PLACE: Held via Videoconference

DATE: Tuesday, September 29, 2020

TIME: 9:00 a.m. - 12:30 p.m.

DOCKET NO.: E-2, Sub 1219

E-2, Sub 1193

BEFORE: Commissioner Daniel G. Clodfelter, Presiding

Chair Charlotte A. Mitchell

Commissioner ToNola D. Brown-Bland

Commissioner Lyons Gray

Commissioner Kimberly W. Duffley

Commissioner Jeffrey A. Hughes

Commissioner Floyd B. McKissick, Jr.

IN THE MATTER OF:

DOCKET NO. E-2, SUB 1219

Application by Duke Energy Progress, LLC,

for Adjustment of Rates and Charges Applicable to

Electric Utility Service in North Carolina

and

DOCKET NO. E-2, SUB 1193

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

VOLUME 11

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

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

E X A M I N A T I O N S Cont'd

E X A M I N A T I O N S Cont'd

E X A M I N A T I O N S Cont'd

E X H I B I T S

E X H I B I T S (Cont'd.)

P R O C E E D I N G S

COMMISSIONER CLODFELTER: Okay, everyone. Madam Court Reporter, let's please open the record and will everyone please come to order. My name is Dan Clodfelter. I will be the presiding Commissioner in these consolidated dockets. Joining me this morning are the Commission's Chair Charlotte Mitchell; Commissioners ToNola Brown-Bland, Lyons Gray, Kim Duffley, Jeff Hughes, and Floyd McKissick, Jr.

The Commission is -- now calls for hearing Docket Number E-2, Sub 1219, which is the Application of Duke Energy Progress for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina; and Docket Number E-2, Sub 1193, which is the Application of Duke Energy Progress for an Accounting Order to Defer Incremental Storm Damage Expenses Incurred as a result of Hurricanes Florence and Michael, and Winter Storm Diego. These two dockets have been consolidated for this hearing by Order of the Commission dated August 11, 2020.

A little procedural history. On November 14, 2019, the Commission issued an Order establishing this general rate case for Docket E-2, Sub 1219, suspending implementation of rates. And on

December 6, 2019, the Commission issued an Order scheduling an investigation and hearings, establishing intervention and testimony dates and discovery deadlines and requiring public notice. This scheduling Order -- pursuant to the scheduling Order, the Commission held several public hearings in Duke Energy Progress' service territory at various dates throughout the early part of the year. The scheduling Order also set an expert witness hearing originally to commence on May 4th, 2020.

On March 10th, 2020, Governor Roy Cooper issued Executive Order No. 116 declaring a state of emergency in North Carolina to coordinate response and protective actions to prevent the spread of the Coronavirus. In doing so, the Governor ordered state agencies including the Commission to cooperate in the implementation of the provisions of the Executive Order. By subsequent Executive Orders, the Governor restricted non-essential movement of the State's residents and, ultimately, prohibited gatherings of certain numbers of persons in order to limit the spread of the Coronavirus.

On March 24, in response to a request by the Public Staff for an extension of time to file testimony in these dockets, the Commission issued an Order suspending procedural schedule and continuing the hearing in Docket E-2, Sub 1219 suspending the procedural schedule and continuing the expert witness hearing scheduled to begin on May 24th, due to the continuing of uncertainty surrounding the state of emergency.

In a filing made on April 3rd, 2020, Duke Energy Progress waived its right to seek to implement its original proposed rates pursuant to General Statute § 62-134(b) through and including December 31, 2020, in the event that the postponement of these hearings rendered it infeasible for the Commission to issue an order prior to the expiration of the rate suspension period provided in that Statute, and subject to the Company's right to implement temporary rates under General Statute § 62-135 and to seek appropriate accounting treatment relief.

The intervention in these dockets by the Public Staff and by the Attorney General has been recognized and acknowledged by the Commission pursuant to applicable Statute and Rules.

In addition, the Commission has previously allowed intervention in these dockets upon petitions filed by each of the following parties: The North Carolina Clean Energy Business Alliance; the North Carolina League of Municipalities; the Department of Defense for Itself and All Other Federal Executive Agencies; Carolina Industrial Group for Fair Utility Rates II; the Fayetteville Public Works Commission; Hornwood, Inc.; Carolina Utility Customers Association, Inc.; the Commercial Group; a group of parties jointly represented and consisting of the North Carolina Justice Center, the North Carolina Housing Coalition, the Natural Resources Defense Council, and the Southern Alliance for Clean Energy; in addition, NC WARN, Inc.; the North Carolina Sustainable Energy Association; the Sierra Club; and Vote Solar.

Numerous individual statements of position have been received by the Commission and have been placed in the Clerk's official file for each of these dockets.

On June 2nd, 2020, Duke Energy Progress and the Public Staff filed their First Agreement and Stipulation of Partial Settlement.

On June 17, 2020, the Commission ordered that the expert witness hearing in this general rate case and the expert witness hearing in the rate case filed by Duke Energy Carolinas, LLC, filed on September 29, 2019, in assigned Docket Number E-7, Sub 1214, that they be consolidated for the purpose of receiving expert testimony on several topics. The consolidated hearing was initially scheduled to commence on Monday, July 27, 2020, but by subsequent order of the consolidated hearing was rescheduled to begin on Monday, August 24, 2020, and it was in fact conducted from August 24th through August 31st.

On July 31st, 2020, Duke Energy Progress and the Public Staff filed a Second Agreement and Stipulation of Partial Settlement along with supporting settlement testimony. Duke Energy Progress has also separately entered into partial settlements with Harris Teeter, the Commercial Group, with CIGFUR II, with Vote Solar, and jointly with the North Carolina Sustainable Energy Association, North Carolina Justice Center, the North Carolina Housing Coalition, the Natural Resources Defense Council, and the Southern Alliance for Clean Energy.

On August 11, 2020, the Commission issued an Order approving Duke Energy's -- Progress' public notice and financial undertaking relating to the

Company's exercise of its statutory right under General Statute § 62-135 to place into effect temporary rates pending final Order by this Commission approving permanent rates.

On September 16, 2020, Duke Energy Progress filed a motion for an Order accepting the company's notice of an extension of its waiver of its right to implement the original proposed rates pursuant to General Statute § 62-134(b) extending that previous waiver to and including March 1, 2121 (sic) in the event that the postponement of these hearings rendered it infeasible for the Commission to issue an Order prior to the expiration of the rate suspension period.

Also, on that same date, September 16, the Commission issued an Order scheduling the hearing for today in these dockets.

So that brings us to today and to these proceedings. This is, as you all know, round three of these consolidated cases and partially consolidated cases I should say, and so I'm going to assume, I think we all are, that practice has made perfect and that these hearings will run accordingly.

Before we get started, I want to make a few points for the record in light of the fact that the hearing is being conducted remotely. This hearing is accessible to the public by way of an access link provided on the Commission's website. Each of the parties has consented to the Commission conducting this hearing by remote means, and such consents are evidenced by filings made with the Clerk.

In the interest of ensuring efficient use of hearing time and minimizing the potential for technical difficulties, the Commission has provided multiple opportunities for the parties to verify that they are able to access remote technology utilized b the Commission for this hearing, including technology checks on July 21st, 22nd, and 24th of this year. We ask that parties connect to the remote technology well in advance of the point in time at which we will go on the record each day. At the beginning of the day you will be able to connect 30 minutes prior to our opening the record in order to check your remote connections. Throughout the course of the day, the link to this hearing will remain live, so you should have no problem rejoining the hearing once we have begun.

Although we are connected through the video conference technology and are not in the hearing room together, it is the Commission's expectation that these hearings will be conducted as if we were present in the hearing room. This means that all parties must maintain order, not interfere with the court reporter's ability to transcribe the hearing accurately. And, to that end, you are all experienced in this, but you've had a week off so let me give a little bit of a refresher about some housekeeping matters on the remote procedures.

First, when you are not speaking, please keep your microphone on mute in order to avoid feedback.

Next, when you are not participating in the examination or in the cross examination of a witness who is currently testifying, please turn off your video which will make it easier for me and for the parties to keep track of those who are participating in the examination and cross examination.

Third, if you need to be recognized for an objection or for other good reason, please let me and the court reporter know your name before you launch into your intervention.

Fourth, when you first use a potential exhibit, please first state very clearly the exhibit number as it appears in the list of potential exhibits filed prior to these hearings, give a short description of the document by title or otherwise so as to enable all participants to locate the document; then ask to have the document marked for identification in the record before you ask questions about it. That will help us to move along and avoid a lot of paper shuffling and trying to catch up to find exhibits after the testimony has already begun.

Last, please be mindful that witness summary statements are to be provided to the participants at least one day in advance of the witness' expected appearance and that such statements are not to be read orally by the witness from the stand.

Next, some procedures about how we'll copy testimony into the record. During the consolidated portion of the Duke Energy Carolinas and Duke Energy Progress cases, the parties moved into evidence prefiled testimony and the exhibits of several witnesses in the consolidated phase which were to be copied into the transcript during this separate Duke Energy Progress hearing at the appropriate time. The court reporter will be instructed that prefiled testimony moved into the record during the consolidated portion of the hearings will be copied into the transcript in these dockets at the beginning of each parties' presentation of its direct witnesses in these separate dockets.

Additionally, at the beginning of each party's presentation of its witnesses for examination, the prefiled testimony for such of those -- that party's witnesses who have been excused from testifying or for whom cross examination has been waived by all of the parties should be moved into the record at that point and will be copied into the transcript at that point. Got that? So if -- when you begin your case presentation as a party, the first thing you want to do is to move into the record those of your witnesses who have been excused from testifying or for whom all cross examination has been waived by all parties. At that point the court reporter will copy their prefiled testimony and exhibits into the record.

For intervenors in this case who will not present any witnesses beyond those witnesses that they presented at the consolidated hearing, if you only presented witnesses at the consolidated hearing but do not intend to present any witnesses in this separate hearing, testimony that was admitted into evidence at the consolidated hearing will be copied into the transcript in these separate dockets at the start of the testimony of all of the intervenor parties. In other words, after the conclusion of the Company's testimony, then at that point when the case goes to the intervenors, then that is the point at which the testimony submitted in the consolidated portion of the hearing will be copied into the transcript.

Lastly for witnesses who will be testifying during these separate hearings, the prefiled testimony and exhibits of that witness will be copied into the transcript after such witness has been sworn at the beginning of that witness' live testimony and followed by the witness summary statement, if there is one.

Now, there are some new matters in this separate proceeding that we have not dealt with before and so let me address those now. They arise out of the hard work that the parties have been doing over the last week to try to see if they can find a way to shorten and to simplify this particular hearing.

So I want to acknowledge first, there's several stipulations concerning testimony and cross examination that various parties have recently filed in these separate dockets and they include the following:

First, the Joint Stipulation of Live Testimony and Exhibits of certain rate design and cost allocation witnesses that were filed on September 24, 2020, among the following parties: Duke Energy Progress, Public Staff, Carolina Industrial Group for Fair Utility Rates II, Harris Teeter, Vote Solar, the North Carolina Sustainable Energy Association, the North Carolina Justice Center, the North Carolina Housing Coalition, the Natural Resources Defense Council, and the Southern Alliance for Clean Energy, Carolina Utility Customers Association, and the Commercial Group.

Second, the Joint Stipulation of Live Testimony and Exhibits of Larry Hatcher filed on September 24, 2020, between Duke Energy Progress and the Office of the Attorney General.

Third, the Joint Testimony of Live Testimony and Exhibits of Stephen De May filed on September 24, 2020, among Duke Energy Progress, the Office of the Attorney General, the Sierra Club, Carolina Utility Customers Association, the North Carolina Justice Center, the North Carolina Housing Coalition, the

Natural Resources Defense Council, and the Southern Alliance for Clean Energy.

Fourth, the Joint Stipulation of Live Testimony and Exhibits of Jane L. McManeus filed on September 25, 2020, between Duke Energy Progress and the Office of the Attorney General, which moved that testimony be entered into these separate dockets as if those same questions were asked and those same answers were given orally from the stand by Duke Energy Progress witness Kim Smith in these dockets. That one is a little different. The Stipulation involves parties moving testimony given by Jane McManeus in the Duke Energy Carolinas case, moving that into the record in these proceedings as if that testimony had been given in these proceedings by witness Kim Smith.

And last, the Joint Stipulation regarding the admission of live testimony and exhibits filed on September 28, 2020, among Duke Energy Progress, the Public Staff, the Office of the Attorney General, and the Sierra Club.

In each of these Stipulations, the Stipulating Parties have requested that the Commission accept the Stipulations, move various exhibits and live testimony taken in the Duke Energy Carolinas' separate proceedings into the record in these proceedings as if given orally from the stand in these proceedings. Additionally, asking that the Commission take judicial notice of certain items noticed in the Duke Energy Carolinas' expert witness hearing during these witnesses' testimony and grant such other relief as the Commission may deem proper.

These are all -- these Stipulations are all the new matters. And I want to go through with you now how we propose to handle those new features of these proceedings. I will defer ruling upon accepting the Stipulations until the time that the pertinent witness who is covered by a stipulation is called to the stand. When that witness is called to testify, and after the oath is administered to that witness, the sponsoring attorney must first move admission and copying into the record of the pertinent prefiled testimony - direct, supplemental, rebuttal, whatever - and the witness' summary statement. If that motion is granted, and after that motion is granted, the sponsoring attorney should then make a second motion for admission and for copying into the transcript that portion of the witness' testimony that was given in Docket E-7, Sub 1219, that has been stipulated. If that motion is granted, then the stipulated testimony from the Duke Energy Carolinas case will be copied into the record in these cases immediately following such witness' prefiled testimony and summary statement.

Again, that procedure is designed to ensure that the transcript in these proceedings, for any given witness who is offering testimony in these proceedings, shall consecutively contain all of the testimony from that witness, whether it was given orally from the stand in these proceedings, prefiled in these proceedings, by way of witness summary in these proceedings, or was given orally in the Duke Energy's Carolinas proceedings. All of the testimony from each witness will be consolidated in the transcript in a single place.

Finally, if you are moving into the record in these proceedings testimony given in the Duke Energy's Carolinas case, for each witness for whom you make such a motion, no later than the day following that witness' testimony in this case, please provide to the court reporter a copy of those portions of the transcript from the Duke Energy's Carolinas proceedings in which that testimony, stipulated testimony appears. This is very important. Our court reporters' right now are under a great deal of time pressure to turn these transcripts around from the consolidated hearing, from the separate Duke Carolinas hearing and now from this hearing, and I really don't need for our court reporters to be running around trying to go back into the record of a prior hearing, find the appropriate references, transcribe them a second time into this transcript. So, please, at the end of the day or the following day, please give Ms. Mitchell and her court reporters a copy of those portions of the stipulated testimony from the Duke Carolinas case that you have moved into the record in this case.

Again, let me note, too, as was noted in the Commission's Order of September 25th acknowledging the Joint Stipulations that not all parties have joined in these Stipulations. In fact, each Stipulation has a different configuration of parties. Accordingly, I will entertain objections, if there are any, concerning the admission of the live testimony from the Duke Energy's Carolinas case into the record in these dockets at the time the motion is made to move such stipulated testimony into the record in these dockets. And I will make an appropriate ruling on any objections there may be at that time.

Next, I ask for a bit of help from all of you. Because each of the Stipulations has a different configuration of parties, and because the Stipulations contain limited waivers of cross examination by the Stipulating Parties, I ask that before you begin cross examination of any of the witnesses covered by a stipulation that you first alert me of whether or not you represent a Stipulating Party as to that witness or not. In other words, that keeps me straight about who has partially waived cross examination and which of the parties may be fully able to cross examine as if the witness were not subject to a stipulation.

Again, we have parties in the case who are not parties to any of the Stipulations and did not appear in the Duke Energy's Carolinas case so I have to be able to allow them a full right of cross examination to the full extent that they would be allowed even in the absence of such a stipulation.

Let me also caution the parties as we did in the Order filed on September 25th that the admission of any testimony taken in Docket E-7, Sub 1214 does not automatically bring into the record in these dockets exhibits that may have been discussed or referred to in the live testimony in those Duke Energy Carolinas cases. And so to the extent the parties wish to rely on any such exhibits, those exhibits must first be identified, designated, and moved into the record in these dockets in accordance with standard Commission practice.

Next, sorry guys, but this is a new sort of feature we're dealing with here so I apologize to you, but we've got to go through this and try to get it right on the front end. I'm sure we'll have missteps along the way. Let me lay it out for you. During the course of the hearing in Docket E-7, Sub 1214, many of the witnesses who testified during that hearing and who also provided testimony -- who will also provide testimony during these hearings were questioned by Commissioners and responded to Commissioners' questions. Many of those questions from Commissioners and the witnesses' responses pertained to topics and issues that were common to the earlier docket for Duke Energy Carolinas and it may arise also in these dockets for Duke Energy Progress. Commissioners are free in this hearing to ask again the same questions of such witnesses along with any other additional or new questions they may have for those witnesses.

Again, the Commissioners are not parties to the Stipulations among the various parties and, therefore, the Commissioners may ask repetitive questions, I discourage that by the way, but Commissioners may has repetitive questions if they choose to do so.

However, in an effort to streamline these proceedings and to try to avoid needless repetition, the Commission proposes pursuant to General Statute § 62-65(b) to take judicial notice of those portions of the record in Docket Number E-7, Sub 1214 where Commissioners ask questions of witnesses testifying in that docket and receive responses from the witnesses at that time, along with those portions of the record in Docket Number E-7, Sub 1214 where the parties asked follow-up questions in response to Commissioners' questions and received answers from the witnesses to those following questions.

In other words, what we're proposing to do here is to take into the record in these cases by judicial notice, all of the Commissioners' questions of witnesses in the prior dockets along with the parties' follow-up questions on Commissioners' questions, and that may save some repetition of Commissioner questioning in these dockets potentially. Of course, parties in this proceeding who did not participate in Docket Number E-7, Sub 1214 will have a full opportunity to ask questions of witnesses that may be in the nature of follow-up questions on Commissioners' questions posed to witnesses in the earlier proceeding. In other words, any material for which we take judicial notice in this proceeding, for any party who did not participate in the prior proceeding, that parties' right of cross examination and of follow up on Commissioners' questions is preserved to the fullest extent. Having said that, I urge all participants to do their very best to avoid repetitive or redundant questioning.

We think that the procedure that we have outlined here and the good work that you've been doing on the Stipulations will give us the best chance of avoiding needless repetition in these proceedings.

And finally, due to the fact that this hearing is being held remotely, the parties have been asked to avoid the use of confidential information to the greatest extent possible. In the event that a party must reference confidential information, we will leave the videoconference and we'll join a separate teleconference line. The party whose confidential information is discussed is responsible for ensuring that only those parties who have executed appropriate confidentiality agreements are on the separate teleconference line. And when discussion of the confidential information is complete, we will leave the teleconference line and go back on the videoconference.

Well, okay, a lot of new material, a lot of old material. So we're going to begin.

Pursuant to the State Ethics Act, I remind all members of the Commission of our duty to avoid conflicts of interest, and inquire at this time if any Commissioner has a known conflict of interest with regard to the matters coming before the Commission in these dockets?

(Pause)

Madam Court Reporter, let the record note that there appear to be no conflicts and so we will proceed.

I will call now upon the parties to announce their appearances, beginning with the Applicant. Mr. Robinson, you're up.

MR. ROBINSON: Yes. Good morning, Commissioner Clodfelter, Chair, Members of the Commission. My name is Camal Robinson appearing on behalf of Duke Energy Progress. Also appearing with me from Duke are Mr. Bo Somers and Mr. Brian Heslin. Additionally, we have appearing with us from the Law Firm of Troutman Pepper, Kiran Mehta, Molly Jagannathan and Brandon Marzo. Mr. Marzo is a member of the Georgia Bar and has a pro hac motion granted for appearance in this proceeding. We also have appearing from the Law Firm of McGuireWoods, Jim Jeffries and Andrea Kells. All of our attorneys have filled out appearance sheets and have provided them to the court reporter in advance. Thank you.

COMMISSIONER CLODFELTER: Thank you. Thank you, Mr. Robinson. The Office of the Attorney General.

MS. TOWNSEND: Good morning, Commissioner Clodfelter and Commissioners. This is Teresa Townsend from the Attorney General's Office. I am here with Ms. Force, Peggy Force, and we are representing the Using and Consuming Public and the State and Its Citizens in this Important Matter of Public Interest.

COMMISSIONER CLODFELTER: Ms. Downey. The

Public Staff.

MS. DOWNEY: Good morning, Commissioners. Dianna Downey, Chief Counsel of the Public Staff. Appearing with me representing the Using and Consuming Public in this matter are Elizabeth D. Culpepper, Layla Cummings, Tim Dodge, Lucy E. Edmondson, William E. Grantmyre, Gina C. Holt, Megan Jost, John D. Little and Nadia L. Luhr.

COMMISSIONER CLODFELTER: Is there anybody left to man the office, Ms. Downey?

MS. DOWNEY: No, I think that's all of us.

COMMISSIONER CLODFELTER: All right. Next, we'll hear appearances for the Carolina Utility Customers Association.

MR. PAGE: Good morning, Commissioner Clodfelter and Commissioners. Robert Page appearing on behalf of Carolina Utility Customers Association.

COMMISSIONER CLODFELTER: Good morning, Mr. Page. CIGFUR II.

MS. CRESS: Good morning, Commissioner Clodfelter and Commissioners. This is Christina Cress with the Law Firm of Bailey & Dixon appearing on behalf of CIGFUR II.

COMMISSIONER CLODFELTER: Thank you,

Ms. Cress. The Commercial Group.

MR. JENKINS: Good morning, Commissioners. Alan Jenkins for the Commercial Group.

COMMISSIONER CLODFELTER: Great. For the Department of Defense and Other Federal Agencies.

MS. MEDLYN: Good morning, Commissioners. This is Emily Medlyn on behalf of the United States Department of Defense and All Other Federal Executive Agencies.

COMMISSIONER CLODFELTER: Good morning, Ms. Medlyn. For the Fayetteville Public Works Commission.

MR. WEST: Good morning, Commissioners. This is James West appearing on behalf of the Fayetteville Public Works Commission.

COMMISSIONER CLODFELTER: Good morning, Mr. West. For Harris Teeter.

MR. BOEHM: Good morning, Your Honor. Kurt Boehm appearing on behalf of Harris Teeter. I'd also like to enter the appearances of Jody Kyler Cohn and Ben Royster.

COMMISSIONER CLODFELTER: Thank you, Mr. Boehm. For Hornwood, Inc.

MS. GOLDSTEIN: Good morning, Commissioner

Clodfelter and Commissioners. I'm Janessa Goldstein with Utility Management Services appearing on behalf of Hornwood, Inc. Thank you.

COMMISSIONER CLODFELTER: Good morning, Ms. Goldstein. Now for the collective group of parties, the North Carolina Justice Center and others.

MR. NEAL: Good morning, Presiding Commissioner Clodfelter. David Neal with the Southern Environmental Law Center. Appearing with me is Gudrun Thompson and Tirrill Moore on behalf of the North Carolina Justice Center, North Carolina Housing Coalition, the Natural Resources Defense Council, and the Southern Alliance for Clean Energy.

COMMISSIONER CLODFELTER: Thank you, Mr. Neal. For NC WARN.

MR. QUINN: Good morning, Commissioner Clodfelter. This is Matthew Quinn. I'm appearing on behalf of NC WARN.

COMMISSIONER CLODFELTER: Thank you, Mr. Quinn. For NCCEBA.

(Pause)

Is anyone appearing this morning on behalf of NCCEBA?

(Pause)

For the North Carolina League of Municipalities.

(Pause)

Anyone appearing for the League of Municipalities?

(Pause)

All right then. For the North Carolina Sustainable Energy Association.

MR. SMITH: Good morning, Commission. This is Ben Smith appearing on behalf of the North Carolina Sustainable Energy Association. With me is Peter Ledford.

COMMISSIONER CLODFELTER: Good morning, Mr. Smith and Mr. Ledford. For the Sierra Club.

MS. CRALLE JONES: Good morning, Commissioner Clodfelter and Commissioners. This is Cathy Cralle Jones. I'm with the Law Office of Bryan Brice, and appearing on behalf of the Sierra Club in this matter. Also appearing on behalf of the Sierra Club is attorney Bridget Lee who is in by pro hac vice and a member of the New York Bar.

COMMISSIONER CLODFELTER: Good morning, Ms. Cralle Jones and Ms. Lee. And Vote Solar.

MR. CULLEY: Good morning, Commissioner

Clodfelter. Thad Culley on behalf of Vote Solar.

COMMISSIONER CLODFELTER: Good morning, Mr. Culley. Are there any other attorneys appearing on behalf of any other intervenors in the case that I have not recognized? Anyone else?

(Pause)

Let me ask again, is none appearing this morning on behalf of NCCEBA?

(Pause)

Or for the North Carolina League of Municipalities?

(Pause)

Madam Court Reporter, I think we have taken the appearances of the parties. And so let me ask if there are any preliminary matters that the Commission needs to consider before we move into the testimony? Mr. Robinson, I'll start with you and see if you have any matters first.

MR. ROBINSON: Thank you, Commissioner Clodfelter. I do have a few. I will try to go as quickly as I can with them. So first thing, Commissioner Clodfelter, just as a point of clarification to make sure we're clear, we do not need to renew our motion from the consolidated phase of the hearings to enter into the DEP record the Application and testimony from the consolidated phase; is that correct, that's already been done?

COMMISSIONER CLODFELTER: Mr. Robinson, your audio was fading a bit as you spoke. So would you restate the question, please?

MR. ROBINSON: Sure thing. Can you hear me now, Commissioner Clodfelter?

COMMISSIONER CLODFELTER: Yes.

MR. ROBINSON: Just as a point of clarification, we wanted to confirm that we do not need to renew our motion from the consolidated phase of the hearing to enter into the DEP record the Application and testimony; is that correct?

COMMISSIONER CLODFELTER: That is correct. As I announced in the beginning, we will copy into the transcript of these dockets, Duke Energy Progress dockets, the testimony that was taken in the consolidated docket and was admitted into the record in the consolidated docket. You do not have to restate that motion. Yes.

MR. ROBINSON: Thank you. That's what I thought you said. I just wanted to confirm. Thank you. Next on my list, so on July 16th, 2020, the

Commission granted the Company's motion to excuse the following witnesses from appearing in the DEP proceeding: Rufus Jackson, Kimberly McGee, Renee Metzler, Rudolph Bonaparte and John Panizza.

Subsequently, on August 13th, 2020, and September 24th, 2020, the Commission granted the Company's motion to excuse Dylan D'Ascendis, Kelvin Henderson, and Erik Lioy from the DEP proceeding. Therefore, at this time, we ask the following testimony and exhibits be moved into the record: The direct testimony and exhibit of Kimberly McGee, direct testimony and two exhibits of Rufus Jackson, the rebuttal testimony of Renee Metzler, the rebuttal testimony and two exhibits of Rudolph Bonaparte, the direct and rebuttal testimony of Kelvin Henderson, and the rebuttal testimony of Erik Lioy.

COMMISSIONER CLODFELTER: You've heard Mr. Robinson's motion, is there any objection to the motion from any party? Hearing no objection, the motion will be granted as made.

Mr. Robinson, I had wanted to make that motion at the beginning of your case, and we're still on preliminary matters, procedural matters, but you've made the motion, I don't want to make you repeat it so the motion is granted. All right. But if you've got any other motions with respect to your case presentation let's hold those. I just want to get generic procedural preliminary matters out of the way first?

MR. ROBINSON: I apologize, Commissioner Clodfelter. All of my other matters are for the Company's sole rate case.

(WHEREUPON, McGee Exhibit 1, McGee Supplemental Exhibit 1, Jackson Exhibits 1 and 2, Bonaparte Rebuttal Exhibits 1 and 2 are marked for identification as prefiled and received into evidence.)

(WHEREUPON, the prefiled direct and supplemental testimony of Kimberly McGee, the direct testimony of Rufus Jackson, rebuttal testimony of Renee Metzler, rebuttal testimony of Rudolph Bonaparte, direct and rebuttal testimony of Kelvin Henderson, rebuttal testimony of

Erik Lioy, rebuttal testimony of Conitsha Barnes is copied into the record as if given orally from the stand.)

NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1219

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

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Kimberly D. McGee. My business address is 550 South Tryon Street, Charlotte, North Carolina.

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

A. I am a Rates and Regulatory Strategy Manager supporting both Duke Energy Progress, LLC ("DE Progress" or "DEP" or the "Company") and Duke Energy Carolinas, LLC ("DE Carolinas or DEC").

Q. PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL QUALIFICATIONS.

A. I graduated from the University of North Carolina at Charlotte with a Bachelor of Science degree in Accountancy. I am a certified public accountant licensed in the State of North Carolina. I began my career in 1989 with Deloitte and Touche, LLP as a staff auditor. In 1992, I began working with DEC (formerly known as Duke Power Company) as a staff accountant and have held a variety of positions in the finance organization. From 1997 until 2009, I worked for Wachovia Bank (now known as Wells Fargo) in a variety of finance and regulatory positions. I rejoined DEC in January 2009 as a Lead Accountant in Financial Reporting. I joined the Rates Department in 2011 as Manager, Rates and Regulatory Filings.

Q. PLEASE DESCRIBE YOUR DUTIES AS RATES & REGULATORY STRATEGY MANAGER.

A. I am responsible for managing DE Progress' and DE Carolinas' rider cost recovery processes, including fuel and renewable compliance; providing guidance on compliance with regulatory conditions and codes of conduct; and providing regulatory support for retail rates.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes. I testified before the North Carolina Utilities Commission ("NCUC" or the "Commission") in DE Progress' 2017 general rate case proceeding, supporting the base fuel factors, in Docket No. E-2, Sub 1142. I also provided testimony in DEC's general rate case proceedings supporting the base fuel factors in Docket No. E-7, Sub 1146 and Docket No. E-7, Sub 1214. I also testified supporting cost recovery in the 2013 Demand Side Management and Energy Efficiency Rider in Docket No. E-7, Sub 1031. I submitted testimony in DEC's fuel and fuel-related cost recovery proceedings in Docket No. E-7, Subs 1190, 1163 and 1129 and DEP's fuel and fuel-related cost recovery proceedings in Docket No. E-2, Subs 1045, 1069 and 1107.

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

A. My testimony supports the fuel component of proposed base rates for all customer classes.

Q. YOUR TESTIMONY INCLUDES ONE EXHIBIT. WAS MCGEE EXHIBIT 1 PREPARED BY YOU OR AT YOUR DIRECTION AND SUPERVISION?

A. Yes. It was.

Q. DID YOU PROVIDE ANY INFORMATION INCLUDED IN EXHIBITS SPONSORED BY OTHER COMPANY WITNESSES?

A. Yes. I provided the proposed fuel rate and annualized fuel expense for the Company's Test Period to Witness Smith.

II. BASE FUEL FACTORS

Q. WHAT BASE FUEL FACTORS DOES DE PROGRESS PROPOSE TO USE IN THIS DOCKET?

A. The Company proposes to use the following base fuel factors by customer class (excluding gross receipts tax and regulatory fees):

- Residential 2.311 cents per kWh
- Small General Service 2.556 cents per kWh
- Medium General Service 2.477 cents per kWh
- Large General Service 1.757 cents per kWh
- Lighting 2.251 cents per kWh

These proposed factors are derived using the total prospective fuel and fuel-related cost factors approved in Docket No. E-2, Sub 1173 and implemented December 1, 2018. These factors represent the fuel-related amounts that the Company expects to collect from its North Carolina retail customers through its approved rates during the next billing period. The Company's intent in using the fuel-related factors that represent expected future rates as a component of its proposed new rates was to make it clear that we are requesting a rate increase that relates to non-fuel revenues only (*i.e.*, a request that includes neither an increase nor a decrease related to recovery of fuel costs).

Q. WHAT LEVEL OF FUEL COSTS HAS THE COMPANY INCLUDED IN COST OF SERVICE?

A. As shown on McGee Exhibit 1, the Company's North Carolina retail adjusted fuel and fuel-related costs expense for the Test Period was $855,154,483. This amount was calculated using the base fuel cost factors identified above and North Carolina retail Test Period actual kWh sales by customer class as adjusted for weather and customer growth. I provided this amount to Witness Smith broken into three categories: 1) the amount related to unadjusted kWh sales, 2) the amount for the weather adjustment, and 3) the amount for the customer growth adjustment. These amounts were used in the pro forma adjustment calculations and are incorporated in the operating expenses shown on Smith Exhibit 1, page 1.

Q. PLEASE EXPLAIN THE DERIVATION OF THE FUEL COST FACTORS BY CUSTOMER CLASS.

A. The fuel cost factors by customer class were derived by using the proposed and approved factors in Docket No. E-2, Sub 1173, supported by the 2018 Ward Exhibits filed in that proceeding and adjusted for potential future impacts. In summary, the costs presented in that proceeding and exhibits are based on: (1) forecasted kWh sales for the billing period December 2018 through November

2019 and estimated fuel and fuel-related costs to supply those sales, and (2) adjustments for over or under recovery from the preceding twelve-month period.[1] These factors are based on the most recently approved billing factors at the time the Company prepared its rate increase application and supporting exhibits in this proceeding.

Q. DOES THE USE OF THESE BASE FUEL FACTORS AFFECT THE COMPANY'S REQUESTED RATE INCREASE?

A. No. The Company's requested increase in revenues in this case is related to non-fuel revenues. There will be no change to customers' bills due to the inclusion of these fuel cost factors in the Company's proposed base rates. The Company will continue to bill customers the fuel rates authorized by the Commission in its annual fuel proceedings.

