAT DO YOU RECOMMEND WITH REGARD TO DEC'S PROPOSED INCREASE IN RATES THAT ARE DESIGNED TO RECOVER COSTS FOR FOSSIL FUEL INFRASTRUCTURE?**~~

~~A: At this juncture, I recommend that the Commission should not allow for an increase in rates to account for new fossil fuel infrastructure because it contravenes the public interest, as encapsulated in E.O. 80 and the Clean Energy~~

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26 ~~Testimony of Shaye Wolf at 9-36.~~

27 ~~NCUC E-7, Sub 1214, DEC Witness Spanos Testimony, Ex. 1 at III-7.~~

28 ~~Testimony of Shaye Wolf at 9-36.~~

~~Plan, and the summary of climate science detailed by Shaye Wolf.~~[29] ~~Instead, DEC should continue to operate under its existing rate structure until after the 2020 IRP is completed.~~

~~I also recommend that the Commission postpone this rate hearing and consideration of the $3 billion investment in non-renewables capital expenditures~~[30] ~~until the completion of DEC's 2020 IRP process. As discussed above, it is critical that the Commission's approval of any new rates take into account the greater North Carolina climate policies.~~

III. GRID IMPROVEMENT PLAN EXPENSES IN GREATER CONTEXT OF CLEAN ENERGY TRANSITION.

Q: PLEASE EXPLAIN THE GRID IMPROVEMENT PLAN EXPENDITURES THAT DEC SEEKS TO FINANCE THROUGH THIS RATE CASE.

A: As featured in the Application, the "Grid Improvement Plan" is a state-wide project of corporate parent Duke Energy, covering territories of both DEC and sister Duke Energy Progress ("DEP"), to expend a total of $2.3 billion in costs that purportedly will modernize the grid across these territories.[31] Before discussing the avenues through which DEC seeks to finance its portion of these

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29 Testimony of Shaye Wolf at 9-36.

30 Intervenors acknowledge that large capital expenditures require DEC's acquisition of a Certificate of Public Convenience and Necessity ("CPCN"). It is unclear as to which fossil facilities the $ 3 billion capital expenditure addresses and whether and when such expenditures acquired a CPCN. In light of that ambiguity and the EO 80 and Clean Energy Plan developments over the course of the past two years, it would be prudent for the Commission to reconsider those expenditures even if CPCNs have been granted.

31 NCUC E-7, Sub 1214, DEC Witness Oliver ex. 10 at 3.

GIP expenditures through this proceeding, it is important to place the GIP in the greater context of recent efforts taken by Duke Energy, DEC, and DEP to fund this massive multi-billion dollar project in grid infrastructure.

Specifically, the GIP is the latest effort in a series of ongoing actions taken by Duke Energy to finance substantial infrastructure investments in the grid. In its 2018 rate case, DEC shared plans for investing $2.9 billion to "modernize" its grid, as part of Duke Energy's $13 billion state-wide "Power/Forward" program. DEC requested a Rider and cost deferral to recover the $2.9 billion in capital.[32] In response, the Commission rejected this request on the grounds that DEC failed to show that (i) exceptional circumstances existed to justify the establishment of a Rider, and (ii) future costs qualified for deferral accounting treatment.[33]

Subsequently, in 2019, Duke Energy advocated the North Carolina Legislature to pass S.B. 559, which would have permitted DEC and DEP to seek Commission approval for successive rate increases covering up to five years, effectively subverting the ordinary and more frequent rate request process.[34] S.B. 559 did not pass.

Here, in this 2020 rate proceeding, DEC is again seeking approval for

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32 *Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction*, NCUC E-7, Sub 1146 p. 128

33 *Id.* at 19.

34 *See* Ouzts, E., "Controversial Duke Energy ratemaking bill stalls in North Carolina," Energy News Network (July 24, 2019) available at https://energynews.us/2019/07/24/southeast/controversial-duke-energy-ratemaking-bill-stalls-in-north-carolina/; North Carolina Securitization Act, S.B. 559, SL 2019-244 (2019).

DEC's portion of Duke Energy's greater state-wide "Grid Improvement Plan" ("GIP")—a $2.3 billion package that covers both DEC and DEP territories.[35] Specifically, DEC seeks to recover up to $224 million in GIP assets in-service costs[36] from 2018-2019 as well as an accounting deferral to ultimately recover approximately $1.3 billion[37] of the Duke Energy's state-wide GIP proposal of $2.3 billion—or 65%.

DEC is pushing GIP costs through two avenues in this rate proceeding. First, DEC is seeking to recover an additional $2.2 billion spent in T&D infrastructure, which was "inclusive of additions through the Grid Improvement Plan," since the last rate case. In response to discovery requests, DEC provided Public Staff and Intervenors with a table of its GIP asset in-service expenses in 2018 and 2019, amounting to a total of $224 million.[38] The $2.2 billion in T&D expenses is broadly categorized as supporting the build-out of 1,393 miles of distribution lines and 12,847 transformers, and would include traditional maintenance activities such as vegetation management and replacing deteriorated wooden poles.[39] However, the GIP-specific costs of up to $224 million out of this $2.2 billion sum are distinct from customary T&D costs as they are meant to significantly "protect," "optimize," and "modernize" the grid.

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[35] NCUC E-7, Sub 1214, DEC Witness Oliver ex. 10 at 3.

[36] DEC Response to CBD & AV DR 1-II-1, Attachment "Public Staff Data Request No. 78-4 GIP COSS follow up.xlsx"

[37] NCUC E-7, Sub 1214, DEC Witness Oliver ex. 10 at 3.

[38] DEC Response to CBD & AV DR 1-II-1, Attachment "Public Staff Data Request No. 78-4 GIP COSS followup.xlsx." Approximately $59 million of these costs were incurred in 2018, and $165 million in 2019.

[39] NCUC E-7, Sub 1214, DEC Witness Oliver Testimony at 7, 15-18.

Second, DEC is seeking to also finance $1.3 billion in *future* GIP expenses through deferral accounting for the period of 2020-2022.[40] An estimated $958 million of this total is for "optimizing" the grid, $308 million for "modernizing" the grid, and $65 million on "protecting" the grid.[41] This $1.3 billion is not inclusive of energy storage and electric transportation expenses.[42]

Q: PLEASE EXPLAIN WHY THE GIP EXPENSES SHOULD NOT BE TREATED AS BUSINESS-AS-USUAL INVESTMENTS TO THE GRID AND INSTEAD MUST BE ROBUSTLY ANALYZED BEFORE COMMISSION APPROVAL.

A: DEC is requesting the Commission effectively approve GIP expenses in this rate case in two ways: (i) requesting to recover up to $224 million in GIP expenses by couching them in with an overall $2.2 in T&D expenditures; and (ii) deferral accounting of $1.3 billion in upcoming GIP costs for recovery in future rate cases.[43] Despite DEC's attempts to characterize already-incurred GIP expenditures as business-as-usual T&D investments such that they are recovered without robust analysis in this rate proceeding, all GIP expenditures should be considered large and distinct from common grid investments and thus should be subject to the Commission's more robust review for several reasons.

First, DEC seeks recovery for expenditures that are outside the realm of customary T&D costs and thus should not be grouped in as part of the $2.2

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40 NCUC E-7, Sub 1214, DEC Witness Oliver ex. 10 at 3.

41 *Id.*

42 *Id.*

43 NCUC E-7, Sub 1214, DEC Witness McManeus Testimony at 37.

billion in T&D expenditures in this rate case, but should be evaluated separately and in detail. As DEC Witness Newlin notes, the expenditures to be made under the GIP are "not simple, regularly occurring, inconsequential investments, but rather, are major non-routine investments"[44]—and thus cannot be sufficiently analyzed with the data provided by DEC in its Application.

Second, the sheer amount of requested $1.3 billion in pre-approved funds via accounting deferral is large enough that the Commission needs to carefully review this GIP expenditure in the context of the 2020 IRP or similarly specific and robust approval process. As EDF Witness Alavarez highlighted in DEC's 2018 rate case, this magnitude of investment is larger than that of generation assets for which the Commission has an established prior review process (a Certificate of Public Convenience and Necessity, or "CPCN").[45] For example, the $1.3 billion GIP costs that DEC plans for the next three years is analogous to DEC's entire yearly budget spent on generation assets; in 2013 and 2014, DEC spent $1.5 billion per year on multiple capital expenditures in generation assets. In parallel, DEC spends hundreds of millions of dollars in single generation assets that require CPCN approval processes.[46] Should the Commission approve this accounting deferral in this rate proceeding, the

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[44] *Id.* at 39.

[45] *See* Direct Testimony of Paul Alvarez on Behalf of EDF, Docket No. E-7, Sub 1146, p 10-11 (discussing the CPCN process for generation assets).

[46] *See, e.g.*, Petition of DEC for an accounting order to defer incremental Hurricanes Florence and Michael and Winter Storm Diego Storm Damage Expenses, No. E-7, Sub 1187 at 11 (noting that the incremental costs of the 2018 storms—amounting to approximately $142 million—"are . . . analogous to a new generation plant").

Commission has effectively committed to finance 52% of Duke Energy's greater GIP through future rate cases and thereby lock in DEC territory into those GIP components—without taking into account the outcome of the 2020 IRP, which I expect will reflect the Commission's consideration of the state's climate policies (which continue to develop through the implementation of the Clean Energy Plan).

Q: WHAT ARE YOUR CONCERNS WITH DEC'S RATIONALE FOR THESE GIP EXPENDITURES, IF ANY?

A: DEC claims these GIP expenses are generally necessary to address seven "megatrends." One such trend is that "technology is advancing at a rapid rate in the areas of renewables and distributed energy resources ("DERs"), which means there are new types of load and resources impacting the grid." Throughout its Application and DEC Witness Oliver's testimony and exhibits, DEC highlights the need to ready the grid to support the growth of "renewable energy technologies like solar energy, battery storage, micro-grids and electric vehicles" as these technologies become more cost-effective and accessible.[47] Further, DEC articulates concerns about spending money to enact the yet-to-be-approved GIP costs in the coming years without this accounting mechanism, because DEC's financials would be negatively affected.

While DEC provides testimony and exhibits broadly categorizing the

[47] NCUC E-7, Sub 1214, DEC Witness Oliver Testimony at Ex. 4; NCUC E-7, Sub 1214, DEC App. at 9.

GIP programs and connecting programs to the seven megatrends,[48] I find this treatment concerning for two reasons. First, DEC has failed to explain how the GIP programs explicitly carry out addressing the megatrends, particularly related to facilitating widespread adoption of DER and clean and renewable resources, which I will discuss more specifically in the next section.

Second, DEC has not, in either its Application or in response to Intervenors' specific discovery requests, explained how much money DEC is investing to address each of the megatrends and what the actual outcome of such expenditures will be. Specifically, DEC has not disclosed how burdensome these expenses will be for ratepayers in future rate cases for the Commission to consider. Rather, DEC Witness McManeus explains that the amounts to be recovered from retail customers will be determined with consideration given to the nature of the expenditures (*i.e.* whether the expenditures are related to the distribution, transmission, or communication systems). For example, distribution system-related expenditures will be fully allocated to the retail class, but transmission and communications systems-related costs will be recovered from both retail and wholesale customers. Witness McManeus does not provide an estimate of how recovery of these expenditures will impact actual residential rates.[49]

Q: PLEASE EXPLAIN HOW DEC SUPPORTS ITS CLAIM THAT GIP EXPENSES ADDRESS MEGATREND NUMBER 2, PARTICULARLY

48 NCUC E-7, Sub 1214, DEC Witness Oliver Testimony at Ex. 4.

49 NCUC E-7, Sub 1214, DEC Witness McManeus Testimony at 38.

IN RELATION TO THE ADVANCEMENT OF RENEWABLES AND DER.

A: In its Application, DEC acknowledges the following:

> DE Carolinas also needs to provide more options for customers to allow more control over the way they use electricity. And as renewable energy technologies like solar energy, battery storage, micro-grids and electric vehicles become more cost-effective, affordable and accessible, the Company needs to take steps now to ready the grid to support the growth of these technologies that are important to North Carolina's energy future.[50]

DEC further claims that the GIP addresses these needs while managing costs.[51] DEC also alleges that it will "provide the foundation for the two-way power flows needed to support more rooftop solar, battery storage, electric vehicles and microgrids—technologies that will increasingly power the lives of customers."[52] While DEC states these and similar broad claims, DEC does not substantiate its claim—in the Application, supporting exhibits, or through discovery when asked these questions—that the $224 million spent on GIP-related expenses to date, as well as $1.3 billion in future expenses DEC is requesting to defer, will meaningfully support the adoption of renewables and

[50] NCUC E-7, Sub 1214, DEC App. p. 9
[51] NCUC E-7, Sub 1214, DEC App. p. 9
[52] *Id.* at 10

DERs.[53]

First, the lack of evidence is further bolstered by DEC's own projections of its future energy usage—and particularly, the failure to include substantial amounts of DEC-generated renewable energy that the climate crisis calls for. DEC only anticipates the energy capacity of 16% "renewables" *total* by 2030.[54] This is further divided into three subcomponents: renewable generation (3,752MW), demand-side management (465MW), and energy efficiency (626MW), demonstrating that actual renewable generation, all in the form of solar capacity, is only 77% of that 16% value.[55] No wind energy or small-scale hydro is expected by 2034.[56]

Second, the lack of evidence regarding the amount of distributed solar capacity that DEC expects to allow into its system in the coming decades undermines DEC's broad claims that parts of the $1.3 billion GIP serve to drive DER deployment in any significant way.

DEC has stated, in response to discovery requests, that it has not performed a system-wide analysis of how much distributed energy or renewable resources would be enabled by the GIP.[57] Specifically, the Company has no projections for how much solar, storage, or other DERs will actually be adopted

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[53] DEC Response to CBD & AV DR 1-II-1, Attachment "PS DR No. 78-4 GIP COSS followup.xlsx"
[54] DEC Response to CBD & AV Request No. 1-10; *See also* DEC 2019 IRP (where "renewables" account for 13% capacity by 2034).
[55] DEC Response to CBD & AV Request No. 1-10
[56] *Id.*
[57] DEC Response to CBD & AV Request No. 1-5

under scenarios with and without GIP expenses.[58]

In response to discovery questioning DEC's intentions to increase DER on its grid, DEC stated that "the 3-year Self Optimizing Grid deployment in North Carolina would enable up to approximately 339 MW of incremental potential capacity for customer-owned distributed energy and renewable resources, all other factors remaining constant."[59] In my professional opinion, such an "enabling" of potential DER would not likely translate to a proportional adoption of DER without further incentive plans and policy support mechanisms for customer adoption of DER. Moreover, even if maximized, this effort still only amounts to less than .5% reduction in DEC's overall load.[60] Overall, DEC fails to provide sufficient evidence, nor does there appear to be intention, for widespread deployment of DER to come on the DEC grid. At base, neither Duke Energy's track record nor DEC's Application support contentions that these costs will actually encourage growth of renewables and DER in North Carolina, at least not at a level necessary to address the climate crisis and adhere to E.O. 80 goals. Given that DEC has made no expenditures on energy storage or microgrid technology from 2005 to date[61] and has shared no plans to strengthen its net metering policy to further encourage distributed solar adoption, it is clear DEC does not have plans for significantly increasing DER in the region.

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58 *Id.*

59 *Id.*

60 Compared to load forecast in 2019 IRP Update at 15.

61 DEC Response to CBD & AV DR 2-37.

Q: EXPLAIN YOUR VIEWPOINT THAT GIP EXPENSES REQUIRE FURTHER REVIEW.

A: As discussed above, the Commission is faced in this rate proceeding with the decision to allow recovery for GIP spending that, in my professional opinion, DEC has failed to sufficiently detail. This is especially concerning with respect to the $1.3 billion in future GIP costs that DEC seeks to defer for future recovery without analyzing these costs' outcomes in terms of adopted renewables and DER, or how these costs will impact the ratepayer.

I believe the Commission's approval of this request on this record would be inconsistent with the public interest. In order for stakeholders to weigh in on the rate impacts of GIP costs for the Commission to consider, particularly as relate to residential electricity bills, DEC should be required to outline these impacts.

Moreover, DEC has failed to explain how the past and future GIP costs ultimately impact the public interest with regard to the climate emergency. In particular, as discussed above, E.O. 80, the Clean Energy Plan, and climate science require a fundamental transformation of DEC's energy portfolio in order to serve the public interest at threat from the climate emergency. As detailed by Intervenors' Witness Shaye Wolf, the Clean Energy Plan emphasizes the foundational importance of modernizing the grid to specifically "accommodate DER [Distributed Energy Resources] growth and new load from electrification of end-use."[62] Significantly, the Clean Energy Plan charges the Commission with the responsibility to carefully evaluate the Grid Improvement Plan in order "to maximize the potential benefits of grid modernization investments and to protect against potential utility capital bias."[63] In my professional opinion, thus far DEC has failed to sufficiently support its claim that GIP costs will encourage renewables and DER adoption. Instead, the Application perpetuates a fossil fuel future for DEC that is inconsistent with the public interest, E.O. 80, and the Clean Energy Plan.