III. PRO FORMA ADJUSTMENTS

Q. ARE YOU SUPPORTING ANY ACCOUNTING AND PRO FORMA ADJUSTMENTS IN THIS PROCEEDING?

A. Yes. As discussed by Company Witness Smith, I provide support for the fuel adjustment.

Q. PLEASE DESCRIBE THESE PRO FORMA ADJUSTMENTS.

A. The pro-forma adjustment I support is the following:

Line 6 in Smith Exhibit 1, Page 3 adjusts fuel and fuel-related expense in the Test Period to reflect the fuel rates approved by the North Carolina Utilities Commission in Docket No. E-2, Sub 1173, effective December 1, 2018,

[1] Ward Exhibits 1 through 7 filed June 20, 2018, in Docket No. E-2, Sub 1173 (collectively "2018 Ward Exhibits").

adjusted for temporary items as discussed above. When applied to the actual test period kWh, this produces fuel and fuel-related expense of $870.5 million. When this amount is added to the adjustments to fuel expense for weather and customer growth on lines 3 and 4 in Smith Exhibit 1, Page 3 of ($18.2) million and $2.9 million, respectively, the three components add to the $855.2 million shown on page 2 of McGee Exhibit 1.

IV. CONCLUSION

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

A. Yes.

BEFORE
THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2 SUB 1219

In the Matter of:	)	
	)	
Application of Duke Energy Carolinas,	)	**SUPPLEMENTAL TESTIMONY OF**
LLC for Adjustments in Electric Rate	)	**KIMBERLY D. MCGEE FOR**
Schedules and Tariffs	)	**DUKE ENERGY PROGRESS, LLC**

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME, TITLE AND BUSINESS ADDRESS.

A. My name is Kimberly D. McGee and I am a Rates Manager for Duke Energy Progress, LLC ("DE Progress" or "the Company"). My business address is 550 South Tryon Street, Charlotte, North Carolina.

Q. PLEASE DESCRIBE YOUR DUTIES AS RATES AND REGULATORY STRATEGY MANAGER FOR DUKE ENERGY PROGRESS.

A. I am responsible for managing DE Progress' fuel charge adjustment cost recovery processes, providing guidance on compliance with regulatory conditions and codes of conduct and providing regulatory support for retail rates.

Q. DID YOU PREVIOUSLY FILE DIRECT TESTIMONY IN THIS DOCKET?

Q. Yes. I filed direct testimony on October 30, 2019.

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

A. My testimony supports the revision to the base fuel factor that the Company proposed to conform to the fuel rates approved by the Commission in its November 25, 2019 Order in Docket No. E-2, Sub 1204 ("the Fuel Cost Docket"). My testimony also updates McGee Exhibit 1, page 2, to reflect updated fuel costs based on revised weather and customer growth adjustments included in Smith Supplemental Exhibit 1.

Q. DID YOU PROVIDE ANY INFORMATION INCLUDED IN EXHIBITS SPONSORED BY OTHER COMPANY WITNESSES?

A. Yes, I provided the proposed fuel rate and annualized fuel expense included on Smith Supplemental Exhibit 1, page 3.

II. <u>BASE FUEL FACTORS</u>

Q. WHAT UPDATED BASE FUEL FACTORS DOES DUKE ENERGY PROGRESS PROPOSE TO USE IN THIS DOCKET?

A. The Company proposes to use the following updated base fuel factors by customer class (excluding gross receipts tax and regulatory fees):

- Residential 2.326 cents per kWh
- Small General Service 2.499 cents per kWh
- Medium General Service 2.456 cents per kWh
- Large General Service 2.0054 cents per kWh
- Lighting 2.217 cents per kWh

These proposed factors are derived using the total prospective fuel and fuel-related cost factors approved in Docket No. E-2, Sub 1204 and implemented on December 1, 2019. These factors represent the fuel-related amounts that the Company is collecting from North Carolina retail customers during the billing period December 2019 – November 2020 and were the fuel factors in effect at the time of filing this supplemental testimony.

Q. YOUR SUPPLEMENTAL TESTIMONY INCLUDES ONE EXHIBIT. WAS MCGEE SUPPLEMENTAL EXHIBIT 1 PREPARED BY YOU OR AT YOUR DIRECTION AND SUPERVISION?

A. Yes, it was.

Q. WHAT LEVEL OF FUEL COSTS HAS THE COMPANY INCLUDED IN ITS COST OF SERVICE?

A. As shown on McGee Supplemental Exhibit 1, the Company's North Carolina retail adjusted fuel costs expense for the Test Period was $871,585,646. This amount was calculated using the base fuel cost factors identified above and North Carolina retail Test Period actual kWh sales by customer class. I provided the amount necessary to adjust test period fuel expense to $871,585,646 to Witness Smith and it is reflected in the operating expenses shown on Smith Supplemental Exhibit 1, page 3.

Q DOES THE USE OF THESE UPDATED BASE FUEL FACTORS AFFECT THE COMPANY'S REQUESTED RATE INCREASE?

A. No. The Company's requested increase in revenues in this case is related to non-fuel revenues. There will be no change to customers' bills as a consequence of inclusion of these updated fuel cost factors in the Company's proposed base rates. The Company will continue to bill customers the fuel rates authorized by the Commission in its annual fuel proceedings.

III. CONCLUSION

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

A. Yes.

BEFORE
THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-2 SUB 1219

In the Matter of:	)	
	)	**DIRECT TESTIMONY OF**
Application of Duke Energy Progress, LLC	)	**RUFUS S. JACKSON**
For Adjustments of Rates and Charges	)	**FOR**
Applicable to Electric Serice in North	)	**DUKE ENERGY PROGRESS, LLC**
Carolina	)	

I. INTRODUCTION AND QUALIFICATIONS.

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Rufus S. Jackson. I am employed by Duke Energy. My business address is 411 Fayetteville Street, Raleigh, North Carolina.

Q. PLEASE TELL US YOUR POSITION WITH DUKE ENERGY, AND DESCRIBE YOUR DUTIES AND RESPONSIBILITIES IN THAT POSITION.

A. I am the Vice President for Carolina East Operations. I direct operations of Duke Energy in the eastern portions of North Carolina and South Carolina to ensure customer expectations are met through direct management of the construction and maintenance workforce. I am responsible for the Duke Energy and contractor workforce that performs day-to-day construction and maintenance as well as storm restoration. I am also the Operations Section Chief in the Carolinas Incident Command Structure. My testimony addresses Duke Energy Progress, LLC's ("DE Progress" or the "Company") distribution storm plan and the execution of that plan for Hurricanes Florence and Michael, Winter Storm Diego, and Hurricane Dorian (the "Storms").

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND EMPLOYMENT EXPERIENCE.

A. I have a Bachelor of Science degree in Mechanical Engineering from North Carolina Agricultural and Technical State University. Prior to assuming my current roles for the Carolinas, I have held various engineering, operational, and leadership positions over a 33-year electric utility/manufacturing career.

II. PURPOSE AND SUMMARY OF TESTIMONY.

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

A. I am testifying on behalf of the Company in support of its request for recovery of the Company's deferred storm-related costs incurred due to Hurricanes Florence, Michael, Dorian, and Winter Storm Diego.

Q. CAN YOU SUMMARIZE YOUR TESTIMONY?

A. My testimony begins by describing our Distribution Storm Response Plan. I then discuss the major storms we encountered during 2018 and 2019, and provide an assessment of our response to those storms. Finally, I discuss the scope of costs incurred by the Company in response to those storms and our successful efforts to restore electric service safely and efficiently to our customers.

Q. ARE YOU SPONSORING ANY EXHIBITS TO YOUR TESTIMONY?

A. Yes. I am sponsoring two exhibits to my testimony. Jackson Exhibits 1 and 2 detail the costs incurred by the Company in responding to Hurricanes Florence, Michael, Dorian, and Winter Storm Diego.

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

A. Yes.

III. DE PROGRESS' DISTRIBUTION STORM PLAN

Q. DOES DE PROGRESS HAVE A PLAN TO DEAL WITH MAJOR STORMS AND THE OUTAGES THEY CAUSE?

A. Yes.

Q. PLEASE DESCRIBE DE PROGRESS' DISTRIBUTION SYSTEM STORM PLAN.

A. DE Progress engages in planning for major storms on a continuous and year-round basis. Hurricane season readiness begins several months before the start of the season and includes training, drills, and implementation of lessons learned from the prior year. Our comprehensive storm plan is modeled on Homeland Security's Incident Command Structure ("ICS") and incorporates the best practices we have developed from experiences with past storms. The ICS affords rapid scalability in response to a specific threat.

In addition to using the ICS, the Company also has an Emergency Preparedness organization solely focused on planning, which incorporates lessons learned from industry experience and other events specific to the Duke Energy system in North Carolina and elsewhere.

The scalability of ICS is reflected in DE Progress' three distinct levels of restoration response (Level I – III). Level I corresponds with typical summer storms, whereas level III is designed for restoration on the scale of a hurricane. The same basic functions are performed at all storm levels, but resources are increased as required to match the storm's anticipated threat and the organization expands to ensure efficient restoration of our system. While it is appropriate for an individual to perform parts of several storm roles in a lower level event, those same roles are broken out and staffed by an increasing number of dedicated resources as the scope of restoration work increases. The decision to activate at a particular response level is made by the storm management team, and is guided by weather forecasts, resource modeling, and expected restoration duration. The flexibility of the storm plan is such that, for any given restoration event, we may have a region that is operating within the Level III model while another region is operating within a Level I model. This allows regions within the Company operating at a lower restoration level to finish sooner and release resources to work in regions operating at a higher restoration.

At a high level, the ICS plan is built around three phases of storm restoration: pre-storm activation; outage restoration; and the return of the distribution grid to normal operation. Pre-storm activation begins as early as 120 hours prior to the storm, and includes detailed weather forecasting, modeling of damage and resource requirements, and preparation of support of logistics needs. The outage restoration phase includes the operational activities following impact from the storm that restore service to all customers capable of receiving it. Returning the grid to normal is necessary to restore our electrical infrastructure to its pre-hurricane condition.

Q. CAN YOU PLEASE DESCRIBE THE DIFFERENT ROLES WITHIN DE PROGRESS' STORM PLAN?

A. Yes. Within the storm plan there are a multitude of roles that facilitate an efficient restoration process. These roles are organized along five functional lines: (1) Operations; (2) Planning; (3) Logistics; (4) Public Information/Liaison, and (5) Finance and Administration. Operations is focused on restoration of service; Planning on forecasts, modeling, and situation awareness; Logistics on staging, materials, and supplies; and External Coordination on outreach and communication to customers, local Emergency Operating Centers ("EOCs"), state and local leaders. Finance and Administration is focused on event cost forecasting, cost tracking and any HR-related issues.

The participants are assigned roles under the storm plan that may differ from their regular daily responsibilities and, as a result, it is imperative that they are effectively trained. This training is normally completed in the second quarter of each year throughout the system and within each of the functional areas of responsibility. To further ensure our storm preparedness, we conduct storm readiness drills to test the effectiveness of the training program and the employees' ability to execute their assigned storm role.

Q. WHEN AND HOW DO YOU ACTIVATE YOUR ICS MAJOR STORM ORGANIZATION?

A. Duke Energy meteorologists continuously monitor the Atlantic Basin and Tropics and begin to issue alerts as early as two weeks before expected impact. Our formal ICS activation process kicks off 120 hours prior to a projected storm event. Our initial focus is to ascertain the most detailed weather information available including date, time, and strength of the storm, when it is forecasted to impact our system, forecasted path of the storm, size and strength of the wind fields, associated amount of precipitation, when the wind is anticipated to exceed and fall below 39 mph, and strength of gusts. Up to five days prior to a predicted significant weather event, we use predictive analytics to estimate the numbers of customers impacted by the weather event and the estimated number of line resources, vegetation personnel and damage assessors needed to restore power in a reasonable period.

This analytic model is based on years of operating history and is updated and refreshed following significant events.

After an event occurs, we rerun the model based on the actual weather outcomes. At this juncture, we also start using an internally developed model, Storm Caster. This model uses the number of events and type of isolating devices from the Outage Management System ("OMS") to forecast the number of resources needed to restore power in an adjustable time frame. To help predict resource needs and the time of restoration, this model estimates the number of nested (embedded) outages behind larger sectionalizing devices. Storm Caster is run continually throughout the restoration effort. As outages are restored and more information is gathered through damage assessment, the accuracy of the model's results improves.

With each forecast update we use storm modeling tools to predict the amount of damage to our system, where that damage will likely occur, and the amount of resources required to restore the projected outages. More specifically, the tools estimate the number of personnel required, such as linemen, vegetation crews, and damage assessors. This gives us an estimate of the necessary scale of restoration response. With that information we conduct a system storm call that includes management teams representing the five functional areas of our storm response plan. As noted above, storm plan activation typically occurs 120 hours before onset of the storm. At this point, efforts are focused upon notifications to our customers and employees of a potential impact and the beginning of our storm readiness activities and our initial efforts to procure resources. A progression of checklists follows each day thereafter prior to system impact.

Q. HOW DOES DE PROGRESS USE THE INFORMATION FROM PREDICTIVE STORM MODELS?

A. Once we have estimated the amount of resources required, where and to what extent each region within our territory will be impacted, several processes begin in unison. Our Resource Management function secures commitments for restoration manpower, and Staging and Logistics prepares to open mustering and base camp sites to receive them.

Resource Management first deploys DE Progress and Duke Energy Carolinas ("DE Carolinas") employees and native contractors currently working on our system to staging sites. The second step is to secure internal line and vegetation resource commitments from the other states served by Duke Energy. Internal Duke Energy personnel are available immediately and can be moved into forward positions to expedite restoration. Next, we contact the Southeastern Electric Exchange ("SEE") Mutual Assistance Group to secure commitments from the participating companies for remaining needs. SEE Mutual Assistance is governed by an existing agreement between all participating utilities. Most Mutual Assistance utilities are also assessing impact to their systems and will hold resources until in the clear. Those utilities not in the storm's projected path typically must travel from significant distance and must be activated several days prior to landfall.

Depending on the time, path, and confidence in the storm's expected impact, decisions are made concerning when committed crews are activated, paid to be mobilized, and sent to mustering locations prior to landfall. To expedite restoration, we mobilize crews to mustering sites located along the routes from their home base to their assigned work location. We want sites that are as close as possible to expected damage; however, safety is our highest priority, so the sites ultimately used depend upon the path of the storm to ensure we are not unnecessarily placing anyone in harm's way. As such, the number of crews mobilized and where they are mustered depends greatly on confidence in the forecast.

Concurrent with the acquisition of resources, our Logistics function establishes a coordinated schedule to open mustering sites, base camps, and secures anticipated lodging needs. The use of mustering sites allows us to validate rosters and crew complements for billing, orient non-native crews to our safety policies, switching practices, technical specifications, and to prepare them for reassignment to a forward base camp. Base camps accommodate truck parking, inventory storage, refueling, meals, and, in some cases, lodging.

Q. HOW DOES THE COMPANY RESPOND TO THE ONSET OF MAJOR STORMS?

A. When the storm-force winds commence in DE Progress' service territory, the Distribution Control Center ("DCC") is in constant communication with the Transmission Control Center ("TCC") and System Operations Center ("SOC") and the distribution and transmission storm centers. The TCC gives both storm centers a thorough description of what transmission lines and substations are dropping out of service as the storm passes, giving us a real-time assessment of the location of the storm damage. Crews in the storm's direct path shelter in place. The Energy

Control Center ("ECC") and the distribution and transmission storm centers jointly establish restoration priorities and coordinate the distribution and transmission restoration strategy to maintain grid stability.

Q. WHAT HAPPENS AFTER THE STORM PASSES?

A. Our initial response has three main components: (1) governmental and EOC support and response; (2) initial damage assessment; and (3) feeder backbone/substation restoration efforts. These three components enable the local and state governments to respond to the storm's impact, and enables DE Progress to both estimate the amount of storm damage actually incurred by the distribution and transmission system and begin restoration of the highest priority feeders.

As local governments and county EOCs encounter issues that require our immediate attention, we can promptly respond. These issues may involve, for example, support for road clearing teams, or removing a downed power line with police personnel standing by at the site. We have account managers and community relations managers at local (zone) storm centers. They are the single point of contact for government and EOC officials.

As the outages are occurring, the ECC and DCC are identifying critical outages and grid stability issues, and are notifying local storm teams of high priority events. As soon as the storm winds drop below 39 miles per hour, local field crews assess and restore, based on their knowledge of the system in their area, starting with the major feeders and substations. In addition, damage assessment teams are activated to get a better understanding of the damage to the distribution and transmission system. The previously identified representative distribution line segments are assigned to damage assessment teams who are responsible for a pole-by-pole survey of those representative segments, to inventory the extent of damage incurred and return that damage information to be entered in a database. Based upon the storm damage found in this representative sample, we extrapolate the amount of storm damage for the rest of the local distribution network and aggregate these assessments to get a system-wide storm damage estimate. These estimates are used to confirm damage and make adjustments as needed to the pre-landfall resource mobilization plan.

The circuit restoration process is a method by which we start at the substation and continue along the line to restore customers based on criticality and number of customers impacted. Highest priority is assigned to feeders that are critical to the health, safety, and welfare of the general public.

Q. HOW IS THE RESTORATION PHASE OF THE STORM PLAN CARRIED OUT?

A. At this juncture of our restoration efforts, we begin to deploy restoration resources to the local operating areas to include them in the storm restoration plan. Restoration priorities begin with restoring our transmission system which also facilitates restoration of end-use power. Repairs to our transmission system also allow restoration points of delivery to wholesale customers such as electric cooperatives and municipalities. Duke Energy gives first priority to facilities needed to ensure public health and safety as well as critical public infrastructure. We then focus on restoring as many customers as quickly as possible. Finally, we work on the individual neighborhoods and homes based upon availability to receive power. To efficiently use this first wave of resources, we assign them to the storm damage that was identified through our initial local field assessments. This allows us to assign them to the highest priority work on the most critical components of our distribution infrastructure.

Based upon the information collected from the initial assessment, any aerial storm damage assessments using helicopters, information reported to our outage management system, and the knowledge of local management, the management team has the information it needs to determine what feeders require detailed damage assessment. When the detailed assessment of a feeder segment is complete, the results of that effort are compiled into an associated work package. This work package allows us to effectively communicate the scope of the work to be completed and further assists us in managing productivity expectations of our line and vegetation crew resources. Additionally, the work package information assists local management in allocating resources and determining Estimated Times of Restoration ("ETRs").

Throughout the storm event, the Company monitors outage events in the impacted areas daily to determine the areas with the need for resources and we redeploy and/or release resources to ensure we are appropriately addressing customer outages and costs.

Q. DOES THE COMPANY UPDATE ETRS DURING THE RESTORATION PROCESS?

A. Yes. We have three levels of ETRs: 1) an initial system level ETR; 2) a view of ETRs by city and county; and 3) device level ETRs. As the storm restoration progresses, we move from higher level ETRs to increasing levels of detail, letting customers know what we know when we know it. ETRs are continuously updated and expanded to greater levels of detail during restoration. Factors that influence the ETR updates include integrating any new information we have collected, the extent and severity of the storm damage, the critical and priority restoration needs we may receive from ECC, state and local governments and EOCs, and the availability of resources. Additionally, timing of resource arrival can be impacted by several external factors such as road and bridge closures, crews that must travel through the path of the storm (after it has cleared), roads, hotels and lodging clogged by evacuees, and lack of fuel along major routes into the state. As required, we shift line and vegetation crews, equipment, and material to address new priorities or to increase productivity. We are constantly striving during the restoration to improve our ETRs and meet or exceed our own ETR goals.

Q. HOW DOES THE COMPANY WIND DOWN ITS RESTORATION PROCESS?

A. As we near the completion of storm restoration work within any part of our service territory, we begin demobilization efforts. DE Progress believes it is imperative to use the most productive and cost-effective resources during our restoration efforts. As a part of our demobilization efforts, we survey local management and feeder coordinators to get their assessment on the productivity of the non-native line and vegetation personnel. Combining this information with the daily cost of the personnel, we build a plan that retains the safest, most productive, and most cost-effective resources.

Q. IS THERE ANYTHING ELSE THAT MUST BE DONE AFTER RESTORATION OF CUSTOMERS IS COMPLETE?

A. Yes. The final phase of our storm response is the restoration of the system to its pre-storm status. When in the storm outage restoration phase, we perform the necessary work to restore the fundamental operating characteristics of our distribution infrastructure. The primary focus is getting "lights on" and safety considerations rather than correcting all damaged facilities that are still capable of functioning. For example, during the storm outage restoration phase, DE Progress will leave in place poles that are damaged and in need of repair but are able to safely provide service to our customers in the short term, capacitor banks and reclosers are returned to service only if immediately required, and animal mitigation hardware is not installed pursuant to our day-to-day standards. After the restoration efforts have concluded, we conduct electrical and physical condition sweeps of our circuits and identify the issues that require mitigation to return the distribution system to its pre-storm state.

The Company also conducts a "tree sweep", which is a detailed vegetation sweep of our circuits to identify any storm damage to trees that was not mitigated during the storm restoration phase. The tree sweep is focused on cracked or broken limbs that are tenuously hanging over-top of facilities and will eventually come down. The Vegetation Management Coordinator for that area and associated vegetation management personnel are responsible for identifying trees or branches damaged by the storm and immediately mitigating any such damage. This process requires considerable subject matter expertise because these issues can be camouflaged when the leaves are still green, meaning that only the most obvious can be easily identified.

Q. WHAT IS THE COMPANY'S OUTAGE MANAGEMENT SYSTEM?

A. The OMS is a series of complex interfacing systems that collect and analyze multiple inputs to provide a source for discrete outage level data and ETRs. Outage level data and ETRs are then communicated to customers via several channels including the online outage map, Voice Response Unit ("VRU"), and outbound email and text messages.

Q. HOW DOES THE COMPANY COMMUNICATE INFORMATION TO ITS CUSTOMERS PRIOR TO, DURING AND AFTER A STORM?

A. The Company has a three-phased communication strategy for storm response that focuses on providing customers and the general public important information 1) before a storm, 2) during a storm; and 3) after a storm. In each phase, messaging focuses on what to expect, how to prepare, how to be safe and how to stay up to date on restoration efforts.

The Company uses a variety of communication channels to disseminate information. For mass communication (information intended for multiple audiences), we share information with media outlets (TV, newspaper, radio), revise advertising to reflect storm-related information, post social media content on

Facebook and Twitter, as well as our website – which is also viewable via mobile devices.

For direct-to-customer communications, we use email, text messaging, outbound calls with recorded messages and, in some cases, live voice calls.

Before a storm, the Company issues news releases, posts social media information related to storm and safety tips, issues public service-like advertisements, sends customers emails focused on preparedness, and proactively pitches stories to the media (and subsequently conducts interviews) focused on our preparedness efforts and to encourage customers to be prepared. To address the needs of customers with medical or other special needs, we conduct outbound call campaigns to ensure these customers are aware of pending severe weather and to prepare for potentially extended outages. We also launch a dedicated webpage focused on the specific storm event where the public can find news releases, safety tips, videos, restoration information and links to other valuable resources, such as the Red Cross or state Emergency Management sites. Banners on the Company's main website direct customers to the storm and safety information and eventually to the new webpage once its launched.

All pre-storm communications include storm and safety tips and instructions on how to report outages through numerous options. Our proactive outreach to the media often results in interviews and stories focused on storm preparedness.

During a storm, the Company develops daily messages to be used with media, customers, social customer care and field personnel. The Company publishes daily updates via news releases and social media on various topics, including storm damage, estimated times of restoration, and out of town resources. We secure TV, print and radio advertising where we provide restoration updates. Customers participating in our proactive outage communications programs receive updates via email, phone and text on restoration progress and estimated times of restoration. Ongoing updates regarding the storm are also provided on the Company's dedicated storm page which includes updated outage maps. Furthermore, during a storm event, updates are continuously provided to elected officials, community leaders and other stakeholders to ensure they have the information they need to share with their audiences and to plan accordingly.

After a storm, the Company prepares wrap-up messages to share with customers, community leaders and other stakeholders. News releases are published to provide final outage-related numbers, thank customers for their patience, and to thank local first responders and the companies that provided off-system resources. Messages of appreciation are also provided via email, social media posts and paid advertisements to customers, first responders, community agencies and other utilities who provided assistance. Location-specific messaging is also provided – generally in the field or other personal contact – to customers with unique situations that may delay a restoration, such as meter box damage, flooding or other issues that may prevent the safe restoration of electric service.

Q. PLEASE DESCRIBE THE COMPANY'S PROCESS FOR SEEKING MUTUAL AID FROM OUTSIDE SOURCES.

A. Once a storm system is identified that could impact DE Progress' service territory, mutual assistance calls are initiated for additional resources including native and non-native contractors and mutual assistance organizations. The mutual assistance calls are for discussing the availability of resources outside the projected impact area that may be able to provide assistance to our service territory should it be necessary. Resources typically include: linemen, vegetation management, damage assessment, support, and logistics for both Distribution and Transmission restoration efforts. Depending on the projected event timing and intensity, the objective is to have some resources mobilized and pre-positioned ahead of the impact.

Q. HOW DOES THE COMPANY ON-BOARD CREWS AND WHAT STEPS DOES THE COMPANY TAKE TO ENSURE THEY ARE DEPLOYED EFFICIENTLY AND EFFECTIVELY?

A. The Company on-boards newly arriving crews at staging and logistics sites where actual roster complements are verified and arrival times documented. Crews go through a detailed overview of Company safety rules and protocols, as well as information on construction standards. Once on the system, crews are assigned to feeder coordinators. For DE Progress, the feeder coordinators are a key oversight resource responsible for managing the work of off-system restoration crews, including contractors. Each feeder coordinator assigns their crews daily work packages prepared in advance and monitors progress of restoration as the day progresses. They review time sheets daily, and provide feedback to the storm center about crew effectiveness. This information is used by Operations and Logistics during demobilization to sequence crew releases so that less productive crews are released first and high productivity, high value crews are released last.

IV. <u>DESCRIPTION OF 2018 AND 2019 STORMS</u>

Q. WHAT ARE THE STORMS THAT MAKE UP DE PROGRESS' REQUEST FOR STORM COST RECOVERY IN THIS PROCEEDING?

A. The four Storms included in DE Progress' request for storm cost recovery are Hurricanes Florence, Michael, Dorian and Winter Storm Diego.

Q. CAN YOU PLEASE DESCRIBE HURRICANE FLORENCE?

A. Just days before making landfall, Hurricane Florence approached the Carolinas' coast as a Category 4 hurricane with a projected inland path through the center of the Triangle, which splits the DE Carolinas and DE Progress service territories. In response, DE Carolinas and DE Progress mobilized an army of staff and crews of approximately 20,000 people, the largest in its history, to stage throughout the Carolinas to immediately deploy as soon it was safe to begin restoration efforts.

Actual landfall occurred near Wrightsville Beach early on September 14, 2019 at which time Hurricane Florence was a Category 1 storm. Maximum wind gusts associated with the storm exceeded 105 miles per hour and it created storm surges in the range of 9 to 13 feet. Because of a high-pressure ridge over the eastern United States, Florence made extremely slow progress once it made landfall, moving at only 2-3 miles per hour. This caused the storm to linger over eastern

North Carolina for most of the next three days during which it dropped excessive amounts of rainfall – more than 35 inches in some locations.

The catastrophic flooding that followed Florence was of historic proportions and resulted in the City of Wilmington being completely cut off from the rest of the State by floodwaters. It also resulted in the major highways in eastern North Carolina – to include Interstates 40 and 95 and US Route 70 – being impassable in multiple locations for several days.

Florence caused 54 deaths, resulted in more than $24 billion in property damage in the Carolinas alone and downed thousands of trees. The flooding and wind damage also resulted in electrical outages across virtually the entire eastern half of North Carolina directly impacting DE Progress' (and DE Carolinas') service territory.

Hurricane Florence caused significant damage to DE Progress' electric system in North Carolina and South Carolina. The total number of DE Progress' customers impacted during the storm was 1,448,419 (1,328,634 in North Carolina and 119,785 in South Carolina). The peak number of customer outages for DE Progress in the Carolinas was approximately 529,000, which occurred Sunday, September 15, 2018, at 8:04 AM. More than 79% of customers had been restored within 48 hours of the hurricane leaving North Carolina. By September 23, 2018, full restoration was accomplished for all customers able to receive service.

DE Progress experienced extraordinary damage to both its transmission and distribution systems because of Florence. Specifically, the DE Progress transmission system had 138 substations and 45 lines out of service. DE Progress distribution system suffered almost 216 miles of downed wire, approximately 5,446 downed poles, and 1,858 damaged transformers across the Progress system. The Company arranged for additional off-system linemen and support men and women from Alabama, Arkansas, the District of Columbia, Florida, Georgia, Illinois, Indiana, Kansas, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, New Jersey, Ohio, Oklahoma, Pennsylvania, Rhode Island, Tennessee, Texas, Wisconsin and Canada to assist with the restoration efforts.

To support this response effort, DE Progress was required to provide housing and logistical operations support for more than 20,000 employees, allies, and contractors in forward deployed areas directly impacted by the hurricane. DE Progress housed thousands of these utility workers at staging areas in the forward operating zones utilizing trailers as well as local housing resources. DE Progress was also required to coordinate meals and other basic services for these crews as they went about the difficult and dangerous work of restoring power to hurricane impacted areas.

In addition to line crews, vegetation management professionals, and damage assessors, and other support personnel worked around the clock in call centers and operations centers to answer customer outage calls, assess damage and dispatch crews. Other support personnel handled logistics, such as meals, housing and refueling for the crews - all of which were complicated by the massive flooding and road closures caused by the storm. The Company also provided pre-storm preparation and post-impact restoration updates to customers through traditional and social media as well as text messages and emails.

In initiating, managing, and implementing this response to Hurricane Florence, Duke mobilized DE Progress employees for "storm duty" by diverting them from their normal day-to-day responsibilities to support storm response and recovery. This reallocation of internal assets occurred at virtually every level of the Company and resulted in hundreds of Duke employees working on a 24/7 basis – many of them forward deployed – to assist in the monumental task of restoring services and systems following the storm.

Q. WAS YOUR PREPARATION ANY DIFFERENT FOR HURRICANE FLORENCE BECAUSE OF THE FORECASTED IMPACT AS A CATEGORY 4 HURRICANE?

A. Yes. Because of the projected forecast, we needed to take additional precautions for restoration and potential flooding. A more concentrated management team was placed in smaller geographic footprints than our normal planning regions to help facilitate and expedite the restoration efforts. The Coastal zone was sub-divided into five areas.

In anticipation of flooding and through lessons learned during Hurricane Matthew, flexible tube Tiger Dams were installed at five sub-stations across the eastern region. To assess damage in difficult to access areas, drones were used to view areas that damage assessors could not reach because of flooding or extensive damage. Also, to facilitate crew movement, we utilized National Oceanographic and Atmospheric Administration ("NOAA") and US Department of Transportation ("DOT") flood map information. We also used these to schedule work in impacted areas prior to the river cresting predictions.

Q. HOW LONG DID THE MOBILIZATION/RESPONSE TO HURRICANE FLORENCE GO ON?

A. We mobilized for the storm on September 10, 2018 and demobilized between September 15 and September 23, 2018. Following demobilization, several crews remained on-system to assist with sweeps and additional repairs.

Q. DID THE COMPANY UTILIZE AMI DURING RESTORATION?

A. Yes. As described in Witness Schneider's testimony, DE Progress now has the capability to interrogate individual smart meters to determine if customers have power. During the damage assessment phase of a storm, the mass meter interrogation capability allows the Company to have a better view of where outages are located on the system. This functionality helps reduce the assessment time, thus reducing outage durations for customers.

During the power restoration phase of a storm, the capability of mass meter interrogation enables the Company to determine whether power has been restored to each meter before leaving an area. Finally, during the cleanup phase of a storm, the capability of interrogating individual meters can tell the Company when a customer's power has already been restored, saving a truck roll to confirm power has been restored.

During Hurricane Florence in September 2018, the Company successfully interrogated 225 meters in North Carolina and avoided the need to send trucks to determine whether power had been restored to those locations. During Hurricane Michael in October 2018, the Company successfully interrogated 193 meters in North Carolina. During Winter Storm Diego in December 2018, the Company successfully interrogated 538 meters in North Carolina. During Hurricane Dorian in September 2019, the Company successfully interrogated 2,156 meters in North Carolina

Q. IS THE COMPANY SATISFIED WITH ITS RESPONSE TO THIS STORM?

A. Yes. As with all events of this nature, the mobilization and restoration of service for this storm taught us lessons that will serve us well in the future but, overall, we believe that the storm vindicated our response planning and that efforts taken to repair facilities and restore service following Florence were extraordinary. We are very pleased with the effort and results achieved by all parties involved in that process, including our own employees, allies, and contractors.

Q. CAN YOU PLEASE DESCRIBE HURRICANE MICHAEL?

A. Hurricane Michael came ashore in the Florida Panhandle on October 10, 2018 as a Category 4 storm with winds as high as 155 miles per hour. The storm was quick-moving and reached the Carolinas as a tropical storm on October 11, 2018. This fast-moving storm brought heavy winds and rain to the already saturated DE Progress service territory, resulting in flooding, widespread damage and outages. This occurred just weeks after Hurricane Florence. DE Progress and DE Carolinas mobilized more than 10,000 personnel from Company, contractor, and off-system mutual assistance crews to restore the grid.

The total number of DE Progress customers impacted during Hurricane Michael was 483,675 (436,216 in North Carolina and 47,459 in South Carolina). The peak number of customer outages for DE Progress in the Carolinas was approximately 170,222, which occurred October 11, 2018, at 8:00 PM. More than

90% of DE Progress' customers had been restored within 72 hours. As of October 16, 2018, full restoration was accomplished for all customers able to receive service.

As was the case with Hurricane Florence, DE Progress experienced substantial damage to both its transmission and distribution systems as a result of Michael. Specifically, the DE Progress transmission system had 14 substations and 9 lines out of service. DE Progress' distribution system suffered almost 25 miles of downed wire, approximately 635 downed poles, and 287 damaged transformers across its system. The Company arranged for additional off-system linemen and support men and women from Alabama, Delaware, Florida, Georgia, Illinois, Kansas, Kentucky, Louisiana, Maryland, Maine, Michigan, New York, Ohio, Oklahoma, Pennsylvania, South Carolina, Tennessee, and Texas to assist with the restoration efforts.

To support this response effort, DE Progress was required to provide housing and logistical operations support for more than 10,000 employees, allies, and contractors in forward deployed areas directly impacted by the hurricane. DE Progress housed thousands of these utility workers at staging areas in the forward operating zones. DE Progress was also required to coordinate meals and other basic services for these crews as they went about the difficult and dangerous work of restoring power to hurricane impacted areas.

In addition to line crews, vegetation management professionals, and damage assessors, and other support personnel worked in call centers and operations centers to answer customer outage calls, assess damage and dispatch crews. Other support personnel handled logistics, such as meals, housing and refueling for the crews. The Company also provided pre-storm preparation and post-impact restoration updates to customers through traditional and social media as well as text messages and emails.

Q. HOW LONG DID THE MOBILIZATION/RESPONSE TO HURRICANE MICHAEL GO ON?

A. We mobilized for the storm on October 11, 2018 and demobilized between October 14 and October 23, 2018. Following demobilization, several crews remained on-system to assist with sweeps and additional repairs.

Q. IS THE COMPANY SATISFIED WITH ITS RESPONSE TO THIS STORM?

A. Yes.

Q. CAN YOU PLEASE DESCRIBE WINTER STORM DIEGO?

A. Beginning on December 9, 2018, Winter Storm Diego blew into DE Progress' North Carolina and South Carolina service territories and dumped a mix of more than a foot of snow, ice and freezing rain in many locations through December 12, 2018. Winter Storm Diego caused widespread damage and outages and was the most significant early December storm since 2002's ice storm. The storm resulted in near record snowfalls in multiple locations throughout the State – Mt. Mitchell had a snowfall of 34 inches from the storm. DE Carolinas and DE Progress again mobilized almost 9,000 personnel from Company, contractor, and off-system mutual assistance crews to restore the grid.

The total number of DE Progress customers impacted during Winter Storm Diego was 254,882 (252,307 in North Carolina and 2,575 in South Carolina). The peak number of customer outages for DE Progress in the Carolinas was approximately 70,158 which occurred Sunday, December 9, 2018, at 3:00 pm. More than 90% of DE Progress' customers had been restored within 48 hours. As of December 11, 2018, full restoration was accomplished for all customers able to receive service.

DE Progress experienced significant damage to its distribution system as a result of Winter Storm Diego. Specifically, the DE Progress transmission system had 1 substation and 1 line out of service. DE Progress distribution system suffered almost 1 mile of downed wire, approximately 12 downed poles, and 100 damaged transformers across the Progress system. The Company arranged for additional off-system linemen and support men and women from Alabama, Delaware, Florida, Georgia, Illinois, Kansas, Kentucky, Missouri, Mississippi, Ohio, South Carolina, Tennessee, and Virginia to assist with the restoration efforts.

To support this response effort, DE Progress was required to provide housing and logistical operations support for more than 9,000 employees, allies, and contractors in forward deployed areas directly impacted by the hurricane. DE Progress housed thousands of these utility workers at staging areas in the operating zones. DE Progress was also required to coordinate meals and other basic services for these crews as they went about the difficult and dangerous work of restoring power to hurricane impacted areas.

In addition to line crews, vegetation management professionals, and damage assessors, and other support personnel worked in call centers and operations centers to answer customer outage calls, assess damage and dispatch crews. Other support personnel handled logistics, such as meals, housing and refueling for the crews. The Company also provided pre-storm preparation and post-impact restoration updates to customers through traditional and social media as well as text messages and emails.

Q. HOW LONG DID THE MOBILIZATION/RESPONSE TO WINTER STORM DIEGO GO ON?

A. We mobilized for the storm on December 6, 2018 and demobilized between December 11 and December 13, 2018.

Q. IS THE COMPANY SATISFIED WITH ITS RESPONSE TO THIS STORM?

A. Yes.

Q. CAN YOU PLEASE DESCRIBE HURRICANE DORIAN?

A. In the early hours of September 6, 2019, slow-moving Dorian impacted the Carolinas as a Category 2 hurricane with maximum sustained winds of 90 mph. Dorian weakened as it moved northeast along the North Carolina coast, just south of the Crystal Coast, clipping Cape Lookout and eventually making landfall at Cape Hatteras.

The total number of DE Progress customers impacted during Hurricane Dorian was 295,176 (267,962 in North Carolina and 27,214 in South Carolina). The peak number of customer outages for DE Progress in the Carolinas was approximately 116,131 which occurred Friday, September 6, 2019, at 8:03 am. More than 95% of DE Progress' customers had been restored within 48 hours. As of September 9, 2019, full restoration was accomplished for all customers able to receive service. Damage assessment records for Hurricane Dorian are still being finalized.

In response to Dorian, the Company arranged for additional off-system linemen and support from Alabama, Arkansas, the District of Columbia, Florida, Georgia, Illinois, Indiana, Kansas, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, New Jersey, Ohio, Oklahoma, Pennsylvania, Rhode Island, Tennessee, Texas, Wisconsin and Canada to assist with the restoration efforts. To support this response effort, DE Progress was required to provide housing and logistical operations support for almost 9,000 employees, allies, and contractors in forward deployed areas directly impacted by the hurricane. Like its other hurricane response efforts, DE Progress housed thousands of these utility workers at staging areas in the operating zones. DE Progress was also required to coordinate meals and other basic services for these crews as they went about the difficult and dangerous work of restoring power to hurricane impacted areas. In preparation for the potential impacts from Hurricane Dorian, the Company installed temporary mitigation structures, such as tiger dams and portadam systems, at seven substations.

Q. HOW LONG DID THE MOBILIZATION/RESPONSE TO HURRICANE DORIAN GO ON?

A. We mobilized for the storm on September 1, 2019 and demobilized between September 6 and September 8, 2019.

Q. IS THE COMPANY SATISFIED WITH ITS RESPONSE TO THIS STORM?

A. Yes.

V. DE PROGRESS' RESPONSE TO FLORENCE, MICHAEL, DORIAN, AND DIEGO.

Q. DID DE PROGRESS FOLLOW ITS DISTRIBUTION STORM PLAN DISCUSSED ABOVE, INCLUDING CUSTOMER COMMUNICATIONS AND REQUESTS FOR MUTUAL AID, IN RESPONDING TO THE STORMS?

A. Yes. Each of these Storms was sufficiently threatening to cause us to implement our distribution storm response plan and we did so in each instance.

Q. HOW DID YOU IMPLEMENT THE PLAN YOU DESCRIBE ABOVE?

A. Notwithstanding significant infrastructure damage resulting from these Storms, we implemented our distribution storm plan as described. We strongly adhered to plan processes and methods including storm planning and management, resource mobilization & de-mobilization, materials and supply chain, damage assessment, and work prioritization and work package development. Regular updates on ETRs were provided to customers and were effective.

Q. HOW DO YOU MEASURE THE EFFECTIVENESS OF YOUR STORM PLANNING AND RESTORATION PROCESS?

A. To measure restoration effectiveness, one of the main measures that we use is the cumulative percentage of customers restored versus our projection of where we should be at the end of each day. Moving backward from our final ETR goals, we set milestones that must be achieved each day to achieve our overall goal. We generate these milestones down to the operations center level based on the amount of storm damage on our system, the level of resources that we have at our disposal, and our own restoration history. This analysis tells us whether we are being as effective as we need to be and, if not, helps to highlight or correct any issues that may be impacting our performance.

Effective planning comes down to ensuring we have the processes in place to provide maximum flexibility. Due to the nature of these storms, we will never be able to precisely predict the location and timing of storms, nor the extent of damage they will cause. It is critical that our planning process ensures we have the flexibly to adapt to inevitable changes in the location, timing, and intensity of storms as they arise. In our judgment, our planning process did in fact provide us with the needed flexibility to cope effectively.

Another critically important measure of effectiveness is safety; in the three storms of 2018, and the single storm in 2019 (so far) we recorded a total of seven injuries for our Duke Energy personnel across all of the Carolinas for both DE Carolinas and DE Progress and had zero electrical contacts. This is a remarkable accomplishment considering the vast number of people working during these restoration efforts. DE Progress is proud of the fact that all its workers, and the workers from outside the state, returned home safely to their families after the events.

Q. WHEN DID THE COMPANY REQUEST MUTUAL ASSISTANCE FOR THESE STORMS?

A. The Company initiated communications regarding mutual aid as outlined in the table below.

Storm	Mutual Assistance Calls Began	Request for
Florence	Monday, 9/10/18	Distribution Line & Veg- Mutual Assistance Organization
Michael	Thursday, 10/11/18	Distribution Line - Mutual Assistance Organization
Diego	Thursday, 12/6/18	Distribution Line - Mutual Assistance Organization
Dorian	Monday, 9/2/2019	Distribution Line - Mutual Assistance Organization

Q. WHEN DID THE COMPANY'S MUTUAL AID COSTS FOR THESE STORMS BEGIN TO ACCRUE?

A. As is industry standard, mutual aid costs begin to accrue when the responding entities begin taking actions towards providing mutual aid in response to a request (including, for example, preparing employees and equipment for travel). Specific dates vary depending on travel times and destinations.

Q. HOW DID THE COMPANY DETERMINE WHEN MUTUAL AID WAS NO LONGER NEEDED TO ASSIST IN RESTORATION EFFORTS?

A. Mutual aid resources are accepted throughout the duration of each storm and are deemed to be no longer needed when they can no longer contribute to achievement or acceleration of restoration times at a reasonable cost.

Q. IN ADDITION TO ITS INTERNAL CUSTOMER COMMUNICATION PROTOCOLS, DID THE COMPANY UTILIZE NON-DE PROGRESS LABOR TO ADDRESS CUSTOMER CONTACTS DURING THE MAJOR STORMS?

A. Yes. The Company deployed an additional 311 persons during Hurricane Florence, 304 additional persons during Hurricane Michael, 356 additional persons during Winter Storm Diego, and 256 additional persons during Hurricane Dorian to address customer contacts.

Q. HOW MANY CUSTOMER CALLS DID THE COMPANY RECEIVE DURING THE STORMS?

A. The Company received the following:

Storm	**Outage**	**Regular Business**	**Total**
Florence	101,986	75,141	177,127
Michael	22,424	21,381	43,805
Diego	16,746	31,450	48,196
Dorian	11,589	18,421	30,010

Q. DID THE COMPANY ISSUE PUBLIC ANNOUNCEMENTS REGARDING THESE STORMS?

A. Yes. To ensure the public was aware of the potential impact of these storms to the electric grid and their services; to enhance our preparedness to restore service quickly and safely; and to aid in our restoration progress throughout the Storms, we issued 29 news releases (English and Spanish) and conducted nearly 900 media interviews. In addition, we published 129 social media posts (Facebook and Twitter) which covered several topics including safety, storm damage, crews/resources, updated outage and restoration numbers and estimated times of restoration. All the information was aggregated and displayed on a dedicated storm page – www.dukeenergyupdates – on the Company's website. Additionally, we used direct-to-customer communication channels, including email, texting and outbound calls – to reach customers for whom we had email addresses on file; customers who had previously registered for Proactive Outage Notifications; and customers who participated in our "medical alert / special needs" programs. Also for these Storms, we completed outbound call messages to nursing homes/assisted living facilities to encourage preparedness and to provide estimated times of restoration.

After each storm, we conduct an internal assessment of our communication efforts and incorporate improvement opportunities to better our performance in future storms. One such example occurred in the aftermath of Hurricane Florence when we implemented an "ETA for ETR" communication strategy. Since Hurricane Florence moved ashore and stalled, estimated times of restoration were delayed for many parts of the service area because crews were unable to access damaged areas. Instead of waiting until we had new information (which could have been days given the amount of flooding in some areas), we began communicating daily with customers a time for when they could expect to receive more information.

Q. DID THE COMPANY UTILIZE CONTRACT LABOR TO HELP RESTORE POWER IN RESPONSE TO THE STORMS?

A. Yes. DE Progress utilized the following contractors in responding to Florence, Michael, Diego and Dorian:

Storm	Line Contractors	Veg Contractors	Damage Assessors
Florence	8,602	2,782	1,649
Michael	4,511	1,899	473
Diego	2,948	1,400	700
Dorian	4,000	650	1,200

Q. WHEN WAS THE COMPANY FULLY-RESTORED FROM THE STORMS?

A. Restoration is considered complete when all customers able to receive power have been restored. DE Progress restored the following:

Storm	# NC Customers Impacted	Days of Restoration	Full Restoration Date
Florence	1,328,634	9	9/24/2018
Michael	436,216	6	10/17/2018
Diego	252,307	4	12/12/2018
Dorian	267,962	4	9/2/2019

Q. HOW WAS VEHICLE FUEL PROCURED FOR COMPANY PERSONNEL AND MUTUAL AID PARTNERS IN PREPARATION FOR THESE STORMS?

A. DE Progress has arrangements with several national vendors to provide fuel and fueling equipment. One week prior to potential landfall, the Company makes notification to vendors of projected need. If necessary, fuel vendors are staged in a safe location close to base camps. Once travel conditions are safe, they set up at the base camps across the impacted areas and provide the majority of fuel needed by Duke employees, contractors and mutual assistance resources.

V. COSTS OF RESPONDING TO FLORENCE, MICHAEL, DIEGO AND DORIAN.

Q. PLEASE IDENTIFY WHAT INCREMENTAL COSTS THE COMPANY INCURRED IN CONNECTION WITH HURRICANE FLORENCE.

A. As reflected on Jackson Exhibit 2, page 1, the incremental O&M storm-related costs incurred by the Company due to Hurricane Florence totaled approximately $453.8 million for the DEP system. Total capital costs for Florence were $84.0 million.

Q. PLEASE IDENTIFY WHAT INCREMENTAL COSTS THE COMPANY INCURRED IN CONNECTION WITH HURRICANE MICHAEL.

A. As reflected on Jackson Exhibit 2, page 2, the incremental O&M storm-related costs incurred by the Company due to Hurricane Michael totaled approximately $30.8 million for the DEP system. Total capital costs for Michael were $9.3 million.

Q. PLEASE IDENTIFY THE INCREMENTAL COSTS THE COMPANY INCURRED IN CONNECTION WITH WINTER STORM DIEGO.

A. As reflected on Jackson Exhibit 2, page 3, the incremental O&M storm-related costs incurred by the Company due to Winter Storm Diego totaled approximately $30.7 million for North Carolina. Total capital costs for Diego were $1.5 million.

Q. PLEASE IDENTIFY THE INCREMENTAL COSTS THE COMPANY INCURRED IN CONNECTION WITH HURRICANE DORIAN.

A. As reflected on Jackson Exhibit 2, page 4, the incremental O&M storm-related costs incurred by the Company due to Hurricane Dorian totaled approximately $204.4 million for North Carolina. Total capital costs for Dorian were $19.7 million.

Q. WERE THESE EXPENSES REASONABLE AND NECESSARY TO RESTORE SERVICE TO CUSTOMERS AND TO PROVIDE FOR THE SAFETY, STABILITY, AND CONTINUITY OF DE PROGRESS' SYSTEM?

A. Yes. Each of the named Storms caused extensive damage and widespread outages to DE Progress' distribution system and required a robust response from the Company. This response involved the activation and deployment of storm response assets internal to the Company, utilization of outside contractors, and the need to seek mutual aid from other electric utilities and allies in the industry.

Q. PLEASE EXPLAIN HOW STORM-RELATED COSTS WERE TRACKED AND ACCOUNTED FOR DURING AND AFTER EACH STORM, AND EXPLAIN THE PROCESS THE COMPANY USES TO VERIFY THAT COSTS ASSIGNED TO THE STORMS WERE IN FACT RELATED TO THE STORMS AND WERE INCREMENTAL.

A. When a potential major storm event is approaching the DE Progress service territory, the Company creates separate project codes (e.g., distribution, transmission, etc.) to be used by employees for processing and aggregating the total amount of storm restoration costs incurred for financial reporting and regulatory recovery purposes. The Company uses these project codes to account for all costs directly associated with restoration, including incremental and non-incremental costs. All storm restoration costs charged to these storm projects were initially captured in FERC Account 593, normal operations and maintenance ("O&M") expense, capital, or below the line expense.

Q. PLEASE FURTHER EXPLAIN THE PROCESS FOR ACCUMULATING ACCOUNTING DATA RELATED TO STORM COSTS.

A. Major storm costs are initially accumulated in these storm project codes, including charges that are considered non-incremental or capital. There are separate storm projects for each function (transmission, distribution, customer operations, fossil/hydro generation) charged during storm restoration. Capital costs are also identified and subsequently credited from O&M FERC Accounts 593 and debited to FERC Account 107, Construction Work in Progress.

In discussing the nature of the costs incurred for these major storms, it is essential to have a clear understanding of what constitutes incremental and non-incremental costs. The Company defines incremental costs as all costs incurred to respond to the storms from resources external to DE Progress and all costs incurred within DE Progress, except for internal base company labor and base fleet costs. All other costs are considered non-incremental.

As outlined in Jackson Exhibit 2, the storm damage costs incurred by the Company because of Florence, Michael, Diego and Dorian fall into the following categories:

1. Company Labor – amounts represent regular and overtime payroll for employee time spent in direct support of storm restoration. During the Storms, payroll costs were incurred related to DE Progress employees as well as Duke Energy affiliate employees from outside of North Carolina assisting in the storm response. All regular payroll amounts associated with DE Progress employees and all bonuses have been removed from our recovery request as either non-incremental or capitalized. All amounts related to Duke Energy affiliates, such as linemen from Duke Energy affiliates in Florida, the Carolinas and Midwest that were used in lieu of third party contractors, are recoverable in this filing or were part of the capitalized amounts for the units of property replaced.
2. All overtime paid to employees of Duke Energy affiliates was incremental to DE Progress and thus is included for recovery in this filing, similar to contractor costs. While the majority of overtime for DE Progress employees incurred due

to storm restoration-related activities was also deemed incremental and thus included for recovery in this filing.

3. Contractor Labor costs – includes actual incurred costs associated with mutual aid utilities, line contractors, staging and logistics personnel and other outside contractors used in storm-restoration related activities.
4. Vegetation Management Labor costs – includes actual incurred costs associated with all vegetation contractors, both native and off-system, used in storm restoration related activities.
5. Materials and Supplies – includes the materials and supplies used to repair and restore service and facilities to pre-storm condition, and excludes the portion of materials and supplies used in restoration activities that are included in capitalized cost.
6. Internal fleet costs – the costs included in the net recoverable request include only the fuel component in this filing.
7. Other expenses – include other minor amounts of storm-related expenses not coded to one of the categories above.

For each of the Storms, the cost category amounts are outlined in Jackson Exhibits 1 and 2.

Q. PLEASE EXPLAIN THE AMOUNTS CAPITALIZED TO PROPERTY, PLANT AND EQUIPMENT BY THE COMPANY.

A. The Company has a process to ensure all units of property installed during storm restoration are capitalized at reasonable material and labor amounts (i.e., resulting in capital amounts at the normal cost for the removal, retirement and replacement of those facilities). During major storm events, only the Company's Distribution Operations and Transmission Operations installed capital units of property.

For Transmission Operations, given the much smaller number of individual repair and replace events, specific projects were issued for capital versus O&M work, allowing real-time tracking of those capital projects. As capital work was performed, those associated material and equipment costs were charged to capital projects.

With respect to Distribution Operations, the nature of repair work is so voluminous and time of the essence that the issuance of individual projects for capital versus O&M work is not feasible. However, the Company's tracking of materials allows it to do an accounting of all units of property used during storm restoration, resulting in the proper capitalization of those units of property. This is accomplished by having DE Progress' Supply Chain organization issue the materials directly to the storm project as they ship them from the distribution center to the various base camps and having Supply Chain personnel at the operating centers issue materials used during the storm to the storm project. Once the restoration effort has been completed all materials from the base camps are picked up and brought back to the distribution center where it is placed in a specific area for return processing. All the returned materials are segregated and tagged so that they can be identified as materials initially charged to the storm restoration. The material is returned to the same accounting that was used during the restoration effort, properly resulting in only the actual units installed during storm restoration being capitalized.

Once the number of units of property were confirmed, the Company's Finance organization determined a normal, reasonable total dollar amount to capitalize for those units of property.

- Material Quantities: the number of units of property ("UOP") were identified and grouped (i.e. poles, transformers, wire, etc.). The quantities for UOP replaced during the storm become the basis of the calculation to determine the estimated total capital amount.
- Baseline UOP Replacement Cost: Twelve months of historical data received from the Company's Asset Accounting group was used to determine a baseline total capitalized cost of each UOP category. Finance calculated the total cost and the total number of each UOP installed during the twelve-month period. Finance divided the total cost into labor, fleet, indirect, material, and all other costs. Once the categories were determined, a unit cost was determined for each category under normal, non-storm, conditions.
- Labor Hours Adder: For each grouping of UOP, DE Progress' Operations group estimated the average number of hours and the number of line resources needed to install that type of UOP under normal conditions. The average number of hours multiplied by the number of resources generated the total hours to install that UOP. The DE Progress Operations group then estimated the average number of hours and the number of line resources needed under storm conditions to install that type of UOP to determine the total hours for storm conditions. The total hours under storm conditions was then divided by the

total hours under normal conditions to develop a gross-up factor for storm conditions.

- Labor Rate Adder: A calculation is performed to compare the blended rate for DE Progress and contractor line resources during normal operating conditions to a blended rate during storm conditions, which includes the impact of off-system contractor and Duke affiliate labor. The calculation results in a labor rate adder that is applied to the baseline UOP cost.
- Staging and Logistics Adder: During major storm restoration, DE Progress incurs incremental costs for staging sites, hotels, and meals to support resources needed for restoration. These are costs that would not be incurred under normal conditions but are necessary costs associated with replacement of UOP's following a storm. As such, a portion of these costs are included in the amount to capitalize. The total Staging and Logistics cost is multiplied by the ratio of capitalized labor to the total labor to determine the portion of Staging and Logistics costs that should be capitalized.
- Amount to Capitalize: The baseline unit cost for labor for each UOP is escalated by the Hours Adder and by the Labor Rate Adder to determine the escalated unit cost for labor. The Staging and Logistics Adder is allocated to each UOP to create a staging and logistics unit cost. The escalated unit cost for labor and the staging and logistics unit cost are added to the baseline unit costs for material, fleet, indirect, and other costs to determine a total escalated unit cost for each UOP. This escalated unit cost per UOP is then multiplied by the associated UOP quantity to determine the amount to capitalize.

For each major storm, the amount of storm costs capitalized are outlined on Jackson Exhibit 2.

Q. IN ADDITION TO TRANSMISSION AND DISTRIBUTION OPERATIONS, PLEASE DESCRIBE THE OTHER FUNCTIONAL AREAS THAT INCURRED COSTS RELATED TO THE STORMS.

A. In addition to the Company's Distribution Operations and Transmission Operations areas, the Company's generation plants (Fossil/Hydro Operations, or "FHO") were damaged during several of the aforementioned storms. And, as further described below, the Company's Customer Operations organization incurred significant costs directly related to the storms.

With respect to Customer Operations, incremental costs include the same categories of costs as noted above (overtime costs, contractor costs, payroll of Duke Energy affiliate employees, employee travel expenses, etc.). The Company followed a similar process as that described above to ensure only incremental Customer Operations costs are being requested for recovery in this filing.

VIII. CONCLUSION

Q. DO YOU HAVE AN ASSESSMENT OF THE COMPANY'S IMPLEMENTATION OF ITS STORM PLAN DURING 2018 AND 2019?

A. Yes. The Company's restoration efforts were reasonable and prudent and resulted in the restoration of service to the vast majority of customers as quickly and safely as reasonably possible, and the Company's restoration costs were prudently incurred. I believe the strength of a storm plan is its flexibility to adapt to unexpected conditions. The Company faced a significant challenge as a result of the Storms and the storm plan proved to be an effective and efficient tool to achieve our goal of restoring customer service as safely and expeditiously as possible. The storm plan proved to be invaluable to us in preparing for and responding to these Storms.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1219

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

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Renee Metzler, and my business address is 550 South Tryon Street, Charlotte, North Carolina.

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

A. I am employed by Duke Energy Business Services LLC ("DEBS"), as Managing Director – Total Rewards. DEBS provides various administrative and other services to Duke Energy Progress, LLC ("DE Progress" or the "Company") and other affiliated companies of Duke Energy Corporation ("Duke Energy").

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I graduated from the University of Mary Washington with a Bachelor of Arts degree in Spanish Language and Literature. I also hold a Professional in Human Resources certification. I have over 30 years of human resources experience, primarily working with benefits and compensation programs. I joined Piedmont Natural Gas Company, Inc. ("Piedmont") in 2001 and have held various leadership positions in human resources. Most recently, I was the Managing Director – Total Rewards at Piedmont with responsibility for broad-based compensation, executive compensation, retirement benefits, health and welfare benefits, the human resources management system ("HRMS") and payroll. I have served in a leadership role on several projects, including the redesign of Piedmont's retirement (pension, 401(k) and retiree medical) program, the design and implementation of a consumer-driven health plan with a Health Savings Account, the implementation of the

Workday HRMS system, the design and implementation of Piedmont's wellness program, the redesign of Piedmont's long-term incentive plan and the integration of Piedmont employees into the Duke Energy compensation and benefits programs. I became an employee of DEBS in October 2016 when Piedmont was acquired by Duke Energy.

Q. PLEASE DESCRIBE YOUR DUTIES AS MANAGING DIRECTOR – TOTAL REWARDS.

A. I am responsible for all compensation, health and welfare and retirement benefits for Duke Energy, including all of Duke Energy's affiliated regulated and non-regulated companies, including DE Progress. Areas of responsibility include: management of key vendor relationships, compensation including executive compensation, benefit plan design and strategy, administration and compliance.

Q. DID YOU PREVIOUSLY FILE DIRECT TESTIMONY IN THIS PROCEEDING?

A. No, I did not.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. Public Staff witness Shawn Dorgan recommends that certain compensation-related costs be disallowed, as follows:

Dorgan Ex. 1 Line No.	Description	Dollar Impact
23	Adjust incentive compensation	$14,705,000
34	Adjust Board of Directors expense	$1,275,000
15	Adjust executive compensation	$161,000

In my rebuttal testimony, I demonstrate that witness Dorgan's proposed adjustments are inappropriate and should be rejected by the Commission.

II. CUSTOMERS BENEFIT FROM MARKET-DRIVEN TOTAL COMPENSATION PROGRAMS

Q. WHAT IS THE COMPANY'S COMPENSATION PHILOSOPHY?

A. Duke Energy's overall compensation philosophy is to target total compensation of base pay and incentives, including both short- and long-term, at the median of the market when compared to peer companies, with the opportunity to earn more or less relative to the market median based on actual performance. Therefore, it is not appropriate to consider the various components of total compensation in isolation, as does witness Dorgan. Doing so inappropriately ignores the Company's obligation to be responsive to the market for talent and assure the competitiveness of the total compensation package, consisting of base salary, cash based incentives, long-term incentive compensation, retirement and other benefits.

Q. PLEASE PROVIDE AN OVERVIEW OF THE COMPENSATION PROGRAMS PROVIDED BY DUKE ENERGY.

A. Duke Energy's compensation programs consist of a base pay component and incentive pay components that together provide a market-competitive, total compensation package for all employees. The base pay component is a set amount, reviewed by management at least annually, and established at a level that: (1) provides compensation based on the nature and responsibilities of the employee's position; and (2) is fair relative to the pay for other similarly-situated positions in the organization. The short-term incentive ("STI") pay component is variable based on performance and is at risk to the employees. All employees have STI as a component of their total pay. Incentive pay is linked to the accomplishment of specific goals established in advance for the individual employee, his or her business unit, one or more of the Duke Energy companies and/or Duke Energy. The purpose of carving out a portion of employees' total compensation and delivering it through variable incentive pay is: (1) to encourage employees to accomplish specific objectives intended to ensure safe, reliable and economical utility service to our customers; (2) to ensure their business unit's and Duke Energy's overall success; and (3) to incorporate a component of any compensation package that is competitive based on the market. The long-term incentive ("LTI") plans round out a competitive total compensation package for certain employees in leadership positions. The purpose of carving out a portion of total compensation and delivering it through LTI programs is to reflect the market for human capital, which in turn is necessary to attract and retain high-caliber leaders needed to ensure safe, reliable and economical utility service to our customers. Simply put, competent management is beneficial to customers. The total compensation concept is depicted in Figures 1 and 2, below.

Figure 1

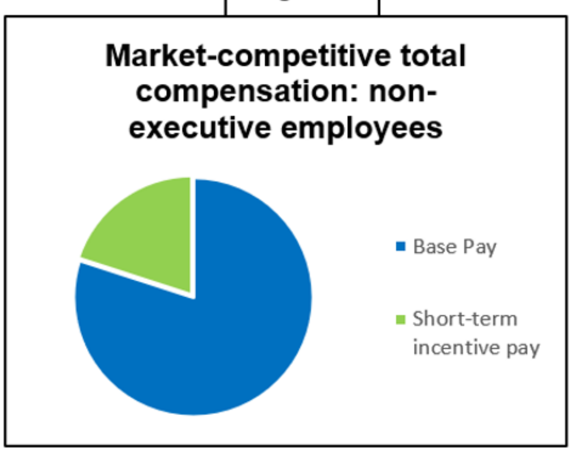
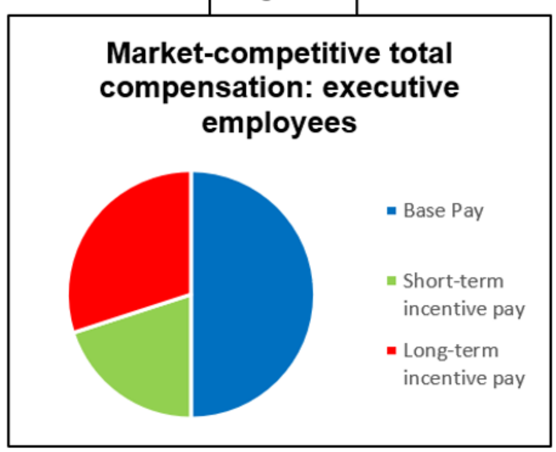


Figure 2



Q. DOES A COMPETITIVE TOTAL COMPENSATION PACKAGE FOR EMPLOYEES BENEFIT THE COMPANY'S RETAIL CUSTOMERS?

A. Yes. Our employees deliver critical services to our customers every day. The energy industry is a knowledge and experience-intensive industry where the tenure of employees matters. For example, we need to attract, develop and retain—over the long term—the engineering professionals that design, help build and operate our plants at a reasonable cost, just like we need to attract, develop and retain our power delivery professionals charged with maintaining and improving our infrastructure necessary to keep the lights on at a reasonable cost. The skills needed for employees to render safe, reliable and high-quality utility service take several years to develop. Line Technicians are highly skilled positions that require experience and knowledge that is acquired over several years. If we were to lose such employees, we would incur additional costs to train replacements for these positions, while experiencing additional risk with regard to reliability issues. Moreover, the industry is an aging industry. If we do not provide our talented employees competitive compensation that is consistent within and outside our industry, then other utilities and companies will hire our employees. Avoiding this circumstance becomes especially important as more experienced employees retire.

Finally, incenting a focus on long-term sustainable company performance provides a benefit to customers, as a financially strong company will have greater access to capital at a lower cost, which in turn benefits customers through a lower cost structure. In addition, the introduction of long-term incentive pay as a component of overall compensation ensures our leadership is focused on the long term, and not overly focused on the short term.

Q. HOW DOES INCLUDING EARNINGS PER SHARE AND TOTAL SHAREHOLDER RETURN METRICS AS PART OF INCENTIVE PAY BENEFIT CUSTOMERS?

A. The measures of our corporate incentive program are designed to drive results. Earnings Per Share ("EPS") is a performance measure included in the STI opportunity for all employees. To achieve strong incentive results, we must operate reliably, we must operate safely, we must deliver strong customer service, we must control our costs and we must grow our company. Including a goal for financial performance in our incentive program incents employees to pursue cost-effective ways to deliver these measures. Using this balanced scorecard approach benefits customers by delivering critical services at competitive rates. EPS and Total Shareholder Return ("TSR") measure overall financial performance, and overall financial performance in turn can reflect how employees take action on a routine basis to support the efficient delivery of safe and reliable energy to customers. In addition, finding sustainable cost savings is an important part of achieving our financial targets, and those sustainable cost savings benefit our customers. Incenting employees to work diligently to ensure costs are responsibly and prudently incurred is critical. These actions provide benefits to customers through competitive rates.