Q: WHAT IS YOUR RECOMMENDATION WITH RESPECT TO DEC'S REQUEST TO APPROVE BOTH ALREADY-INCURRED AND FUTURE GIP COSTS?

A: As the Application stands, in lieu of postponing this rate increase request until after the 2020 IRP, I recommend the Commission (i) require DEC to outline the $224 million of GIP-specific already-incurred costs separately from customary T&D spending for the Commission to review; (ii) reject any rate increase associated with already-incurred GIP capital expenditures that encourage fossil fuel infrastructure and did not go through an IRP, CPCN, or similar review process; and (iii) reject the request for accounting deferral of future GIP costs. As discussed above, approval of this request is not in the public interest because it would allow recovery of costs without DEC providing requisite information with regards to how these expenses affect ratepayers and the public interest.

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62 Testimony of Shaye Wolf at 6-9 (quoting Clean Energy Plan at 83).

63 *Id.* (quoting Clean Energy Plan at 83-4).

IV. COSTS ASSOCIATED WITH RECOVERY FOR CLIMATE-EXACERBATED STORMS.

Q: IS DEC SEEKING TO RECOVER COSTS ASSOCIATED WITH STORM DAMAGE AS PART OF THE RATE BASE?

A: Yes. Overall, DEC seeks to recover $36 million to pay for deferred incremental costs incurred from storm-related damage due to Hurricanes Florence and Michael and Winter Storm Diego.[64] Of those total deferred costs, at least two-thirds—or $23.7 million—is proposed as capitalized costs that form part of the rate base in this proceeding for which DEC seeks a return on investment.[65] DEC has not made clear whether the remaining one-third of the $36 million is also capitalized and part of the rate base, though DEC Witness Jackson's testimony mentions that additional areas, including generation plants and operations, also incurred damage for which DEC is seeking cost recovery.[66]

~~**Q: WHAT WAS THE ROLE OF CLIMATE CHANGE ON THE DEVASTATION TO NORTH CAROLINIANS IMPACTED BY HURRICANES FLORENCE AND MICHAEL AND WINTER STORM DIEGO?**~~

~~A: As detailed in Intervenors' Witness Wolf's testimony, human-caused climate~~

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[64] ~~NCUC E-7, Sub 1214, DEC App. at 4, 6.~~

[65] ~~NCUC E-7, Sub 1214, DEC Witness Jackson Testimony, 36-40 and Ex. RSJ-1; *see also* NCUC E-7, Sub 1214, DEC App. at 18 and 6 n. 1 (noting that "with respect to capital investments" for storm damage, DEC seeks "a return on investment").~~

[66] ~~NCUC E-7, Sub 1214, DEC Witness Jackson Testimony at 39-40. Separately, DEC claimed an additional $224 million of recoverable storm restoration costs that are not capitalized but which DEC considers recoverable operations and maintenance costs that ratepayers should bear. *Id.* at Ex. RSJ-1. DEC seeks to amortize these incremental costs over an eight-year period. NCUC E-7, Sub 1214, DEC App. at 18.~~

~~change, fueled by the combustion of fossil fuels like those dominating DEC's energy system, is increasing the destructive power of hurricanes by boosting their rainfall, intensity, and storm surge.~~[67] ~~Scientists have confirmed that global climate change exacerbated the severity of Hurricane Florence, Hurricane Michael, and Super Storm Diego in 2018, which devastated DEC's own energy system and more importantly, hundreds of thousands of North Carolinians.~~[68] ~~Unlike many places in the United States where climate change is not yet particularly palpable, DEC's customers have already suffered extraordinary damage in property and lives lost.~~[69]

Q: DO YOU HAVE AN OPINION CONCERNING DEC REQUESTING TO RECOVER STORM DAMAGE COSTS AS PART OF ITS RATE BASE?

A: Yes, in my professional opinion, it is contrary to the public interest for DEC to earn a rate of return on storm damage costs. As detailed by Intervenors' Witness Shaye Wolf's testimony, DEC's parent company Duke Energy is a major contributor to the greenhouse gas emissions fueling the climate crisis and climate-related storm events.[70] At the same time, as a threshold matter, the restoration of electricity during and after major climate-exacerbated events, like Hurricanes Florence and Matthew and Winter Storm Diego, is vital to protecting the health and safety of all DEC customers.[71] Compromising or delaying that

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[67] Testimony of Shaye Wolf at 21-24.
[68] *Id.*
[69] *Id.*
[70] Testimony of Shaye Wolf at 16-17.
[71] Power shut-offs threaten the public interest by canceling safe lighting, electric heat and cooling, power for medical devices that literally keep people alive, refrigeration of food

restoration—for the hundreds of thousands of customers who experienced power outages in these disasters[72]—would undermine the public interest and thus my concern does not extend to Duke recovering costs for getting electricity back online for its customers as quickly as possible.

However, it is unjust for those restoration costs to be capitalized and thus a source of return on equity. By capitalizing those expenses and earning a return off them as DEC now seeks to do, DEC is profiting to a tune of 10.3% off the climate-induced disaster costs that they are helping to bring about through DEC's historic and continued investments in majority fossil fuels.

In my professional opinion this recovery contravenes rate regulation principles, under which a utility is generally entitled to earn a return on a capital expenses made to improve electricity service. The costs of storm recovery are dedicated to only restoring status quo electricity service, and should instead be categorized as an operating and maintenance expense.

Further, in response to a discovery question whether it is just and reasonable for DEC to pay for disaster relief by decreasing the ROE, DEC stated that because "funding storm restoration costs requires financial liquidity to fund the day-to-day expenses," it is important to maintain rates of return to access such short-term liquid capital to fund storm expenses.[73]

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and medications, and fuel for electric cooking appliances and electrically-heated water—and not only across residential but also commercial and industrial sectors. *See* A. Kenward and U. Raja, Climate Central, Blackout: Extreme Weather, Climate Change, and Power Outages (2014), 3. https://assets.climatecentral.org/pdfs/PowerOutages.pdf.

[72] NCUC E-7, Sub 1214, DEC Witness Jackson Testimony, at 19, 23, 25.

[73] DEC Response to CBD & AV DR 2-34.

Finally, in light of the connections between greenhouse gas emissions and climate-change fueled storms[74], in my professional opinion it is not in the public interest for DEC, on the one hand, to be an enormous greenhouse gas emissions contributor, and on the other hand be permitted to obtain a rate of return on the costs associated with the very storms that are the inevitable consequence of these ongoing emissions.

Q: WHY IS IT IMPORTANT THAT THE COMMISSION CAREFULLY CONSIDER THE WAY STORM DAMAGE COSTS ARE HANDLED IN THIS RATE PROCEEDING?

A: In my professional opinion, the Commission should carefully consider the treatment of storm damage costs for its important precedential value. The issue of how to properly categorize storm damage costs will only continue to arise for DEC in the wake of the climate emergency and the resulting increase in frequency and severity of hurricanes and snow storms.

Through this proceeding, DEC seeks to consolidate the rate increase request with the request to allow DEC to defer the depreciation expense and earn a return on investment of storm-related "capital investments."[75] Importantly, DEC notes, in the related docket, that such requests regarding storm damage departs from the Commission's historical treatment of storm costs, and DEC requests the Commission make such an exception "due to the unprecedented costs and financial impact from Hurricanes Florence and Michael and Winter

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74 Testimony of Shaye Wolf at 20-24.

75 NCUC E-7, Sub 1214, DEC App. at 18.

Storm Diego."[76]

Unfortunately, as Intervenors' Witness Shaye Wolf outlines, the devastation and ultimate costs of Florence, Michael and Diego are anything but an exception in today's state of the climate emergency.[77] Hurricanes like the tragic tryptic of 2018 are only set to intensify and occur more frequently.[78] Therefore, the Commission should consider that the way it capitalizes storm damage costs now is not an exception but creates a precedent and therefore warrants careful consideration of what is just and reasonable for the DEC ratepayer.

Q: WHAT IS YOUR RECOMMENDATION AS TO HOW STORM COSTS SHOULD BE RECOVERED?

A: For the reasons I have discussed, the storm damage costs should be transferred from the rate base to an operating and maintenance expense.

In the alternative, the Commission should require that DEC purchase climate risk insurance on its fossil fuel investments to offset storm damage costs. Increasingly, insurance companies are including climate risk as part of their commercial packages to support the damage that corporations will face from

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[76] Petition of DEC for an accounting order to defer incremental Hurricanes Florence and Michael and Winter Storm Diego Storm Damage Expenses, No. E-7, Sub 1187. DEC itself estimates an annual budget of $24 million to address major storm damage, though this is likely to be far greater in near future because DEC stated that it did not "factor climate change into the consideration of the frequency of major events or in determining the budget amount." DEC Response to CBD & AV DR 1-IV-5; DEC Response to CBD & AV DR 2-33.

[77] Testimony of Shaye Wolf at 20-24.

[78] *Id.*

climate-driven disasters, like Florence, Michael, Diego,[79] and it is fiscally responsible for DEC to purchase such insurance as a way to ultimately lower the burden on ratepayers. At the same time, for surplus cost, the Commission should move any remaining storm costs to DEC's operating expenses under the condition that DEC's 2020 IRP incorporate significant investments in clean and renewable energy that displaces and phases out the fossil fuel energy that is contributing to the climate-induced disasters, including Florence, Michael, and Diego.

V. DEC'S CHARGING OF CUSTOMERS FOR DUES AND PAYMENTS TO OUTSIDE ENTITIES ENGAGED IN LOBBYING ACTIVITIES.

Q: DOES DEC SEEK TO RECOVER AS AN 'ABOVE THE LINE' EXPENSE FOR PAYMENTS MADE TO OUTSIDE ENTITIES THAT ENGAGE IN POLITICAL LOBBYING?

A: Yes. DEC pays dues and makes other payments to outside entities that engage in lobbying and other political activities, and DEC's Application includes charging as 'above the line expenses' portions of its payments to these organizations. These include the Edison Electric Institute ("EEI"), Utility Water Action Group, the Institute for Nuclear Power Operations, the Nuclear Energy

[79] See, e.g., UNFCCC, Partnerships to Advance Climate Risk Insurance Approaches I Grenada, Jamaica, Saint Lucia, available at https://unfccc.int/climate-action/momentum-for-change/financing-for-climate-friendly/establishing-partnerships-to-advance-climate-risk-insurance-approaches.

Institute, and various Chambers of Commerce.[80]

Q: WHAT IS DEC'S EXPLANATION FOR THESE PAYMENTS?

A: DEC asserts that it does not pay these entities for their lobbying activities, stating, for example:

- With respect to Edison Electric Institute, DEC asserts that the utility's $1,037,568 payment represents "DE Carolinas' allocated portion of the non-lobbying membership dues paid to EEI."[81]
- With respect to the Institute of Nuclear Power Operations, which DEC paid $5,389,891, DEC asserts that "[t]hough this organization does engage in some lobbying activities, the Company has confirmed that this amount is not related to lobbying activities."[82]
- With respect to the Nuclear Energy Institute, which DEC paid $3,062,234, DEC asserts that "[t]hough this organization does engage in some lobbying activities, the Company has confirmed that this amount is not related to lobbying activities." *Id.*
- Finally, with respect to various branches of the Chamber of Commerce, DEC asserts that "[f]unds paid to the Chamber of Commerce that are not specified as a donation or lobbying on the Chamber invoice are generally assumed to be in support of business or economic development and are considered to be properly

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[80] DEC Response to CBD & AV DR 2-20, 2-21 and 2-22 .

[81] DEC Response to CBD & AV DR 2-20.

[82] DEC Response to CBD & AV DR 2-21, Attachment CBD & AV 2-21-E1-16c.xlsx.

charged as a utility operating expense that should be included in the Company's cost of providing electric service to customers."[83]

Q: WHAT ARE YOUR CONCERNS REGARDING THESE PAYMENTS?

A: I have two related concerns with DEC's inclusion as an 'above the line' expense its financial support for outside entities that engage in lobbying and other political activities. First, as I will discuss next, the U.S. Supreme Court has ruled that, to comply with the First Amendment, individuals may not be compelled to provide financial support to entities that engage in political activities, regardless of how those specific funds are used. Under this precedent, DEC cannot be permitted to include any of its financial support to these organizations as a cost of service.

Second, even assuming it could be permissible to allocate a portion of the funds paid to these entities as an 'above-the-line' expense, DEC has not demonstrated that, in fact, these funds are not being used to support lobbying or other political activities. For these reasons, I recommend that the Commission reject DEC's request to include payments to these third party organizations as part of the cost of service.

Q: PLEASE EXPLAIN THE BASIS FOR YOUR CONCERN THAT EDISON ELECTRIC INSTITUTE ENGAGES IN CONTROVERSIAL POLITICAL ACTIVITIES.

A: The Edison Electric Institute ('EEI") is the leading trade association for investor-

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[83] DEC Response to CBD & AV DR 2-22, Attachment "CBD AV 2-22 Dues and Subscriptions," n.1.

owned utilities and other entities.[84] With a budget of more than $90 million,[85] most of which is derived from membership dues, EEI wields tremendous power in influencing regulatory and policy decisions at federal, state, and international levels.

EEI has long been engaged in controversial political advocacy regarding activities that adversely impact the public. For example, according to publicly available internal documents, in recent years EEI itself has emphasized its own efforts toward:

- Advocating that the U.S. Environmental Protection Agency ("EPA.") set an ozone standard "at the top end of the proposed range," rather than a more environmentally-protective ozone standard;[86]
- Challenging EPA actions designed to protect human health and the environment;[87]
- "[A]chiev[ing] the industry's goals of preserving existing regulation of" toxic chemicals in amending the Toxic Substances Control Act[88]; and
- Delaying implementation of the federal Clean Power Plan, which was designed to protect human health and the environment from air and climate pollution, and succeeding in implementing "less stringent"

[84] *See* "About EEI," available at https://www.eei.org/about/Pages/default.aspx.

[85] *See* EEI Form 990, 2018, available at https://www.documentcloud.org/documents/6553997-Edison-Electric-Institute-2018.html.

[86] *See* GR-2 (EEI "2015 Results in Review"), also available at http://big.assets.huffingtonpost.com/eeibooklet.pdf.

[87] *Id.* at 6.

[88] *See* GR-3 (EEI 2016 Results in Review").

requirements for coal plants.[89]

EEI also regularly funds other groups that engage in controversial political advocacy, including the Utility Solid Waste Activities Group and Utility Air Regulatory Group.[90] These groups, in turn, have a long history of anti-environmental advocacy, including litigation and lobbying against efforts to advance environmental protection.[91]

According to EEI's Form 990s – a reporting document which it is required to provide to the Internal Revenue Service and make publicly available each year[92] – EEI also provides direct funding to purely political activities, such as funding the Republican and Democratic Governors and Attorney Generals' Associations and contributions to state and local offices, as well as other political

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89 *See* GR-2 (EEI 2015 Results in Review)

90 *See* Anderson, et al., *Paying for Utility Politics: How utility ratepayers are forced to fund the Edison Electric Institute and other political organizations,* Energy and Policy Institute, (2017) at 15 (available at https://www.energyandpolicy.org/wp-content/uploads/2017/05/Paying-for-utility-politics-ratepayers-funding-the-Edison-Electric-Institute.pdf)*; see also* Coleman, Z. and Guillen, A, *Documents detail multimillion-dollar ties involving EPA official, secretive industry group,* Politico (2019) available at https://www.politico.com/story/2019/02/20/epa-air-pollution-regulations-wehrum-1191258; *see also* https://www.energyandpolicy.org/utility-air-regulatory-group/ (summarizing UARG's work)*; see also* GR-4 (sample invoices).

91 *See* Kasper, M., *UWAG and USWAG the secretive utility groups that also target EPA safeguards remain after Utility Air Regulatory Group disbands*, Energy and Policy Institute, (2019), available at https://www.energyandpolicy.org/uwag-and-uswag-the-secretive-utility-groups-that-target-epa-rules/; *see also, e.g.,* Utility Water Act Group's Petition for Reconsideration of EPA's final rule titled "Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category," 80 Fed. Reg. 67,838 (Nov. 3, 2015), available at https://www.epa.gov/sites/production/files/2017-03/documents/letter_to_epa_submitting_petition_for_reconsideration_w_exhibits-c_508.pdf (requesting the weakening of environmental protections afforded under the Clean Water Act).

92 *See* https://www.irs.gov/forms-pubs/about-form-990.

organizations.[93]

EEI has also lobbied extensively against policies designed to advance the transition to clean energy solutions, such as rooftop solar policies.[94]

Q: WHAT PORTION OF THE FUNDING THAT DEC IS PROVIDING TO EEI IS FOR LOBBYING ACTIVITIES?

A: DEC has reported $261,742 in payment to EEI that relates to the "lobbying-related membership dues paid to" EEI, and which DEC asserts is not included as an 'above-the line' expense and thus is "not included in the cost of service." DEC has reported $1,037,568 in payment to EEI that represents DEC's "non-lobbying membership dues paid to EEI." Relying on those amounts, the total paid to EEI is $1,299,310, of which approximately 20% represents payments for lobbying.[95]

Q: PLEASE EXPLAIN THE BASIS FOR YOUR CONCERN THAT THE

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[93] *See* EEI Form 990, 2018, at 17-20, available at https://www.documentcloud.org/documents/6553997-Edison-Electric-Institute-2018.html; *see also* EEI 2017 Form 990, available at https://www.documentcloud.org/documents/5218920-EEI-2017-Form-990.html (listing over $1 million on lobbying)

[94] *See, e.g.* Joby Warrick. Utilities wage campaign against rooftop solar, Washington Post, March 7, 2015, available at https://www.washingtonpost.com/national/health-science/utilities-sensing-threat-put-squeeze-on-booming-solar-roof-industry/2015/03/07/2d916f88-c1c9-11e4-ad5c-3b8ce89f1b89_story.html; *see also* "Edison Electric Institute Campaign Against Distributed Solar," Energy and Policy Center, available at https://www.energyandpolicy.org/edison-electric-institute-campaign-against-distributed-solar/; *see also* Climate Investigations Center, EEI (detailing EEI's support for anti-renewables legislation) (available at https://climateinvestigations.org/trade-association-pr-spending/edison-electric-institute/); *accord* John M. Broder, *Industry Flexes Muscle, Weaker Energy Bill Passes*, New York Times, Dec. 14, 2007 (explaining how EEI "carried out an extensive lobbying campaign warning that" a renewable energy mandate " would cause sharp increases in electric rates"), available at https://www.nytimes.com/2007/12/14/washington/14energy.html?_r=1&hp&oref=slogin.

[95] DEC Response to CBD & AV Request No. 2-20.

NUCLEAR ENERGY INSTITUTE ENGAGES IN CONTROVERSIAL POLITICAL ACTIVITIES.

A: The Nuclear Energy Institute ("NEI") is the trade association for the nuclear industry.[96] According to publicly available records, NEI reported approximately $2 million on lobbying in both 2018 and 2017.[97] NEI also donates to political PACs, with 35% going to Democrats and 65% to Republicans in 2018.[98]

NEI advocates for nuclear power, which the Supreme Court itself has characterized as a "controversial issue[],"*Consolidated Edison Co. v. PSC*, 447 U.S. 530, 543 (1980), and for ratepayers to subsidize nuclear power.[99] On behalf of its members, NEI also seeks to preserve existing nuclear plants[100] and build small modular reactors.[101]

Q: **PLEASE ELABORATE ON YOUR CONCERN THAT ALLOWING DEC**

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96 *See* About NEI, available at https://www.nei.org/about-nei.

97 *See* Center for Responsive Politics, *Annual Lobbying by Nuclear Energy Institute (2017)*, https://www.opensecrets.org/lobby/clientsum.php?id=D000000555&year=2017; *see also* Center for Responsive Politics, *Annual Lobbying by Nuclear Energy Institute (2018)*, https://www.opensecrets.org/lobby/clientsum.php?id=D000000555&year=2018; *see also* U.S. Senate Office of Public Records, *Nuclear Energy Institute Search Results (2017-2018)*, Query the Lobbying Disclosure Act Database, https://soprweb.senate.gov/index.cfm?event=processSearchCriteria).

98 *See* Center for Responsive Politics, *Contributions to Federal Candidates, 2018 cycle, Nuclear Energy Institute*, https://www.opensecrets.org/orgs/summary.php?id=D000000555&cycle=2018; *see also* U.S. Federal Election Commission, *Nuclear Energy Institute Federal Political Action Committee (C00239848), 2017-2018 Disbursements,* Campaign Finance Data, https://www.fec.gov/data/disbursements/?committee_id=C00239848&two_year_transaction_period=2018&data_type=processed).

99 *See* Nuclear Energy Institute, "Incentives for Energy Production," available at https://www.nei.org/Issues-Policy/Economics/Incentives-for-Energy-Production

100 *See* Nuclear Energy Institute, "Preserve Nuclear Plants" available athttps://www.nei.org/advocacy/preserve-nuclear-plants

101 *See* "With New Reactors, a Better World Awaits," NEI website, available at https://www.nei.org/advocacy/build-new-reactors.

TO INCLUDE PORTIONS OF ITS PAYMENTS TO THESE TYPES OF ENTITIES AS PART OF THE COST OF SERVICE CONTRAVENES RATEPAYERS' RIGHTS UNDER THE FIRST AMENDMENT.

A: Prior to 2018, it had been well-accepted that utilities could charge as a cost of service *part* of their payment to trade groups and other organizations that engage in lobbying and political activities, based on the premise that the funds being charged as an 'above-the-line' expense are only being used to support the groups' non-political work. The Supreme Court long ago indicated that such an approach is appropriate, *Consolidated Edison Co. v. Pub. Svc. Commn*, 447 U.S. 530 (1980), relying on a similar approach the Court had applied for compelled union dues. *Id.* at 543 n.13 (citing *Abood v. Detroit Board of Educ.*, 431 U.S. 209 (1977)).

However, in 2018 the Supreme Court found this approach inconsistent with the First Amendment in the union dues context, and instead concluded that because it is too difficult to distinguish how the funds are being used, employees could not be compelled to pay even for a union's non-political work. *Janus v. AFSCME, Council 31*, 138 S. Ct. 2448 (2018); *see also Knox v. SEIU, Local 1000*, 567 U.S. 298 , 318-19 (2012).

DEC ratepayers object to the work of groups like EEI, NEI and other entities they are forced to support as part of the cost of service, because these groups not only support political candidates and activities they oppose, but also lobby against regulations designed to protect the environment, oppose clean energy initiatives, and otherwise promote the entrenched interests of incumbent utilities at the expense of the public interest.[102]

In light of these concerns, and consistent with recent Supreme Court rulings, DEC should not be permitted to include as a cost of service *any* portion of its payments to entities that engage in lobbying or other political activities.

Q: WHAT OTHER CONCERNS DO YOU HAVE REGARDING DEC'S TREATMENT OF PAYMENTS TO THESE GROUPS AS A COST OF SERVICE?

A: Even under the approach taken prior to the Supreme Court's 2018 ruling in *Janus*, DEC has not demonstrated that it is affirmatively not seeking to charge lobbying or political activities as a cost of service. In particular, it should not be sufficient for DEC to simply assert, in response to discovery requests, that payments are "generally assumed" to be properly charged,[103] or for DEC to simply claim in Excel spreadsheets that "the Company has confirmed" that the amounts it is charging customers are "not related to lobbying activities."[104] In short, DEC has provided no evidence regarding the specific steps taken to insure that lobbying or political expenses are not being included as part of the cost of service.

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[102] *See* GR-5 (declarations from DEC ratepayers opposed to the activities of these groups); *see also, e.g.,* "Conservatives for Clean Energy poll finds strong bipartisan support for renewables in North Carolina," Solar Power World, Apr. 4, 2019 (reporting that "78% of voters believe that North Carolina's current system of a controlled utility serving as the sole source of energy is an outdated model and that elected officials need to enact laws that promote innovation and competition to meet our energy needs").

[103] DEC Response to CBD & AV DR 2-22, Attachment "CBD AV 2-22 Dues and Subscriptions", n.1.

[104] DEC Response to CBD & AV DR 2-21, Attachment "CBD & AV 2-21-E1-16c.xlsx". *see also supra* at 29 (summarizing DEC's statements regarding these payments).

After DEC provided its initial discovery responses on this issue to Intervenors, the Center and Appalachian Voices asked DEC to confirm that it would not be relying on any additional evidence to demonstrate that customers will not be charged as a cost of service to support the lobbying or political activities of outside organizations, asking DEC to: "confirm DEC does not intend to introduce or rely on any further justification for the payments reflected in the documents provided, including, for example, (a) why DEC maintains such dues and fees should be included in the cost of service; (b) how the funds will be used by recipients; or (c) any other information requested about the recipient organizations."[105] Intervenors further stated that, "[u]nless we hear from you otherwise, we will assume that DEC has no such further information or justifications and will not seek to introduce them into this proceeding."[106] DEC's complete response to this request is detailed above.[107]

Given that DEC's assertions of what is "generally assumed," DEC's summary claim to have "confirmed" how payments are used, and narrative of services these organizations provide, is the entirety of the evidence DEC has provided to substantiate its assertion that the funds are being properly used, Intervenors recommend that the Commission deny recovery of all these political expenses.

At bare minimum, Intervenors urge the Commission to apply the new

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105 Response to CBD & AV Supplemental Data Request 1-2.
106 *Id.*
107 *See supra* at 36.

standard under Docket No. M-100, SUB 150, where the Commission has proposed that, to address this precise concern, "[i]n every application for a change in rates, the utility shall certify in its prefiled testimony that its application does not include costs for lobbying, political or promotional advertising, a political contribution, or a charitable contribution."[108] Given that DEC has provided no such certification, and has assured Intervenors that it will not be providing any "further information or justifications" related to these payments[109], I recommend that DEC's request to include these payments as a cost of service be denied.

Q: DO ANY THIRD-PARTY REGULATORY ORGANIZATIONS PROVIDE OVERSIGHT OF EDISON ELECTRIC INSTITUTE OR OTHER GROUPS THAT ENGAGE IN LOBBYING AND ARE FUNDED BY UTILITIES LIKE DEC?

A: I do not believe there is any regulatory oversight of the allocation of trade association membership dues today. Until about twenty years ago, the National Association of Regulated Utility Commissioners ("NARUC") conducted annual trade association audits, which helped to inform which portion of EEI payments could reasonably be allocated to customers.[110] Unfortunately, it does not appear

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108 *See In the Matter of Petition for Rulemaking Proceeding to Consider Proposed Rule to Establish Procedures for Disclosure and Prohibition of Public Utility Lobbying, Advertising and Other Expenditures*, No. M-100, SUB 150, Order Aug. 29, 2019, at Appendix B, p. 3.

109 Response to CBD & AV Supplemental Data Request 1-2.

110 *See* NARUC Bd. of Directors, Resolution Regarding Discontinuation of the Committee on Utility Oversight (adopted Mar. 8, 2000), available at http://pubs.naruc.org/pub/5398B543-354-D714-51D3-90ACAB1DA952.

that there is any ongoing third-party mechanism to ensure that these payments are properly allocated.

Q: ARE YOU RECOMMENDING THAT DEC NOT BE ALLOWED TO FUND TRADE ASSOCIATIONS OR OTHER OUTSIDE GROUPS FROM FUNDS THAT ARE NOT CHARGED TO RATEPAYERS?

A: No. Intervenors are not suggesting that DEC and/or its parent company are not free to spend their profits as they see fit, including deciding to fund groups engaged in anti-environmental advocacy, if that is how the company chooses to spend its resources. Intervenors simply are asserting that customers should not be required to pay directly for such activities as part of the cost of service, and that even if the Commission does not agree that the First Amendment proscribes any such payments at all to such groups, DEC should not be permitted to charge customers for these payments because it has failed to provide sufficient evidence demonstrating that the payments will not in fact be used for lobbying or political activities.

Q: SPEFICALLY, WHICH PAYMENTS ARE YOU ASKING THE COMMISSION TO EXCLUDE FROM THE COST OF SERVICE?

A: In light of the foregoing, I recommend that the Commission disallow recovery for DEC payments to: (i) Edison Electric Institute; (ii) Nuclear Energy Institute; (iii) Institute of Nuclear Power Operations; (iv) Utility Water Act Group; (v) all Chambers of Commerce entities.

VI. CONCLUSION

Q: PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

~~A: I recommend that the Commission center considerations of the climate crisis, particularly in the context of E.O. 80 and Clean Energy Plan goals, in this rate proceeding and other utility proceedings as a means of safeguarding the public interest.~~

Specifically, I respectfully recommend that the Commission:

- Postpone this rate case until after the 2020 IRP, or on the alternative, reject the rate increase associated with new fossil fuel capital expenditures and certain fossil power-related Grid Improvement Plan costs;
- Reject the request for accounting deferral of GIP costs until after DEC's upcoming 2020 Integrated Resource Plan proceeding;
- Remove all storm damage costs from the rate base and place them in operating expenses; and
- Disallow cost recovery for DEC payments to political advocacy and lobbying groups.

Q: DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A: Yes, it does.

CHAIR MITCHELL: All right. Next up we have the North Carolina Justice Center.

MR. NEAL: Thank you, Chair Mitchell. This is David Neal. At this time we'd call Jonathan Wallach to the screen.

CHAIR MITCHELL: All right. Good afternoon, Mr. Wallach. I'd like you to raise your right hand, please, sir.

Jonathan Wallach; Having been duly affirmed,
Testified as follows:

CHAIR MITCHELL: All right. Thank you, Mr. Neal. You may proceed.

DIRECT EXAMINATION BY MR. NEAL:

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

A Yes. My name is Jonathan Wallach. I am Vice President of Resource Insight, and my business address is 5 Water Street, Arlington, Massachusetts.

Q Mr. Wallach, on February 18th, 2020, did you cause to be prefiled in Docket Number E-7, Sub 1214, direct testimony consisting of 51 pages, as well as nine exhibits to your testimony?

A I did.

Q Do you have any changes or corrections to your prefiled direct testimony?

A I do not.

Q If I asked you the same questions here today, would your answers be the same?

A They would.

Q And do you have any changes or corrections to the exhibits to your direct testimony?

A I do not.

MR. NEAL: Chair Mitchell, at this time, I would move that Mr. Wallach's prefiled direct testimony be entered into the record and copied as if given orally from the stand, and that Mr. Wallach's exhibits attached to his testimony be marked for identification as Exhibits JFW-1 through JFW-9.

CHAIR MITCHELL: All right. Mr. Neal, hearing no objection to your motion, Mr. Wallach's testimony shall be copied into the record as if given orally from the stand, and the exhibits to his testimony shall be marked as they were when prefiled.

MR. NEAL: Thank you.

(Whereupon, the prefiled direct testimony of Jonathan F. Wallach was copied into the record as if given orally from the stand.)

(Whereupon, Exhibits JFW-1 through JFW-9 were identified as premarked.)

STATE OF NORTH CAROLINA
BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

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

DIRECT TESTIMONY AND EXHIBITS OF

JONATHAN F. WALLACH

ON BEHALF OF

THE NORTH CAROLINA JUSTICE CENTER,
NORTH CAROLINA HOUSING COALITION,
NATURAL RESOURCES DEFENSE COUNCIL, AND
SOUTHERN ALLIANCE FOR CLEAN ENERGY

February 18, 2020

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JFW-3 – Duke Energy Carolinas Response to North Carolina Justice Center, *et. al*., Data Request 3-3, Docket No. E-7, Sub 1214, January 20, 2020.

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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 U.S. 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. 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 September 30, 2019, Duke Energy Carolinas, LLC ("DEC" 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 Facilities Charge ("BFC") 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 BFC.

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

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[1] On October 23, 2019, DEC filed a corrected version of Mr. Pirro's direct testimony. I respond to the this corrected version of Mr. Pirro's 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 DEC'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 DEC to discontinue its use of the minimum-system method for classifying distribution costs in the Company's COSS. Instead, consistent with best practice, DEC 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.

[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 DEC'S PROPOSAL REGARDING THE RESIDENTIAL BFC.

A: The Company has not justified its proposal to maintain the residential BFC 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 BFC. The Company's proposal to continue recovering usage-driven costs through the residential BFC 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 BFC for residential customers at its current rate of $14.00 per bill. Instead, I recommend that the residential BFC be reduced to $11.15, reflecting the actual cost to connect a residential customer. Consistent with long-standing cost-causation and rate-design principles, a monthly BFC of $11.15 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 zeroload 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 DEC 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 DEC and other electric utilities of minimum-system classification methods for either cost-allocation or rate-design purposes. Instead, DEC 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 DEC's proposal for the residential BFC 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. <u>DEC'S COSS OVER-ALLOCATES COSTS TO THE RESIDENTIAL RATE CLASSES</u>

Q: PLEASE DESCRIBE THE COMPANY'S REQUESTED REVENUE INCREASE.