Q. IS THE COMPANY'S APPROACH TO EMPLOYEE COMPENSATION REASONABLE AND PRUDENT?

A. Yes. As I previously stated, the Company must maintain a competitive total compensation package to attract and retain talent needed to run a safe and reliable electric system. While the Company's employee compensation methodology is comprised of several components, including base salary and variable incentive pay, the reasonableness of the total compensation package is commensurate with the market. Further, the EPS/TSR metrics, as a subcomponent of the variable incentive pay formula, encourage eligible employees to reduce expense, operate efficiently and conserve financial resources, all of which benefit customers by keeping rates competitive. To eliminate any portion of incentive compensation would decrease employees' total compensation to less than competitive levels, compelling the Company to consider an offset to this reduction by an increase to its fixed costs through base pay adjustments or face severe workforce challenges. This is shown by Figures 3 and 4, below – removing either of the cross-hatched pie pieces, representing the portions of compensation that the Public Staff wishes to exclude from rates, would leave the compensation at a below-median level.

Figure 3

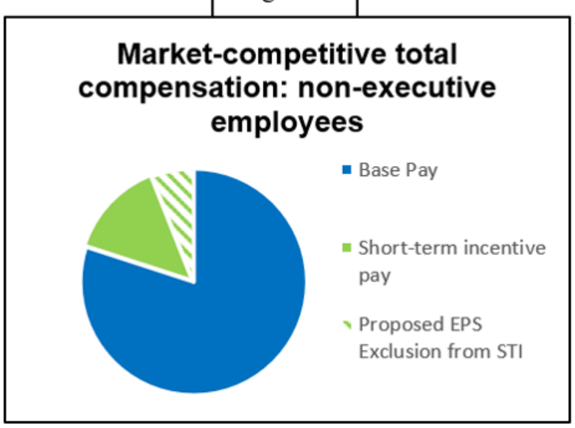
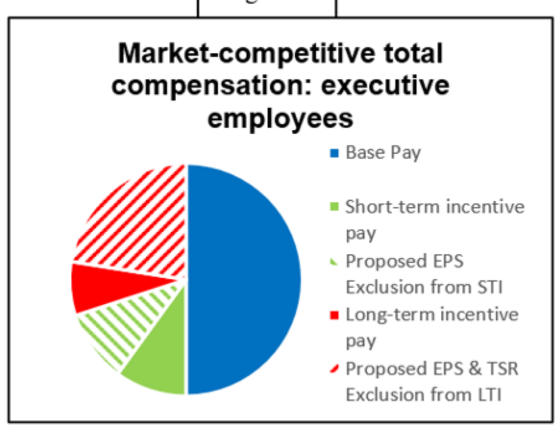


Figure 4



Q. WHAT WOULD BE THE IMPLICATIONS TO CUSTOMERS IF THE TOTAL COMPENSATION LEVELS WERE ALLOWED TO FALL BELOW MARKET-COMPETITIVE LEVELS?

A. Allowing total compensation to fall below market-competitive levels would have substantial negative implications for the cost of service to customers. Given the length of time necessary to fully train employees to safely perform all aspects of their jobs, allowing the turnover rate to escalate due to lowering the competitive levels of pay and benefits would be imprudent. Many craft positions require lengthy apprenticeships to learn the skills needed to perform work independently and safely. The expense incurred to hire and train new employees and the loss of productivity realized through high turnover rates would negatively affect the ability of the Company to provide safe and reliable service at a reasonable cost. This is also true for leadership positions. Duke Energy invests in developing highly effective leaders who carry out the organization's mission and inspire employees to work together to achieve results the right way. Paying less than competitive levels of compensation would put the Company at risk of losing these valuable leaders to other companies and potentially having to pay more to attract the same level of leadership talent externally. The financial cost of turnover and negative implications from lost productivity, hiring, training and job vacancy can put a significant level of productivity and financial value at risk to the Company. Incentive pay is similar to the other costs related to producing and distributing electricity. It is a necessary cost to provide customers safe and reliable service. In the competitive market for talent, employees consider total rewards, including base pay, incentive pay and benefits, as a key determinant in deciding whether to work for a particular employer. The target incentive compensation provided by Duke Energy is necessary to achieve market-competitive compensation and, thus, is a reasonable and appropriate cost of doing business that should not be eliminated.

In my opinion, the Company's entire incentive pay expense is reasonable and necessary to attract and retain high quality employees with the critical skills necessary to provide safe, efficient and reliable service to customers, and, therefore, it should be recoverable in its entirety.

III. PUBLIC STAFF'S PROPOSED ADJUSTMENTS

Q. PLEASE DESCRIBE PUBLIC STAFF WITNESS DORGAN'S PROPOSED ADJUSTMENT RELATING TO INCENTIVE COMPENSATION.

A. The incentive compensation witness Dorgan seeks to disallow (Adjustment 23) is based upon the stance that EPS and TSR metrics provide a direct benefit to shareholders rather than to ratepayers.

As I have demonstrated in my testimony, employee compensation and incentives tied to metrics such as EPS and TSR benefit customers, because those metrics reflect how employees' contributions translate into overall financial performance. EPS, for example, is a measure of the Company's financial performance, and that performance is reflective of how certain goals – safety, individual performance, team performance and customer satisfaction (all of which are components of incentive pay) – are met in a cost-effective way. Divorcing employee performance from such an important measure of a rate regulated company's overall health makes no sense and is counterproductive.

The incentive components of employee compensation incent employees to be cost conscious, to work efficiently and to find the least cost solutions to issues and problems posed every day, which in turn reduces operations and maintenance ("O&M") costs. This benefits customers by rates being established on a lower O&M cost than what they would otherwise be. In short, incentive compensation tied to these readily measurable metrics incent employees to help DE Progress deliver safe, reliable and competitively priced energy to its customers, every day, day in and day out. For the Commission to abrogate these incentives would be a severe detriment to customers, not a benefit to customers, and would result in disallowance of a prudently incurred cost.

Finally, in order to attract a well-qualified and well-led workforce, the Company must compete in the marketplace to obtain the services of these employees. No witness in this proceeding, including Public Staff witness Dorgan, challenges the reasonableness of the level of compensation expenses reflected in the rate-making test period for the Company. No one has challenged that the compensation and benefit programs provided to employees of Duke Energy, including those who work on behalf of DE Progress, are necessary and critical in their entirety for attracting, engaging, retaining and directing the efforts of employees with the skills and experience necessary to safely, efficiently and effectively provide electric services to DE Progress customers. Instead, witness Dorgan wants to have the benefit of the Company employing qualified and well-managed employees productively engaged in providing safe, reliable, and affordable electric service to our customers today and tomorrow, but not to reflect the business share of that cost of service.

Q. PLEASE EXPLAIN THE COMPANY'S ADJUSTMENT TO EXECUTIVE COMPENSATION.

A. As noted in the direct testimony of Company witness Kim Smith, as part of its initial filing, in the current rate case, the Company has already made an adjustment to remove 50 percent of the compensation of the five Duke Energy executives with the highest allocation to DE Progress in the test period. In the last DE Progress rate case, the Company made an upfront adjustment to remove 50 percent of the compensation of the four Duke Energy executives with the highest allocation to DE Progress in the test period, then later agreed to remove 50 percent of the compensation of a fifth executive, at the recommendation of Public Staff witness Darlene Peedin.

Q. IN THIS CASE, DOES WITNESS DORGAN PROPOSE ADDITIONAL DISALLOWANCES FOR THESE FIVE EXECUTIVES?

A. Yes. Witness Dorgan proposes the additional removal of corresponding benefits for these five executives. He offers no evidence to support this disallowance, one that diminishes the contributions these individuals make on behalf of DE Progress customers, misrepresents the focus and deliverables of their positions and ignores the common interests between shareholders and customers. The Company believes that Public Staff has not provided sufficient justification for such disallowance. Simply stated, the Company cannot operate without leaders. To address the known concern of Public Staff, the Company proactively removed 50% of the compensation for these leaders, despite its belief that it would have been appropriate to include in cost of service—that should be enough to address the matter. Public Staff takes it too far in asserting the reduction is justified because such leaders address shareholder interests. Customers would be terribly affected if the Company did not have leaders to address shareholder matters because, simply stated, the Company needs shareholders to help finance operations and construction, and to ignore that need is unjust.

For the reasons I have described, there is no justification with any substance for the proposed disallowances of reasonable and prudent retail operating expenses.

Q. DID WITNESS DORGAN PROPOSE ANY OTHER CORPORATE-FOCUSED DISALLOWANCES?

A. Yes. He proposed, under the same theory, to exclude 50 percent of Board of Directors' expenses and compensations.

Q. DO YOU BELIEVE THIS DISALLOWANCE IS APPROPRIATE?

A. No. By definition, the Company is required to have a Board of Directors. We cannot pretend that an investor-owned utility is not an investor-owned utility. The costs of being one, including Board costs, are in fact costs of service. It is not fair or reasonable to penalize the Company for merely being an investor-owned utility with attendant requirements to that corporate structure.

IV. CONCLUSION

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

A. Yes, it does.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1219

In the Matter of:	)	
	)	**REBUTTAL TESTIMONY OF**
Application of Duke Energy Progress, LLC	)	**RUDOLPH BONAPARTE**
For Adjustments of Rates and Charges	)	**FOR DUKE ENERGY**
Applicable to Electric Service in North Carolina	)	**PROGRESS, LLC**

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

A. My name is Rudolph ("Rudy") Bonaparte. I am Chairman and a Senior Principal with Geosyntec Consultants, Inc. and my business address is 2002 Summit Blvd., N.E., Suite 885, Brookhaven, GA 30319. When providing services in North Carolina, I provide them through our North Carolina-based affiliated company, Geosyntec Consultants of North Carolina, P.C., with offices in Charlotte and Raleigh.

Q. ON WHOSE BEHALF ARE YOU SUBMITTING YOUR TESTIMONY?

A. I am submitting my testimony before the North Carolina Utilities Commission ("Commission") on behalf of Duke Energy Progress, LLC ("DE Progress ").

Q. PLEASE SUMMARIZE YOUR EDUCATION QUALIFICATIONS.

A. I obtained my B.S. in civil engineering in 1977 from the University of Texas at Austin (UT). I received my M.S. and Ph.D degrees in civil engineering from the University of California, Berkeley in 1978 and 1982, respectively. At Berkeley, I was a National Science Foundation Graduate Research Fellow.

Q. PLEASE SUMMARIZE YOUR PROFESSIONAL EXPERIENCE.

A. I am Chairman and a Senior Principal with Geosyntec Consultants, Inc. and have nearly 40 years of professional experience in the areas of geoenvironmental and geotechnical engineering applied to municipal, industrial, hazardous, and low-level radioactive waste disposal facility projects. In addition to this project experience, I was lead co-author of several technical resource and guidance documents on the design, construction, and performance of waste containment systems published by the United States Environmental Protection Agency ("USEPA"). My experience with CCR landfills and impoundments spans 25 years. I am knowledgeable regarding the physical and chemical characteristics of coal combustion residuals ("CCRs"), the Federal CCR Rule, and the design and construction of storage, disposal, and closure systems for CCRs. I am an elected member of the United States National Academy of Engineering ("NAE"). I am also a Fellow of the American Society of Civil Engineers and received the society's 2016 Lifetime Achievement Award in Design. I also received the 2019 Georgia Engineering Alliance Lifetime Achievement in Engineering Award. and I am a registered professional civil engineer in North Carolina and 18 other states.

Q. DOES YOUR TESTIMONY INCLUDE ANY EXHIBITS?

A. Yes. Bonaparte Rebuttal Exhibit 1 includes my full educational and professional background. In addition, Bonaparte Rebuttal Exhibit 2 is a March 2020 report entitled "CCR Surface Impoundment Public Information Review".

Q. WAS EXHIBIT 2 PREPARED UNDER YOUR DIRECTION AND SUPERVISION?

A. Yes. Bonaparte Rebuttal Exhibit 2 was prepared under my direction and supervision.

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

A. As outlined in Exhibit 2, under my direction and supervision, a team of professionals with our firm prepared a report entitled "CCR Surface Impoundment Public Information Review," dated March 2, 2020. We prepared this report to document our observations and findings regarding closure planning of coal combustion residual (CCR) surface impoundments in the states of Georgia, North Carolina, South Carolina, and Virginia during the approximate timeframe of 2009 to 2011, or earlier. The report presents the results of a review of two sets of publicly available documents for coal-fired electric power plants for these states:

- reports presenting the results of safety assessments for CCR impoundment dams prepared by private engineering firms under subcontract to the USEPA in the timeframe 2009-2011 (hereafter referred to as "USEPA dam safety assessment reports"); and,
- for the CCR impoundments identified in the USEPA dam safety assessment reports, closure plans prepared by the utility owners/operators of the CCR impoundments (or their consultants) in or around 2016 pursuant to the Federal CCR Rule (40 CFR §257.102(b)); in a few instances, the posted closure plans were prepared pursuant to state regulations rather than the CCR Rule; for our report, these facilities are considered together and collectively referred to as CCR Rule closure plans.

From the USEPA dam safety assessment reports, Geosyntec recorded information regarding each CCR impoundment's location, year built, report preparer (engineering consultant), active/inactive status, lined or unlined condition, operating information, and most relevant to our report, whether there was any indication in the report that planning for, or implementation of, an engineered impoundment closure had occurred prior to or during the 2009-2011 timeframe.

From the CCR Rule closure plans, Geosyntec recorded information about each CCR impoundment's closure plan date, closure plan preparer, closure method (e.g., closure by removal, cap-in-place), details of the closure cover system, actual or anticipated closure construction start date, and whether the CCR Rule closure plans referenced or mentioned prior closure plans (during or prior to the 2009-2011 timeframe) and/or any earlier closure planning or closure construction activities.

The results of the review of this publicly available information are contained in two tables for each of the reference states, one presenting the results of the review of the USEPA dam safety assessment reports, and the second presenting the results of the review of the CCR Rule closure plans.

Q. IS THERE ANYTHING YOU WOULD LIKE TO CLARIFY IN YOUR MARCH 2020 REPORT IN EXHIBIT 2?

A. Yes. The EPA CCR Impoundment Inspection Form in the US EPA dam safety assessment report for the DE Progress Asheville Plant's 1964 CCR surface impoundment indicated that it had a geomembrane liner. In response to the Public Staff's Data Request No. 150-1 asking about a liner for the Asheville Plant's 1964 CCR surface impoundment, DE Progress responded that the geomembrane liner noted in the form is actually for a constructed wetland built on top of the inactive impoundment. Therefore, the Asheville Plant's 1964 CCR surface impoundment itself is unlined, and with this testimony, I am clarifying that point in my report.

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

A. Yes.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1219

In the Matter of:	)	
	)	**DIRECT TESTIMONY OF**
Application of Duke Energy Progress, LLC	)	**KELVIN HENDERSON**
for Adjustments of Rates and Charges	)	**FOR DUKE ENERGY**
Applicable to Electric Service in North Carolina	)	**PROGRESS, LLC**

I. INTRODUCTION AND OVERVIEW

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Kelvin Henderson and my business address is 526 South Church Street, Charlotte, North Carolina.

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

A. I am Senior Vice President of Nuclear Operations for Duke Energy Corporation ("Duke Energy"), with direct executive accountability for Duke Energy's North Carolina nuclear stations, including Duke Energy Progress, LLC's ("DE Progress" or the "Company") Brunswick Nuclear Station ("Brunswick") in Brunswick County, North Carolina; the Harris Nuclear Station ("Harris") in Wake County, North Carolina; and Duke Energy Carolinas, LLC's ("DE Carolinas") McGuire Nuclear Station, located in Mecklenburg County, North Carolina.

Q. WHAT ARE YOUR RESPONSIBILITIES AS SENIOR VICE PRESIDENT OF NUCLEAR OPERATIONS?

A. As Senior Vice President of Nuclear Operations, I am responsible for providing oversight for the safe and reliable operation of Duke Energy's nuclear stations in North Carolina. I am also involved in the operations of Duke Energy's other nuclear stations, including DE Progress' Robinson Nuclear Station ("Robinson"), located in Darlington County, South Carolina.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I have a Bachelor's degree in Mechanical Engineering from Bradley University and over 27 years of nuclear energy experience with increasing responsibilities. My nuclear career began at Commonwealth Edison's Zion Nuclear Station in Illinois where I received a senior reactor operator license from the Nuclear Regulatory Commission ("NRC") and served as a control room unit supervisor. In 1998, I joined Progress Energy in the operations department at the Harris Nuclear Station. After serving in various leadership roles in Operations, Work Management, and Maintenance, I was named plant manager at Harris. In 2011, I was named general manager of nuclear fleet operations for Progress Energy. Following the merger between Duke Energy and Progress Energy, Inc. in 2012, I became site vice president of DE Carolinas' Catawba Nuclear Station in York County, South Carolina. In 2016, I was named senior vice president of corporate nuclear, and I assumed my current role as senior vice president of Nuclear Operations in December 2017.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes. I provided testimony to this Commission in DE Progress' 2018 annual fuel proceeding in Docket No. E-2, Sub 1173, and DE Progress' 2019 annual fuel proceeding in Docket No. E-2, Sub 1204.

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

A. The purpose of my testimony is to provide information in support of the Company's request for a base rate adjustment. To this end, I describe DE Progress' nuclear generation assets; update the Commission on capital additions since the Company's last rate case filed in 2017, Docket No. E-2 Sub 1142 (the "2017 Rate Case"); explain key drivers impacting nuclear operations and maintenance ("O&M") costs; and provide operational performance results for calendar year 2018 (the "Test Period").

Q. WHAT ARE THE PRIMARY CAPITAL AND O&M DRIVERS WITHIN THE NUCLEAR FLEET DRIVING THIS REQUEST?

A. Since the 2017 rate case, capital investments have been made to enhance safety, comply with new or revised regulatory requirements, enhance reliability and efficiency, and manage aging and obsolescence.

Since the Company's last rate case, O&M expense has declined slightly. DE Progress has effectively managed O&M challenges driven primarily from inflationary pressure on labor and materials. External supplemental labor is critical to the safe and efficient execution of refueling outages. Most of the supplemental labor required during refueling outages is highly trained, skilled, and specialized, and the Company competes with other nuclear companies to secure the supplemental labor required. Inflationary pressures among this labor pool have exceeded routine inflation. By leveraging the size of the Company's nuclear fleet and the number of refueling outages, the Company has been successful in mitigating some of this inflationary pressure. However, despite these aggressive and significant efforts, DE Progress continues to face new costs and inflationary pressures.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. The remainder of my testimony is organized as follows:

II. NUCLEAR FLEET: Generation Capacity and Asset Descriptions

III. CAPITAL ADDITIONS: In-Service for This Proceeding

IV. O&M AND OTHER ADJUSTMENTS

V. NUCLEAR OPERATIONAL PERFORMANCE: Metrics and Industry Benchmarking

VI. CONCLUSION

II. NUCLEAR FLEET

Q. PLEASE LIST DE PROGRESS' NUCLEAR FLEET.

A. The Company's nuclear generation portfolio consists of 3,575[1] megawatts ("MWs") of power capacity made up as follows:

Brunswick - 1,870 MWs

Harris - 964 MWs

Robinson - 741 MWs

[1] As of January 1, 2019.

Q. PLEASE GENERALLY DESCRIBE DE PROGRESS' NUCLEAR GENERATION ASSETS.

A. DE Progress' nuclear fleet consists of three generating stations and a total of four units. Brunswick is a boiling water reactor facility with two units and was the first nuclear plant built in North Carolina. Unit 2 began commercial operation in 1975, followed by Unit 1 in 1977. The operating licenses for Brunswick were renewed in June 2006 by the NRC, extending operations up to 2036 and 2034 for Units 1 and 2, respectively. Harris is a single unit pressurized water reactor that began commercial operation in 1987. The NRC issued a renewed license for Harris in 2008, extending operations up to 2046. Robinson, also a single unit pressurized water reactor, began commercial operation in 1971. The license renewal for Robinson Unit 2 was issued by the NRC in 2004, extending operation for Robinson up to 2030.

Q. WERE THERE ANY POWER CAPACITY CHANGES WITHIN DE PROGRESS' NUCLEAR PORTFOLIO SINCE THE LAST RATE CASE?

A. Yes. During the spring 2018 refueling outage at Harris, the Company replaced the station's low-pressure turbines. Efficiency improvements from the new turbines resulted in capacity gains. After testing, observations, and validation during the summer of 2018, the station's maximum dependable capacity was increased by 32 megawatts net effective January 1, 2019.

Q. WHAT ARE DUKE ENERGY'S PLANS RELATED TO SUBSEQUENT LICENSE RENEWAL FOR THE EXISTING NUCLEAR FLEET?

A. Duke Energy recently publicly announced intentions to seek subsequent license renewal ("SLR") for all six nuclear plants, including DE Progress' Brunswick, Harris, and Robinson plants. Based on current plans, Duke Energy will file first for SLR for DE Carolinas' Oconee plant in 2021, followed soon thereafter for DE Progress' Robinson plant. The remaining plant SLR submittals are scheduled to follow based on the expiration dates of the current licenses. The SLR application process is detailed and thorough, and each application review is expected to take approximately eighteen months or longer.

III. <u>CAPITAL ADDITIONS</u>

Q. PLEASE PROVIDE ADDITIONAL DETAILS REGARDING MAJOR CAPITAL PROJECTS FOR NUCLEAR BEING INCLUDED IN THIS CASE.

A. Since the 2017 Rate Case, DE Progress has, or will have by February 29, 2020, invested approximately $1.2 billion in beneficial capital projects. These capital improvements were required to enhance safety, preserve performance and reliability of the plants throughout their extended life operations, and address regulatory requirements. For example, all three DE Progress stations have upgraded their turbine control systems ("TCS") from electro-hydraulic to digital systems. The fleet based TCS upgrade projects share technology and operating experience across the three stations. The new digital systems address both equipment obsolescence issues and single-point vulnerabilities. Additionally, to comply with Nuclear Energy Institute ("NEI") 13-12, *Open Phase Condition Industry Guidance Document*, and NRC Bulletin 2012-01, the Company has completed open phase detection system upgrades at all three DE Progress nuclear stations. These upgrades result in fully redundant open phase detection systems, thus improving safety margins related to offsite power. All three stations also completed upgrades to their fiber optics backbone networks. The enhanced fiber networks provide higher capacity and more reliable service to support station needs. The new networks also enable more wireless monitoring of plant systems and components, and facilitate mobile work platforms designed to increase efficiencies.

At Brunswick, capital investments have been made to improve the safety and reliability of the emergency diesel generators ("EDGs"). The multi-year project, designed to resolve aging and obsolescence issues, involved the installation of new automatic voltage regulators and governors. With the completion of this work on EDG number 2 in 2018, this project has been completed. Main bearings have also been replaced on all four EDGs. Similarly, projects to remediate and replace portions of the saltwater containing systems, including replacements of both service water and circulating water pumps, which began in 2016, continue. To date, four of ten service water pumps and four of eight circulating pumps have been replaced. Two additional circulating pumps are scheduled for replacement in November 2019 and January 2020, respectively. When the pump upgrade project completes in 2024, a total of eighteen pumps will have been replaced. The new pumps are designed to better withstand the corrosive effects of the saltwater environment, improving equipment reliability and reducing long-term operating and maintenance costs.

During the spring 2018 refueling outage at Harris, the station's low-pressure turbines were replaced. The new turbines addressed the aging of the existing turbines and mitigated the free-standing blade root cracking concerns. As I stated earlier in my testimony, the new turbines also improved thermal efficiency resulting in a 32 MW increase in the station's maximum dependable capacity. This capacity increase benefits customers without incurring any additional fuel cost. The station will replace the reactor vessel head during the fall 2019 refueling outage. The replacement of the reactor vessel head will resolve the susceptibly of stress corrosion cracking and reduce O&M costs and time required for inspections and repairs. Finally, regulatory related projects, including all near-term requirements stemming from Fukushima, and cyber security are complete.

At Robinson, the replacement of both low-pressure turbines in 2018 addressed blade design issues that had resulted in reliability challenges. Transmission upgrades, completed in late 2018, provide a second source of off-site power and improve reliability of the station's electrical distribution and protective relaying systems of major plant components. The transmission upgrade project installed a second 230 kV start-up transformer and replaced the existing 115 kV start-up transformer with an upgraded unit containing an automatic load tap charger. All modifications related to current cyber security requirements are complete.

Q. MR. HENDERSON, ARE THE CAPITAL ADDITIONS AND ENHANCEMENTS YOU HAVE DESCRIBED IN YOUR TESTIMONY USED AND USEFUL IN PROVIDING ELECTRIC SERVICE TO DE PROGRESS' ELECTRIC CUSTOMERS IN NORTH CAROLINA?

A. Yes. They are used and useful in safely and efficiently providing reliable electric service to the Company's customers. Because of the Company's successful efforts to renew the licenses, refurbish obsolete equipment and systems, enhance safety margins in compliance with new NRC requirements, and increase output and capacity, customers will continue to benefit from the power provided by this reliable, efficient, cost-effective and greenhouse gas emissions-free, 24/7 source of energy for many years to come. These investments have positioned the Company to maintain high levels of operational safety, efficiency, reliability and performance that is reflected in the nuclear performance results I discuss later in my testimony.

Q. HAS THE COMPANY ATTEMPTED TO LIMIT COST INCREASES FOR CAPITAL ADDITIONS AND O&M EXPENSES?

A. Yes. The Company controls costs for capital projects and O&M using a rigorous cost management program. For example, the Company routinely conducts executive oversight of project budget and activity reporting, with new projects requiring approval by progressively higher levels of management depending on total project cost. The Company also controls ongoing capital and O&M costs through strategic planning and procurement, efficient oversight of contractors by a trained and experienced workforce, rigorous monitoring of work quality, thorough critiques to drive out process improvement, and industry benchmarking to ensure best practices are being utilized. Several of the capital projects I detailed earlier in my testimony were jointly designed and scheduled across multiple stations. These efforts reduce cost, and since many of the projects are scheduled across multiple time periods, allow the Company to apply learning and improve as the multi-station projects progress to completion. The Nuclear Generation Department works to leverage the size of the nuclear fleet whenever possible, benefiting the Company's customers in both cost and performance. However, despite these considerable efforts, DE Progress continues to face inflationary pressures.

V. O&M AND OTHER ADJUSTMENTS

Q. PLEASE DESCRIBE SIGNIFICANT COST DRIVERS IMPACTING O&M EXPENSES FOR DE PROGRESS' NUCLEAR FLEET.

A. During the Test Period, approximately 28 percent of the required O&M expenditures for DE Progress' nuclear fleet were fuel-related. A complete discussion of nuclear fuel costs can be found in Witness Kenneth Church's testimony filed with this Commission on June 11, 2019 in the Company's annual fuel proceeding in Docket No. E-2, Sub 1204. In his testimony, Witness

Church noted that the Company anticipates a modest decrease in nuclear fuel costs on a cents per kilowatt hour ("kWh") basis through the next several years. Customers will continue to benefit from the Company's diverse energy mix and the strong performance of its nuclear fleet through lower fuel costs than would otherwise result absent the significant contribution of nuclear power to meeting customers' demands.

Non-fuel items comprise the remainder of O&M expenditures for the nuclear fleet. Nuclear power plant operations are very labor intensive and, therefore, a significant portion of O&M expenses are related to internal and contracted labor. The Company continues to face upward pressure on these ongoing labor costs and other challenges have occurred with rising costs for materials and supplies.

Q. WHAT EXAMPLES CAN YOU PROVIDE RELATED TO THE COMPANY'S EFFORTS TO CONTROL O&M COSTS AS NOTED ABOVE?

A. The Company has many efforts in place for controlling and/or saving costs. One area of continued effort has been outage optimization, focusing on duration, budget, dose, and production. This approach applies strict controls to reduce outage durations, align typical maintenance work within duration templates, allocate costs based on duration templates, improve alignment of bulk work to minimize schedule impacts, and target dose to the five-year

ALARA[2] plan. In addition, the Company continues to identify ways to leverage technology to improve worker efficiency.

For example, in May 2018, Robinson employees were recognized by the Nuclear Energy Institute with a Top Innovation Practice award associated with their work on the control room glass top simulator currently in use at the station. The control room glass top simulator environment replicates the training simulator environment, including all peripheral systems, as well as other details of the control room. The screens, invented by the Robinson team, were first of their kind in the industry, and provided the training environment at a fraction of the costs that would have otherwise been required.

Q. PLEASE DESCRIBE THE NRC REQUIREMENTS COMMUNICATED TO DATE WITH RESPECT TO FUKUSHIMA AND THE COMPANY'S STATUS WITH RESPECT TO COMPLIANCE.

A. In 2012, the NRC issued reactor licensees three orders[3] and a multifaceted letter request for information and actions under 10 C.F.R. § 50.54(f). The orders require the Company to implement safety enhancements related to (1) mitigation strategies to respond to extreme natural events resulting in the loss

[2] Code of Federal Regulations (10 C.F.R. § 20.1003) acronym for "as low as (is) reasonably achievable."

[3] See EA-12-049 "Order to Modify Licenses with regard to Requirements for Mitigation Strategies for Beyond-Design-Basis External Events;" EA-12-050 "Order to Modify Licenses with regard to Reliable Hardened Containment Vents;" and EA-12-051 "Order Modifying Licenses with regard to Reliable Spent Fuel Pool Instrumentation."

of power at plants, and (2) enhancing spent fuel pool instrumentation. DE Progress' units have completed all required modifications associated with the three orders.

The 10 C.F.R. § 50.54(f) letter required (i) a re-evaluation of seismic hazards and associated risks and description of any resulting mitigation actions, (ii) plant walk downs to assess seismic vulnerabilities, (iii) a flood hazard re-evaluation and description of any resulting mitigation actions, (iv) flood protection walk downs to assess flooding vulnerabilities, (v) an assessment of emergency communications equipment, and (vi) an assessment of the adequacy of plant staffing to address large scale natural events. Brunswick has a few minor modifications remaining associated with flooding mitigations. These minor modifications primarily involve replacing temporary flood doors with permanent installations. Brunswick will also revise some existing procedures related to flood mitigation. The Brunswick efforts are required to be completed by September 2022. Flood related procedures at Robinson will also be revised, with completion required by September 2021. Finally, Robinson will submit a seismic probability risk assessment report ("SPRA") to the NRC by year end 2019. Once the NRC completes its review of the SPRA, other actions could be required. All Fukushima related actions at Harris have been completed.

Q. ARE THERE ADDITIONAL REQUIREMENTS SPECIFIC TO THE BOILING WATER REACTOR UNITS AT BRUNSWICK?

A. Yes. The NRC Order Number EA-13-109, "Order to Modify Licenses with Regard to Reliable Hardened Containment Vents Capable of Operation Under Severe Accident Conditions" required modifications to both Brunswick units. Unit 1 related work was completed during the spring 2018 refueling outage and Unit 2 work was completed during the spring 2019 refueling outage.

Q. PLEASE DESCRIBE THE NRC REQUIREMENTS COMMUNICATED TO DATE WITH RESPECT TO CYBER SECURITY.

A. In 2009, the NRC published regulations requiring that licensees protect digital assets associated with, and important to, safety, security and emergency preparedness functions.[4] The NEI worked with the NRC and industry representatives (including Duke Energy) to develop NEI 08-09, "Cyber Security Plan for Nuclear Power Reactors," which was endorsed by the NRC in early 2010 as an acceptable means of meeting the requirements. NEI 08-09 utilizes cyber security controls from the National Institute of Standards and Technology standards,[5] which are heavily used throughout the U.S. government.

[4] 10 C.F.R. § 73.54, "Protection of digital computer and communication systems and networks."
[5] SP 800-53, "Recommended Security Controls for Federal Information Systems," Revision 2 and SP 800-82, "Guide to Industrial Control Systems (ICS) Security," Final Public Draft, September 2008.

Q. WHAT IS THE STATUS OF THE COMPANY'S EFFORTS TO MEET THE NRC REQUIREMENTS COMMUNICATED TO DATE WITH RESPECT TO CYBER SECURITY?

A. DE Progress submitted its Cyber Security Plan and implementation schedule to the NRC, and received NRC approval. The Company has completed the necessary actions for implementation of the NRC requirements at all three nuclear plants. The activities outlined by the Company within its Cyber Security Plan included examining current practices, developing cyber security program processes, reviewing critical digital assets, performing validation testing, and implementing new controls. The Company's necessary efforts to meet and maintain the NRC's cyber security requirements will place upward pressure on its O&M expense long-term, especially in the areas of labor and maintenance.

Q. ARE THERE CURRENT ISSUES IN THE NUCLEAR INDUSTRY THAT MAY FURTHER IMPACT COSTS FOR CAPITAL AND/OR O&M?

A. Yes. Additional requirements related to Fukushima are possible as the NRC's review efforts are on-going. Additionally, the Environmental Protection Agency ("EPA") has been developing new and/or stricter regulations regarding, among other things, water intake and cooling functions, which could result in significant impacts on the operational requirements of the Company's nuclear fleet. These key areas of focus could result in added and perhaps significant capital and/or O&M costs.

VI. NUCLEAR OPERATIONAL PERFORMANCE

Q. WHAT ARE DE PROGRESS' OBJECTIVES IN THE OPERATION OF ITS NUCLEAR GENERATION ASSETS?

A. The primary objective of DE Progress' nuclear generation department is to safely provide reliable and cost-effective energy to DE Progress customers. The Company achieves this objective by focusing on several key areas. Operations personnel and other station employees are well-trained and execute their responsibilities to the highest standards in accordance with detailed procedures. The Company maintains station equipment and systems reliably, and endeavors to ensure timely implementation of work plans and projects that enhance the performance of systems, equipment, and personnel. Station refueling and maintenance outages are conducted through the execution of well-planned, well-executed, and high-quality work activities, which effectively ready the plant for operation until the next planned outage.