A: The Company is requesting that electric retail base rates be increased on average by 9.7% in order to recover an expected revenue deficiency of about $445.3 million in the 2018 test year.[3] Of the total $445.3 million requested base revenue

[3] Derived from data provided in Pirro Exhibit 4, attached to *Corrected Direct Testimony of Michael J. Pirro for Duke Energy Carolinas, LLC*, Docket No. E-7, Sub 1214 (October 23, 2019) [hereinafter "Corrected Pirro Direct"]. The 9.7% value represents the percentage increase over revenues under current base rates exclusive of current rider revenues.

increase, DEC proposes to allocate about $233.9 million to residential customers. This amount represents a 10.7% increase over residential test-year revenues under current base 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 DEC 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

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[4] *Id.* The $233.9 million amount represents the total allocation to all residential rate schedules. Standard residential service is provided under Rate Schedule RS. Rate Schedule RE is applicable to residential customers who use electricity for all major end-uses. Rate Schedule ES is applicable to residential customers whose homes meet Energy Star standards. Rate Schedule ESA is applicable to residential customers who use electricity for all major end-uses and whose homes meet Energy Star standards. Time-of-use residential service is provided under Rate Schedule RT.

[5] Corrected Pirro Direct, 11.

[6] Pirro Exhibit 4.

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.

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

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[7] *Direct Testimony of Janice Hager for Duke Energy Carolinas, LLC*, Docket No. E-7, Sub 1214, 5-6 (September 30, 2019) [hereinafter "Hager Direct"].

based on customer demand coincident with class peaks. 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.

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

[8] Specifically, DEC 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).

equipment is sized to meet minimal load.[9] In other words, the Company's 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 DEC incurs a "minimum" amount of distribution-grid costs to serve customers at

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[9] Hager Direct, 14.

[10] The Company's minimum-system analysis of pole costs does not assume the same number of poles as currently installed on the DEC distribution system. Instead, DEC 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 DEC distribution system.

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 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

[11] In fact, it is unlikely that DEC would incur the cost to connect a zero-load customer under the Company's line-extension policies and would instead require the zero-load customer to bear any such connection cost. The Company's line-extension policies and procedures are set forth in the *Distribution 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).

as demand-related.[13] Consequently, applying the minimum-size method to the 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

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[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 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. On the other hand, DEC simply assumes without any reasonable basis that all conduits currently installed on the system are minimum-size. Thus, the Company's approach arbitrarily classifies all conduit costs as customer-related.

cost for this minimum-size equipment should be classified as demand-related. However, under the minimum-size method, that demand-related portion of the 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]

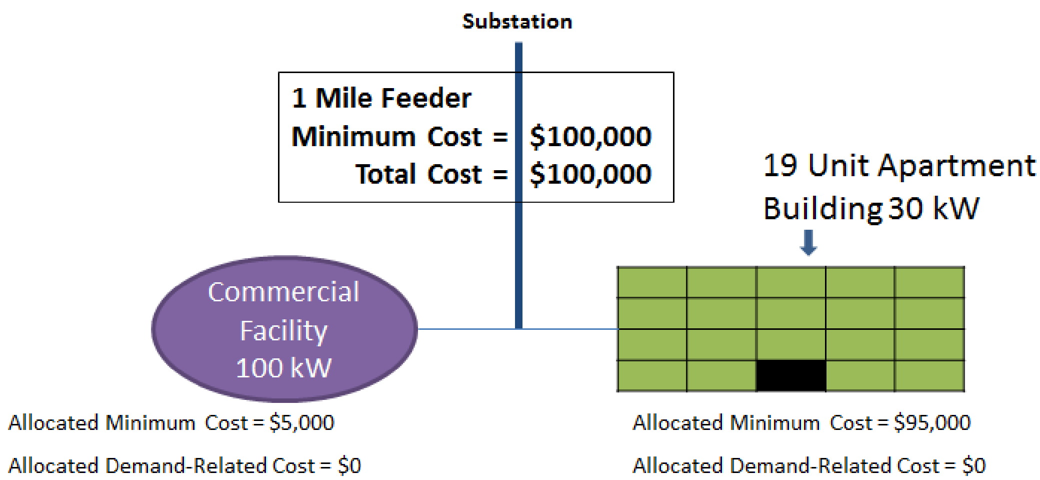
Q: PLEASE PROVIDE AN ILLUSTRATIVE EXAMPLE OF THIS DOUBLE-ALLOCATION PROBLEM.

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-

[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.

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. 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]

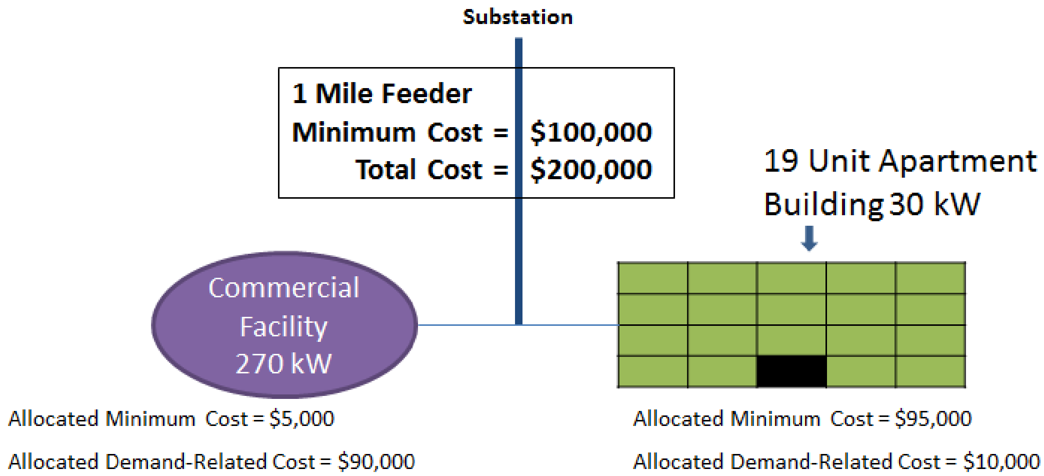
Figure 1a



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

[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 DEC 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, DEC in South Carolina had been relying on the basic customer method to classify distribution-grid costs as demand-related, and had been doing so ever since the South Carolina Public Service Commission ordered the Company's predecessor to stop relying on the minimum-system classification method in 1991.[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 DEC 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, DEC modified its COSS to classify distribution plant costs based on the basic customer method rather than on the minimum-size method.[20] Specifically, DEC classified all pole, conductor, conduit, and line

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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] Public Service Commission of South Carolina, *Order Approving Rate Increase*, Order No. 91-1022, Docket No. 91-216-E, 7 (November 18, 1991). Because the Company's most recent rate case in South Carolina was settled, 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. *See* Public Service Commission of South Carolina, *Order*, Order No. 2019-323, Docket No. 2018-319-E, 22 (May 21, 2019).

[20] DEC response to NC Justice Center et al. Data Request Item No. 3-3. Attached as Exhibit JFW-3.

transformer costs as demand-related for this version of the COSS. This modified 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, DEC is requesting an increase in base revenues (i.e., excluding rider revenues) of 9.7% on average for all customers and proposing an increase of 10.7% 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 9.7% – equivalent 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 DEC to discontinue its use of the minimum-system method for classifying distribution plant costs in the Company's COSS. Instead, DEC 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, DEC 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 DEC 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.

[21] Hager Direct, 11.

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 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 DEC ACCOUNT FOR LOAD DIVERSITY IN THE SIZING OF DISTRIBUTION PLANT?

A: Yes. As is typical for electric utilities, DEC 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)", DEC 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 DEC 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, DEC 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.

[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 DEC 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 DEC 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 DEC 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, DEC 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 does not have this data available".[24]

While DEC 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 would likely be less than the 9.7%

[24] DEC response to NC Justice Center et al. Data Request Item No. 3-2. Attached as Exhibit JFW-5. In a follow-up e-mail, the Company's counsel clarified that the data is available, but that revising the Company's COSS to incorporate such data "is not easily done and would require original work". A copy of this e-mail is included in Exhibit JFW-5.

requested system-average increase if the Company's COSS were 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 DEC 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. RESIDENTIAL BASE REVENUES SHOULD BE INCREASED BY NO MORE THAN THE APPROVED SYSTEM-AVERAGE INCREASE

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 9.7% in order to recover an expected revenue deficiency of about $445.3 million in the 2018 test year. Of the total $445.3 million requested base revenue increase, DEC proposes to allocate about $233.9 million to residential customers. This amount represents a 10.7% 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

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[25] RAP Cost Allocation Manual, 150.

results of the Company's COSS. Under Mr. Pirro's proposed allocation method, the residential class is first allocated $229.8 million of the total requested $445.3 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 $16.2 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 $4.0 million, representing 25% of the current under-earnings relative to the system-average achieved rate of return.[26]

Q: WOULD THE COMPANIES' 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 10.7%. In contrast, if the misclassification of distribution plant costs in the Company's COSS were corrected, residential base revenues would increase by only 9.7% (equivalent to the requested system-average increase) 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

[26] Pirro Exhibit 4.

rate classes in aggregate are currently over-earning relative to the system-average achieved rate of return. The increase in residential base revenues would be even less than 9.7% 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 FACILITIES CHARGE FOR RESIDENTIAL CUSTOMERS IS NOT COST-BASED</u>

Q: WHAT IS THE BASIC FACILITIES CHARGE?

A: The BFC 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 BFC FOR RESIDENTIAL CUSTOMERS?

A: The Company proposes to maintain the residential BFC at its current rate of $14.00 per monthly bill.[27]

Q: IS THE COMPANY'S PROPOSAL FOR THE RESIDENTIAL BFC REASONABLE?

[27] Corrected Pirro Direct, 12.

A: No. As discussed in detail below, the current rate for the residential BFC inappropriately recovers usage-driven costs through the BFC. This recovery of usage-driven costs in the fixed BFC 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. DEC's Proposal for the Residential BFC 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]

[28] These problems of cross-subsidization and economically inefficient pricing would be even more pronounced if the residential BFC were increased to the level that Mr. Pirro believes would "better reflect all customer-related costs". [Corrected Pirro Direct, 11.] For example, Mr. Pirro believes that it would be appropriate to increase the BFC for Rate Schedule RS customers to $22.56 per bill. [Pirro Exhibit 8.] However, such an increase would result in the inappropriate recovery through the BFC 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 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]

[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

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[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 BFC 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 BFC 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 BFC?

A: Uncollectible costs tend to vary with revenues and thus with usage. Thus, as discussed above, such costs are appropriately recovered through the volumetric energy rate.

Q: HOW DOES DEC ESTIMATE THE CUSTOMER-RELATED DISTRIBUTION-GRID COSTS THAT ARE INAPPROPRIATELY RECOVERED THROUGH THE CURRENT RESIDENTIAL BFC?

A: As discussed in Section II, DEC 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 DEC TO RECOVER COSTS THROUGH THE RESIDENTIAL BFC 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 BFC 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 BFC 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 BFC of $11.15 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 BFC be reduced from its current rate of $14.00 to $11.15.

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, DEC provided the unit cost results from a cost of service study that classifies distribution costs using the basic customer method.[37] These results show an allocation to the residential rate classes of about $244.5 million in customer-related costs. I then adjusted this total in order to remove uncollectible costs for the reasons discussed above. Dividing the net amount of $234.9 million by the number of residential bills yields a connection cost per residential customer of $11.15 per month.

Table 2: Derivation of the Cost to Connect a Residential Customer

	Residential Cost	Residential Bills	Cost per Bill
Customer-Related Cost	$244,483,314	21,061,063	$11.61
Less			
Uncollectible Expense	($9,605,989)	21,061,063	($0.46)
Total	$234,877,326		$11.15

Q: WHAT ACCOUNTS FOR THE $2.85 DIFFERENCE BETWEEN YOUR $11.15 ESTIMATE OF THE RESIDENTIAL CONNECTION COST AND THE CURRENT RATE OF $14.00 FOR THE RESIDENTIAL BFC?

[37] DEC response to Public Staff Data Request Item No. 100-18 (revised). Attached as Exhibit JFW-6.

A: The $2.85 difference between my $11.15 estimate of the cost to connect a residential customer and the current $14.00 BFC 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 $2.85 IN USAGE-DRIVEN COSTS THROUGH THE CURRENT RESIDENTIAL BFC?

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.

B. The Current Residential BFC Creates Intra-Class Cost Subsidies

Q: HOW DOES THE CURRENT RESIDENTIAL BFC CAUSE SUBSIDIZATION WITHIN THE RESIDENTIAL CLASS?

A: As discussed above, the current residential BFC 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 BFC?

A: The Company estimates about 21.1 million residential bills in the test year.[38] This means that about $60.0 million of usage-driven costs are inappropriately recovered annually through the current residential BFC.[39]

If the usage-driven costs recovered through the current residential BFC 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 22.8 million megawatt-hours.[40] Therefore, if the $60.0 million of usage-driven costs were instead recovered through the volumetric energy rate rather than through the current residential BFC, they would be charged at a rate of 0.26 cents per kilowatt-hour ("¢/kWh").[41] In this case, a residential customer with below-average monthly usage of 500 kWh would contribute about $16 per year toward recovery of the $60.0 million of usage-driven costs while a customer with above-average monthly usage of 1,500 kWh would contribute about $47 per year.[42] Thus, the 1,500 kWh customer would contribute three times more than the 500 kWh customer, in direct proportion to their usage and consistent with accepted principles of cost-causation.

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[38] 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).

[39] The $60.0 million result is derived by taking the product of the annual number of residential bills (21.1 million) and the amount of the current residential BFC in excess of residential connection cost ($2.85 per bill).

[40] The Company's estimate of residential sales in the test year is provided in NCUC Form E-1 Data Request, Item No. 42(c).

[41] The 0.26¢/kWh result is derived by dividing $60.0 million by residential sales of 22.8 million megawatt-hours.

[42] Based on data provided in NCUC Form E-1 Data Request, Item No. 42(c), I estimate monthly usage of 1,081 kWh for an average residential customer.

In contrast, with the current recovery of $60.0 million of usage-driven costs through the residential BFC, each residential customer contributes about $34 per year toward recovery of such costs, regardless of that customer's usage. A below-average 500 kWh customer therefore pays more than double their fair share of these usage-driven costs with the current BFC while an above-average 1,500 kWh customer pays only 72% of their fair share.

Q: WOULD SUBSIDIZATION OF HIGH-USAGE RESIDENTIAL CUSTOMERS BY LOW-USAGE CUSTOMERS BE ELIMINATED IF THE RESIDENTIAL BFC WERE SET AT YOUR RECOMMENDED RATE OF $11.15?

A: No. Even with the residential BFC set at my estimate of residential connection cost, low-usage customers would likely continue to subsidize high-usage customers' costs because customer charges and energy rates are priced at the cost to serve an average-usage customer. For example, Rate Schedule RS 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 BFC 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 BFC 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."[43] In this case, the "what" causing DEC 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.

Within the residential class, higher-usage energy consumers will likely reap greater benefits than lower-usage customers from AMI technologies and services.[44] 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 BFC 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.

[43] National Association of Utility Regulatory Commissioners, *Electric Utility Cost Allocation Manual*, 38 (January 1992).

[44] 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 Carolinas, LLC*, Docket No. E-7, Sub 1214 (September 30, 2019).

C. The Current Residential BFC Dampens Energy Price Signals

Q: DOES THE CURRENT RESIDENTIAL BASIC FACILITIES CHARGE SEND APPROPRIATE PRICE SIGNALS?

A: No. As discussed above, the current residential BFC 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 BFC rather than in the volumetric energy rate dampens price signals and discourages economically efficient behavior by residential customers.

Q: TO WHAT EXTENT DOES THE CURRENT RESIDENTIAL BFC DAMPEN PRICE SIGNALS PROVIDED BY THE RATE SCHEDULE RS VOLUMETRIC ENERGY RATE?

A: With a fixed amount of revenue requirements to be recovered from Rate Schedule RS customers, the higher the BFC, the lower the volumetric energy rate, and vice versa. With the fixed BFC set at its current rate of $14.00 per bill, DEC proposes a volumetric energy rate of 9.91¢/kWh for Rate Schedule RS customers. If, instead, the BFC were set at the cost-based rate of $11.15, I estimate that the volumetric energy rate would have to be increased to 10.38¢/kWh to recover the same allocated revenue requirement.

In other words, DEC is proposing a Rate Schedule RS energy rate that is 0.47¢/kWh, or about 4.5%, less than what the volumetric rate would be if the BFC were set at the cost-based rate of $11.15. Thus, the current residential BFC dampens the price signal provided by the volumetric energy rate by about 4.5%.[45]

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[45] If the BFC were instead set at $22.56 per bill, as Mr. Pirro believes would be appropriate, I estimate that the volumetric energy rate would have be set at 9.09¢/kWh in order to recover the Company's proposed allocation of revenue requirements to the RS rate class. At $22.56, the residential BFC would dampen the price signal provided by the volumetric energy rate by 12.4%.

Q: HOW WOULD RATE SCHEDULE RS CUSTOMERS LIKELY RESPOND TO THE REDUCTION IN THE ENERGY PRICE SIGNAL RESULTING FROM THE COMPANY'S PROPOSAL TO MAINTAIN THE RESIDENTIAL BFC AT ITS CURRENT RATE?

A: Since the volumetric energy rate under the Company's proposal for the residential BFC would be lower than the volumetric energy rate with a cost-based BFC of $11.15, we would expect Rate Schedule RS customers to consume more energy with the current BFC than they would with a cost-based BFC. The magnitude of the increase in energy consumption would depend on: (1) the extent to which the volumetric energy rate with the current BFC is lower than the volumetric energy rate with a cost-based BFC; 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.[46] 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.[47] Table 3 below

[46] The citation for this study is provided in Exhibit JFW-7.

[47] For Rate Schedule RS customers, that would be the energy rate.

lists the results of seven studies of marginal-price elasticity over the last forty years.[48]

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 RS 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 BFC?

A: As discussed above, if the residential BFC continued at $14.00, the Rate Schedule RS volumetric energy rate would be about 4.5% less than it would be if the BFC were set at $11.15. Assuming an elasticity of –0.3, this 4.5% reduction in the volumetric energy rate would result in an increase in energy consumption of about 1.4% for the average Rate Schedule RS customer. This means that all else equal, Rate Schedule RS load after a few years with a $14.00 BFC is expected to

[48] The citations for these studies are provided in Exhibit JFW-7.

be about 1.4% higher than it would be if the BFC were set at the cost-based rate of $11.15.

For comparison, DEC 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 0.2% of forecasted annual residential energy sales.[49] 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 due to the Company's proposal to retain the current $14.00 BFC would undo about seven years of Rate Schedule RS energy-efficiency savings.

V. <u>THE PUBLIC STAFF MSM REPORT FAILS TO MAKE THE CASE FOR MINIMUM-SYSTEM CLASSIFICATION METHODS</u>

Q: WHY DID THE PUBLIC STAFF ISSUE ITS REPORT ON THE MINIMUM SYSTEM METHODOLOGY?

A: In its order in the previous rate case for DEC, the Commission directed the Public Staff to determine whether continued use of minimum-system approaches is warranted for cost-allocation purposes:

[49] Estimated based on data regarding residential sales and energy efficiency savings for the entire DEC service territory provided in response to NC Justice Center et al. Data Request Item No. 1-4 (supplemental). Attached as Exhibit JFW-8.

> 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.[50]

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."[51]

This general belief notwithstanding, the Public Staff recommends that the Commission "request that NARUC, or some other independent entity, undertake

[50] 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).

[51] Public Staff MSM Report, 16-17.

a study of these issues from a national perspective, so as to gain insight from best practices and ideas across the country”.[52]

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. The RAP study concludes that the basic customer method represents best practice with respect to the classification of distribution costs.[53]

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.[54] 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.[55]

Q: IS THIS IDEA OF A MINIMUM PORTION OF UTILITY SPENDING ON DISTRIBUTION SYSTEMS A REALISTIC PORTRAYAL OF TYPICAL DISTRIBUTION PLANNING PRACTICE?

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[52] *Id.*, 17.

[53] RAP Cost Allocation Manual, 18.

[54] Public Staff MSM Report, 8.

[55] *Id.*, 9.

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:

> 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.[56]
>
> 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.[57]
>
> The load growth of the geographical area served by a utility company is the most important factor influencing the expansion of the distribution system.[58]

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 INVESTEMENTMENT ANY MORE PLAUSIBLE WHEN APPLIED TO

[56] Turan Gonen, *Electric Power Distribution System Engineering*, McGraw-Hill, Inc., 3-4 (1986).

[57] *Id.*, 4.

[58] *Id.*, 5.

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, DEC has purportedly designed the Grid Improvement Plan to more reliably, intelligently, and economically serve load in the 21st century.[59]

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.[60] 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.[61]

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[59] *Corrected Direct Testimony of Jay W. Oliver for Duke Energy Carolinas*, LLC, Docket No. E-7, Sub 1214, 9 (October 23, 2019).

[60] *Id.*

[61] Maryland Public Service Commission, Order No. 87591, Case No. 9406, 187 (June 3, 2016) [emphasis added].

On that basis, the Maryland commission committed to considering a benefits-based approach for allocating smart grid investments in future rate cases.[62] 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.

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:

[62] *Id.*, 184.

> 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.[63]

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.[64] 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:

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[63] National Association of Regulatory Utility Commissioners, *Electric Utility Cost Allocation Manual*, 136 (January, 1992).

[64] I attach a copy of this letter as Exhibit JFW-9.

> 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 only 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.[65]

Indeed, as discussed above in Section II, the South Carolina Public Service Commission rejected the use of minimum-system methods and directed the Company's predecessor to use the basic customer method in an order issued one year prior to publication of the NARUC Manual. And despite the fact that the chapter on embedded cost of service studies does not discuss the basic customer method, the 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.[66] The Public Staff furthermore recommends that electric utilities "utilize data gained from AMI meters to implement … demand charges for all rate classes".[67]

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,

[65] Exhibit JFW-9. Emphasis in original.

[66] Public Staff MSM Report, 8.

[67] *Id.*, 17.

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 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."[68]

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

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[68] 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.

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.

VI. <u>RECOMMENDATIONS</u>

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 DEC 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 DEC 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 BFC at its current rate of $14.00 per bill and instead direct DEC to reduce the rate to $11.15 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.

Q Mr. Wallach, did you prepare a summary of your testimony?

A I did.

MR. NEAL: Chair Mitchell, that summary was provided to the Commission and the parties to this docket, as ordered by the Commission, and I would ask that his summary be entered into the record as if given orally from the stand.

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

MR. NEAL: Thank you.

(Whereupon, the summary of Jonathan F. Wallach was copied into the record as if given orally from the stand.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-7, SUB 1214

SUMMARY OF TESTIMONY OF JONATHAN WALLACH
ON BEHALF OF NORTH CAROLINA JUSTICE CENTER,
NORTH CAROLINA HOUSING COALITION,
NATURAL RESOURCES DEFENSE COUNCIL, AND
SOUTHERN ALLIANCE FOR CLEAN ENERGY

My name is Jonathan Wallach and I am Vice President of Resource Insight, Inc. Thank you for the opportunity to testify before the Commission.

In my pre-filed testimony, I first responded to issues relating to problems with the Company's cost-of-service study (COSS). The Company's COSS misallocates distribution costs in two key ways: (1) it misclassifies a portion of such costs as customer-related by relying on a flawed "minimum-system" analysis to classify distribution costs; and (2) it misallocates 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.

In light of the above, I recommended that the Commission direct DEC to stop its use of minimum-system to classify a portion of distribution costs as customer related in the COSS. Instead, DEC should use the "basic customer method" to classify customer-related costs. The basic customer method more accurately reflects those costs that are truly customer-related, in other words, those costs that are driven by the number of customers rather than by usage. The customer-related costs captured by the basic customer method include service drops, customer service and billing costs, and basic metering. This method removes the distribution costs that are improperly included in the minimum system as customer related. Because those distribution costs are incurred to serve load, and thus vary with usage, they should instead be allocated to demand.

In addition, I recommended that the Commission reject the Company's use of the non-coincident peak demand allocator to allocate distribution costs. The non-coincident peak allocator fails to accurately reflect usage patterns of residential customers and causes distribution costs to be over-allocated to the residential classes. 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. To account for these two corrections, I recommended increasing base revenues for the residential rate classes by no more than the overall system-average percentage increase authorized by the Commission, if any.

My testimony next responded to the Company's use of the minimum system in its rate design. The Company justifies maintaining a basic customer charge of $14.00 per month based on the inclusion of usage-driven costs. The Company's proposal runs counter to long-standing principles of rate design and results in a basic customer charge that is higher than is cost-justified. Instead, I recommend a residential basic customer charge of $11.15 per month. This number is based on the unit cost of only those costs which are truly customer-related costs: the costs for meters, service drops, and customer services other than uncollectible accounts.

Without my recommended reduction to the current basic customer charge, residential customers with below-average usage will continue to subsidize larger customers. All residential customers will also receive inaccurate price signals, which dampen incentives to conserve energy or invest in energy efficiency or rooftop solar.

I also reviewed the Public Staff's Minimum System Report and concluded that it did not fulfill the Commission's directive to "document a basis for continued use of minimum system." The Public Staff Report offers no specific guidance or recommendations regarding the appropriate approach for classifying distribution costs in a COSS. Instead, the Public Staff states that it "believes" generally that it is reasonable to use the results of a minimum-system approach for setting the maximum allowable amount that could be recovered in a basic customer charge. The Public Staff assumes that there is a minimum portion of distribution grid costs that are incurred regardless of demand and should thus be deemed "fixed." The Public Staff does not support this assumption, which ignores the actual utility practice of building the grid to serve load.

Finally, in my pre-filed testimony I noted a concern with relying on the minimum system method for cost allocation and rate design when considering the Company's Grid Improvement Plan ("GIP"). These costs are justified on the basis of the benefits they provide, and should therefore be allocated based on the economic benefits received.

Since I submitted my pre-filed testimony, the Justice Center *et al.* and the North Carolina Sustainable Energy Association have reached a partial settlement and stipulation with the Company on certain issues, including support of an accounting order to defer GIP costs for a specific subset of GIP investments. Based on my review of the relevant testimony in support of the settlement and knowledge of routine utility practice, deferral accounting is appropriate in part because these are extraordinary investments intended to provide specific, new benefits and are not routine investments. For those reasons, I support the deferral of certain GIP costs as agreed to in the settlement.

This concludes my summary.

MR. NEAL: Chair Mitchell, Mr. Wallach is available for questions from the Commissioners. I believe no parties have indicated cross.

CHAIR MITCHELL: All right. Abundance of caution for purposes of the record, is there any cross examination for the witness?

(No response.)

CHAIR MITCHELL: All right. Hearing none, we will proceed to questions from Commissioners, beginning with Commissioner Brown-Bland.

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

CHAIR MITCHELL: Okay. Commissioner Gray?

COMMISSIONER GRAY: No questions.

CHAIR MITCHELL: Commissioner Clodfelter?

COMMISSIONER CLODFELTER: I have no questions.

CHAIR MITCHELL: Commissioner Duffley?

COMMISSIONER DUFFLEY: I have no questions.

CHAIR MITCHELL: Commissioner Hughes?

COMMISSIONER HUGHES: No questions, either.

CHAIR MITCHELL: And Commissioner McKissick?

COMMISSIONER McKissick: No questions.

CHAIR MITCHELL: All right, Mr. Wallach. It looks like you are off the hook. We appreciate your being here with us today. You may -- you may step down. Thank you, sir.

MR. WALLACH: Thank you, Chair Mitchell.

CHAIR MITCHELL: Mr. Neal?

MR. NEAL: At this time, we would -- Chair Mitchell, we would move that Mr. Wallach's direct exhibits that have been marked for identification JFW-1 through JFW-9, be entered into the record at this time.

CHAIR MITCHELL: Hearing no objection to your motion, Mr. Neal, the exhibits to Mr. Wallach's testimony will be admitted into evidence.

(Whereupon, Exhibits JFW-1 through JFW-9 were admitted into evidence.)

MR. NEAL: At this time, Justice Center et al. would ask Mr. John Howat to come to the screen. There he is.

CHAIR MITCHELL: All right. Good afternoon, Mr. Howat. Good to see you again. Please raise your right hand.

John Howat; Having been duly affirmed,
Testified as follows:

CHAIR MITCHELL: All right. You may proceed, Mr. Neal.

DIRECT EXAMINATION BY MR. NEAL:

Q Mr. Howat, could you give your name and business address and title for the record?

A Good afternoon. John Howat. I'm Senior Policy Analyst with National Consumer Law Center, 7 Winthrop Square, Boston, Massachusetts.

MR. NEAL: Chair Mitchell, Mr. Howat's prefiled direct and exhibits have already been entered into the record from the consolidated hearing.

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

(Whereupon, Exhibits JH-1 through JH-8 were admitted into evidence.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

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

DIRECT TESTIMONY AND EXHIBITS OF

JOHN HOWAT

ON BEHALF OF

**THE NORTH CAROLINA JUSTICE CENTER,
NORTH CAROLINA HOUSING COALITION,
NATURAL RESOURCES DEFENSE COUNCIL, AND
SOUTHERN ALLIANCE FOR CLEAN ENERGY**

February 18, 2020

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EXHIBITS

Exhibit JH-1 – Resume of John Howat.

Exhibit JH-2 – Duke Energy Carolinas Supplemental Response to North Carolina Justice Center, *et. al.*, Data Request 7-2, Docket No. E-7, Sub 1214, February 17, 2020.

Exhibit JH-3 – Ohio Energy Assistance Resource Guide.

Exhibit JH-4 – Low Income Home Energy Assistance Program Clearinghouse 2014 Ratepayer-funded Affordability Programs.

Exhibit JH-5 – Evaluation of Duke Energy's Helping Home Fund (October 2017).

Exhibit JH-6 – Duke Energy Carolinas response to Public Staff Data Request 171-4, Docket No. E-7, Sub 1214, February 10, 2020.

Exhibit JH-7 – Statement of Position and Comment Letter on Duke Energy Carolinas' Pre-Paid Advantage.

Exhibit JH-8 – Duke Energy Carolinas Response to Public Staff Data Request 171-5 (Tariff-Duke Energy Ohio Rate RSLI), Docket No. E-7, Sub 1214, February 7, 2020.

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

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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

presented testimony before the North Carolina Utilities Commission ("Commission") in Dockets No. E-2 Sub 1142 and No. E-7 Sub 1146.

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 Carolinas' ("Company's" or "DEC'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 DEC service territory. Further, I will comment on the affordability and "home energy security"[6] aspects of prepaid electric service, as recently proposed by DEC. Finally, I present evidence demonstrating that elevated basic customer charges

[6] The term, "home energy security," as used in this testimony, refers residential customer access to and retention of basic, necessary, home utility service without foregoing other necessities (e.g., food, medicine and health care) or maintaining unhealthy indoor temperatures.

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 DEC and approve the $11.15 BFC as proposed by witness Jonathan Wallach. I will also recommend that the Commission direct DEC 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 DEC) service territory as well as programs available to DEC's customers that address affordability with particular focus on residential energy customers."[7] 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.

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[7] North Carolina Utilities Commission, Order Directing Public Staff to File Testimony, p. 2 (Jan. 22, 2020).

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. DEC 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 could help accomplish this goal."[8] Mr. De May also outlined existing programs intended to assist low-income customers, including the Share the Warmth Program, and energy-efficiency programs including the Neighborhood Energy Saver Program.[9]

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.[10]

Disconnections for nonpayment are a key indicator of bill affordability challenges in a utility service territory. Increased disconnections for nonpayment in the DEC service territory over the past two years offer an indication of

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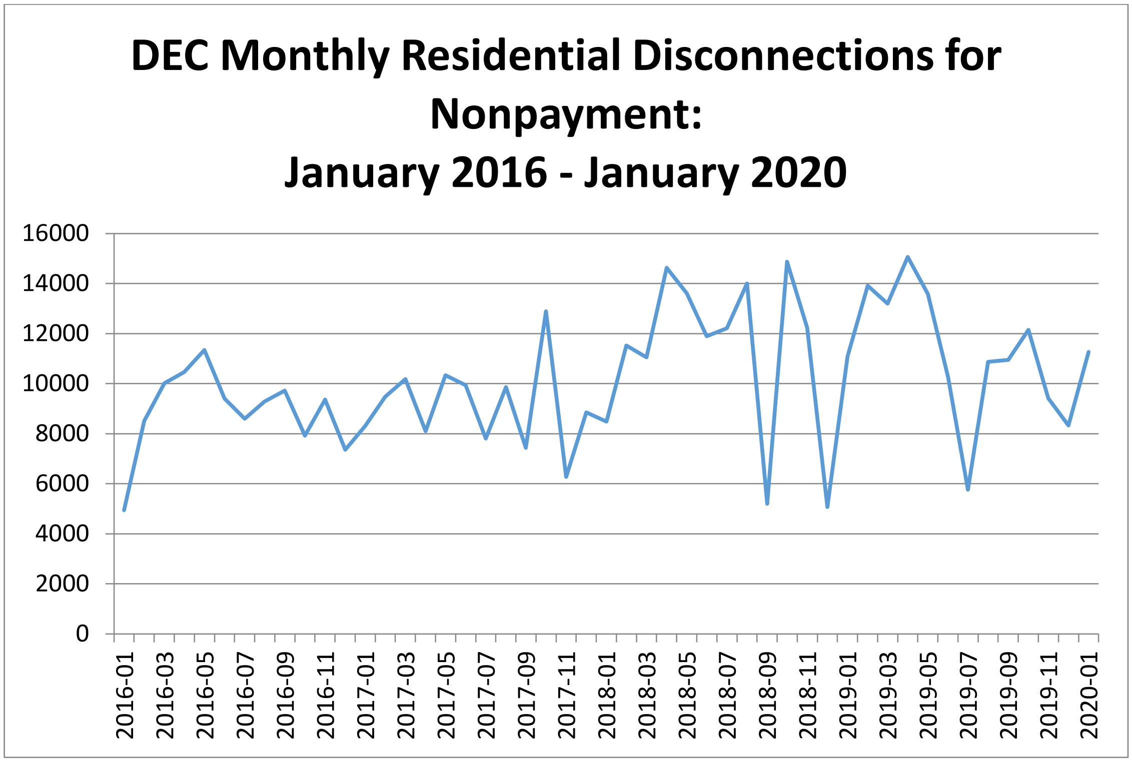
[8] Direct Testimony of Stephen G. De May, p. 9.
[9] *Id.*, p. 8.
[10] *See*, e.g., Direct Testimony of John Howat, Docket No. E-7, Sub 1146 (Jan. 19, 2018).

affordability challenges faced by residential customers. Over the last four years, monthly disconnections for nonpayment more than doubled—from 4,948 in January, 2016 to 11,276 in January, 2020—and have generally trended upward, as reflected the chart below.[11]



Additional information provided by DEC likewise demonstrates that many of the Company's customers regularly face difficulty affording their electric utility service. Each month, large numbers of DEC residential customers are charged late payment fees, or receive a disconnection notice. In the most recent 12 month period, an average of 26% of all DEC residential customers were charged a late payment fee each month.[12] During that same period, an average of over 9% of all residential customers were sent a notice of disconnection each

[11] Implementation of Rule Regarding Customer Disconnects, Docket M-100, Sub 61A (filings of Duke Energy Carolinas from January 2016 to January 2020).
[12] DEC Supplemental Response to NCJC *et al* Data Request 7-2 (Exhibit JH-2).

month.[13] 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.