Q. PLEASE DISCUSS THE PERFORMANCE OF THE COMPANY'S NUCLEAR FLEET DURING THE TEST PERIOD.

A. During the 2018 test year, output from three of the four DE Progress nuclear units was significantly impacted by Hurricane Florence. Prior to the expected landfall of Hurricane Florence, both Brunswick units were brought offline, consistent with site procedures. Brunswick Unit 1 was offline for 8.8 days and

Unit 2 was offline for 6.3 days. Additionally, the availability of Robinson was impacted by Hurricane Florence. The Robinson fall refueling outage, which was delayed by one week due to the expected arrival of Hurricane Florence, was impacted by resource constraints directly attributable to the hurricane and its aftermath. Brunswick 1 and Harris also completed refueling outages during 2018. Despite these challenges, the DE Progress nuclear units provided approximately 45% of DE Progress' generation needs during 2018, and achieved a capacity factor of 88.58 percent. The most recent published North American Electric Reliability Council's ("NERC") Generating Unit Statistical Brochure ("NERC Brochure") indicates an average capacity factor of 92.74 percent, for comparable units representing the five-year period 2014 through 2018. DE Progress' nuclear units achieved a five-year average capacity factor of 92.93 percent during the same five-year period. This was accomplished even with Hurricane Florence impacts in 2018 as I described previously, and with Robinson forced offline in 2016 due to grid disturbances caused by Hurricane Matthew.

The performance results discussed above support DE Progress' continued commitment for achieving high performance without compromising safety and reliability.

Q. WHAT INITIATIVES HAS THE COMPANY TAKEN TO INCREASE EFFICIENCIES IN NUCLEAR OPERATIONS?

A. The Company uses benchmarking, long-range planning, work prioritization tools, and other processes to continuously improve operational and cost performance. Over the years, the Company has gained efficiencies from the implementation of common policies, practices and procedures across the Duke Energy nuclear fleet. In addition, efficiencies are sought through incorporation of industry best practices. Since the merger, a focused effort remains on improving fleet performance in various areas, and a focus on organizational effectiveness continues identifying and addressing work improvements. The goal is aligning operations at a fleet level, taking advantage of shared experiences and process improvement opportunities. Overall, improvement efforts result in enhanced fleet reliability and efficiency on a cost per kWh basis. The Company is also fully engaged in exploiting new digital platforms enabling improved work efficiencies. The completion of the fiber backbone network upgrades at all three plants that I mentioned earlier in my testimony allow for increased remote equipment monitoring and mobile work technologies and applications.

Q. WHAT CHALLENGES DOES DE PROGRESS FACE REGARDING ITS NUCLEAR OPERATIONS?

A. Despite the success of the Company's efficiency initiatives to mitigate cost increases, DE Progress continues to face upward pressure on O&M costs. A significant challenge facing the nuclear industry is the cost and technological requirements for modernizing systems and equipment within nuclear stations across the country to ensure safe, reliable and economical power that emits zero greenhouse gases. Therefore, maintaining the Company's nuclear assets is critical to achieving significant reductions to current and future levels of greenhouse gas emissions. The Company also faces upward cost pressure on specialty supplemental labor that is critical to efficient refueling outage support.

Q. HOW DOES THE DUKE ENERGY NUCLEAR FLEET COMPARE TO OTHERS IN THE INDUSTRY?

A. Duke Energy's nuclear fleet has a history of top performance. The most recently published NERC Brochure indicates an average capacity factor of 91.98 percent, for comparable units representing the period 2014 through 2018. During the same five-year period, the Duke Energy nuclear fleet achieved an annual capacity factor of 94.37 percent.

Duke Energy's nuclear fleet continues to rank among the top performers when compared to other large domestic nuclear fleets using Key Performance Indicators ("KPIs") in the areas of personal safety, radiological dose, manual and automatic shutdowns, capacity factor, forced loss rate, industry performance index, and total operating cost. Industry benchmarking efforts are a principal technique used by the Company to ensure best practices. These efforts further ensure overall prudence, safety and reliability of DE Progress' nuclear units.

VII. CONCLUSION

Q. IS THERE ANYTHING YOU WOULD LIKE TO SAY IN CLOSING?

A. Yes. The Company has a proven history of cost competitive operation of its nuclear assets concurrent with maintaining safety, quality, and reliability. DE Progress is positioned to continue as a leader in the industry with a solid base of knowledge and experience, and with a nuclear fleet that is highly efficient and reliable. This base rate increase will allow the Company to continue the tradition of operational excellence and focus on safe operations, reliable generation, and strong performance that ultimately benefits our customers.

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

A. Yes.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1219

In the Matter of:	)	
	)	**REBUTTAL TESTIMONY OF**
Application of Duke Energy Progress, LLC	)	**KELVIN HENDERSON**
for Adjustments of Rates and Charges	)	**FOR DUKE ENERGY**
Applicable to Electric Service in North Carolina	)	**PROGRESS, LLC**

I. INTRODUCTION AND OVERVIEW

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Kelvin Henderson and my business address is 526 South Church Street, Charlotte, North Carolina.

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

A. I am Senior Vice President of Nuclear Operations for Duke Energy Corporation ("Duke Energy"), with direct executive accountability for Duke Energy's North Carolina nuclear stations, including Duke Energy Progress, LLC's ("DE Progress" or the "Company") Brunswick Nuclear Station ("Brunswick") in Brunswick County, North Carolina; the Harris Nuclear Station ("Harris") in Wake County, North Carolina; and Duke Energy Carolinas, LLC's ("DE Carolinas") McGuire Nuclear Station, located in Mecklenburg County, North Carolina.

Q. DID YOU OFFER ANY DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes. I filed direct testimony in this proceeding.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. My rebuttal testimony responds to the adjustment recommended by witness Dustin Metz of the Public Staff of the North Carolina Utilities Commission ("Public Staff") to nuclear material and supplies inventory ("M&S inventory") and to witness Metz's recommended end of life nuclear reserve. I also respond to recommendations made by witness Metz regarding post-hearing collaboration on project documentation and auditing of M&S inventory.

II. REBUTTAL TESTIMONY

M&S INVENTORY DISALLOWANCE RECOMMENDATION

Q. WHAT ADJUSTMENT DID WITNESS METZ RECOMMEND WITH REGARD TO NUCLEAR M&S INVENTORY?

A. Witness Metz recommended disallowance of the Company's costs associated with M&S inventory categorized as Repair Hold and Quality Assurance Hold ("QA Hold") that has been held for four years or longer. He recommended a $8.9 million adjustment to remove these items from nuclear M&S inventory.

Q. WHY DOES WITNESS METZ BELIEVE IT IS APPROPRIATE TO REMOVE REPAIR HOLD AND QA HOLD ITEMS FOUR YEARS OR OLDER FROM NUCLEAR M&S INVENTORY?

A. In witness Metz's opinion, if inventory and its associated cost cannot be used for extended time periods, that inventory is unavailable for use and customers should not pay for those costs.

Q. WHAT IS THE COMPANY'S RESPONSE TO THE PROPOSED ADJUSTMENT?

A. The Company does not agree with the proposed adjustment. This inventory is held to support plant operations and is therefore of benefit to customers.

Q. IS IT APPROPRIATE TO INCLUDE REPAIR HOLD AND QA HOLD ITEMS THAT ARE FOUR OR MORE YEARS OLD IN NUCLEAR M&S INVENTORY?

A. Yes. Including these items is prudent and appropriate because the nuclear M&S inventory ultimately benefits the customer by ensuring adequate spare parts and material are available to support the safe and efficient operation of the plants. Items in a repair hold status can usually be repaired and made available to support plant needs much more cost effectively than purchasing new items. In some cases, new replacement material is no longer readily available, and repair and refurbishment is the most viable option to maintain necessary spares. Even when similar components or parts can be procured, they require engineering analysis and validation before they can be installed and placed in service. Many items in the QA hold status fall into this category. These inventory items in QA hold status require some type of vendor or engineering resolution prior to installation.

Q. PLEASE EXPLAIN FURTHER WHY IT IS PROPER TO HAVE INVENTORY CATEGORIZED AS REPAIR HOLD FOR A TIME GREATER THAN FOUR YEARS.

A. In general, inventory should be held in a state that supports immediate issue and use. However as with many decisions, priorities and cost impacts are always a consideration. This best serves the Company’s customers. Inventory on Repair Hold falls into two categories: items that can be repaired on-site or at other Company facilities, and items that are sent to external vendors for repair. Repair under both circumstances requires the use of resources, either internal labor, or financial in the case of off-site repairs. Once a specific need is identified and work is forecasted or scheduled, the resources to repair the items are deployed. Items on Repair Hold are stored and maintained in a state to support the eventual repair and reuse of the item. In many cases, the items on Repair Hold are no longer manufactured, and it is more economic to maintain these items on hold and repair when needed versus immediately engineering an approved change and procuring new components. In each case the Company balances priority and cost in order to maximize safety and reliable operation, which in turn benefits customers.

Q. UNDER WHAT CIRCUMSTANCES MIGHT INVENTORY BE CATEGORIZED AS QA HOLD FOR A TIME GREATER THAN FOUR YEARS?

A. Generally, items on QA Hold for greater than four years indicate that efforts to resolve the deficiency with the vendor have concluded and additional engineering analysis by the Company is required. Even replacement components that have been upgraded by the vendor may require analysis by the Company's engineering organizations prior to use. As with Repair Hold items, the Company deploys its limited engineering resources to resolve the items on QA Hold status based on overall priorities.

Q. DO REPAIR HOLD AND QA HOLD TIMES EXCEEDING FOUR YEARS INDICATE THAT THE PARTS WILL NEVER BE USED?

A. No. In general, nuclear M&S inventory should be kept in a state that will allow it to be used when needed and the Company continues to apply available resources to resolve hold items prior to a need arising. However, it is incorrect to assume that simply because a Repair Hold or QA Hold is longer than four years that such inventory will not ultimately be used or available for use, when needed. In fact, the inventory can be made available should priorities dictate applying the maintenance or engineering attention to the cause for the hold. For example, the single most expensive item on QA hold for greater than 4 years is a reactor recirculating pump internal assembly at Brunswick station. The $2.7M pump assembly was cannibalized (parts were removed for the item in inventory) to facilitate repairs to a pump assembly in service. This pump assembly is on hold awaiting receipt of the component parts to restore it. Several other items on QA hold are parts need to support the emergency diesel generators. In many cases, the exact replacements are no longer available, and the vendor sent upgraded components that require evaluation by the Company prior to use. As a demand for these type items is scheduled, resources are directed to resolve the hold issues to support the maintenance schedule. These maintenance strategies are prudent and beneficial to the customer.

Q. IS THE COMPANY WORKING TO REDUCE ON HOLD M&S INVENTORY?

A. Yes. The Commission's final order in the Company's 2017 rate case (E-2, Sub 1142) directed the Company to work to conform its practices and procedures for managing materials and supplies, both nuclear and non-nuclear, to the current practices and procedures utilized by Duke Energy Carolinas, LLC, with the goal to ensure that proper levels of inventory are maintained. On March 25, 2020, the Company reported to the Commission on the status of this effort. As that report stated, Company efforts to address "on hold" inventory in DE Progress nuclear warehouses since the 2017 rate case have resulted in a reduction of 26% (end of 2016 test year vs. end of 2018 test year). Work remains, and the effort is continuing. Procedural changes have also been implemented that place stronger requirements on the return to stock of material that has been issued but not used. Before the project or work order can be credited with the value of returned material, the organization requesting the return and associated credit must confirm that the material continues to have valid applications before it can be accepted back into inventory. An initiative is currently underway to combine two separate Supply Chain directives; SCDP-401 Material Acquisition (Procurement) which applies to DEP and SCD280 Catalog Information for QA Condition which governs DEC. The initiative is now scheduled to complete by July 21, 2020, and once these two directives are combined, this effort, along with actions already completed, will result in full compliance with the Sub 1142 order directive for the Nuclear Generation Department.

END OF LIFE NUCLEAR RESERVE

Q. WHAT DID THE PUBLIC STAFF RECOMMEND REGARDING END OF LIFE NUCLEAR RESERVE?

A. The Public Staff proposed a salvage value of 10% be assigned to M&S inventory, an increase from the Company's proposed value of 0%.

Q. WHAT IS THE COMPANY'S RESPONSE TO THIS PROPOSAL?

A. While the Company generally agrees that there will be some small amount of salvage value for nuclear M&S inventory at its end of life ("EOL"), this value will be offset because the Company had not applied inflation rates to the inventory values presented in this case. The Company therefore believes that current inventory value is a reasonable approximate of EOL value less any salvage amounts.

POST-HEARING COLLABORATION/AUDITS

Q. WHAT IS WITNESS METZ'S RECOMMENDATION WITH REGARD TO POST-HEARING COLLABORATION ON PROJECTS DOCUMENTATION?

A. Witness Metz recommends the Commission direct the Company to begin collaborating with the Public Staff within three months following conclusion of the rate case to clarify expectations for project evaluation and selection and document creation and retention.

Q. WHAT IS YOUR RESPONSE TO THIS PROPOSAL?

A. The Company does not oppose this recommendation.

Q. WHAT DOES WITNESS METZ RECOMMEND WITH RESPECT TO THE COMPANY'S M&S INVENTORY?

A. Witness Metz recommends that "the Company complete an independent audit of M&S inventory for at least one nuclear station, one fossil station, and one hydro station by the time of its next general rate case filing, or within the next three years, whichever is sooner, and establish a long term schedule for a continuous independent audit cycle (e.g. a three to five year rotational cycle)."

Q. WHAT IS YOUR RESPONSE TO WITNESS METZ'S RECOMMENDATION WITH RESPECT TO PERIODIC INDEPENDENT AUDITS OF M&S INVENTORY?

A. The Company does not oppose witness Metz's recommendation, with the exception that DE Progress believes that the Company should utilize Duke Energy's own independent Corporate Audit Services department to meet this recommendation. The Corporate Audit Services department is required by its charter to maintain independence from the business units that it reviews and to maintain objectivity in its work. It reports to the Audit Committee of the Board of Directors and to Duke Energy's senior ethics and compliance officer. The department is authorized to have full, unrestricted access to all Duke Energy functions, records, property, and personnel, and to obtain the necessary assistance of personnel in audited units, as well as other specialized services from within or outside the Duke Energy enterprise. It is already familiar with the tools and processes used by the business units. Company witness Turner will address this recommendation with respect to DE Progress' fossil and hydroelectric facilities.

III. CONCLUSION

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1219

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

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

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

Q. ON WHOSE BEHALF ARE YOU SUBMITTING YOUR TESTIMONY?

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

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

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

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

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. No.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to respond to and comment upon the direct testimony of Steven C. Hart, a witness sponsored by the Office of the Attorney General ("AGO"). In his testimony, Witness Hart recommended certain disallowances be applied to the coal ash basin closure costs that DE Progress incurred during the period from September 1, 2017 through February 29, 2020 (the "Cost Recovery Period"), which it seeks to recover in this case.

Specifically, Witness Hart performed an analysis, which he terms a "time value of money" analysis, and related calculations that purport to measure the alleged difference between the costs incurred during the Cost Recovery Period and costs which should have been incurred at various earlier points in time – 1992, 1996, and 2009. I demonstrate in my testimony that Witness Hart's calculations do not correctly utilize the time value of money methodology, and, therefore are flawed and not in accord with generally accepted financial practices.

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

A. I reviewed Witness Hart's direct testimony filed April 13, 2020 and a Microsoft Excel spreadsheet (named "Cost Reduction Spreadsheet Steps A through C"). I understand the spreadsheet constitutes Witness Hart's workpapers, and was prepared by him in support of his testimony. I also was provided and have reviewed the transcript of Witness Hart's initial deposition taken March 2, 2020 taken in the currently pending Duke Energy Carolinas ("DE Carolinas") rate case, Docket No. E-7, Sub 1214, as well as the transcript of his deposition taken April 28, 2020 in both this Docket and the DE Carolinas case (the "DEC/DEP Deposition"). I note that his workpapers for the DE Progress docket were referenced in the DEC/DEP Deposition as Exhibit 6.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

A. Yes. Witness Hart applies a multi-step process in his time value of money calculation. He first takes the cost of the coal ash compliance work performed by DE Progress in the period from September 1, 2017 through June 30, 2019 and makes certain adjustments (which he terms Step A and Step B) to arrive at total cost of approximately $216 million, which he defines in his workpapers as the "Amount Not Excluded."[1] As Witness Hart defines it, the Amount Not Excluded equates to the amount of cost to which his time value of money disallowance is to be applied. The comparable term he used in his time value of money calculation in the DE Carolinas case was the "Revised Cost." (DEC/DEP Deposition, p. 61). Using the term "Amount Not Excluded" is confusing, inasmuch as Witness Hart proceeds to attempt to exclude tens of millions of dollars of these costs, so for purposes of this rebuttal testimony I will refer to the "Amount Not Excluded" as the "Revised Cost." Although those costs were incurred between January 1, 2018 and June 30, 2019, he treated them as being incurred all in 2014, which is one of the errors in his work. Ignoring for the moment that error, in his second step Witness Hart then applies the time value of money concept to attempt to calculate what the Revised Cost was worth at various points in time in the past (specifically, 1992, 1996 and 2009) using an average inflation rate for each period. In the final step of his time value of money calculation, Witness Hart compares the amount he calculates using his time value of money methodology at those various points in the past to the

[1] The adjustments that Witness Hart makes are, first, to remove water connection costs of $3.5 million, and, second, to perform a rudimentary allocation of costs to what he terms the "old" basins. The allocation is made with reference to the percentage of ash in what he calls "old" basins versus all basins. Witness Hart does not provide any justification for his allocation. Company witnesses Bednarcik and Williams further address these two adjustments. My testimony focuses on what Witness Hart terms "Step C" – his proposed disallowance of costs based upon his application (actually, *mis*-application) of the time value of money concept.

Revised Cost, subtracting in each instance the calculated amounts (expressed in prior period dollars) from the Revised Cost (expressed in 2014 dollars) to arrive at a portion of his recommended disallowance at those various points in time, a portion that he calls the "inflation cost." In short, he attempted to calculate some (but not all) of the costs incurred during the Cost Recovery Period, expressed the resulting figures in 1992, 1996, and 2009 dollars, and compared the amount for each of those years to the actual amount of costs incurred in 2017, 2018 and part of 2019 which he erroneously treats as having been incurred in 2014 dollars.

Q. CAN YOU PROVIDE US WITH AN EXAMPLE?

A. Yes. let's take for example Witness Hart's recommended "inflation cost" disallowance based upon his calculation for 1992. Working through his first two steps and based upon his workpapers and the testimony he provided in the DEC/DEP Deposition, Witness Hart determined through trial and error that $125,000,000 (expressed in 1992 dollars) when future valued to 2014 would be worth $215,876,573.34, which he deemed close enough to the Revised Cost (approximately $216 million). In his final step, he then subtracts this 1992 calculated amount ($125 million) from the Revised Cost to arrive at what he refers to as "the inflation cost," calculated as of 1992, when, according to Witness Hart, DE Progress "knew it had issues with groundwater contamination, and when it started planning for basin closure in 2014." (Hart Direct Testimony, p. 172, lines 2-4). Thus, Witness Hart calculates the "inflation cost" as of 2014 to be approximately $91 million ($216 million - $125 million = $91 million).

Q. WHAT DOES THAT $91 MILLION AMOUNT REPRESENT?

A. That difference ($91 million dollars) is simply the arithmetic difference between the Revised Cost (or, in actuality, a sum derived through trial and error to be "close enough" to the Revised Cost) expressed in 2014 dollars and the Revised Cost (or, again, in actuality a sum derived through trial and error to be "close enough" to the Revised Cost) expressed in 1992 dollars. The Revised Cost (or, once again, in actuality a sum "close enough" to the Revised Cost as indicated above) is simply inflation adjusted using the interest rate used by Witness Hart, which appears to be the Consumer Price Index or CPI.

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

A. No. The point of calculating the time value of money is to make things equivalent, so that a comparison of costs at different time periods can be made using constant dollars. Under his calculation, $216 million in today's dollars (again ignoring Witness Hart's error of using 2014 instead of "today") is equivalent to $91 million in 1992 dollars. But to assert, as Witness Hart does, that there is a "difference" between these figures actually results from an apples (1992 dollars) to oranges ("today's" – although actually 2014 – dollars) comparison. In fact, these amounts are equivalent, just expressed at different points in time.

A correct apples-to-apples time value of money analysis would determine that those amounts, compared in constant dollars, are equivalent. Witness Hart's analysis actually demonstrates this – in constant dollars, the difference between the cost of the work had it been performed in 1992 ($125 million in 1992 dollars, or its equivalent in today's dollars, $216 million) and the Revised Cost is ZERO.

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

A. Yes. For each of his other time periods (1996 and 2009), the difference, in constant dollars, of the cost of the work, had it been performed as of those earlier periods, and the Revised Cost is also ZERO. This is because, as demonstrated by his calculations, the cost of work at those earlier periods is the equivalent of the Revised Cost, but is simply expressed in earlier period dollars.

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

A. It is my understanding based on reading his written testimony and deposition transcripts that he was attempting to quantify the amount DE Progress would have spent as of the earlier time periods in his analysis (1992, 1996, and 2009) in an attempt, however flawed, to quantify alleged imprudently incurred costs.

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

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

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

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

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

Moreover, there are a number of factors that would need to be considered to determine what DE Progress would have spent in 1992 (or as of any of the other earlier time periods). For example, to fully evaluate work that would or could have been done in, say, 1992 would require the evaluator to take into account different applicable laws and regulations in 1992 as compared to today, and different technologies, means and methods available in 1992 as compared to today, among other potential differences. Witness Hart does not even attempt to do this – indeed, he indicates that doing so presents many difficulties, including the difficulty "at this point in time to estimate what costs would have been incurred 10 or more years ago." (Hart Testimony, p. 167, lines 12-13). I agree – Witness Hart's calculation is purely speculative, not based on reasonable assumptions, and, accordingly, wholly unreliable.

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

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

That being said, Witness Hart made a number of errors. As a threshold matter, he did not actually calculate the time value of money correctly, but, as he testified to, used a trial and error method to reach an approximation of the actual amount. In addition, he takes costs incurred over a period of time in 2017, 2018 and 2019 and treats them as being incurred on a single day, December 31, 2014. Witness Hart then discounts them back to January 1 of each specific year. By treating costs in 2017, 2018 and 2019 as occurring in 2014, he completely ignores the time value of money concept. Further, his approach of assuming all costs (hundreds of millions of dollars-worth) occurred on a single day for purposes of his calculation defies reason and normal convention where the costs are incurred and spread out over multiple years. Taking these factors into consideration, even if one were to accept his methodology (which I have explained does not make sense) his calculations are wholly unreliable, not prepared in accordance with normal conventions, and wholly speculative.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

Erik C. Lioy | Partner | DHG Forensics | Charlotte, NC

office: 704.324.3394 | mobile: 704.517.0132 | email: erik.lioy@dhg.com

Erik is a Dixon Hughes Goodman LLP (DHG) partner and a member of DHG's Forensic and Valuation Services Practice. He has more than 25 years of experience serving clients across industry sectors. Prior to joining DHG, Erik spent more than 15 years with an international accounting firm where he served in a number of leadership roles, most recently as the National Managing Partner (U.S.) and Global Co-Leader for Forensic Advisory Services. He has also held senior financial management positions in the technology and construction sectors.

Recognized locally and nationally, Erik has served as an expert witness, arbitrator, court-appointed expert and leader for complex investigations. He has provided expert testimony regarding fraud, damages and the application of generally accepted accounting principles (GAAP) in numerous business disputes.

Erik has led investigations of financial statement fraud for public companies, corruption and kickback schemes (FCPA), health care billing fraud, and construction and real estate fraud. His investigations have led to financial restatements, criminal convictions, and successful recovery of losses from insurance companies and perpetrators.

His dedication to the profession was recognized when he was awarded the Dr. D. Larry Crumbley Award for Outstanding Service by Pfeiffer University. In addition, Erik serves on the advisory board for the Henry C. Lee College of Criminal Justice and Forensic Sciences at University of New Haven, and is a frequent speaker at professional events.

CERTIFICATIONS

Certified Public Accountant (CPA) (NC Lic. No. 30969)

Certified in Financial Forensics (CFF)

Certified Fraud Examiner (CFE)

Certified Construction Auditor (CCA)

Certified Global Management Accountant (CGMA)

EDUCATION

Masters of Business Administration - University of Pittsburgh

BS in Business Administration - Duquesne University

PROFESSIONAL AND CIVIC INVOLVEMENT

Former Board Chair and current Board Member, MeckEd

Advisory Board Member, University of New Haven, Henry C. Lee College of Criminal Justice and Forensic Sciences

DIXON HUGHES GOODMAN LLP

TESTIMONY HISTORY – Past 4 Years

Mattress Recycling Council California, LLC v. Eco-Modity, LLC d/b/a Blue Marble Materials; and AeroFund Financial, Inc.

- American Arbitration Association, Arbitration No. 01-18-0003-5297
- Rendered expert report dated, February 3, 2020

Federal Trade Commission v. Ecological Fox LLC et al.

- United States District Court for the District of Maryland Southern Division, No. 18-cv-03309-PJM
- Rendered expert report dated October 8, 2018
- Provided supplemental report dated February 26, 2019
- Provided deposition testimony on February 28, 2019
- Rendered expert testimony at preliminary injunction hearing on March 14, 2019
- Rendered expert testimony at trial on January 31, 2020

God's Little Gift, Inc. d/b/a Helium & Balloons Across America (A/K/A HABAA), and Gary Page v. Airgas, Inc.

- United States District Court for the Western District of North Carolina, Civil Action No. 3:17-ev-00004-FDW-DSC
- Rendered expert report dated, October 9, 2017

Primo Distribution, LLC v. Primo Water Corporation

- Arbitration No. 01-14-0001-1265
- Rendered expert report dated, January 14, 2017
- Provided expert report regarding damages in breach of contract, distribution termination matter.

Hongda Chemical USA, LLC and Hongda Group Limited, LLC v. Shangyu Sunfit Chemical Company, LTD and YMS Agriculture International Corp.; and Shangyu Sunfit Chemical Company, LTD v. Gary David McKnight; Raymond P. Perkins; Wei Xu; Eco Agro Resources LLC; Vasto Chemical Company, Inc.; and Kadi Resources LLC

- United States District Court for the Middle District of North Carolina, Greensboro Division; Case No. 1:12-CV-1146
- Rendered expert report dated December 16, 2016
- Provided expert report regarding damages in breach of contract matter.

The Moses H. Cone Memorial Hospital Operating Corporation d/b/a Cone Health v. Conifer Physician Services, Inc. f/k/a Springfield Service Corporation

- United States District Court Middle District of North Carolina, Case No. 13-cv-00651
- Rendered expert report dated, October 21, 2016
- Deposition testimony, November 21, 2016
- Provided expert report and deposition testimony regarding damages in breach of contract matter.

DS Services of America, Inc. and Primo Water Corporation v. Artesia Springs, LLC, HOD Enterprises, L.P. and John C. Cooke

- American Arbitration Association, Arbitration No. 01-15-0003-2518
- Expert report dated, March 25, 2016
- Testimony at arbitration, January 12, 2017
- Rendered expert report regarding damages in a breach of contract, distributor termination matter.

DIXON HUGHES GOODMAN LLP

Tampa Park Apartments, Inc., a Florida Not-for-Profit Corporation v. Julian Castro, as Secretary of the United States Department of Housing and Urban Development

- United States District Court Middle District of Florida Tampa Division, Case No. 8:14-cv-1230-T-23AEP
- Rendered expert report, dated June 18, 2015
- Expert declaration, dated September 29, 2015
- Provided expert report and declaration in a loan servicing and accounting dispute.
- Expert testimony at trial, February 15-22, 2018.

CIVIC AND PROFESSIONAL ORGANIZATIONS

- Lecturer, Contemporary Issues in Forensic Accounting, Pfeiffer University, MBA Program, Fall 2013
- Board Member, MeckEd
- Charlotte Mayor's Efficient and Effective Government Task Force
- Charlotte-Mecklenburg Police Activities League – Former Board Chairman
- American Institute of Certified Public Accountants
- North Carolina Association of Certified Public Accountants
- Association of Certified Fraud Examiners (ACFE) and Former Board Member of the ACFE's Charlotte Chapter
- Institute of Internal Auditors, member

PUBLICATIONS AND SELECTED PRESENTATIONS

Planning Investigations in the New Normal, article published at DHG.com, April 2020

Planning Investigations in the New Normal, Part Two - Collecting and Preserving Evidence, article published at DHG.com, April 2020

Three Prong Strategy for Professional Services Firms to Thrive in the New Normal, article published at DHG.com, April 2020

Expense Management in the New Normal, article published at DHG.com, April 2020

Thriving in the New Normal, article published at DHG.com, March 2020

New Normal Means New Priorities for Chief Audit Executives, article published at DHG.com, March 2020

Health Care Fraud Check-up, joint presentation with Kurt C. Stakeman, NCACPA Health Care Conference, June 23, 2017

A Risk Based Approach to Reviewing Construction Projects, joint presentation with Scott Shaffer, UNC, Chapel Hill, May 10, 2017

Health Care Check-up!, joint presentation with Kurt C. Stakeman, NCACPA 2016 Fraud Conference, October 17, 2016

Solve the Problem: Avoid the Crisis, joint presentation with Claire Rauscher and Anne Tompkins, NACD conference, June 8, 2016

False Claims, Fraud and Abuse, panel moderator, McGuireWoods 10th Annual Healthcare Provider Conference, September 17, 2015

Red Flags of Construction Fraud, joint presentation with R. Cory Rogers, Pfeiffer University Fraud and Forensic Investigations Conference, June 10, 2015

Red Flags of Construction Fraud, joint presentation with Scott Shaffer, National Association of Construction Auditors Annual Conference, March 31, 2015

DIXON HUGHES GOODMAN LLP

Keeping What Is Yours...Study of Recent Fraud Trends and How to Avoid Being a Victim, joint presentation with R. Cory Rogers, Grant Thornton Annual CPE Day, November 5, 2014

Corporate Investigations: 5 Fatal Flaws and How to Avoid Them, joint presentation with R. Cory Rogers, Pfeiffer University First Annual Fraud Conference, June 11, 2014

Internal Audit: The Front Lines of Fraud Detection and Deterrence, joint presentation with R. Cory Rogers of Grant Thornton to Bank of America Internal Audit Department, February 25, 2013

Timeless Fraud Schemes, joint presentation with R. Cory Rogers to the Charlotte Chapter of the Commercial Finance Association, January 29, 2013

What Does the Foreign Corrupt Practices Act (FCPA) Mean for Internal Auditors?, presentation to the Triad Chapter of the Institute of Internal Auditors, December 7, 2012

Real Estate Fraud - Everything You Ever Wanted to Know But Were Afraid to Ask, presentation to the Charlotte Chapter of the Association of Certified Fraud Examiners, September 22, 2011

Internal Investigations: Considerations for Auditors, Internal Auditors, Forensic Accountants and other Stakeholders, joint presentation with LT Lafferty, Esq., 2011 Fowler White Boggs CPE Extravaganza, May 4, 2011

Conducting Internal Investigations, presentation to the Institute of Internal Auditors, Greenville, SC Chapter, December 3, 2010

Construction Project Auditing, presentation to the Institute of Internal Auditors, Palmetto Chapter, December 15, 2009

Update and Overview of Managing the Business Risk of Fraud, presentation to the Charlotte Chapter of the Association of Certified Fraud Examiners, October 23, 2008

Managing Fraud Risk in a Slowing Economy, Top Ten Indicators of Fraud, presentation at the Grant Thornton LLP, Down Economy Symposium, July 8, 2008 (Raleigh) and September 25, 2008 (Greensboro)

Deal Indigestion – Avoiding Post Acquisition Disputes and Resolving Those You Can't, panel discussion, October 29, 2008 (Atlanta, GA) and November 18, 2008 (Charlotte, NC)

Detecting and Deterring Fraud, presentation to Blackbaud, Inc., December 18, 2007

Addressing and Managing Fraud Risk, presentation to Duke University, December 12, 2007 and to the Scott Insurance CFO Conference, December 14, 2007

Fraud and Closely Held Businesses, presentation to the Wake Forest Family Business Center, February 22, 2007

Recent Developments in Fraud for the Construction Industry, presentation to the Charlotte Chapter of the Construction Financial Management Association, November 14, 2006

The Not-So-Perfect Payday: Stock Option Backdating, Spring Loading and Bullet Dodging, presentation to the North Carolina Bankers Association, October 23, 2006

The Not-So-Perfect Payday: Stock Option Grant Practices and Problems, joint presentation with Alexander Donaldson, Esq., Wyrick Robbins Yates & Ponton LLP, August 16, 2006

Purchase Price Adjustment Mechanisms, Avoiding Disputes and Resolving Those You Didn't Avoid,joint presentation with Michael J. Ryan, Partner, Grant Thornton; Private Equity Conference hosted by CLE International, Charlotte, NC, November 17, 2005

Proactive Fraud Prevention, Biz Life Magazine, April 2005

Fraud Not Limited to Large Enterprises, Charlotte Business Journal, October 2004

DHG
DIXON HUGHES GOODMAN LLP

WORK HISTORY

- **Dixon Hughes Goodman LLP, 2020 - Current**

  Erik is a Dixon Hughes Goodman LLP (DHG) partner and member of DHG Forensics.