In addition, data from the United States Census Bureau provides evidence of high rates of poverty in the DEC service territory. The table below, reflecting aggregated census block data within the DEC territory, shows a territory-wide poverty rate of 15.2%, above the national rate of 14.6%. Analysis of the DEC service territory also reveals that just over 35% of the population lives at or below 200% of the federal poverty guidelines, the income-eligibility ceiling for means-tested programs such as the federal Weatherization Assistance Program.

Population, Race, Ethnicity, Poverty, Income, and Housing Characteristics of DEC Service Territory[14]	
Population	3,331,668
Percent White	64.90%
Percent Black	24.30%
Percent Latinx	10.50%
Percent People of Color	35.10%
Total people in poverty	492,031
Poverty Rate	15.20%
Percent under twice poverty limit	35.10%
Median Income	$59,418
Total occupied housing units	1,300,537
Percent Renters	38.6%
Percent Owners	61.4%
Percent Cost-Burdened[15] *Renters*	44.0%
Percent Cost-Burdened Owners	19.8%
Percent Cost Burdened (all)	29.2%

[13] *Id.*
[14] US Census Bureau, American Community Survey 5-year Estimates (2014-2018); Platts, Electric Investor Owned Utility Service Territories. Westminster, Colorado (2009). http://www.gisdata.platts.com (aggregate of all census block groups with centroids falling within the Duke Energy Carolinas service territory).
[15] A cost burdened household is one that spends more than 30% of monthly income on housing expenses, including rent or mortgage payments and household utility bills. *See, e.g.*, Schwartz and Wilson, *Who Can Afford To Live in a Home?: A look at data from the 2006 American Community Survey*, U.C. Census Bureau (https://www.census.gov/housing/census/publications/who-can-afford.pdf).

Thus, in light of the increase in involuntary loss of electric utility service and the high rates of poverty within the DEC service territory, 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 DEC 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;
- 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 DEC'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. DEC 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[16] of participants. 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

[16] 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.

- 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 DEC 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.[17]

Q. PLEASE DESCRIBE YOUR RECOMMENDATIONS REGARDING INCORPORATION OF AN ARREARAGE MANAGEMENT COMPONENT INTO AN AFFORDABLE BILL PAYMENT PROGRAM.

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

[17] 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.

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 DEC 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.

DEC would be responsible for collecting program-related charges, and assigning qualified customers to a tariffed, low-income rate. DEC 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 $1,374/year[18] 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	$1,374	$1,374	$1,374	$1,374	$1,374
Arrearage Payment ($200/4)	$1,424	$1,424	$1,424	$1,374	$1,374
Undiscounted Electricity Burden (During Arraerage Payoff)	9.4%	8.3%	5.5%	2.6%	1.4%
Discounted (25%) Electricity Expenditure	$1,031	$1,031	$1,031	$1,374	$1,374
Discounted Electricity Burden	6.8%	6.0%	4.0%	2.6%	1.4%

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

[18] DEC 2018 FERC Form 1, p. 304.

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 $1,374/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	$1,374	$1,374	$1,374	$1,374	$1,374
Arrearage Payment ($200/4)	$1,424	$1,424	$1,424	$1,374	$1,374
Undiscounted Electricity Burden (During Arraerage Payoff)	9.4%	8.3%	5.5%	2.6%	1.4%
Discounted Electricity Expenditure	$754.00	$862.00	$1,293.00	$1,374	$1,374
Discounted Electricity Burden	5.0%	5.0%	5.0%	2.6%	1.4%

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.

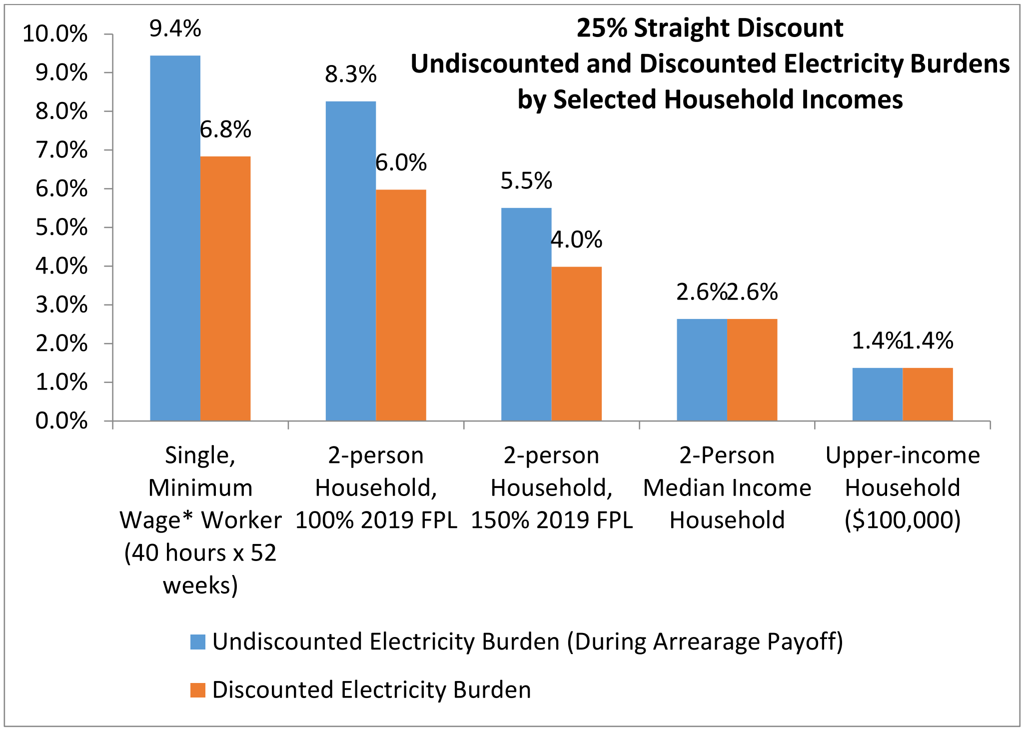
Thus, benefits are targeted according to a household's income circumstances, but the individual payment arrangements and billing typified by a PIPP are not required. A tiered discount entails somewhat higher administrative cost than a straight discount, but considerably less than a PIPP. Tiered discount 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 $1,374/year and preprogram arrears of $200.

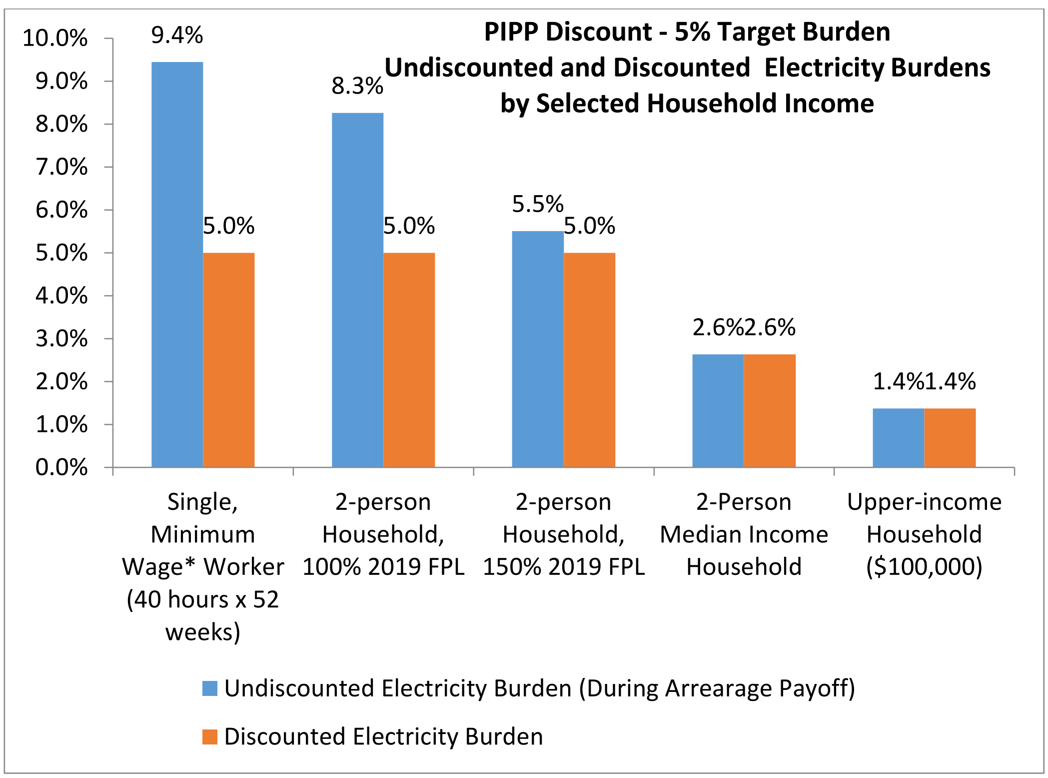
Electricity Burden Impacts: Tiered Discount (5% Target Burden)

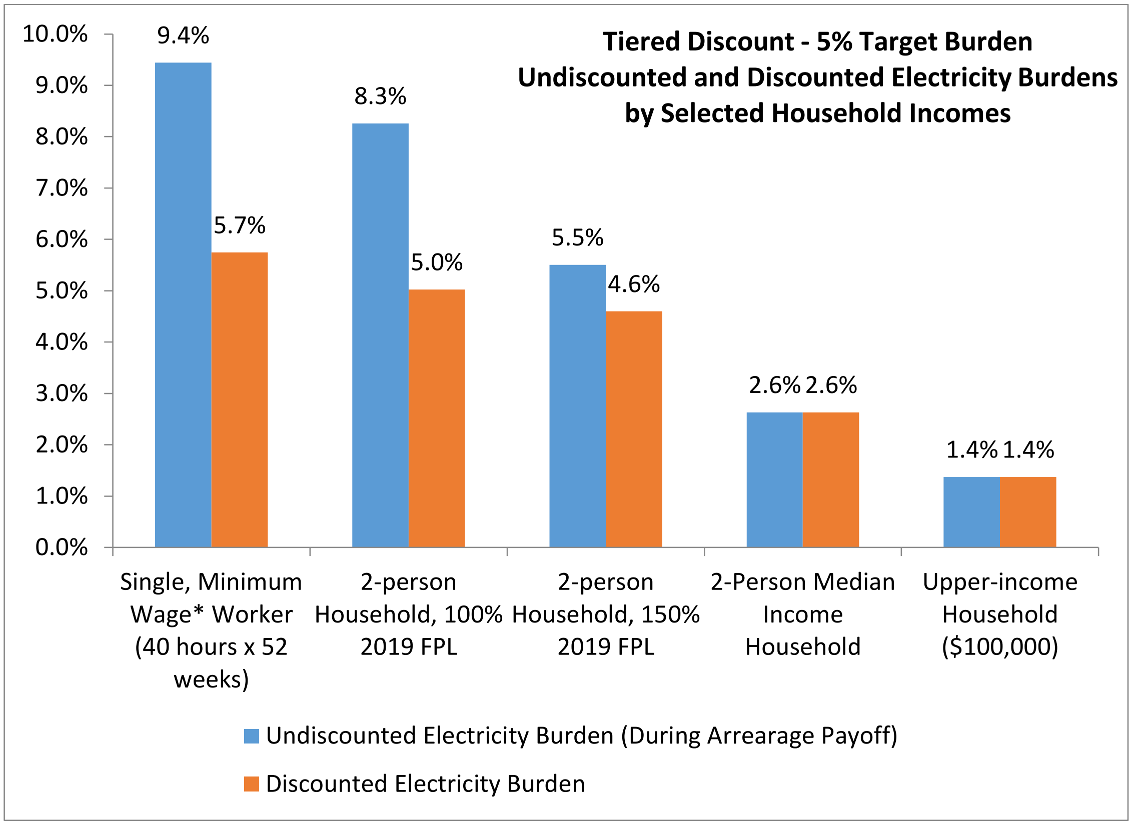
	Single, Minimum Wage* Worker (40 hours x 52 weeks)	2-person Household, 100% 2019 FPL	2-person Household, 150% 2019 FPL	2-Person Median Income Household	Upper-income Household ($100,000)
Annual Pretax Income	$15,080	$17,240	$25,860	$52,172	$100,000
Monthly Pretax Income	$1,257	$1,437	$2,155	$4,348	$8,333
Undiscounted Annual Current Electricity Expenditure	$1,374	$1,374	$1,374	$1,374	$1,374
Arrearage Payment ($200/4)	$1,424	$1,424	$1,424	$1,374	$1,374
Undiscounted Electricity Burden (During Arraerage Payoff)	9.4%	8.3%	5.5%	2.6%	1.4%
Discounted Electricity Expenditure	$866.31	$866.31	$1,189.56	$1,374	$1,374
Discounted Electricity Burden	5.7%	5.0%	4.6%	2.6%	1.4%

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.

1 
25% Straight Discount
Undiscounted and Discounted Electricity Burdens
by Selected Household Incomes
10.0%
9.0%
8.0%
7.0%
6.0%
5.0%
4.0%
3.0%
2.0%
1.0%
0.0%
9.4%
6.8%
8.3%
6.0%
5.5%
4.0%
2.6%
2.6%
1.4%
1.4%
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

2 
PIPP Discount - 5% Target Burden
Undiscounted and Discounted Electricity Burdens
by Selected Household Income
10.0%
9.0%
8.0%
7.0%
6.0%
5.0%
4.0%
3.0%
2.0%
1.0%
0.0%
9.4%
5.0%
8.3%
5.0%
5.5%
5.0%
2.6%
2.6%
1.4%
1.4%
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, DEC 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.[19] 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?

[19] De May Direct Testimony, p. 10.

A. Yes. The National Center for Appropriate Technology has operated the LIHEAP Clearinghouse through a contract from the United States Department of Health 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[20] 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

[20] https://liheapch.acf.hhs.gov/Supplements/2014/supplement14.htm

these measures and contributing to increased affordability of home energy services. In addition, effective, comprehensive, deep retrofit efficiency programs 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 DEC LOW-INCOME CUSTOMERS HAD ACCESS TO COMPREHENSIVE ENERGY EFFICIENCY PROGRAMMING AS YOU DESCRIBE ABOVE?

A. Yes. In the past, a limited number of DEC 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 DEC 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).[21]

[21] 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

Unfortunately, in 2019, no funding was made available to income-eligible DEC customers.[22]

Q. WHAT IS YOUR RECOMMENDATION REGARDING DEC'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 DEC be authorized and directed to reinstate and 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.

Q. IS PREPAID UTILITY SERVICE, AS PROPOSED BY DEC[23], AN AFFORDABILITY PROGAM THAT ENHANCES LOW-INCOME HOME ENERGY SECURITY?

A. No. While prepaid service typically includes (1) streaming participants useful information regarding usage and expenditures, (2) features allowance for numerous, small payments at any time rather than paying for usage during a monthly billing cycle in a single, lump sum, and (3) involves waiver of security deposit requirements for new customers or, for existing customers, application of

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homes that they worked on would have otherwise been deferred were it not for the Helping Home Fund dollars) (Exhibit JH-5).

[22] DEC response to PS DR 171-4 (Exhibit JH-6).

[23] DEC's petition for approval of its prepay program was consolidated with this general rate case. Order Consolidating Dockets, *In the Matter of Petition of Duke Energy Carolinas, LLC, for Approval of Prepaid Advantage Program*, Docket No. E-7, Sub 1213 (Nov. 20, 2019).

a deposit toward the prepaid account, it also brings considerable risk to home energy security.