- **Grant Thornton LLP, 2004 - 2019, Admitted to Partnership 2007**

  Erik most recently was a Grant Thornton LLP Partner and served as the National Managing Partner for Forensic Advisory Services.

- **Pascarella & Wiker, LLP, Senior Consultant, 2001 - 2004**

  Provided forensic accounting, due diligence, bankruptcy and other financial advisory services.

- **North America Telecommunications Corporation, Chief Financial Officer, 2001**

  Served as CFO of distressed construction subcontractor. During tenure, initiated cost reduction plan including major reduction in force and conversion to union represented work force.

- **Rapidigm, Inc., Financial Analyst, 1999 - 2001**

  Reported to Vice President of Corporate Development and Treasurer. Responsibilities included evaluating acquisition candidates, performing due diligence and acquisition integration.

- **Innovative Systems, Inc., Controller, 1997 - 1999**

  Responsible for financial reporting, management reporting, tax planning and compliance for closely held software and consulting firm.

- **Price Waterhouse LLP, Senior Consultant, 1993 - 1997**

  Provided audit and tax services to clients including Fortune 500 corporations and high growth technology companies.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1219

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

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Conitsha B. Barnes. My business address is 550 South Tryon Street, Charlotte, North Carolina 28202.

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

A. I am employed by Duke Energy Carolinas, LLC ("DE Carolinas") as Regulatory Affairs Manager. DE Carolinas is an affiliate of Duke Energy Progress, LLC ("DE Progress" or the "Company") and I also provide support on DE Progress regulatory matters.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I graduated from North Carolina State University with a Bachelor of Arts in Political Science. I started my career with Duke Energy Carolinas in 1998. From 1998 to 2008, I worked in the call center organization in a variety of roles of increasing responsibility including customer service specialist, alternate shift supervisor and business analyst. In 2008, I joined the Marketing Department, where I managed the portfolio of energy efficiency income-qualified low income programs offered in North Carolina, South Carolina, Ohio, Kentucky and Indiana. I joined the Market Solutions Regulatory Strategy and Evaluation group in 2010 as a Strategy and Collaboration Manager – Carolinas, where I was responsible for analysis and support of DEC's Energy Efficiency ("EE") and Demand-Side Management ("DSM") programs. In 2015, I became Senior Strategy Manager, where I supported development and review of testimony for strategic initiatives and regulatory proceedings across Duke Energy's six regulated utilities. I assumed my current role as Regulatory Affairs Manager for DEC in 2017.

Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES AS REGULATORY AFFAIRS MANAGER.

A. I am responsible for leading and supporting DE Carolinas' North Carolina regulatory matters, including the development and support for regulatory initiatives such as new customer programs and offerings, special tariffs, cost recovery proceedings, investigation and response to customer complaints, and implementation of the Company's Service Regulations. I also identify, research and analyze emerging regulatory issues. I also provide regulatory support for DE Progress as requested.

Q. DID YOU OFFER ANY DIRECT TESTIMONY IN THIS PROCEEDING?

A. No. I did not.

Q. HAVE YOU TESTIFIED PREVIOUSLY BEFORE THIS COMMISSION?

A. Yes. I testified on behalf of DE Carolinas in its DSM/EE cost recovery rider proceeding in Docket No. E-7, Sub 1023. I have also appeared before the Commission at various staff conferences. I filed testimony on similar issues on behalf of Duke Energy Carolinas, LLC in its pending general rate case in Docket No. E-7, Sub 1214.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to respond to portions of the direct testimony of Jack Floyd, filed on behalf of the Public Staff, and portions of the direct testimony of John Howat, filed on behalf of the North Carolina Justice Center, North Carolina Housing Coalition, Natural Resources Defense Council, and Southern Alliance for Clean Energy regarding the Company's low-income support and programs and customer affordability issues.

Q. IN THEIR TESTIMONY, MR. FLOYD AND MR. HOWAT DISCUSS VARIOUS CUSTOMER AFFORDABILITY ISSUES AND PROGRAMS. WHAT IS THE COMPANY'S POSITION ON THIS TOPIC?

A. The Company fully understands that many of our customers have difficulty paying their energy bills, and affordability is an important issue for all customers. During the current COVID-19 pandemic, we know that even more customers are facing hardships, and with Commission approval we have waived disconnections for nonpayment, late fees, reconnection fees and other charges in recognition of these unprecedented circumstances.

In his direct testimony, Mr. De May acknowledged affordability concerns and proposed a collaborative process to seek input on and recommend ways we can expand DE Progress' low-income energy assistance programs. In his testimony, Mr. Howat proposes various definitions of, and approaches to, affordability issues. This is why the Company believes that a stakeholder process, with guidance from the Commission, is the most effective forum to discuss these issues, propose and evaluate options, and then make recommendations to the Commission in a future docket. In particular, Mr. Floyd set forth some parameters for a stakeholder process at pages 44-45 of his direct testimony, and DE Progress agrees with the Public Staff's recommendations.

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

A. Yes.

COMMISSIONER CLODFELTER: Okay. Does any other party have any preliminary procedural matters before we turn the case over to the Applicant?

MS. DOWNEY: Commissioner Clodfelter, just one thing.

COMMISSIONER CLODFELTER: Yes, Ms. Downey.

MS. DOWNEY: And this is for everybody's convenience. The witness list that was filed last week I noticed was missing some of the Public Staff attorneys and I just wanted to draw those to your attention so when you go to look for a Public Staff attorney you'll know who's supposed to be there. For DEP witness Turner, John Little will be the Public Staff attorney. For Public Staff witness Tommy Williamson, Layla Cummings will be the Public Staff attorney. And for DEP witness Oliver, again Layla Cummings will be the Public Staff attorney. And that's all.

COMMISSIONER CLODFELTER: Thank you, Ms. Downey. Anything else?

MS. CRESS: Yes, Commissioner Clodfelter. This is Christina Cress with CIGFUR.

COMMISSIONER CLODFELTER: Yes, Ms. Cress.

MS. CRESS: This may be a bit premature, but

I did want to just let you know that CIGFUR witness Phillips has to take his wife for a surgical procedure on Monday and for a follow-up on Tuesday. I hope that he will have testified before we hit Monday and Tuesday, but I wanted to just go ahead and let you know that, unfortunately, there is a pretty pressing conflict there that we're not able to get around.

COMMISSIONER CLODFELTER: That will be Monday the 5th and Tuesday the 6th?

MS. CRESS: That's correct, Commissioner. Thank you.

COMMISSIONER CLODFELTER: Ms. Cress, your pessimist will be done by Friday. (Laughing) But if we are not, we will make accommodations for Mr. Phillips, and if we need to take him out of sequence we will do so. Okay?

MS. CRESS: I appreciate the accommodation. Thank you, Commissioner.

COMMISSIONER CLODFELTER: Anyone else?

MS. JONES: Commissioner Clodfelter.

COMMISSIONER CLODFELTER: Yes.

MS. CRALLE JONES: Cathy Cralle Jones on behalf of Sierra Club. Just one clarification as to cross examination exhibits that were entered in the

DEC matter. I understand from your prior instruction that those will not be automatically transferred over into DEP. Is the appropriate procedure that at the -- when we are given the opportunity for cross on a particular witness that we would move exhibits from the prior -- from the DEC matter for admission in this matter whether or not we have cross in this matter?

COMMISSIONER CLODFELTER: That would be the appropriate time to make such a motion. Ms. Cralle Jones, we read the Stipulations as they were written as not bringing into the record the exhibits, which is why I gave the caution that I did. If the parties had intended for the Stipulations to bring exhibits along with the live testimony, we did not read the Stipulations as being so worded. So you will need to move your exhibits if you want them in this record. And we will talk about how to number those exhibits because, again, they have a designation from the Duke Energy's Carolinas case. And the witness who would have testified in the Duke Energy's Carolinas case would be testifying with reference to the designation given to that exhibit in that case. And so I'm going to during the morning break consult with our court reporter and be clear with her about how we want to have those exhibits that you may choose to import from the Duke Carolinas' case into this case, how they should be so designated in this case in order to have the proper references in the transcript. So we'll be talking with Ms. Mitchell about that during that break. And thank you for raising the point. All right.

MS. CRALLE JONES: Thank you.

COMMISSIONER CLODFELTER: Anyone else? Going once. Going twice. Okay, Mr. Robinson, the case is now with Duke Energy Progress.

MR. ROBINSON: Thank you, Commissioner Clodfelter. I do have a few additional procedural matters to go through before we call our first two witnesses.

COMMISSIONER CLODFELTER: Very good. We're now on your case so you may make the appropriate motions.

MR. ROBINSON: Thank you. So, Commissioner Clodfelter, in light of your instructions this morning, we would request to permit the Company to at least move the stipulated testimony for witness Sean Riley who we will then, provided the motion is granted, move to excuse as a result of the Stipulation with -- as it pertains to the coal ash and the accounting witnesses. May I move that transcript citation into the record at this time?

COMMISSIONER CLODFELTER: Mr. Robinson, I'll let you make your motion. It is out of the sequence but I understand your rational for making the motion. I will let you make the motion, but I'm going to give all parties an opportunity to make any objections they wish to that motion. These Stipulations were filed yesterday and I want to be mindful of the fact that a number of the parties, including those who were not parties to the Duke Energy Carolinas case, may still be contemplating whether or not they wish to cross examine these witnesses. And so I will give them an opportunity to be heard on your motion, but I will take the motion at this time.

MR. ROBINSON: Thank you, Commissioner Clodfelter. So at this time the Company proposes to move DE Carolinas' witness Sean Riley, transcript volume 23, page 150, lines 1 through page 183, line 20, and transcript volume 24, page 12, line 2 through page 36, line 24 into the DEC record as if given -- as if given orally from the stand in the DEP record. This is pursuant to the Stipulation with the Public

Staff, the Attorney General's Office, and the Sierra Club regarding certain coal ash and accounting witnesses, as amended, and filed on September 28th.

COMMISSIONER CLODFELTER: Mr. Robinson, I will ask you if we may take your motion with the following amendment, and that being that the testimony of Mr. Riley would be copied into the record in these cases in the same sequence in which Mr. Riley would have been called as a witness to testify if the motion to excuse had not been made. Again, we're trying to preserve the integrity of the sequencing and consistency of the transcript. All right.

MR. ROBINSON: Thank you, Commissioner Clodfelter.

COMMISSIONER CLODFELTER: Now, you've heard Mr. Robinson's motion. I will consider objections to the motion and hear the objections at this time. With respect to the motion to excuse Mr. Riley, I do want to defer ruling on that until after the morning break because I want to be sure Commissioners have an opportunity to advise me as to whether they may have any questions for Mr. Riley in these proceedings. But let me first hear if any parties to the proceedings, intervenors, Public Staff, or the Attorney General's

Office have objections to Mr. Robinson's motion?

MS. DOWNEY: Commissioner Clodfelter, I don't have an objection, but I need some guidance here to the extent there were cross examination exhibits by the Public Staff that were likewise introduced in the DEC proceedings, we would want those included but I'm not prepared to identify those at this time.

COMMISSIONER CLODFELTER: All right. Mr. Robinson, you've heard Ms. Downey's concern here. I think what we're going to do -- let me hear if there are any objections from any other parties to the motion?

MS. FORCE: I don't have an objection, but I want to point out that as I understand it Mr. Riley is a rebuttal witness and so we're taking it out of order.

COMMISSIONER CLODFELTER: We are.

MS. FORCE: And I just will comment that based on the Stipulations that were entered, we did agree not to cross examine and I'm listed as being the one -- the attorney who had questions for him.

COMMISSIONER CLODFELTER: Mr. Robinson, let me tell you what I'm going to do. I'm going to hold your motion at this time. Again, I think this is a new procedure here and we're learning this procedure as we go. I'm going to hold your motion for a little while. Let's see if you and Ms. Downey can perhaps talk about the issue with respect to exhibits. I think as Ms. Cralle Jones also has identified the issue of how to handle exhibits in the stipulated testimony was not addressed in the Stipulations themselves. So let's all take a little bit of time to look at that issue. I will hold your motion under advisement and will also give other parties a chance to consider, and will give Commissioners an opportunity to advise me whether they wish to ask questions of Mr. Riley. So let's take the motion and I will hold it under advisement at this time.

MR. ROBINSON: Thank you, Commissioner Clodfelter. I will try my next one here.

COMMISSIONER CLODFELTER: All right.

(Laughter)

MR. ROBINSON: Commissioner Clodfelter, so the Company, the Public Staff, the Attorney General's Office, and the Sierra Club submitted a list of Joint Exhibits on September 8th consisting of historical coal ash documents that are referred to in multiple witnesses' testimony and are expected to come up in cross and redirect exhibits for many parties. There are 13 of these exhibits. And at this time we would like to mark those exhibits and, if appropriate, move them into evidence. I'm happy to walk through each of the exhibits and mark them now, Commissioner Clodfelter. However, we know that these are the same joint exhibits in the same order of what was entered into the DEC case and was also identified in our September 8th filing.

COMMISSIONER CLODFELTER: So Mr. Robinson has moved that the Joint Exhibits 1 through 13, designated as Joint Exhibit 1 through 13 in the materials submitted prior to the hearing, that they be so designated in these proceedings and admitted into the record in these proceedings so that the parties' hereafter may refer to those exhibits and examine all witnesses with respect to those exhibits without need for separately identifying and moving their admission into the record later in the proceedings. Is there any objection to Mr. Robinson's motion?

(Pause)

Hearing none, Mr. Robinson, your motion shall be granted and the documents identified in the pre-submission list of exhibits as Joint Exhibits 1 through 13 shall be so marked for identification in these purposes and shall be admitted into the record for these -- for all purposes.

(WHEREUPON, Joint Exhibits 1 - 13 were marked for identification as prefiled and received into evidence.)

MR. ROBINSON: Thank you, Commissioner Clodfelter. I have one more.

COMMISSIONER CLODFELTER: All right.

MR. ROBINSON: So this is independent of the Stipulations, Commissioner Clodfelter. No parties have indicated cross for Company witnesses Don Schneider, Shana Angers, and John Spanos on direct. So at this time, we would move to excuse those three witnesses and move the following testimony and exhibits into the record: The prefiled direct testimony of John Schneider; the prefiled direct testimony and two exhibits, and rebuttal testimony and one exhibit of Shana Angers; the prefiled direct testimony and one exhibit of John Spanos as well.

COMMISSIONER CLODFELTER: You've heard Mr. Robinson's motion. Is there any objection to the motion?

MS. FORCE: Commissioner Clodfelter.

COMMISSIONER CLODFELTER: Ms. Force.

MS. FORCE: Margaret Force for the Attorney General. Mr. Schneider is a witness who we had listed time for, and provided that all -- our Stipulation is adopted as to Mr. Hatcher's testimony, we would have no objection but it's -- we're not there yet. So at this point I'd ask that you postpone the decision on Mr. Schneider.

COMMISSIONER CLODFELTER: All right. Is there any other objection to Mr. Robinson's motion?

(Pause)

All right. Mr. Robinson we will grant your motion as made as to Mr. Spanos and as to Ms. Angers. We will hold your motion open as to Mr. Schneider until such time as he would, in the normal course of the order of witnesses, be called and at that point you may renew the motion and we'll see if Ms. Force still wishes to cross examine. Is that acceptable?

MR. ROBINSON: Yes, it is, Commissioner Clodfelter. Thank you.

COMMISSIONER CLODFELTER: Actually, as I understood Ms. Force, she will know her decision after we hear from witness Hatcher. So we'll consider your motion again, if you'll remind me after Mr. Hatcher has completed his testimony and before Ms. Turner is called to the stand, if you will remind me again that we have that motion to rule upon.

Okay. Last call on any other objections? As I said, the motion is granted as to Mr. Spanos and Ms. Angers and we will hold the motion in abeyance as to Mr. Schneider.

(WHEREUPON, Angers Direct Exhibits 1 and 2, Angers Rebuttal Exhibit 1, and Spanos Direct Exhibit 1 are marked for identification as prefiled and received into evidence.)

(WHEREUPON, the prefiled direct and rebuttal testimony of Shana Angers, and the prefiled direct testimony of John Spanos is copied into the record as if given orally from the stand.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1219

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

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Shana W. Angers, and my business address is 550 South Tryon Street, Charlotte, North Carolina.

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

A. I am employed by Duke Energy Business Services, LLC as Accounting Manager for Duke Energy Progress, LLC ("DE Progress" or the "Company"). DE Progress is a subsidiary of Duke Energy Corporation ("Duke Energy").

Q. PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL QUALIFICATIONS.

A. I graduated from the University of Florida with a bachelor of science degree and master's degree in Accounting. I am also a Certified Public Accountant licensed in the state of Florida.

Q. PLEASE SUMMARIZE YOUR WORK EXPERIENCE.

A. I have 12 years of professional experience with Duke Energy in various accounting and finance roles. I was named to my current position as Accounting Manager of DE Progress in December 2018.

Q. PLEASE BRIEFLY DESCRIBE YOUR DUTIES AS ACCOUNTING MANAGER.

A. I am responsible for ensuring that the accounting impacts of the Company's business activities and transactions are understood and properly recorded to the general ledger and that such accounting impacts, as well as any applicable related variances to budget and prior year results, are clearly explained and properly presented in internal and/or external financial reports. I am also responsible for ensuring that the accounting team performs its tasks in an accurate and timely manner in accordance with published deadlines while strictly adhering to Company policies and controls.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS OR ANY OTHER COMMISSION?

A. No. I have not.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony will cover the financial position of DE Progress at December 31, 2018, and the actual results of the Company's operations for the twelve months ending December 31, 2018 (the "Test Period"). The Company's financial position and operating results and the actual data required under Rule R1-17(b) of the North Carolina Utilities Commission's (the "NCUC" or the "Commission") Rules and Regulations are set forth in Angers Exhibit 1. While the Company is not requesting a change in decommissioning expense in this rate request, I discuss the amount of the Company's nuclear decommissioning costs allocated to the Company's North Carolina retail electric operations. I also discuss the amount of investor funds for operations included in rate base, calculated based on the Company's lead-lag study. A summary of the calculation of investor funds for operations is presented in Angers Exhibit 2. The detailed lead-lag Study prepared by Ernst & Young LLP is included as Angers Exhibit 3. I also discuss the amount of DE Progress' depreciation expense based on the Company's depreciation study being filed in this docket (the “Depreciation Study”), and included as Exhibit 1 to the direct testimony of Company witness John Spanos.

Q. WERE ANGERS EXHIBITS 1, 2, AND 3 PREPARED OR PROVIDED HEREIN BY YOU, UNDER YOUR DIRECTION AND SUPERVISION?

A. Yes. They were.

Q. ARE YOU FAMILIAR WITH THE ACCOUNTING PROCEDURES AND BOOKS OF ACCOUNT OF DE PROGRESS?

A. Yes. The books of account of DE Progress follow the Uniform System of Accounts prescribed by the Federal Energy Regulatory Commission. This Uniform System of Accounts has been adopted by the Commission and is followed by the investor-owned utilities subject to its jurisdiction.

Q. WHAT STEPS DOES THE COMPANY TAKE TO ENSURE THAT ITS BOOKS AND RECORDS ARE ACCURATE AND COMPLETE?

A. DE Progress maintains and relies upon an extensive system of internal accounting controls and audits by both internal and external auditors. The system of internal accounting controls provides reasonable assurance that all transactions are executed in accordance with management’s authorization and are recorded properly.

The system of internal accounting controls is reviewed annually, tested, and documented by the Company to provide reasonable assurance that amounts recorded on the books and records of the Company are accurate and proper. In addition, independent certified public accountants perform an annual audit to provide assurance that internal accounting controls are operating effectively and that the Company's financial statements are materially accurate.

II. FINANCIAL POSITION AND RESULTS

Q. PLEASE DESCRIBE WHAT IS PRESENTED ON ANGERS EXHIBIT 1.

A. Angers Exhibit 1 sets forth the Company's financial statements. Pages 1 and 2 contain the Company's Balance Sheet as of December 31, 2018. Page 3 is the Company's Income Statement for the twelve months ending December 31, 2018. Page 4 is the Company's Statement of Capitalization at December 31, 2018. Certain information shown on Angers Exhibit 1 is also included in Exhibit C to the Company's Application.

Q. ARE THE CAPITAL EXPENDITURES AND OPERATING EXPENSES REPRESENTED ON ANGERS EXHIBIT 1 ACCURATE?

A. Yes. An integral part of the Company's system of internal accounting controls includes various budgeting, planning, and review procedures to establish and monitor the capital and operating budgets, as well as actual expenditures.

III. NUCLEAR DECOMMISSIONING

Q. WHAT AMOUNT OF NUCLEAR DECOMMISSIONING EXPENSE IS INCLUDED IN DE PROGRESS' PER BOOK AMOUNT FOR DEPRECIATION EXPENSE?

A. Included in the 2018 DE Progress E.S.-1 and Cost of Service is an amount for nuclear decommissioning expenses directly assigned to the Company's North

Carolina retail operations of $17,337,167.[1] The current annual amount of nuclear decommissioning expense being collected from North Carolina retail customers is $19,590,285 based on the Commission's ruling in DE Progress' last rate case in Docket No. E-2, Sub 1142. Of this amount, $16,536,686 will be collected in base rates and $3,053,599 will be recovered through the Joint Agency Asset Rider.

DE Progress is required by the Commission to update the Company's site-specific decommissioning cost studies for its four nuclear units every five years.[2] DE Progress has initiated an update to its nuclear decommissioning cost studies and expects for these to be complete in December 2019. The results of those studies will be filed with the Commission within 90 days of management approval of the new estimates. Funding studies are required to be filed within 210 days of management approval of the revised estimates, which is anticipated to be in 2020. Since these activities are pending, DE Progress has not included any proposed change in the North Carolina retail annual funding amount of $19,590,285 for nuclear decommissioning costs in its initial filing.

IV. INVESTOR ADVANCED FUNDS

Q. PLEASE EXPLAIN ANGERS EXHIBIT 2.

A. Angers Exhibit 2 shows the calculation of the Company's North Carolina retail amount for investor funds invested in operations. This Exhibit applies the

[1] Please note that this amount reflects two and a half months of nuclear decommissioning expense at the annual rate of $8,762,878, which was effective prior to the implementation of new base rates under NCUC Docket E-2, Sub 1142.

[2] *See Order Approving Guidelines* issued on November 3, 1998 in Docket No. E-100, Sub 56.

revenue lags and expense leads to the applicable components of the Test Year cost of service per books as allocated to the Company's North Carolina retail operations. The resulting working capital requirement for investor funds for North Carolina retail operations in the amount of $160,141,423 shown on Angers Exhibit 2 is included as a component of working capital as shown in Column 2, Line 1 on Smith Exhibit 1, Page 4d. This amount is derived from the detailed lead-lag study. In the Commission's *Order Accepting Stipulation, Deciding Contested Issues, and Granting Partial Rate Increase* issued on February 23, 2018 in Docket No. E-2, Sub 1142, the Commission directed DE Progress to prepare and file an updated lead-lag study in its next general rate case, as agreed to by the Company and the Public Staff. In accordance with this order, the Company engaged Ernst and Young to perform a detailed lead-lag study, which was completed on July 22, 2019. This updated lead-lag study was submitted in Item 14 of the E-1 that is a part of this filing and is also Angers Exhibit 3 of my testimony. The results of the lead-lag study were applied to the updated Test Year cost of service to produce the per books cash working capital requirement requested in this case.

Q. WHAT IS THE PURPOSE OF A LEAD-LAG STUDY?

A. The purpose of a lead-lag study is to provide a measure of the amount of investor funds used to sustain utility operations from the time expenditures are made until the time payment is received. Generally, a utility provides service prior to receipt of payment from customers, and there is also a delay in payment for goods and services acquired by the utility. A lead-lag study is used to analyze transactions throughout the year to determine the number of days between the time services are rendered and payment is received (revenue lag), and the number of days between the time expenditures are incurred and payment is made for such services (expense or payment lead). In some instances, revenue may be received prior to payment for the related expense (*i.e.*, a net lead or alternatively a negative net lag). The revenue lag is compared to the expense lead and the net lag is applied to each category of cost of service to determine the DE Progress' cash working capital requirements.

Q. PLEASE EXPLAIN THE DEPRECIATION RATES SHOWN ON SMITH EXHIBIT 1, PAGE 4B.

A. The depreciation rates shown on Page 4b of Smith Exhibit 1 are the depreciation rates from the Depreciation Study as of December 31, 2018 that is being filed in this Docket. The Depreciation Study was prepared by Gannett Fleming Valuation and Rate Consultants, LLC and is discussed in more detail by Company witness Spanos. Spanos Exhibit 1 is the complete Depreciation Study. The Company believes that these depreciation rates are reasonable for use in this proceeding.

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

A. Yes.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1219

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

I. <u>INTRODUCTION AND PURPOSE</u>

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

A. My name is Shana W. Angers, and my business address is 550 South Tryon Street, Charlotte, North Carolina. I am employed by Duke Energy Business Services, LLC ("DEBS") as Accounting Manager for Duke Energy Progress, LLC ("DE Progress" or the "Company").

Q. DID YOU FILE DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes. I filed direct testimony and exhibits supporting DE Progress' financial position and operating results, nuclear decommissioning costs, investor funds for operations, and depreciation expense. I also filed supplemental direct testimony and exhibits on March 13, 2020 relating to the Company's updated lead lag study.

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

A. The purpose of my rebuttal testimony is to address Public Staff's testimony and proposed adjustments relating to: (1) the Company's lead-lag study; (2) what the Public Staff characterizes as "lobbying expenses"; and (3) Chamber of Commerce expenses.

Q. DOES YOUR TESTIMONY INCLUDE ANY EXHIBITS?

A. Yes. I have one rebuttal exhibit. As described in more detail below, Angers Rebuttal Exhibit 1 is a true and accurate copy of the August 31, 2016

Independent Lobbying Labor Cost Study prepared by KPMG for Duke Energy Corporation and its public utility subsidiaries, including DE Progress.

Q. WAS THIS EXHIBIT PREPARED BY YOU OR UNDER YOUR DIRECTION AND SUPERVISION?

A. Angers Rebuttal Exhibit 1 was prepared by KPMG at the request of DEBS and has been used by the Company since August 31, 2016 to inform its accounting practices with respect to lobbying expenses. The study is publicly available by virtue of its filing by Duke Energy with the Federal Energy Regulatory Commission ("FERC").

II. LEAD-LAG STUDY

Q. PLEASE SUMMARIZE PUBLIC STAFF COMMENTS AND RECOMMENDATIONS RELATED TO THE COMPANY'S LEAD-LAG STUDY.

A. Public Staff witness Shawn Dorgan commented that the Public Staff discovered several errors in the lead-lag study filed by the Company and incorporated corrections to those errors in calculating the cash working capital under present rates.

Q. WHAT IS THE COMPANY'S RESPONSE TO MR. DORGAN'S RECOMMENDATION?

A. In my supplemental direct testimony, I summarized the adjustments Ernst & Young made to their original lead-lag study and attached the updated lead-lag study as Angers Supplemental Exhibit 3. The Company agrees with the Public Staff's adjustments to cash working capital based on their review of the lead-lag study, as these adjustments are consistent with the changes described in my supplemental testimony and that are included in the updated lead-lag study.

III. LOBBYING EXPENSES

Q. PLEASE SUMMARIZE THE PUBLIC STAFF'S RECOMMENDATION RELATED TO "LOBBYING EXPENSES."

A. Witness Dorgan testified that he removed O&M expenses associated with stakeholder engagement, state government affairs, and federal affairs that were recorded above-the-line.

Q. PLEASE DESCRIBE THE DIFFERENCE BETWEEN ABOVE-THE-LINE AND BELOW-THE-LINE EXPENSES.

A. Expenses recorded above-the-line are included in the Company's cost of service and are recovered from customers through rates. Expenses recorded below-the-line are not included in the Company's cost of service and are not sought to be recovered from customers, but rather are paid by shareholder dollars. Lobbying expenses are below-the-line, and thus not included in rates.

Q. WHAT IS THE COMPANY'S RESPONSE TO MR. DORGAN'S PROPOSED ADJUSTMENT?

A. The Company opposes this adjustment. On page 28 of his testimony, Witness Dorgan states that he applied the "but for" test used in a Formal Advisory Opinion of the State Ethics Commission. However, based on a review of the Public Staff's calculation, it appears that the Public Staff's recommendation is founded on a broad assumption that 50% of the Company's O&M expense related to certain departments that perform public affairs, political, or lobbying functions or activities should be considered non-recoverable, based on their review of job descriptions of employees in those departments.

This approach appears to be the same approach the Public Staff used, and the Commission rejected, in its *Order Granting General Rate Increase* issued in Dominion North Carolina Power's rate case in Docket No. E-22, Sub 479 ("DNCP Order"). On page 71 of the DNCP Order, the Commission stated:

> the Commission also finds that the Public Staff's 50% exclusion adjustment, based on its overall conclusion upon an apparent cursory review with selective highlighting of job descriptions/roles, is an overly broad, very general approach that is not sufficiently supported by the evidence to justify such a 50% adjustment in this proceeding.

Q. HOW DID THE COMPANY DETERMINE WHICH EXPENSES RELATED TO STAKEHOLDER ENGAGEMENT, STATE GOVERNMENT AFFAIRS, AND FEDERAL AFFAIRS SHOULD BE RECORDED ABOVE-THE-LINE VERSUS BELOW-THE-LINE?

A. In 2016, the Company engaged KPMG to perform a detailed time study for the purposes of determining the percentage of time certain individuals spent on lobbying activities per the federal definition in Code of Federal Regulations ("CFR") Section 367.4264. Under this definition, expenditures related to certain civic, political, and related activities should be recorded in FERC Account 426.4, which includes:

> expenditures for the purpose of influencing public opinion with respect to the election or appointment of public officials, referenda, legislation, or ordinances (either with respect to the possible adoption of new referenda, legislation or ordinances or repeal or

> modification of existing referenda, legislation or ordinances) or approval, modification or revocation of franchises; or for the purpose of influencing the decisions of public officials.

Charges to Account 426.4 are <u>not</u> included or recoverable for ratemaking purposes, or in other words, are "below-the-line." The remaining labor charges associated with these personnel – i.e., those that do not fall within the definition in CFR Section 367.4264 – are applied to FERC Account 920, which is "above-the-line."

KPMG conducted a series of interviews with select personnel and reviewed internal documentation related to lobbying costs to develop a system-wide survey based on typical activities that would be performed throughout the year. Surveys were distributed to all lobbyist and support personnel. Upon receipt of completed surveys, KPMG analyzed the results by person and jurisdiction.

Q. WHAT WERE THE RESULTS OF THE STUDY?

A. KPMG delivered a report with the results of the study to the Company on August 31, 2016. A true and accurate copy of this report is included as Angers Rebuttal Exhibit 1. In the study, KPMG divided activities into two groups, as follows:

> **(1) Manage External Relationships (applied to the below-the-line Account 426.4) –** examples of items in this category include direct lobbying services, such as contacting members of Congress, holding meetings with executive and agency officials, and testifying before a Congressional committee or at a legislative hearing; evaluating and communicating strategic positions, such as analyzing and drafting legislation, conducting or

> publishing research to support legislative initiatives, and promoting strategic positioning; and developing and maintaining key relationships, such as participating in networking, charity, and philanthropic events and managing relationships with organizations such as PACs and non-profits.
>
> **(2) Manage Internal Relationships (applied to the above-the-line Account 920) –** examples of items in this category include coordinating and meeting with internal departments; conducting training; communicating company positions to employees; assisting legislative officials with solving any constituent inquiries/issues; and general office management support, such as coordinating meetings, travel arrangements, and training events, managing executive calendars, and tracking invoices, time and expense coding.

Based on the results of the detailed time labor study, including the survey results, KPMG provided a percentage breakdown of the percentage of time relevant employees spent on these activities for each jurisdiction.

Q. HOW DID THE COMPANY REFLECT THE RESULTS OF THE STUDY?

A. The Company booked journal entries to ensure that the 2016 labor costs were aligned with the results of the KPMG study.

Q. HAS THE COMPANY REVIEWED THESE RESULTS SINCE THE 2016 KPMG STUDY WAS COMPLETED?

A. Yes. In 2018, as recommended by KPMG, the Company performed an internal assessment of the labor cost percentages using KPMG's survey templates based on interviews conducted with individuals in the relevant groups. Based on the results of the internal assessment, the percentage of time relevant employees spent on these activities remained unchanged from the 2016 KPMG study.

Q. DO YOU BELIEVE THAT THE AMOUNTS THE COMPANY HAS BOOKED ABOVE-THE-LINE ARE REASONABLE AND APPROPRIATE TO BE RECOVERED FROM DE PROGRESS CUSTOMERS IN THIS CASE?

A. Yes. As noted above, the amounts the Company has booked above-the-line align with the independent study performed by KPMG. Moreover, the types of costs that are recorded above-the-line include internal and operational activities, such as managing and supporting other internal departments, managing constituent inquiries, and providing general office management support. Activities like managing constituent inquiries directly benefit customers. For example, a customer may contact a local government official with an issue relating to power outages, downed power lines, billing questions, etc. That government official may reach out to a representative in the Company's state and government affairs group. In turn, that Company representative would coordinate with other internal DE Progress personnel to resolve the issue. It is reasonable for expenses related to this activity to be booked above-the-line.

Q. DID THE PUBLIC STAFF MAKE ANY OTHER ADJUSTMENTS RELATING TO "LOBBYING EXPENSES"?

A. Yes. In addition to the 50% of O&M expenses it excluded as discussed above, it appears that the Public Staff also removed a percentage of above-the-line expenses relating to dues paid to the Edison Electric Institute ("EEI"). Though witness Dorgan does not address this exclusion in his direct or supplemental testimony, the Company discovered that this amount had been removed through reviewing his workpapers and was able to confirm via the Public Staff's response to a data request.

Q. PLEASE EXPLAIN HOW THE COMPANY ACCOUNTS FOR EEI DUES.

A. Any payments made to EEI (and similar industry organizations) that are related to lobbying, political activities, or contributions to a charitable foundation (e.g., The Edison Foundation) are recorded to Account 426.4, which, as discussed above, is below-the-line. With respect to EEI, the Company receives from EEI a Schedule of Expenses[1] that details EEI's budgeted spend for lobbying. The Company uses the percentage of EEI's budget that relates to lobbying to record the portion of the payment related to lobbying below-the-line.

Q. PLEASE DESCRIBE THE PUBLIC STAFF'S ADJUSTMENT TO EEI DUES.

A. In addition to the percentage of EEI dues that the Company recorded below-the-line and did not include in cost of service, the Public Staff appears to have also removed a percentage of the EEI dues unrelated to lobbying that the Company records above-the-line. Since the Public Staff did not include a discussion of this adjustment in testimony, it is unclear what its rationale is for excluding this percentage, but the Company believes that it was simply an error perhaps based on a failure to recognize that the Company had already excluded amounts of EEI dues related to lobbying.

[1] This schedule was provided in the Company's Confidential response to Public Staff Data Request 35-5.

Q. DO YOU AGREE WITH THE PUBLIC STAFF'S ADJUSTMENT RELATING TO EEI DUES?

A. No. As stated above, I believe that the Public Staff excluded this amount in error, and to accept this adjustment would result in removing a proportion of the EEI dues attributable to lobbying, political contributions, and charitable donations twice. In the event that these amounts were not removed by mistake, the Public Staff has offered no reason to exclude additional amounts over and above those the Company has already recorded below-the-line. Electric industry trade organizations like EEI provide valuable resources to their member utilities, which in turn benefit customers. For example, EEI offers training and testing for members' employees; information relating to cybersecurity initiatives, energy efficiency programs, and customer solutions; access to industry data; and breaking news on topics such as addressing the novel coronavirus. Customers benefit from the Company's participation in industry organizations as it keeps DE Progress current on industry trends, developments, innovative programs, and emerging safety issues, among other things. It is not reasonable to assume that activities beyond those identified by EEI constitute lobbying or that because this organization does engage in some lobbying and political activities, its other activities do not benefit customers.

IV. EXPENSES RELATED TO CHAMBERS OF COMMERCE

Q. WITNESS DORGAN ARGUES THAT ALL PAYMENTS TO CHAMBER OF COMMERCE ENTITIES SHOULD BE EXCLUDED. DO YOU AGREE?

A. Public Staff witness Dorgan argues that these expenses should be disallowed because they do not represent actual costs of providing electric service to customers. I do not agree.

Q. WHY SHOULD THE COMPANY BE ABLE TO RECOVER EXPENSES RELATED TO CHAMBERS OF COMMERCE?

A. Chambers of Commerce promote business and economic development which in turn helps to retain and attract customers to the Company's service territory. Funds paid to Chambers of Commerce that are not specified as a donation or lobbying on the Chamber invoice are supporting business or economic development and are considered to be properly charged as a utility operating expense that should be included in the Company's cost of providing electric service to customers.

V. CONCLUSION

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

A. Yes.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1219

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

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND ADDRESS.

A. My name is John J. Spanos. My business address is 207 Senate Avenue, Camp Hill, Pennsylvania, 17011.

Q. ARE YOU ASSOCIATED WITH ANY FIRM?

A. Yes. I am associated with the firm of Gannett Fleming Valuation and Rate Consultants, LLC ("Gannett Fleming").

Q. HOW LONG HAVE YOU BEEN ASSOCIATED WITH GANNETT FLEMING?

A. I have been associated with the firm since college graduation in June 1986.

Q. WHAT IS YOUR POSITION WITH THE FIRM?

A. I am President.

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

A. I am testifying on behalf of Duke Energy Progress ("DE Progress" or the "Company").

Q. PLEASE STATE YOUR QUALIFICATIONS.

A. I have 33 years of depreciation experience, which includes giving expert testimony in over 300 cases before 40 regulatory commissions, including this Commission. These cases have included depreciation studies in the electric, gas, water, wastewater and pipeline industries. In addition to cases where I have submitted testimony, I have also supervised over 600 other depreciation or valuation assignments. Please refer to Appendix A for my qualifications statement, which includes further information with respect to my work history, case experience, and leadership in the Society of Depreciation Professionals.

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

A. My testimony will support and explain the depreciation study conducted under my direction and supervision for the electric utility plant of DE Progress. The study represents all electric plant assets.

Q. PLEASE DEFINE THE CONCEPT OF DEPRECIATION.

A. Depreciation refers to the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of utility plant in the course of service from causes which are known to be in current operation, against which the Company is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, obsolescence, changes in the art, changes in demand and the requirements of public authorities.

Q. HAVE YOU FILED ANY EXHIBITS WITH YOUR TESTIMONY?

A. Yes. Attached to my testimony is Spanos Exhibit 1.

Q. WAS SPANOS EXHIBIT 1 PREPARED UNDER YOUR DIRECTION AND CONTROL?

A. Yes.

Q. PLEASE DESCRIBE SPANOS EXHIBIT 1.

A. Spanos Exhibit 1 is a report entitled, "2018 Depreciation Study - Calculated Annual Depreciation Accruals Related to Electric Plant as of December 31, 2018." This report sets forth the results of my depreciation study for DE Progress.

Q. IS SPANOS EXHIBIT 1 A TRUE AND ACCURATE COPY OF YOUR DEPRECIATION STUDY?

A. Yes.

Q. DOES SPANOS EXHIBIT 1 ACCURATELY PORTRAY THE RESULTS OF YOUR DEPRECIATION STUDY AS OF DECEMBER 31, 2018?

A. Yes.

II. DEPRECIATION STUDY

Q. WHAT WAS THE PURPOSE OF YOUR DEPRECIATION STUDY?

A. The purpose of the depreciation study was to estimate the annual depreciation accruals related to electric plant in service for ratemaking purposes and determine appropriate average service lives and net salvage percentages for each plant account.

Q. PLEASE DESCRIBE THE CONTENTS OF YOUR REPORT.

A. The Depreciation Study is presented in nine parts. Part I, Introduction, presents the scope and basis for the Depreciation Study. Part II, Estimation of Survivor Curves, includes descriptions of the methodology of estimating survivor curves. Parts III and IV set forth the analysis for determining service life and net salvage estimates. Part V, Calculation of Annual and Accrued Depreciation, includes the concepts of depreciation and amortization using the remaining life. Part VI, Results of Study, presents a description of the results of my analysis and a summary of the depreciation calculations. Parts VII, VIII and IX include graphs and tables that relate to the service life and net salvage analyses, and the detailed depreciation calculations by account.

The Depreciation Study also includes several tables and tabulations of data and calculations. Table 1 on pages VI-4 through VI-11 of the Depreciation Study presents the estimated survivor curve, the net salvage percent, the original cost as of December 31, 2018, the book depreciation reserve, and the calculated annual depreciation accrual and rate for each account or subaccount. The section beginning on page VII-2 presents the results of the retirement rate analyses prepared as the historical bases for the service life estimates. The section beginning on page VIII-2 presents the results of the net salvage analysis. The section beginning on page IX-2 presents the depreciation calculations related to surviving original cost as of December 31, 2018.

Q. PLEASE EXPLAIN HOW YOU PERFORMED YOUR DEPRECIATION STUDY.

A. I used the straight line remaining life method of depreciation, with the average service life procedure for all plant assets except some general plant accounts. The annual depreciation is based on a method of depreciation accounting that seeks to distribute the unrecovered cost of fixed capital assets over the estimated remaining useful life of each unit, or group of assets, in a systematic and rational manner.

For General Plant Accounts 391.0, 391.1, 393.0, 394.0, 395.0, 397.0, and 398.0, I used the straight line remaining life method of amortization. The annual amortization is based on amortization accounting that distributes the unrecovered cost of fixed capital assets over the remaining amortization period selected for each account and vintage.

Q. HOW DID YOU DETERMINE THE RECOMMENDED ANNUAL DEPRECIATION ACCRUAL RATES?

A. I did this in two phases. In the first phase, I estimated the service life and net salvage characteristics for each depreciable group, that is, each plant account or subaccount identified as having similar characteristics. In the second phase, I calculated the composite remaining lives and annual depreciation accrual rates based on the service life and net salvage estimates determined in the first phase.

Q. PLEASE DESCRIBE THE FIRST PHASE OF THE DEPRECIATION STUDY, IN WHICH YOU ESTIMATED THE SERVICE LIFE AND NET SALVAGE CHARACTERISTICS FOR EACH DEPRECIABLE GROUP.

A. The service life and net salvage study consisted of compiling historic data from records related to DE Progress' plant; analyzing the data to obtain historic trends of survivor and net salvage characteristics; obtaining supplementary information from DE Progress' management, and operating personnel concerning practices and plans as they relate to plant operations; and interpreting the above data and the estimates used by other electric utilities to form judgments regarding average service life and net salvage characteristics.

Q. WHAT HISTORIC DATA DID YOU ANALYZE FOR THE PURPOSE OF ESTIMATING SERVICE LIFE CHARACTERISTICS?

A. I analyzed the Company's accounting entries that record plant transactions during the period 1954 through 2018. The transactions included additions, retirements, transfers and the related balances. The Company records also included surviving dollar value by year installed for each plant account as of December 31, 2018.

Q. WHAT METHOD DID YOU USE TO ANALYZE THIS SERVICE LIFE DATA?

A. I used the retirement rate method. This is the most appropriate method when aged retirement data are available, because this method determines the average rates of retirement actually experienced by the Company during the period of time covered by the study.

Q. PLEASE DESCRIBE HOW YOU USED THE RETIREMENT RATE METHOD TO ANALYZE DE PROGRESS' SERVICE LIFE DATA.

A. I applied the retirement rate method to each different group of property in the study. For each property group, I used the retirement rate method to form a life table which, when plotted, shows an original survivor curve for that property group. Each original survivor curve represents the average survivor pattern experienced by the several vintage groups during the experience band studied. The survivor patterns do not necessarily describe the life characteristics of the property group; therefore, interpretation of the original survivor curves is required to use them as valid considerations in estimating service life. The Iowa-type survivor curves were used to perform these interpretations.

Q. WHAT IS AN "IOWA-TYPE SURVIVOR CURVE" AND HOW DID YOU USE SUCH CURVES TO ESTIMATE THE SERVICE LIFE CHARACTERISTICS FOR EACH PROPERTY GROUP?

A. Iowa type curves are a widely used group of generalized survivor curves that contain the range of survivor characteristics usually experienced by utilities and other industrial companies. The Iowa curves were developed at the Iowa State College Engineering Experiment Station through an extensive process of observing and classifying the ages at which various types of property used by utilities and other industrial companies had been retired.

Iowa type curves are used to smooth and extrapolate original survivor curves determined by the retirement rate method. The Iowa curves and truncated Iowa curves were used in this study to describe the forecasted rates of retirement based on the observed rates of retirement and the outlook for future retirements.

The estimated survivor curve designations for each depreciable property group indicate the average service life, the family within the Iowa system to which the property group belongs, and the relative height of the mode. For example, the Iowa 45-R1 survivor curve indicates an average service life of forty-five years; a right-moded, or R, type curve (the mode occurs after average life for right-moded curves); and a low height, 1, for the mode (possible modes for R type curves range from 1 to 5).

Q. WHAT APPROACH DID YOU USE TO ESTIMATE THE LIVES OF SIGNIFICANT PRODUCTION FACILITIES?

A. I used the life span technique to estimate the lives of significant facilities for which concurrent retirement of the entire facility is anticipated. In this technique, the survivor characteristics of such facilities are described using interim survivor curves and estimated probable retirement dates. The interim survivor curve describes the rate of retirement related to the replacement of elements of the facility, such as, for a power plant, the retirement of assets such as pumps, motors and piping that occur during the life of the facility. The probable retirement date provides the rate of final retirement for each year of installation for the facility by truncating the interim survivor curve for each installation year at its attained age at the date of probable retirement. The use of interim survivor curves truncated at the date of probable retirement provides a consistent method for estimating the lives of the several years of installation for a particular facility inasmuch as a single concurrent retirement for all years of installation will occur when it is retired.

Q. IS THIS APPROACH WIDELY ACCEPTED FOR ESTIMATING THE SERVICE LIVES OF PRODUCTION FACILITIES?

A. Yes. The life span technique has been used previously for DE Progress as well as for Duke Energy Carolinas. My firm has also used the life span technique in performing depreciation studies presented to many other public utility commissions across the United States and Canada.

Q. HOW ARE THE LIFE SPANS ESTIMATED FOR DE PROGRESS' PRODUCTION FACILITIES?

A. The life span estimates are based on informed judgment that incorporates factors for each facility such as the technology of the facility, management plans and outlook for the facility, and the estimates for similar facilities for other utilities. For nuclear and hydro facilities that have operating licenses, the life span estimates are based on the license dates for each facility.

Q. HAVE ANY LIFE SPAN ESTIMATES CHANGED SINCE THE LAST STUDY WAS CONDUCTED?

A. Yes. Mayo Unit 1 and Roxboro Units 3 and 4 have life spans that are planned to be shorter than currently approved. However, all these units are scheduled to be retired in 2029. Additionally, the continued recovery of Asheville Units 1 and 2 through December 2027 is maintained as the units will be retired in 2019.

Q. ARE THE NEW LIFE SPANS REASONABLE?

A. Yes. The new life span for Mayo is 46 years, for Roxboro Unit 3 is 56 years, and for Roxboro Unit 4 is 49 years. The most common range of life spans for steam production facilities is 55 to 65 years; however, in recent years, originally proposed life spans have been shortened due to unit efficiencies and environmental regulations. The industry average of similar units in recent years has been 46 years.

Q. ARE THE NEW LIFE SPANS CONSISTENT WITH COMPANY PLANS?

A. Yes. During the conduct of this depreciation study, DE Progress personnel identified the revised life spans for some steam facilities.

Q. ARE THE FACTORS CONSIDERED IN YOUR ESTIMATES OF SERVICE LIFE AND NET SALVAGE PERCENTS PRESENTED IN SPANOS EXHIBIT 1?

A. Yes. A discussion of the factors considered in the estimation of service lives and net salvage percents are presented in Part III and Part IV of Spanos Exhibit 1.

Q. ARE THERE ANY ASSETS FOR WHICH THERE ARE ADDITIONAL CONSIDERATIONS?

A. Yes. The Company has a program in place to replace its existing legacy electric meters with new technology meters. This replacement project is planned to be completed by the end of 2020. Per the prior case, the net book value of $68,041,378 for the legacy meters has been amortized over 10 years from implementation date. Assets that will not be replaced due to this program, such as instrument transformers, remain in Account 370, Metering Equipment and have a 28-R4 survivor curve.

Q. DID YOU PHYSICALLY OBSERVE DE PROGRESS' PLANT AND EQUIPMENT AS PART OF YOUR DEPRECIATION STUDY?

A. Yes. I made field reviews of DE Progress' property during June 2019 to observe representative portions of plant. Also, I have conducted field visits in a prior study in December 2016 and January 2017. Field reviews are conducted to become familiar with Company operations and obtain an understanding of the function of the plant and information with respect to the reasons for past retirements and the expected future causes of retirements. This knowledge was incorporated in the interpretation and extrapolation of the statistical analyses.

Q. WOULD YOU PLEASE EXPLAIN THE CONCEPT OF "NET SALVAGE"?

A. Net salvage is a component of the service value of capital assets that is recovered through depreciation rates. The service value of an asset is its original cost less its net salvage. Net Salvage is the salvage value received for the asset upon retirement less the cost to retire the asset. When the cost to retire exceeds the salvage value, the result is negative net salvage.

Because depreciation expense is the loss in service value of an asset during a defined period, *e.g.*, one year, it must include a ratable portion of both the original cost and the net salvage. That is, the net salvage related to an asset should be incorporated in the cost of service during the same period as its original cost so that customers receiving service from the asset pay rates that include a portion of both elements of the asset's service value, the original cost and the net salvage value.

For example, the full recovery of the service value of a $1,000 line transformer will include not only the $1,000 of original cost, but also, on average, $75 to remove the line transformer at the end of its life and $25 in salvage value. In this example, the net salvage component is negative $50 ($25 - $75), and the net salvage percent is negative 5% (($25 - $75)/$1,000).

Q. PLEASE DESCRIBE HOW YOU ESTIMATED NET SALVAGE PERCENTAGES.

A. The net salvage percentages estimated in the Depreciation Study were based on informed judgment that incorporated factors such as the statistical analyses of historical net salvage data; information provided to me by the Company's operating personnel, general knowledge and experience of industry practices; and trends in the industry in general. The statistical net salvage analyses incorporate the Company's actual historical data for the period 1979 through 2018, and considers the cost of removal and gross salvage ratios to the associated retirements during the 40-year period. Trends of these data are also measured based on three-year moving averages and the most recent five-year indications.

Q. WERE THE NET SALVAGE PERCENTAGES FOR GENERATING FACILITIES BASED ON THE SAME ANALYSES?

A. Yes, for the interim net salvage estimates. The net salvage percentages for generating facilities were based on two components, the interim net salvage percentage and the final net salvage percentage. The interim net salvage percentage is determined based on the historical indications from the period 1979 to 2018 of the cost of removal and gross salvage amounts as a percentage of the associated plant retired. The final net salvage or dismantlement component was determined based on the retirement activities associated with the assets anticipated to be retired at the concurrent date of final retirement.

Q. HAVE YOU INCLUDED A DISMANTLEMENT OR DECOMMISSIONING COMPONENT INTO THE OVERALL RECOVERY OF GENERATING FACILITIES?

A. Yes. A dismantlement or decommissioning component has been included in the net salvage percentage for steam, hydro and other production facilities.

Q. CAN YOU EXPLAIN HOW THE FINAL NET SALVAGE COMPONENT IS INCLUDED IN THE DEPRECIATION STUDY?

A. Yes. The dismantlement component is part of the overall net salvage for each location within the production assets. Based on studies for other utilities and the cost estimates of DE Progress, it was determined that the dismantlement or decommissioning costs for steam and other production facilities is best calculated by dividing the dismantlement cost by the surviving plant at final retirement. These amounts at a location basis are added to the interim net salvage percentage of the assets anticipated to be retired on an interim basis to produce the weighted net salvage percentage for each location. The detailed calculations of the overall net salvage for each location is set forth on page VIII-3 of the Depreciation Study.

Q. WHAT IS THE BASIS OF THE DISMANTLEMENT OR DECOMMISSIONING COST ESTIMATES?

A. The decommissioning cost estimates are based on decommissioning studies of each generating site performed by Burns and McDonnell. These estimates are based on the current cost to decommission the facility. However, the costs to decommission power plants has tended to increase over time (as have construction costs in general). For this reason, to recover the full decommissioning costs for each site, these costs need to be escalated to the time of retirement. The calculations of the escalation of these costs have been provided in the table set forth on pages VIII-2 and VIII-3 of the Depreciation Study.

Q. PLEASE DESCRIBE THE SECOND PHASE OF THE PROCESS THAT YOU USED IN THE DEPRECIATION STUDY IN WHICH YOU CALCULATED COMPOSITE REMAINING LIVES AND ANNUAL DEPRECIATION ACCRUAL RATES.

A. After I estimated the service life and net salvage characteristics for each depreciable property group, I calculated the annual depreciation accrual rates for each depreciable group based on the straight line remaining life method, using remaining lives weighted consistent with the average service life procedure. The calculation of annual depreciation accrual rates was developed as of December 31, 2018.

Q. PLEASE DESCRIBE THE STRAIGHT LINE REMAINING LIFE METHOD OF DEPRECIATION.

A. The straight line remaining life method of depreciation allocates the original cost of the property, less accumulated depreciation, less future net salvage, in equal amounts to each year of remaining service life.

Q. PLEASE DESCRIBE AMORTIZATION ACCOUNTING.

A. Amortization accounting is used for accounts with a large number of units, but small asset values. In amortization accounting, units of property are capitalized in the same manner as they are in depreciation accounting. However, depreciation accounting is difficult for these assets because periodic inventories are required to properly reflect plant in service. Consequently, retirements are recorded when a vintage is fully amortized rather than as the units are removed from service. That is, there is no dispersion of retirement. All units are retired when the age of the vintage reaches the amortization period. Each plant account or group of assets is assigned a fixed period, which represents an anticipated life during which the asset will render service. For example, in amortization accounting, assets that have a 20-year amortization period will be fully recovered after 20 years of service and taken off the Company books, but not necessarily removed from service. In contrast, assets that are taken out of service before 20 years remain on the books until the amortization period for that vintage has expired.

Q. AMORTIZATION ACCOUNTING IS BEING IMPLEMENTED FOR WHICH PLANT ACCOUNTS?

A. Amortization accounting is only appropriate for certain General Plant accounts. These accounts are 391.0, 391.1, 393.0, 394.0, 395.0, 397.0, and 398.0, which represent slightly more than one percent of depreciable plant.

Q. PLEASE USE AN EXAMPLE TO ILLUSTRATE THE DEVELOPMENT OF THE ANNUAL DEPRECIATION ACCRUAL RATE FOR A PARTICULAR GROUP OF PROPERTY IN YOUR DEPRECIATION STUDY.

A. I will use Account 368, Line Transformers, as an example because it is one of the largest depreciable groups.

The retirement rate method was used to analyze the survivor characteristics of this property group. Aged plant accounting data were compiled from 1954 through 2018 and analyzed in periods that best represent the overall service life of this property. The life tables for the 1954-2018 and 1979-2018 experience bands are presented in the depreciation study on pages VII-219 through VII-224. Each life table displays the retirement and surviving ratios of the aged plant data exposed to retirement by age interval. For example, page VII-219 of Spanos Exhibit 1, shows $2,324,176 retired during age interval 0.5-1.5 with $1,260,631,441 exposed to retirement at the beginning of the interval. Consequently, the retirement ratio is 0.0018 ($2,324,176/$1,260,631,441) and the survivor ratio is 0.9982 (1-0.0018). The life tables, or original survivor curves, are plotted along with the estimated smooth survivor curve, the 40-R2, on page VII-218 of Spanos Exhibit 1.

The net salvage percent is presented on pages VIII-85 through VIII-87. The percentage is based on the result of annual gross salvage minus the cost to remove plant assets as compared to the original cost of plant retired during the period 1979 through 2018. The 40-year period experienced $495,642 ($28,789,112-$28,263,470) in net salvage for $168,897,541 plant retired. The result is net salvage of 0 percent ($495,642/$168,897,541). However, the three-year and most recent five years show a trend to negative net salvage. Therefore, net salvage for line transformers is set at negative 5 percent.

My calculation of the annual depreciation related to original cost of electric utility plant at December 31, 2018 for Account 368 is presented on pages IX-171 and IX-172 of Spanos Exhibit 1. The calculation is based on the 40-R2 survivor curve, 5% negative net salvage, the attained age, and the allocated book reserve. The tabulation sets forth the installation year, the original cost, calculated accrued depreciation, allocated book reserve, future accruals, remaining life and annual accrual. These totals are brought forward to Table 1 on page VI-8.

Q. IN YOUR OPINION, ARE THE DEPRECIATION AND AMORTIZATION RATES SET FORTH IN SPANOS EXHIBIT 1 THE APPROPRIATE RATES FOR THE COMMISSION TO ADOPT IN THIS PROCEEDING FOR DE PROGRESS?

A. Yes. These rates appropriately reflect the rates at which the costs of DE Progress' assets are being consumed over their useful lives. These rates are an appropriate basis for setting electric rates in this matter and for the Company to use for booking depreciation and amortization expense going forward.

Q. HAVE YOU DEVELOPED DEPRECIATION RATES FOR FUTURE ASSETS?

A. Yes. There are plans to add a new combined cycle facility of Asheville in 2019. The rates for these assets will be based on interim survivor curves for each account, a weighted net salvage percent for each account and a 40-year life span for the location. Additionally, depreciation rates for new battery storage assets for generation, transmission and distribution have been included. These assets are based on a 15-L3 survivor curve and zero percent net salvage. Each of these future rates are presented on page VI-11 of Spanos Exhibit 1.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Appendix A

JOHN SPANOS

DEPRECIATION EXPERIENCE

Q. Please state your name.

A. My name is John J. Spanos.

Q. What is your educational background?

A. I have Bachelor of Science degrees in Industrial Management and Mathematics from Carnegie-Mellon University and a Master of Business Administration from York College.

Q. Do you belong to any professional societies?

A. Yes. I am a member and past President of the Society of Depreciation Professionals and a member of the American Gas Association/Edison Electric Institute Industry Accounting Committee.

Q. Do you hold any special certification as a depreciation expert?

A. Yes. The Society of Depreciation Professionals has established national standards for depreciation professionals. The Society administers an examination to become certified in this field. I passed the certification exam in September 1997 and was recertified in August 2003, February 2008, January 2013 and February 2018.

Q. Please outline your experience in the field of depreciation.

A. In June 1986, I was employed by Gannett Fleming Valuation and Rate Consultants, Inc. as a Depreciation Analyst. During the period from June 1986 through December, 1995, I helped prepare numerous depreciation and original cost studies for utility companies in various industries. I helped perform depreciation studies for the following telephone companies: United Telephone of Pennsylvania, United Telephone of New Jersey, and Anchorage Telephone Utility. I helped perform depreciation studies for the following companies in the railroad industry: Union Pacific Railroad, Burlington Northern Railroad, and Wisconsin Central Transportation Corporation.

I helped perform depreciation studies for the following organizations in the electric utility industry: Chugach Electric Association, The Cincinnati Gas and Electric Company (CG&E), The Union Light, Heat and Power Company (ULH&P), Northwest Territories Power Corporation, and the City of Calgary - Electric System.

I helped perform depreciation studies for the following pipeline companies: TransCanada Pipelines Limited, Trans Mountain Pipe Line Company Ltd., Interprovincial Pipe Line Inc., Nova Gas Transmission Limited and Lakehead Pipeline Company.

I helped perform depreciation studies for the following gas utility companies: Columbia Gas of Pennsylvania, Columbia Gas of Maryland, The Peoples Natural Gas Company, T. W. Phillips Gas & Oil Company, CG&E, ULH&P, Lawrenceburg Gas Company and Penn Fuel Gas, Inc.

I helped perform depreciation studies for the following water utility companies: Indiana-American Water Company, Consumers Pennsylvania Water Company and The York Water Company; and depreciation and original cost studies for Philadelphia Suburban Water Company and Pennsylvania-American Water Company.

In each of the above studies, I assembled and analyzed historical and simulated data, performed field reviews, developed preliminary estimates of service life and net salvage, calculated annual depreciation, and prepared reports for submission to state public utility commissions or federal regulatory agencies. I performed these studies under the general direction of William M. Stout, P.E.

In January 1996, I was assigned to the position of Supervisor of Depreciation Studies. In July 1999, I was promoted to the position of Manager, Depreciation and

Valuation Studies. In December 2000, I was promoted to the position as Vice-President of Gannett Fleming Valuation and Rate Consultants, Inc., in April 2012, I was promoted to the position as Senior Vice President of the Valuation and Rate Division of Gannett Fleming Inc. (now doing business as Gannett Fleming Valuation and Rate Consultants, LLC) and in January of 2019, I was promoted to my present position of President of Gannett Fleming Valuation and Rate Consultants, LLC. In my current position I am responsible for conducting all depreciation, valuation and original cost studies, including the preparation of final exhibits and responses to data requests for submission to the appropriate regulatory bodies.

Since January 1996, I have conducted depreciation studies similar to those previously listed including assignments for Pennsylvania-American Water Company; Aqua Pennsylvania; Kentucky-American Water Company; Virginia-American Water Company; Indiana-American Water Company; Iowa-American Water Company; New Jersey-American Water Company; Hampton Water Works Company; Omaha Public Power District; Enbridge Pipe Line Company; Inc.; Columbia Gas of Virginia, Inc.; Virginia Natural Gas Company National Fuel Gas Distribution Corporation - New York and Pennsylvania Divisions; The City of Bethlehem - Bureau of Water; The City of Coatesville Authority; The City of Lancaster - Bureau of Water; Peoples Energy Corporation; The York Water Company; Public Service Company of Colorado; Enbridge Pipelines; Enbridge Gas Distribution, Inc.; Reliant Energy-HLP; Massachusetts-American Water Company; St. Louis County Water Company; Missouri-American Water Company; Chugach Electric Association; Alliant Energy; Oklahoma Gas & Electric Company; Nevada Power Company; Dominion Virginia Power; NUI-Virginia Gas Companies; Pacific Gas & Electric Company; PSI Energy; NUI - Elizabethtown Gas Company; Cinergy Corporation – CG&E; Cinergy Corporation – ULH&P; Columbia Gas of

Kentucky; South Carolina Electric & Gas Company; Idaho Power Company; El Paso

Electric Company; Aqua North Carolina; Aqua Ohio; Aqua Texas, Inc.; Aqua Illinois, Inc.; Ameren Missouri; Central Hudson Gas & Electric; Centennial Pipeline Company; CenterPoint Energy-Arkansas; CenterPoint Energy – Oklahoma; CenterPoint Energy – Entex; CenterPoint Energy - Louisiana; NSTAR – Boston Edison Company; Westar Energy, Inc.; United Water Pennsylvania; PPL Electric Utilities; PPL Gas Utilities; Wisconsin Power & Light Company; TransAlaska Pipeline; Avista Corporation; Northwest Natural Gas; Allegheny Energy Supply, Inc.; Public Service Company of North Carolina; South Jersey Gas Company; Duquesne Light Company; MidAmerican Energy Company; Laclede Gas; Duke Energy Company; E.ON U.S. Services Inc.; Elkton Gas Services; Anchorage Water and Wastewater Utility; Kansas City Power and Light; Duke Energy North Carolina; Duke Energy South Carolina; Monongahela Power Company; Potomac Edison Company; Duke Energy Ohio Gas; Duke Energy Kentucky; Duke Energy Indiana; Duke Energy Progress; Northern Indiana Public Service Company; Tennessee-American Water Company; Columbia Gas of Maryland; Maryland-American Water Company; Bonneville Power Administration; NSTAR Electric and Gas Company; EPCOR Distribution, Inc.; B. C. Gas Utility, Ltd; Entergy Arkansas; Entergy Texas; Entergy Mississippi; Entergy Louisiana; Entergy Gulf States Louisiana; the Borough of Hanover; Louisville Gas and Electric Company; Kentucky Utilities Company; Madison Gas and Electric; Central Maine Power; PEPCO; PacifiCorp; Minnesota Energy Resource Group; Jersey Central Power & Light Company; Cheyenne Light, Fuel and Power Company; United Water Arkansas; Central Vermont Public Service Corporation; Green Mountain Power; Portland General Electric Company; Atlantic City Electric; Nicor Gas Company; Black Hills Power; Black Hills Colorado Gas; Black Hills Kansas Gas; Black Hills Service Company; Black Hills Utility Holdings; Public Service Company of Oklahoma; City of

Dubois; Peoples Gas Light and Coke Company; North Shore Gas Company; Connecticut Light and Power; New York State Electric and Gas Corporation; Rochester Gas and Electric Corporation; Greater Missouri Operations; Tennessee Valley Authority; Omaha Public Power District; Indianapolis Power & Light Company; Vermont Gas Systems, Inc.; Metropolitan Edison; Pennsylvania Electric; West Penn Power; Pennsylvania Power; PHI Service Company - Delmarva Power and Light; Atmos Energy Corporation; Citizens Energy Group; PSE&G Company; Berkshire Gas Company; Alabama Gas Corporation; Mid-Atlantic Interstate Transmission, LLC; SUEZ Water; WEC Energy Group; Rocky Mountain Natural Gas, LLC; Illinois-American Water Company; Northern Illinois Gas Company; Public Service of New Hampshire and Newtown Artesian Water Company.

My additional duties include determining final life and salvage estimates, conducting field reviews, presenting recommended depreciation rates to management for its consideration and supporting such rates before regulatory bodies.

Q. Have you submitted testimony to any state utility commission on the subject of utility plant depreciation?

A. Yes. I have submitted testimony to the Pennsylvania Public Utility Commission; the Commonwealth of Kentucky Public Service Commission; the Public Utilities Commission of Ohio; the Nevada Public Utility Commission; the Public Utilities Board of New Jersey; the Missouri Public Service Commission; the Massachusetts Department of Telecommunications and Energy; the Alberta Energy & Utility Board; the Idaho Public Utility Commission; the Louisiana Public Service Commission; the State Corporation Commission of Kansas; the Oklahoma Corporate Commission; the Public Service Commission of South Carolina; Railroad Commission of Texas – Gas Services Division; the New York Public Service Commission; Illinois Commerce Commission; the Indiana

Utility Regulatory Commission; the California Public Utilities Commission; the Federal Energy Regulatory Commission ("FERC"); the Arkansas Public Service Commission; the Public Utility Commission of Texas; Maryland Public Service Commission; Washington Utilities and Transportation Commission; The Tennessee Regulatory Commission; the Regulatory Commission of Alaska; Minnesota Public Utility Commission; Utah Public Service Commission; District of Columbia Public Service Commission; the Mississippi Public Service Commission; Delaware Public Service Commission; Virginia State Corporation Commission; Colorado Public Utility Commission; Oregon Public Utility Commission; South Dakota Public Utilities Commission; Wisconsin Public Service Commission; Wyoming Public Service Commission; the Public Service Commission of West Virginia; Maine Public Utility Commission; Iowa Utility Board; Connecticut Public Utilities Regulatory Authority; New Mexico Public Regulation Commission; Commonwealth of Massachusetts Department of Public Utilities; Rhode Island Public Utilities Commission and the North Carolina Utilities Commission.