Prepaid service is typically concentrated among lower income households and brings highly-elevated rates of service disconnection. While reporting of disconnections has been avoided by most utilities implementing prepaid service, evidence that does exist confirms very high rates of disconnection. For example, in March, 2012, Arizona Public Service Company launched a prepaid service pilot program, ultimately enrolling approximately 2,000 of its residential customers. Similar to other programs, the APS pilot entailed customers prepaying for electricity rather than receiving a monthly bill after usage of electricity.[24] Analysis based on the entire pilot program participant pool reflected a very high rate of disconnections throughout the implementation period. In the APS prepaid service pilot there was an average of 0.8 disconnections per customer per month.[25] This result is similar to the reported Salt River Project ("SRP") disconnection rate. SRP, like other utilities implementing prepaid service, does not publicly report rates of service disconnections for prepaid service customers or post-paying customers. However, in response to a media inquiry in 2012, SRP divulged the troubling fact that, on average, M-Power customers experience loss of electric service once per month, compared to an average disconnection rate among traditional payment customers of less than

[24] Arizona Public Service Company, "Demand Side Management Residential Prepaid Energy Conservation Pilot Program: End of Pilot Report," February, 2015, p. 2.
[25] *Id.* at p. 21.

once per year.[26] Finally, prepaid service customers forfeit key consumer protections regarding bill payment timeframes, secure, reliable notification prior to disconnection of service, limitations on disconnection under certain circumstances, the right to dispute a bill, and special protections for the elderly and disabled.

It should be noted that the customer benefits cited by prepaid service proponents are generally not exclusive to a program that requires forfeiture of consumer protections and heightened risk of service loss. The same technology that is used to facilitate transfer of near-real-time usage and expenditure information, which can support non-punitive conservation benefits, can be modified and used to provide *all* smart metered customers with such information. In addition, security deposit affordability problems may be addressed through regulatory and programmatic solutions that do not require participation in a prepaid service program. Further, no customers are currently precluded from making payment in advance of receiving a monthly bill. However, under the traditional prepaid service model, evidence shows concentration of participation among lower-income households, high rates of service disconnection, rates that do not enhance affordability of service, limitations on access to budget billing and other customer service programs that can benefit lower-income customers, and requirements that participating customers forego essential consumer protections.

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[26] Randazzo, "Prepaid Utilities Criticized as Unfair," The Republic, AZcentral.com, June 19, 2012. http://archive.azcentral.com/business/articles/2012/06/18/20120618prepaid-utilities-criticized-unfair.html.

Based on the forgoing, I conclude that prepaid service is not a legitimate means of addressing home energy affordability and security challenges. Less punitive approaches entailing well designed bill affordability and energy efficiency programs are known to enhance affordability without bringing the risks of prepaid service. Based on the foregoing, I recommend that the Commission not approve DEC's proposal to implement a prepaid service program. This recommendation is consistent with the Comment Letter of North Carolina Justice Center and other organizations recommending denial of the DEC petition in Docket No. E-7, Sub 1213 for approval of a prepaid service program. The Comment Letter is attached as Exhibit JH-7.

IV. Ramifications of DEC's Residential Basic Facilities Charge For Low-Income Customer Electricity Affordability

Q. WHAT HAVE DEC AND INTERVENORS PROPOSED IN THIS PROCEEDING WITH RESPECT TO THE RESIDENTIAL BASIC FACILITIES CHARGE?

A. DEC proposes to retain the current residential basic facilities charge ("BFC") at $14 per bill.[27] 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 $11.15.[28] Mr. Wallach further states that an inappropriately high BFC results in both intra-class cross subsidization of high-

[27] Corrected Direct Testimony of Michael J. Pirro, p.12.
[28] Direct Testimony of Jonathan Wallach, pp. 26-33.

volume consumers by low-volume consumers and reduction of the economic incentive to invest in energy efficiency and other usage-reduction measures.[29]

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[30], 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

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[29] *Id.*, pp. 35 – 39.
[30] Direct Testimony of John Howat, Docket No. E-7, Sub 1146 (Jan. 19, 2018).

was conducted using a sample large enough to support results for geographic areas smaller than census divisions.

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.[31] 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.[32] The Survey instrument

[31] https://www.eia.gov/consumption/residential/data/2009/index.php?view=microdata.

[32] 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

includes questions regarding a broad range of demographic factors and household 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[33] reflects this consistent pattern.

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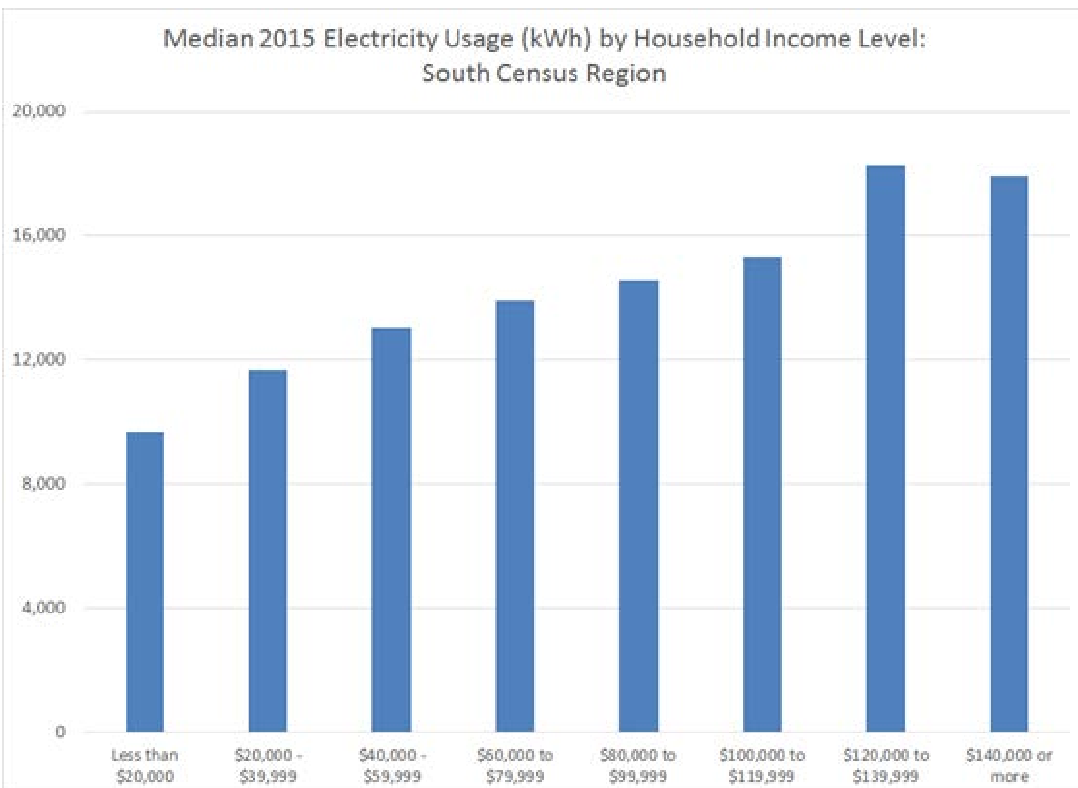
usage, the relative usage patterns identified in the North Carolina and South Carolina region are highly consistent with those from other geographic regions across the United States. It is therefore reasonable to assume that the general usage patterns identified in North Carolina and South Carolina – and throughout the United States – apply to the DEC service territory.

[33] 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.[34] 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

[34] Ohio Public Utilities Commission, "Energy Assistance Resource Guide – 2019-2020," p. 5. (Exhibit JH-3.)

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 charge paid by participants in the RSLI program is set at $2 per month. The tariff sheet for Rate RSLI, provided by DEC in response to Public Staff 171-5, is attached as Exhibit JH-8. These examples demonstrate the compatibility of reduced customer charges and low-income bill affordability programs, including ones delivered by DEC'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 DEC.
- DEC 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.

- DEC 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.
- PrePaid Advantage service as proposed by DEC does not enhance affordability, poses excessive risks, and should not be approved.
- The Commission should reject the BFC proposed by DEC 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.

CERTIFICATE OF SERVICE

I certify that the parties of record on the service list have been served with the Direct Testimony of John Howat on Behalf of the North Carolina Justice Center, North Carolina Housing Coalition, Natural Resources Defense Council, and Southern Alliance for Clean Energy either by electronic mail or by deposit in the U.S. Mail, postage prepaid.

This the 18th day of February, 2020.

s/ David L. Neal

David L. Neal

MR. NEAL: So at this time I would just note that -- I would ask him about his summary.

Q Mr. Howat, did you prepare a summary of your testimony relating to the Prepaid Advantage Program in this -- in this case?

A I did.

MR. NEAL: And Chair Mitchell, that summary, again, was provided to the Commission and the parties in this docket, and I would ask that Mr. Howat's summary be entered into the record as if given orally from the stand.

CHAIR MITCHELL: All right. Hearing no objection to that motion, Mr. Neal, it will be allowed.

(Whereupon, the summary of John Howat was copied into the record as if given orally from the stand.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET No. E-7, SUB 1214

SUMMARY OF TESTIMONY OF JOHN HOWAT

ON BEHALF OF

NORTH CAROLINA JUSTICE CENTER,
NORTH CAROLINA HOUSING COALITION,
NATURAL RESOURCES DEFENSE COUNCIL, AND
SOUTHERN ALLIANCE FOR CLEAN ENERGY

My name is John Howat. I am a Senior Policy Analyst at the National Consumer Law Center. Thank you for the opportunity to testify before the Commission.

In addition to the affordability issues covered in my pre-filed testimony in the Duke Energy Carolinas ("Company") rate case docket that were taken up in the consolidated hearing, I also expressed my concerns relating to the Company's proposed Prepaid Advantage program in Docket E-7, Sub 1213, which was consolidated with this rate case docket.

Prepaid service is typically concentrated among lower income households and often brings highly-elevated rates of service disconnection. While most utilities implementing prepaid service have avoided clear reporting, evidence that does exist confirms high rates of disconnection. For example, in March of 2012, Arizona Public Service Company ("APS") launched a prepaid service pilot program, ultimately enrolling approximately 2,000 of its residential customers. Analysis based on the entire pilot program participant pool reflected a very high rate of disconnections throughout the implementation period. The Salt River Project's ("SRP") prepay program also had a high disconnection rate. In response to a media inquiry in 2012, SRP revealed that, on average, its prepay customers experienced non-pay disconnections once per month, compared to an average disconnection rate among traditional payment customers of less than once per year.

Prepaid service customers forfeit key consumer protections regarding bill payment timeframes, secure, reliable notification prior to disconnection of service, limitations on disconnection under certain circumstances, and the right to dispute a bill.

Prepaid service includes some welcome elements, but it should not be viewed as an affordability program that enhances energy security for low-income customers. There is no reason to require a waiver of long-standing protections against rapid disconnections for the following positive elements of prepaid service: (1) providing participants with timely information regarding energy usage and billing, including usage alerts; (2) allowance for numerous, small payments rather than requiring payment in a lump sum; and (3) waiver of security deposit requirements for new customers.

Based on the foregoing, I recommend that the Commission not approve DEC's proposal to implement a prepaid service program that removes consumer protections relating to disconnections. This recommendation is consistent with the Comment Letter of North Carolina Justice Center and other organizations submitted to the Commission recommending denial of the DEC petition.

This concludes my summary.

MR. NEAL: And at this time, Mr. Howat is available again for cross examination or questions from the Commission. I would also note that I know Commissioner Hughes had begun to ask some questions about Prepaid Advantage during the consolidated hearing, but I rudely interrupted since he was going to be here for the DEC case.

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

(No response.)

CHAIR MITCHELL: All right. Hearing none, we will move to questions from Commissioners, beginning with Commissioner Brown-Bland.

COMMISSIONER BROWN-BLAND: No questions at this time.

CHAIR MITCHELL: Commissioner Gray?

COMMISSIONER GRAY: No questions at this time.

CHAIR MITCHELL: Commissioner Clodfelter?

COMMISSIONER CLODFELTER: No questions.

CHAIR MITCHELL: Commissioner Duffley?

COMMISSIONER DUFFLEY: No questions.

CHAIR MITCHELL: Commissioner Hughes?

COMMISSIONER HUGHES: No additional questions.

CHAIR MITCHELL: Okay. And Commissioner

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.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
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	)

DIRECT TESTIMONY OF
JUSTIN R. BARNES
ON BEHALF OF
NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION

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" or "Company") 2017 general rate case application and in Docket No. E-2, Sub 1142 on the Duke Energy Progress, LLC's ("DEP") 2017 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

[1] The North Carolina Solar Center is now known as the North Carolina Clean Energy Technology Center.

Orleans, 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 DEC 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 DEC'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.

[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.

Q. WHAT ARE YOUR RECOMMENDATIONS TO THE COMMISSION?

A. First, I recommend that the Commission direct DEC to, within 60 days of a final order, file separate, targeted EV-specific tariffs for both residential and non-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. DEC 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.

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 ARE THE CHARACTERISTICS THAT YOU RECOMMEND FOR A RESIDENTIAL EV-SPECIFIC RATE?

A. I recommend that the rate be designed in accordance with the following parameters:

1. A monthly submetering charge that is limited to the cost of the additional meter;
2. The rates should use a more granular time-varying pricing period design than the Company's currently available time-varying rate. I recommend a three-period design with shorter duration peak periods guided by the pricing periods used in DEC Schedule PP;
3. The price differential between the off-peak rate(s) and the otherwise applicable flat rate should be sufficient to produce meaningful bill savings for EV charging, taking into account the incremental metering charge and a typical amount of home EV charging; and
4. The lowest pricing period should have a duration of at least eight hours in order to allow ample time for low voltage charging to produce a battery charge sufficient for a reasonable length trip or commute.

Q. WHAT CHARACTERISTICS DO YOU RECOMMEND FOR A NON-RESIDENTIAL EV-SPECIFIC RATE?

A. Characteristics (1) and (2) for a residential EV-specific rate should also be applied to a non-residential EV-specific rate. However, recommendation (1) would only apply where EV load is being submetered at an existing meter. For standalone charging stations, the monthly Basic Facilities Charge ("BFC") should be consistent with the rate that would otherwise apply to the account. Beyond that I recommend that the non-residential rate:

1. Address the issues presented by demand rates for non-residential EV charging installations by establishing a variation on Schedule OPT-V for EV charging load that: (a) substitutes volumetric time-varying rates for on-peak demand rates, or (b) uses a demand charge limit that caps demand charges at an implied maximum volumetric rate, or alternatively, a percentage of the ratepayer's monthly bill.
2. 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 EV submetering rate may 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 DEC RATEPAYERS?

A. There are several benefits. 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.

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) 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] Executive Order 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 design. If one makes the reasonable assumption that EV charging will in the future take place principally, or even entirely, under time-varying rate designs, the analyses of EV charging under traditional rates that are not designed for EV charging is not predictive of the impacts of EV charging.

[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] NC. 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. 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.

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 would pay 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 DEC does not study the marginal costs of transmission and distribution. However, the pricing periods in Schedule PP 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 the pricing periods in Schedule PP, 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.

III. RESIDENTIAL EV RATE OPTIONS

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.[5] 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 DEC CURRENTLY OFFER AN EV-SPECIFIC CHARGING RATE FOR RESIDENTIAL RATEPAYERS?

A. No.

[5] 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 DEC PROPOSING AN EV-SPECIFIC CHARGING RATE FOR RESIDENTIAL RATEPAYERS IN THIS RATE CASE?

A. No.

Q. IS DEC PROPOSING AN EV-SPECIFIC CHARGING RATE FOR RESIDENTIAL RATEPAYERS IN ANY OTHER FORUM?

A. No. DEC'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 limit the size and duration of the EV pilot programs.[6]

Q. WHAT RATE OPTIONS ARE CURRENTLY AVAILABLE FOR A PROSPECTIVE RESIDENTIAL EV OWNER?

A. DEC's residential ratepayers can choose from several rate schedules. The generally-available rate options and their basic rate designs are as follows:

- Schedule RS – Includes a monthly Basic Facilities Charge ("BFC") and a flat energy charge.

[6] *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 RE (Electric Water and Space Conditioning) – Includes a monthly BFC and a flat energy charge, which is tiered to offer a lower rate for usage above 350 kWh from November – June.
- Schedule ES (Energy Star Homes) – Includes a monthly BFC and a flat energy charge, which is tiered to offer a lower rate for usage above 350 kWh during all months.
- Schedule RT – 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.

DEC also offers six advanced metering infrastructure ("AMI")-enabled pilot rates (three each for electric heating and non-heating ratepayers) with time-varying elements. These rates are capped at 500 ratepayers each and not generally available to all ratepayers that might wish to enroll.

Q. ARE THESE EXISTING RATE OPTIONS WELL-SUITED FOR RESIDENTIAL EV HOME CHARGING?

A. No. The primary options feature flat energy charges and as a consequence fail to take advantage of the potential for managed charging. Schedule RT has two primary shortcomings. First, it is a whole home rate and does not contain a submetering option. Managing usage behavior for a whole home is far more complex than doing so for a single, and theoretically highly flexible, EV load. This is true regardless of the whether the time-varying rate is fully volumetric or contains a demand component like Schedule RT. Second, the demand component in Schedule RT 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.

Q. WOULD AN OPTION FOR RATEPAYERS TO SUBMETER AN EV LOAD UNDER SCHEDULE RT BE SUFFICIENT TO PROVIDE RATEPAYERS WITH A VIABLE TIME-VARYING EV RATE OPTION?

A. No. The design of Schedule RT, which contains an on-peak demand charge and only a small peak to off-peak rate spread for the energy component is not well-suited for home charging. The demand charge creates an unbalanced risk and reward signal and fails to provide a price signal that consistently incentivizes off-peak charging. In order for the rate to be an effective motivator, the ratepayer must charge exclusively and without fail during the off-peak period. If a ratepayer charges their EV for only a 30-minute period during the on-peak window during a billing month, they are charged the same demand charge as if they charged exclusively during the on-peak window. The small rate spread between the on-peak and off-peak volumetric rates provides only a minimal incentive to charge off-peak once an on-peak demand charge is triggered. Only a few instances of on-peak charging for a short duration could cause a ratepayer to pay more under Schedule RT than they would pay to charge their vehicle under a flat rate.

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 while 88% percent of charging is off-peak on Southern California Edison's EV-specific rate.[7]

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 does not forgive occasional departures from the ideal makes perfect the enemy of the very good. Schedule RT fails to achieve at this test of balance and consistency.

Q. ARE YOU AWARE OF ANY RESIDENTIAL EV CHARGING RATES THAT CONTAIN A DEMAND CHARGE?

A. No. It is possible that one could exist, but I have reviewed numerous residential EV rate proposals and never come across one.

[7] 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-2**.

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.[8] A more recent report from the Smart

[8] Ahmad Faruqui, Ryan Hledik, and John Higham. "The State of Electric Vehicle Home Charging Rates." October 15, 2018. Attached as **Exhibit JRB-3**.

Electric Power Alliance ("SEPA") shows a median differential ratio of 3.6:1 and a median price differential of $0.20/kWh.[9]

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.[10]

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.

[9] SEPA. "Residential Electric Vehicle Rates that Work". November 2019. Attached as **Exhibit JRB-4**.
[10] **Exhibit JRB-3**. 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[11]

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. The relative flexibility and controllability of EV loads lends itself to a more complex rate design than may be appropriate for whole home or whole building loads.

[11] 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-5**.

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 an additional meter 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 the 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.[12] However, it is not clear whether submetering costs would present a barrier in North Carolina. At the time of its closure Schedule 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.

Q. PLEASE SUMMARIZE THE APPROPRIATE DESIGN CHARACTERISTICS FOR A RESIDENTIAL EV-SPECIFIC RATE.

A. I recommend that a residential EV rate offered by DEC have the following characteristics:

[12] *See* **Exhibit JRB-2** and **Exhibit JRB-4** for an additional discussion of metering cost issues and submetering options.

- Three pricing periods that are generally aligned with the high cost and low cost pricing periods found in Schedule PP, with a constraint to ensure that EV owners have at least an eight-hour off-peak charging window during all months of the year;
- Any additional fixed charge should be limited to the incremental cost of the additional metering required to measure EV charging usage; and
- An off-peak rate that produces meaningful savings for off-peak charging relative to a flat rate, after consideration of the incremental metering cost and a typical amount of home EV charging.

The overarching goal of this design is to produce ratepayer savings that offset incremental costs associated with an EV purchase and charging equipment while retaining a solid connection to the marginal costs of home charging load.

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.[13] 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.[14] 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.

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

[13] *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; Garrett Fitzgerald and Chris Nelder. "DCFC Rate Design Study for the Colorado Energy Office." 2019. Rocky Mountain Institute.
[14] Garrett Fitzgerald and Chris Nelder. "EVgo Fleet and Tariff Analysis." Rocky Mountain Institute, 2017. Attached as **Exhibit JRB-6**.

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. CAN YOU PROVIDE AN EXAMPLE OF HOW DEMAND CHARGES CAN AFFECT THE COST OF EV CHARGING?

A. Yes. Figure 1 below depicts the hypothetical impact of a demand charge on the cost of charging under a high demand charge scenario (High Case) and a moderate demand charge (Mid Case) under different utilization rates. It assumes that the charging station has a 100 kW demand composed of two charging ports each with a 50 kW demand.[15]

[15] **Exhibit JRB-2**, p. 11, Table 1.

Figure 1: Effects of Demand Rates on Charging Costs

		High Case	Mid Case
Demand Charge ($/kW)		$20	$6
Customer Charge (4/Month)		$70	$70
Energy Charge ($/kWh)		$0.08	$0.08
Energy per Session (kWh)		50	50
15 charging sessions/month	Annual DCFC Bill	$25,560	$8,760
	Cost/session	$142	$49
	Cost/kWh	$2.84	$0.97
60 charging sessions/month	Annual DCFC Bill	$27,720	$10,920
	Cost/session	$39	$15
	Cost/kWh	$0.77	$0.30

As shown in Figure 1, even in the lower demand rate case with a relatively high utilization rate of 60 sessions per month (two per day), the cost of charging is very high. To be clear, Figure 1 is intended to be illustrative only and does not reflect DEC's rates.

Q. DOES DEC CURRENTLY OFFER AN EV-SPECIFIC RATE FOR NON-RESIDENTIAL RATEPAYERS?

A. No.

Q. IS DEC PROPOSING AN EV-SPECIFIC CHARGING RATE FOR NON-RESIDENTIAL RATEPAYERS IN THIS RATE CASE?

A. No.

Q. IS DEC 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 DEC does propose a few modest modifications under several pilot programs. 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 the current Small General Service ("SGS") Schedule, plus $0.02/kWh. For DCFC charging, DEC'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.[16]

Q. WHAT RATE SCHEDULES ARE AVAILABLE TO DEC'S NON-RESIDENTIAL RATEPAYERS FOR EV CHARGING?

A. Since DEC 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

[16] *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).

voluntary time-varying rate. For example, the standard rate options for SGS and Large General Service ("LGS") ratepayers include a monthly BFC, a demand charge, and a declining block rate for energy usage. The declining block design incorporates a pricing system that offers lower rates for high load factor ratepayers. DEC offers a time-varying rate option under Schedule OPT-V, which features a monthly BFC, a small non-coincident demand charge (the Economy Demand Charge), seasonal time-varying demand charges, and seasonal on-peak and off-peak energy rates.

Schedule SGS would likely not be an option for any ratepayer that installs a DCFC station or standalone DCFC stations because it is only available to ratepayers with demands of 75 kW or less. As shown previously in Table 1 DCFC stations often exceed this demand threshold.[17]

Q. ARE THESE RATE OPTIONS WELL-SUITED TO NON-RESIDENTIAL EV CHARGING?

A. No. The SGS and LGS schedules do not contain any time variation and charge higher rates to ratepayers with low load factors. Schedule OPT-V contains time varying rate elements, but the principal price signal is contained within the on-peak demand component. 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, which run on weekdays from 1 PM - 9 PM

[17] DCFC stations typically have a charging capacity of 50 kW per charging port but an individual station will often have multiple ports that sum to demands in excess of 100 kW.

from June through September and 6 AM - 1 PM from October through May would be virtually impossible to avoid entirely.

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 translate the existing on-peak demand charges found in Schedule OPT-V to on-peak energy charges for dedicated EV load. That would leave a small non-coincident demand charge for costs that do not have a time-varying characteristic in place, but eliminate the negative effects of the bulk of the demand-based charges.

Q. BEYOND THE SUBSTITUTION OF ENERGY CHARGES FOR DEMAND CHARGES, WOULD ANY OTHER MODIFICATIONS TO SCHEDULE OPT-V MAKE THE RATE MORE SUITABLE FOR EV CHARGING?

A. Yes. As I previously noted, the current on-peak windows run on weekdays from 1 - 9 PM during June through September and 6 AM - 1 PM from October through May. Both of these peak windows, in particular the eight-hour summer window during daytime hours, could encompass a considerable amount of non-residential charging. Pricing windows should be driven by the timing of cost variations, which places some constraints on design. However, a more granular three-period design could retain and improve this connection to cost causation while also making it easier to avoid on-peak charges through managed charging. A three-period system with shorter on-peak pricing periods guided by the Premium Energy and Capacity hours in Schedule PP would send a signal to EV charging ratepayers to avoid the truly peak times.

Q. HOW COULD AN ALTERNATIVE EV-SPECIFIC RATE ALONG THESE LINES BE IMPLEMENTED IF THE COMMISSION WERE TO DIRECT THE COMPANY TO OFFER ONE?

A. The rate could be tariffed as Schedule OPT-EV, available only for non-residential EV charging. A separate tariff would be preferable in order to avoid confusion over the applicable pricing windows. Schedule OPT-EV would feature a submetering charge if the EV load is located behind an existing whole building meter, or the OPT-V BFC for standalone charging installations.

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.[18]

- 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.[19]

- 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.[20] [21]

[18] *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.

[19] 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.

[20] 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

[21] 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.[22]

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 Schedule OPT-V for ratepayers with EV load (i.e., not separately metered), or it could be reflected in a dedicated tariff for dedicated EV charging.

[22] 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.[23] 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 2 followed by the rate that these customers would have paid under the capped demand charge in Table 3. 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.[24]

[23] 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.
[24] 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 2: 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 3: 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, including the proposed commercial EV charging tariff, as **Exhibit JRB-7**. Minnesota Power has not yet filed compliance tariffs addressing the modifications made by the Minnesota Public Utilities Commission in approving the tariff, but the proposed tariff illustrates the demand charge limit aspect.

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.[25]

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. 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 Schedule OPT-V to apply the limit to EV-only loads. For standalone installations, the standard BFC would apply. Submetered EV loads behind another meter would incur an incremental submetering charge.

[25] 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.[26] 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.[27] PSE expressly justified its proposal as a way to mitigate high demand charges that pose a barrier to EV

[26] Washington Utilities and Transportation Commission, Docket No. UE-190529.

[27] *Prefiled Direct Testimony of Jon A. Piliaris*, Washington Utilities and Transportation Commission, Docket No. UE-190529 (June 20, 2019).

deployment.[28] PSE's proposed tariffs for implementing the program are attached as **Exhibit JRB-8**.

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

[28] 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.

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 DEC to deploy a non-residential EV-charging rate under options (1) or (2). Option 1 substitutes volumetric time-varying energy charges for the on-peak demand components of Schedule OPT-V for separately metered or submetered EV charging load, modifies the OPT-V pricing periods to provide a more granular three-period price signal with a shorter peak window using Schedule PP as a guide, and uses a submetering charge limited to the cost of additional metering in place of the OPT-V BFC where the EV load is located behind an existing meter.

Option 2 establishes a demand charge limit for separately metered or submetered EV charging load within Schedule OPT-V 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 RS. 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.

V. CONCLUSION

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS TO THE COMMISSION?

A. I recommend that the Commission direct DEC 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 DEC 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.

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 ARE THE CHARACTERISTICS THAT YOU RECOMMEND FOR A RESIDENTIAL EV-SPECIFIC RATE?

A. I recommend that the rate be designed in accordance with the following parameters:

1. A monthly submetering charge that is limited to the cost of the additional meter;
2. The rates should use a more granular time-varying pricing period design than the Company's currently available time-varying rate. I recommend a three-period design with shorter duration peak periods guided by the pricing periods used in DEC Schedule PP;
3. The price differential between the off-peak rate(s) and the otherwise applicable flat rate should be sufficient to produce meaningful bill savings for EV charging, taking into account the incremental metering charge and a typical amount of home EV charging; and
4. The lowest pricing period should have a duration of at least eight hours in order to allow ample time for low voltage charging to produce a battery charge sufficient for a reasonable length trip or commute.

Q. WHAT CHARACTERISTICS DO YOU RECOMMEND FOR A NON-RESIDENTIAL EV-SPECIFIC RATE?

A. Characteristics (1) and (2) for a residential EV-specific rate should also be applied to a non-residential EV-specific rate. However, recommendation (1) would only apply where EV load is being submetered at an existing ratepayer meter. For standalone charging stations, the monthly BFC should be consistent with the rate that would otherwise apply to the account. Beyond that I recommend that the non-residential rate:

1. Address the issues presented by demand rates for non-residential charging installations by establishing a variation on Schedule OPT-V for EV charging load that: (a) substitutes volumetric time-varying rates for on-peak demand rates, or (b) uses a demand charge limit that caps demand charges at an implied maximum volumetric rate, or alternatively, a percentage of the ratepayer's monthly bill.
2. 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. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Q Mr. Barnes, did you prepare a summary of your testimony?

A Yes, I did.

Q Can you please read that at this time?

A 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'm appearing here on behalf of the North Carolina Sustainable Energy Association, or NCSEA.

The purpose of my testimony is to propose the establishment of targeted electric vehicle, 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 -- of EV charging load to produce benefits for EV owners and non-EV ratepayers.

With respect to 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 in 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 could 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.

Current rate options available for residential home EV charging are insufficient because they lack an option to have relatively more flexible EV charging load measured and priced separately from whole building load, and the fact that -- and the fact that the only time-varying rate option available contains a demand rate component that produces an unbalanced and inconsistent price signal for incentivizing off-peak charging. I recommend the establishment of a rate option that, one, permits home EV charging to be separately measured; two, uses a more granular three-period pricing design with a shorter on-peak window while retaining an off-peak window of at least eight hours during all months of the year; three, limits any incremental fixed charges to the cost of metering necessary to separately measure EV charging load; and four, produces meaningful cost savings relative to a flat-rate after consideration of any incremental metering costs and typical amounts of home EV charging.

For non-residential EV charging, including public charging, insufficiencies in the current suite of rate options center on the fact that the available options either, one, lack a time-varying price signal or, two, provide a time-varying price signal principally through demand charges, which tends to produce extraordinarily high effective electric rates for the higher capacity -- for the higher capacity charging units, such as direct current, fast charger, DCFC stations that are commonly used for non-residential charging applications. I then describe several options for addressing the issue of demand charges specifically, which include substituting volumetric rate components for 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 ultimately recommend that Duke Energy Carolinas be directed to deploy a rate for separately measured non-EV charging -- non-residential EV charging using existing Schedule OPT-V as a base, but with a more granular three-period pricing design with a shorter on-peak window than the two-period design contained in Schedule OPT-V. The rate should either substitute volumetric charges for the on-peak demand charges or, two, contain a demand charge limit or cap design to produce a maximum implied electricity rate that approximates the rate a residential customer would pay to charge an EV under a standard flat-rate option, such as Schedule RS. 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 the standalone charging units be charged the otherwise applicable BFC.

Thank you again for this opportunity. I look forward to your questions.

CHAIR MITCHELL: All right. Mr. Smith, by Order of the Commission on September 2nd, we indicated that testimony summaries would be introduced, but not read -- introduced into the record, but not read by the witness, just in the interest of making efficient use of hearing time. Your witness has obviously just read his summary. No one objected to his reading, so I'm assuming that you worked this out with the parties in advance of your witness providing his testimony summary?

MR. SMITH: Chair Mitchell, I apologize. We did not work this out, and I can --

CHAIR MITCHELL: Okay. Okay. Thank you. Thank you, Mr. Smith. So I would remind the parties that we are -- we are trying to make the most efficient use of hearing time here, and we have issued an Order that spoke directly to this issue. Because there have been other witnesses today for whom no questions have been asked, but who complied with the Order and who had their testimony summaries introduced, but did not read their testimony summaries, I'm going to give them a chance to read their testimony summaries now, just in the interest of fairness, if they choose to do that. But I would like to remind the parties again that we have issued an Order that speaks directly to this, and it is my expectation that we will all work our -- our hardest and our best to comply with the Orders of this Commission. That is the expectation. Again, in the interest of making the most 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 on September 10, 2020, at 9:00 a.m.)

STATE OF NORTH CAROLINA

COUNTY OF WAKE

C E R T I F I C A T E

I, Linda S. Garrett, Notary Public/Court Reporter, do hereby certify that the foregoing hearing before the North Carolina Utilities Commission in Docket Nos. E-7, Sub 1214, E-7, Sub 1213, and E-7, Sub 1187, was taken and transcribed under my supervision; and that the foregoing pages constitute a true and accurate transcript of said Hearing.

I do further certify that I am not of counsel for, or in the employment of either of the parties to this action, nor am I interested in the results of this action.

IN WITNESS WHEREOF, I have hereunto subscribed my name this 14th day of September, 2020.

Linda S. Garrett

Linda S. Garrett, CCR
Notary Public No. 19971700150