Q. Have you had any additional education relating to utility plant depreciation?

A. Yes. I have completed the following courses conducted by Depreciation Programs, Inc.: "Techniques of Life Analysis," "Techniques of Salvage and Depreciation Analysis," "Forecasting Life and Salvage," "Modeling and Life Analysis Using Simulation," and "Managing a Depreciation Study." I have also completed the "Introduction to Public Utility Accounting" program conducted by the American Gas Association.

Q. Does this conclude your qualification statement?

A. Yes.

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY

	Year	Jurisdiction	Docket No.	Client Utility	Subject
01.	1998	PA PUC	R-00984375	City of Bethlehem – Bureau of Water	Original Cost and Depreciation
02.	1998	PA PUC	R-00984567	City of Lancaster	Original Cost and Depreciation
03.	1999	PA PUC	R-00994605	The York Water Company	Depreciation
04.	2000	D.T.&E.	DTE 00-105	Massachusetts-American Water Company	Depreciation
05.	2001	PA PUC	R-00016114	City of Lancaster	Original Cost and Depreciation
06.	2001	PA PUC	R-00017236	The York Water Company	Depreciation
07.	2001	PA PUC	R-00016339	Pennsylvania-American Water Company	Depreciation
08.	2001	OH PUC	01-1228-GA-AIR	Cinergy Corp – Cincinnati Gas & Elect Company	Depreciation
09.	2001	KY PSC	2001-092	Cinergy Corp – Union Light, Heat & Power Co.	Depreciation
10.	2002	PA PUC	R-00016750	Philadelphia Suburban Water Company	Depreciation
11.	2002	KY PSC	2002-00145	Columbia Gas of Kentucky	Depreciation
12.	2002	NJ BPU	GF02040245	NUI Corporation/Elizabethtown Gas Company	Depreciation
13.	2002	ID PUC	IPC-E-03-7	Idaho Power Company	Depreciation
14.	2003	PA PUC	R-0027975	The York Water Company	Depreciation
15.	2003	IN URC	R-0027975	Cinergy Corp – PSI Energy, Inc.	Depreciation
16.	2003	PA PUC	R-00038304	Pennsylvania-American Water Company	Depreciation
17.	2003	MO PSC	WR-2003-0500	Missouri-American Water Company	Depreciation
18.	2003	FERC	ER-03-1274-000	NSTAR-Boston Edison Company	Depreciation
19.	2003	NJ BPU	BPU 03080683	South Jersey Gas Company	Depreciation
20.	2003	NV PUC	03-10001	Nevada Power Company	Depreciation
21.	2003	LA PSC	U-27676	CenterPoint Energy – Arkla	Depreciation
22.	2003	PA PUC	R-00038805	Pennsylvania Suburban Water Company	Depreciation
23.	2004	AB En/Util Bd	1306821	EPCOR Distribution, Inc.	Depreciation
24.	2004	PA PUC	R-00038168	National Fuel Gas Distribution Corp (PA)	Depreciation
25.	2004	PA PUC	R-00049255	PPL Electric Utilities	Depreciation
26.	2004	PA PUC	R-00049165	The York Water Company	Depreciation
27.	2004	OK Corp Cm	PUC 200400187	CenterPoint Energy – Arkla	Depreciation
28.	2004	OH PUC	04-680-El-AIR	Cinergy Corp. – Cincinnati Gas and Electric Company	Depreciation
29.	2004	RR Com of TX	GUD#	CenterPoint Energy – Entex Gas Services Div.	Depreciation
30.	2004	NY PUC	04-G-1047	National Fuel Gas Distribution Gas (NY)	Depreciation
31.	2004	AR PSC	04-121-U	CenterPoint Energy – Arkla	Depreciation
32.	2005	IL CC	05-	North Shore Gas Company	Depreciation
33.	2005	IL CC	05-	Peoples Gas Light and Coke Company	Depreciation

34.	2005	KY PSC	2005-00042	Union Light Heat & Power	Depreciation

	Year	Jurisdiction	Docket No.	Client Utility	Subject
35.	2005	IL CC	05-0308	MidAmerican Energy Company	Depreciation
36.	2005	MO PSC	GF-2005	Laclede Gas Company	Depreciation
37.	2005	KS CC	05-WSEE-981-RTS	Westar Energy	Depreciation
38.	2005	RR Com of TX	GUD #	CenterPoint Energy – Entex Gas Services Div.	Depreciation
39.	2005	FERC		Cinergy Corporation	Accounting
40.	2005	OK CC	PUD 200500151	Oklahoma Gas and Electric Company	Depreciation
41.	2005	MA Dept Tele-com & Ergy	DTE 05-85	NSTAR	Depreciation
42.	2005	NY PUC	05-E-934/05-G-0935	Central Hudson Gas & Electric Company	Depreciation
43.	2005	AK Reg Com	U-04-102	Chugach Electric Association	Depreciation
44.	2005	CA PUC	A05-12-002	Pacific Gas & Electric	Depreciation
45.	2006	PA PUC	R-00051030	Aqua Pennsylvania, Inc.	Depreciation
46.	2006	PA PUC	R-00051178	T.W. Phillips Gas and Oil Company	Depreciation
47.	2006	NC Util Cm.		Pub. Service Company of North Carolina	Depreciation
48.	2006	PA PUC	R-00051167	City of Lancaster	Depreciation
49.	2006	PA PUC	R00061346	Duquesne Light Company	Depreciation
50.	2006	PA PUC	R-00061322	The York Water Company	Depreciation
51.	2006	PA PUC	R-00051298	PPL GAS Utilities	Depreciation
52.	2006	PUC of TX	32093	CenterPoint Energy – Houston Electric	Depreciation
53.	2006	KY PSC	2006-00172	Duke Energy Kentucky	Depreciation
54.	2006	SC PSC		SCANA	
55.	2006	AK Reg Com	U-06-6	Municipal Light and Power	Depreciation
56.	2006	DE PSC	06-284	Delmarva Power and Light	Depreciation
57.	2006	IN URC	IURC43081	Indiana American Water Company	Depreciation
58.	2006	AK Reg Com	U-06-134	Chugach Electric Association	Depreciation
59.	2006	MO PSC	WR-2007-0216	Missouri American Water Company	Depreciation
60.	2006	FERC	IS082, ETC. AL	TransAlaska Pipeline	Depreciation
61.	2006	PA PUC	R-00061493	National Fuel Gas Distribution Corp. (PA)	Depreciation
62.	2007	NC Util Com.	E-7 SUB 828	Duke Energy Carolinas, LLC	Depreciation
63.	2007	OH PSC	08-709-EL-AIR	Duke Energy Ohio Gas	Depreciation
64.	2007	PA PUC	R-00072155	PPL Electric Utilities Corporation	Depreciation
65.	2007	KY PSC	2007-00143	Kentucky American Water Company	Depreciation

	Year	Jurisdiction	Docket No.	Client Utility	Subject
66.	2007	PA PUC	R-00072229	Pennsylvania American Water Company	Depreciation
67.	2007	KY PSC	2007-0008	NiSource – Columbia Gas of Kentucky	Depreciation
68.	2007	NY PSC	07-G-0141	National Fuel Gas Distribution Corp (NY)	Depreciation
69.	2008	AK PSC	U-08-004	Anchorage Water & Wastewater Utility	Depreciation
70.	2008	TN Reg Auth	08-00039	Tennessee-American Water Company	Depreciation
71.	2008	DE PSC	08-96	Artesian Water Company	Depreciation
72.	2008	PA PUC	R-2008-2023067	The York Water Company	Depreciation
73.	2008	KS CC	08-WSEE1-RTS	Westar Energy	Depreciation
74.	2008	IN URC	43526	Northern Indiana Public Service Company	Depreciation
75.	2008	IN URC	43501	Duke Energy Indiana	Depreciation
76.	2008	MD PSC	9159	NiSource – Columbia Gas of Maryland	Depreciation
77.	2008	KY PSC	2008-000251	Kentucky Utilities	Depreciation
78.	2008	KY PSC	2008-000252	Louisville Gas & Electric	Depreciation
79.	2008	PA PUC	2008-20322689	Pennsylvania American Water Co. - Wastewater	Depreciation
80.	2008	NY PSC	08-E887/08-00888	Central Hudson	Depreciation
81.	2008	WV TC	VE-080416/VG-8080417	Avista Corporation	Depreciation
82.	2008	IL CC	ICC-09-166	Peoples Gas, Light and Coke Company	Depreciation
83.	2009	IL CC	ICC-09-167	North Shore Gas Company	Depreciation
84.	2009	DC PSC	1076	Potomac Electric Power Company	Depreciation
85.	2009	KY PSC	2009-00141	NiSource – Columbia Gas of Kentucky	Depreciation
86.	2009	FERC	ER08-1056-002	Entergy Services	Depreciation
87.	2009	PA PUC	R-2009-2097323	Pennsylvania American Water Company	Depreciation
88.	2009	NC Util Cm	E-7, Sub 090	Duke Energy Carolinas, LLC	Depreciation
89.	2009	KY PSC	2009-00202	Duke Energy Kentucky	Depreciation
90.	2009	VA St. CC	PUE-2009-00059	Aqua Virginia, Inc.	Depreciation
91.	2009	PA PUC	2009-2132019	Aqua Pennsylvania, Inc.	Depreciation
92.	2009	MS PSC	09-	Entergy Mississippi	Depreciation
93.	2009	AK PSC	09-08-U	Entergy Arkansas	Depreciation
94.	2009	TX PUC	37744	Entergy Texas	Depreciation
95.	2009	TX PUC	37690	El Paso Electric Company	Depreciation
96.	2009	PA PUC	R-2009-2106908	The Borough of Hanover	Depreciation
97.	2009	KS CC	10-KCPE-415-RTS	Kansas City Power & Light	Depreciation
98.	2009	PA PUC	R-2009-	United Water Pennsylvania	Depreciation

	Year	Jurisdiction	Docket No.	Client Utility	Subject
99.	2009	OH PUC		Aqua Ohio Water Company	Depreciation
100.	2009	WI PSC	3270-DU-103	Madison Gas & Electric Company	Depreciation
101.	2009	MO PSC	WR-2010	Missouri American Water Company	Depreciation
102.	2009	AK Reg Cm	U-09-097	Chugach Electric Association	Depreciation
103.	2010	IN URC	43969	Northern Indiana Public Service Company	Depreciation
104.	2010	WI PSC	6690-DU-104	Wisconsin Public Service Corp.	Depreciation
105.	2010	PA PUC	R-2010-2161694	PPL Electric Utilities Corp.	Depreciation
106.	2010	KY PSC	2010-00036	Kentucky American Water Company	Depreciation
107.	2010	PA PUC	R-2009-2149262	Columbia Gas of Pennsylvania	Depreciation
108.	2010	MO PSC	GR-2010-0171	Laclede Gas Company	Depreciation
109.	2010	SC PSC	2009-489-E	South Carolina Electric & Gas Company	Depreciation
110.	2010	NJ BD OF PU	ER09080664	Atlantic City Electric	Depreciation
111.	2010	VA St. CC	PUE-2010-00001	Virginia American Water Company	Depreciation
112.	2010	PA PUC	R-2010-2157140	The York Water Company	Depreciation
113.	2010	MO PSC	ER-2010-0356	Greater Missouri Operations Company	Depreciation
114.	2010	MO PSC	ER-2010-0355	Kansas City Power and Light	Depreciation
115.	2010	PA PUC	R-2010-2167797	T.W. Phillips Gas and Oil Company	Depreciation
116.	2010	PSC SC	2009-489-E	SCANA – Electric	Depreciation
117.	2010	PA PUC	R-2010-22010702	Peoples Natural Gas, LLC	Depreciation
118.	2010	AK PSC	10-067-U	Oklahoma Gas and Electric Company	Depreciation
119.	2010	IN URC		Northern Indiana Public Serv. Company - NIFL	Depreciation
120.	2010	IN URC		Northern Indiana Public Serv. Co. - Kokomo	Depreciation
121.	2010	PA PUC	R-2010-2166212	Pennsylvania American Water Co. - WW	Depreciation
122.	2010	NC Util Cn.	W-218,SUB310	Aqua North Carolina, Inc.	Depreciation
123.	2011	OH PUC	11-4161-WS-AIR	Ohio American Water Company	Depreciation
124.	2011	MS PSC	EC-123-0082-00	Entergy Mississippi	Depreciation
125.	2011	CO PUC	11AL-387E	Black Hills Colorado	Depreciation
126.	2011	PA PUC	R-2010-2215623	Columbia Gas of Pennsylvania	Depreciation
127.	2011	PA PUC	R-2010-2179103	City of Lancaster – Bureau of Water	Depreciation
128.	2011	IN URC	43114 IGCC 4S	Duke Energy Indiana	Depreciation
129.	2011	FERC	IS11-146-000	Enbridge Pipelines (Southern Lights)	Depreciation
130.	2011	IL CC	11-0217	MidAmerican Energy Corporation	Depreciation
131.	2011	OK CC	201100087	Oklahoma Gas & Electric Company	Depreciation
132.	2011	PA PUC	2011-2232243	Pennsylvania American Water Company	Depreciation

	Year	Jurisdiction	Docket No.	Client Utility	Subject
133.	2011	FERC	2011-2232243	Carolina Gas Transmission	Depreciation
134.	2012	WA UTC	UE-120436/UG-120437	Avista Corporation	Depreciation
135.	2012	AK Reg Cm	U-12-009	Chugach Electric Association	Depreciation
136.	2012	MA PUC	DPU 12-25	Columbia Gas of Massachusetts	Depreciation
137.	2012	TX PUC	40094	El Paso Electric Company	Depreciation
138.	2012	ID PUC	IPC-E-12	Idaho Power Company	Depreciation
139.	2012	PA PUC	R-2012-2290597	PPL Electric Utilities	Depreciation
140.	2012	PA PUC	R-2012-2311725	Borough of Hanover – Bureau of Water	Depreciation
141.	2012	KY PSC	2012-00222	Louisville Gas and Electric Company	Depreciation
142.	2012	KY PSC	2012-00221	Kentucky Utilities Company	Depreciation
143.	2012	PA PUC	R-2012-2285985	Peoples Natural Gas Company	Depreciation
144.	2012	DC PSC	Case 1087	Potomac Electric Power Company	Depreciation
145.	2012	OH PSC	12-1682-EL-AIR	Duke Energy Ohio (Electric)	Depreciation
146.	2012	OH PSC	12-1685-GA-AIR	Duke Energy Ohio (Gas)	Depreciation
147.	2012	PA PUC	R-2012-2310366	City of Lancaster – Sewer Fund	Depreciation
148.	2012	PA PUC	R-2012-2321748	Columbia Gas of Pennsylvania	Depreciation
149.	2012	FERC	ER-12-2681-000	ITC Holdings	Depreciation
150.	2012	MO PSC	ER-2012-0174	Kansas City Power and Light	Depreciation
151.	2012	MO PSC	ER-2012-0175	KCPL Greater Missouri Operations Company	Depreciation
152.	2012	MO PSC	GO-2012-0363	Laclede Gas Company	Depreciation
153.	2012	MN PUC	G007,001/D-12-533	Integrys – MN Energy Resource Group	Depreciation
153.	2012	TX PUC		Aqua Texas	Depreciation
155.	2012	PA PUC	2012-2336379	York Water Company	Depreciation
156.	2013	NJ BPU	ER12121071	PHI Service Company– Atlantic City Electric	Depreciation
157.	2013	KY PSC	2013-00167	Columbia Gas of Kentucky	Depreciation
158.	2013	VA St CC	2013-00020	Virginia Electric and Power Company	Depreciation
159.	2013	IA Util Bd	2013-0004	MidAmerican Energy Corporation	Depreciation
160.	2013	PA PUC	2013-2355276	Pennsylvania American Water Company	Depreciation
161.	2013	NY PSC	13-E-0030, 13-G-0031, 13-S-0032	Consolidated Edison of New York	Depreciation
162.	2013	PA PUC	2013-2355886	Peoples TWP LLC	Depreciation
163.	2013	TN Reg Auth	12-0504	Tennessee American Water	Depreciation
164.	2013	ME PUC	2013-168	Central Maine Power Company	Depreciation
165.	2013	DC PSC	Case 1103	PHI Service Company – PEPCO	Depreciation

	Year	Jurisdiction	Docket No.	Client Utility	Subject
166.	2013	WY PSC	2003-ER-13	Cheyenne Light, Fuel and Power Company	Depreciation
167.	2013	FERC	ER13- -0000	Kentucky Utilities	Depreciation
168.	2013	FERC	ER13- -0000	MidAmerican Energy Company	Depreciation
169.	2013	FERC	ER13- -0000	PPL Utilities	Depreciation
170.	2013	PA PUC	R-2013-2372129	Duquesne Light Company	Depreciation
171.	2013	NJ BPU	ER12111052	Jersey Central Power and Light Company	Depreciation
172.	2013	PA PUC	R-2013-2390244	Bethlehem, City of – Bureau of Water	Depreciation
173.	2013	OK CC	UM 1679	Oklahoma, Public Service Company of	Depreciation
174.	2013	IL CC	13-0500	Nicor Gas Company	Depreciation
175.	2013	WY PSC	20000-427-EA-13	PacifiCorp	Depreciation
176.	2013	UT PSC	13-035-02	PacifiCorp	Depreciation
177.	2013	OR PUC	UM 1647	PacifiCorp	Depreciation
178.	2013	PA PUC	2013-2350509	Dubois, City of	Depreciation
179.	2014	IL CC	14-0224	North Shore Gas Company	Depreciation
180.	2014	FERC	ER14-	Duquesne Light Company	Depreciation
181.	2014	SD PUC	EL14-026	Black Hills Power Company	Depreciation
182.	2014	WY PSC	20002-91-ER-14	Black Hills Power Company	Depreciation
183.	2014	PA PUC	2014-2428304	Borough of Hanover – Municipal Water Works	Depreciation
184.	2014	PA PUC	2014-2406274	Columbia Gas of Pennsylvania	Depreciation
185.	2014	IL CC	14-0225	Peoples Gas Light and Coke Company	Depreciation
186.	2014	MO PSC	ER-2014-0258	Ameren Missouri	Depreciation
187.	2014	KS CC	14-BHCG-502-RTS	Black Hills Service Company	Depreciation
188.	2014	KS CC	14-BHCG-502-RTS	Black Hills Utility Holdings	Depreciation
189.	2014	KS CC	14-BHCG-502-RTS	Black Hills Kansas Gas	Depreciation
190.	2014	PA PUC	2014-2418872	Lancaster, City of – Bureau of Water	Depreciation
191.	2014	WV PSC	14-0701-E-D	First Energy – MonPower/PotomacEdison	Depreciation
192	2014	VA St CC	PUC-2014-00045	Aqua Virginia	Depreciation
193.	2014	VA St CC	PUE-2013	Virginia American Water Company	Depreciation
194.	2014	OK CC	PUD201400229	Oklahoma Gas and Electric Company	Depreciation
195.	2014	OR PUC	UM1679	Portland General Electric	Depreciation
196.	2014	IN URC	Cause No. 44576	Indianapolis Power & Light	Depreciation
197.	2014	MA DPU	DPU. 14-150	NSTAR Gas	Depreciation
198.	2014	CT PURA	14-05-06	Connecticut Light and Power	Depreciation
199.	2014	MO PSC	ER-2014-0370	Kansas City Power & Light	Depreciation

	Year	Jurisdiction	Docket No.	Client Utility	Subject
200.	2014	KY PSC	2014-00371	Kentucky Utilities Company	Depreciation
201.	2014	KY PSC	2014-00372	Louisville Gas and Electric Company	Depreciation
202.	2015	PA PUC	R-2015-2462723	United Water Pennsylvania Inc.	Depreciation
203.	2015	PA PUC	R-2015-2468056	NiSource - Columbia Gas of Pennsylvania	Depreciation
204.	2015	NY PSC	15-E-0283/15-G-0284	New York State Electric and Gas Corporation	Depreciation
205.	2015	NY PSC	15-E-0285/15-G-0286	Rochester Gas and Electric Corporation	Depreciation
206.	2015	MO PSC	WR-2015-0301/SR-2015-0302	Missouri American Water Company	Depreciation
207.	2015	OK CC	PUD 201500208	Oklahoma, Public Service Company of	Depreciation
208.	2015	WV PSC	15-0676-W-42T	West Virginia American Water Company	Depreciation
209.	2015	PA PUC	2015-2469275	PPL Electric Utilities	Depreciation
210.	2015	IN URC	Cause No. 44688	Northern Indiana Public Service Company	Depreciation
211.	2015	OH PSC	14-1929-EL-RDR	First Energy-Ohio Edison/Cleveland Electric/ Toledo Edison	Depreciation
212.	2015	NM PRC	15-00127-UT	El Paso Electric	Depreciation
213.	2015	TX PUC	PUC-44941; SOAH 473-15-5257	El Paso Electric	Depreciation
214.	2015	WI PSC	3270-DU-104	Madison Gas and Electric Company	Depreciation
215.	2015	OK CC	PUD 201500273	Oklahoma Gas and Electric	Depreciation
216.	2015	KY PSC	Doc. No. 2015-00418	Kentucky American Water Company	Depreciation
217.	2015	NC UC	Doc. No. G-5, Sub 565	Public Service Company of North Carolina	Depreciation
218.	2016	WA UTC	Docket UE-17	Puget Sound Energy	Depreciation
219.	2016	NY PSC	Case No. 16-W-0130	SUEZ Water New York, Inc.	Depreciation
220.	2016	MO PSC	ER-2016-0156	KCPL – Greater Missouri	Depreciation
221.	2016	WI PSC		Wisconsin Public Service Commission	Depreciation
222.	2016	KY PSC	Case No. 2016-00026	Kentucky Utilities Company	Depreciation
223.	2016	KY PSC	Case No. 2016-00027	Louisville Gas and Electric Company	Depreciation
224.	2016	OH PUC	Case No. 16-0907-WW-AIR	Aqua Ohio	Depreciation
225.	2016	MD PSC	Case 9417	NiSource - Columbia Gas of Maryland	Depreciation
226.	2016	KY PSC	2016-00162	Columbia Gas of Kentucky	Depreciation
227.	2016	DE PSC	16-0649	Delmarva Power and Light Company – Electric	Depreciation
228.	2016	DE PSC	16-0650	Delmarva Power and Light Company – Gas	Depreciation
229.	2016	NY PSC	Case 16-G-0257	National Fuel Gas Distribution Corp – NY Div	Depreciation
230.	2016	PA PUC	R-2016-2537349	Metropolitan Edison Company	Depreciation
231.	2016	PA PUC	R-2016-2537352	Pennsylvania Electric Company	Depreciation
232.	2016	PA PUC	R-2016-2537355	Pennsylvania Power Company	Depreciation

	Year	Jurisdiction	Docket No.	Client Utility	Subject
233.	2016	PA PUC	R-2016-2537359	West Penn Power Company	Depreciation
234.	2016	PA PUC	R-2016-2529660	NiSource - Columbia Gas of PA	Depreciation
235.	2016	KY PSC	Case No. 2016-00063	Kentucky Utilities / Louisville Gas & Electric Co	Depreciation
236.	2016	MO PSC	ER-2016-0285	KCPL Missouri	Depreciation
237.	2016	AR PSC	16-052-U	Oklahoma Gas & Electric Co	Depreciation
238.	2016	PSCW	6680-DU-104	Wisconsin Power and Light	Depreciation
239.	2016	ID PUC	IPC-E-16-23	Idaho Power Company	Depreciation
240.	2016	OR PUC	UM1801	Idaho Power Company	Depreciation
241.	2016	ILL CC	16-	MidAmerican Energy Company	Depreciation
242.	2016	KY PSC	Case No. 2016-00370	Kentucky Utilities Company	Depreciation
243.	2016	KY PSC	Case No. 2016-00371	Louisville Gas and Electric Company	Depreciation
244.	2016	IN URC		Indianapolis Power & Light	Depreciation
245.	2016	AL RC	U-16-081	Chugach Electric Association	Depreciation
246.	2017	MA DPU	D.P.U. 17-05	NSTAR Electric Company and Western Massachusetts Electric Company	Depreciation
247.	2017	TX PUC	PUC-26831, SOAH 973-17-2686	El Paso Electric Company	Depreciation
248.	2017	WA UTC	UE-17033 and UG-170034	Puget Sound Energy	Depreciation
249.	2017	OH PUC	Case No. 17-0032-EL-AIR	Duke Energy Ohio	Depreciation
250.	2017	VA SCC	Case No. PUE-2016-00413	Virginia Natural Gas, Inc.	Depreciation
251.	2017	OK CC	Case No. PUD201700151	Public Service Company of Oklahoma	Depreciation
252.	2017	MD PSC	Case No. 9447	Columbia Gas of Maryland	Depreciation
253.	2017	NC UC	Docket No. E-2, Sub 1142	Duke Energy Progress	Depreciation
254.	2017	VA SCC	Case No. PUR-2017-00090	Dominion Virginia Electric and Power Company	Depreciation
255.	2017	FERC	ER17-1162	MidAmerican Energy Company	Depreciation
256.	2017	PA PUC	R-2017-2595853	Pennsylvania American Water Company	Depreciation
257.	2017	OR PUC	UM1809	Portland General Electric	Depreciation
258.	2017	FERC	ER17-217	Jersey Central Power & Light	Depreciation
259.	2017	FERC	ER17-211	Mid-Atlantic Interstate Transmission, LLC	Depreciation
260.	2017	MN PUC	Docket No. G007/D-17-442	Minnesota Energy Resources Corporation	Depreciation
261.	2017	IL CC	Docket No. 17-0124	Northern Illinois Gas Company	Depreciation
262.	2017	OR PUC	UM1808	Northwest Natural Gas Company	Depreciation
263.	2017	NY PSC	Case No. 17-W-0528	SUEZ Water Owego-Nichols	Depreciation
264.	2017	MO PSC	GR-2017-0215	Laclede Gas Company	Depreciation
265.	2017	MO PSC	GR-2017-0216	Missouri Gas Energy	Depreciation

	Year	Jurisdiction	Docket No.	Client Utility	Subject
266.	2017	ILL CC	Docket No. 17-0337	Illinois-American Water Company	Depreciation
267.	2017	FERC	Docket No. ER17- _	PPL Electric Utilities Corporation	Depreciation
268.	2017	IN URC	Cause No. 44988	Northern Indiana Public Service Company	Depreciation
269.	2017	NJ BPU	BPU Docket No. WR17090985	New Jersey American Water Company, Inc.	Depreciation
270.	2017	RI PUC	Docket No. 4800	SUEZ Water Rhode Island	Depreciation
271.	2017	OK CC	Cause No. PUD 201700496	Oklahoma Gas and Electric Company	Depreciation
272.	2017	NJ BPU	ER18010029 & GR18010030	Public Service Electric and Gas Company	Depreciation
273.	2017	NC Util Com.	Docket No. E-7, SUB 1146	Duke Energy Carolinas, LLC	Depreciation
274.	2017	KY PSC	Case No. 2017-00321	Duke Energy Kentucky, Inc.	Depreciation
275.	2017	MA DPU	D.P.U. 18-40	Berkshire Gas Company	Depreciation
276.	2018	IN IURC	Cause No. 44992	Indiana-American Water Company, Inc.	Depreciation
277.	2018	IN IURC	Cause No. 45029	Indianapolis Power and Light	Depreciation
278.	2018	NC Util Com.	Docket No. W-218, Sub 497	Aqua North Carolina, Inc.	Depreciation
279.	2018	PA PUC	Docket No. R-2018-2647577	NiSource - Columbia Gas of Pennsylvania, Inc.	Depreciation
280.	2018	OR PUC	Docket UM 1933	Avista Corporation	Depreciation
281.	2018	WA UTC	Docket No. UE-108167	Avista Corporation	Depreciation
282.	2018	ID PUC	AVU-E-18-03, AVU-G-18-02	Avista Corporation	Depreciation
283.	2018	IN URC	Cause No. 45039	Citizens Energy Group	Depreciation
284.	2018	FERC	Docket No. ER18-	Duke Energy Progress	Depreciation
285.	2018	PA PUC	Docket No. R-2018-3000124	Duquesne Light Company	Depreciation
286.	2018	MD PSC	Case No. 948	NiSource - Columbia Gas of Maryland	Depreciation
287.	2018	MA DPU	D.P.U. 18-45	NiSource - Columbia Gas of Massachusetts	Depreciation
288.	2018	OH PUC	Case No. 18-0299-GA-ALT	Vectren Energy Delivery of Ohio	Depreciation
289.	2018	PA PUC	Docket No. R-2018-3000834	SUEZ Water Pennsylvania Inc.	Depreciation
290.	2018	MD PSC	Case No. 9847	Maryland-American Water Company	Depreciation
291.	2018	PA PUC	Docket No. R-2018-3000019	The York Water Company	Depreciation
292.	2018	FERC	Docket Nos. ER-18-2231-000	Duke Energy Carolinas, LLC	Depreciation
293.	2018	KY PSC	Case No. 2018-00261	Duke Energy Kentucky, Inc.	Depreciation
294.	2018	NJ BPU	BPU Docket No. WR18050593	SUEZ Water New Jersey	Depreciation
295.	2018	WA UTC	Docket No. UE-180778	PacifiCorp	Depreciation
296.	2018	UT PSC	Docket No. 18-035-36	PacifiCorp	Depreciation
297.	2018	OR PUC	Docket No. UM-1968	PacifiCorp	Depreciation
298.	2018	ID PUC	Case No. PAC-E-18-08	PacifiCorp	Depreciation
299.	2018	WY PSC	20000-539-EA-18	PacifiCorp	Depreciation
300.	2018	PA PUC	Docket No. R-2018-3003068	Aqua Pennsylvania, Inc.	Depreciation

	Year	Jurisdiction	Docket No.	Client Utility	Subject
301.	2018	IL CC	Docket No. 18-1467	Aqua Illinois, Inc.	Depreciation
302.	2018	KY PSC	Case No. 2018-00294	Louisville Gas & Electric Company	Depreciation
303.	2018	KY PSC	Case No. 2018-00295	Kentucky Utilities Company	Depreciation
304.	2018	IN URC	Cause No. 45159	Northern Indiana Public Service Company	Depreciation
305.	2018	VA SCC	Case No. PUR-2019-00175	Virginia American Water Company	Depreciation
306.	2019	PA PUC	Docket No. R-2018-3006818	Peoples Natural Gas Company, LLC	Depreciation
307.	2019	OK CC	Cause No. PUD201800140	Oklahoma Gas and Electric Company	Depreciation
308.	2019	MD PSC	Case No. 9490	FirstEnergy – Potomac Edison	Depreciation
309.	2019	SC PSC	Docket No. 2018-318-E	Duke Energy Progress	Depreciation
310.	2019	SC PSC	Docket No. 2018-319-E	Duke Energy Carolinas	Depreciation
311.	2019	DE PSC	DE 19-057	Public Service of New Hampshire	Depreciation
312.	2019	NY PSC	Case No. 19-W-0168 & 19-W-0269	SUEZ Water New York	Depreciation
313.	2019	PA PUC	Docket No. R-2019-3006904	Newtown Artesian Water Company	Depreciation
314.	2019	MO PSC	ER-2019-0335	Ameren Missouri	Depreciation
315.	2019	MO PSC	EC-2019-0200	KCP&L Greater Missouri Operations Company	Depreciation
316.	2019	MN DOC	G011/D-19-377	Minnesota Energy Resource Corp.	Depreciation
317.	2019	NY PSC	Case 19-E-0378 & 19-G-0379	New York State Electric and Gas Corporation	Depreciation
318.	2019	NY PSC	Case 19-E-0380 & 19-G-0381	Rochester Gas and Electric Corporation	Depreciation
319.	2019	WA UTC	Docket UE-19 / UG-19	Puget Sound Energy	Depreciation
320.	2019	PA PUC	Docket No. R-2019-	City of Lancaster	Depreciation
321.	2019	IURC	Cause No. 45253	Duke Energy Indiana	Depreciation
322.	2019	FERC	Case No. 2019-00271	Duke Energy Kentucky, Inc.	Depreciation
323.	2019	OH PUC	Case No. 18-1720-GA-AIR	Northeast Ohio Natural Gas Corp	Depreciation
324.	2019	NC Util. Com.	Docket No. E-2, Sub 1219	Duke Energy Carolinas	Depreciation

COMMISSIONER CLODFELTER: Mr. Robinson, any other motions?

MR. ROBINSON: Not at this time, Commissioner Clodfelter.

(WHEREUPON, DEP Application; DEP NCUC Form E-1; DEP Agreement and Stipulation of Partial Settlement with the Public Staff; DEP Settlement Agreement with Harris Teeter, LLC; DEP Agreement and Stipulation of Settlement with CIGFUR; DEP Settlement Agreement with the Commercial Group; DEP Agreement and Stipulation of Settlement with Vote Solar; DEP Agreement and Stipulation of Settlement with NCSEA, NCJC, NCHC, NRDC, and SACE; DEP Second Agreement and Stipulation of Partial Settlement with the Public Staff; DEP Supplemental E-1 Item 23 (Confidential Information filed under seal); and DEP Supplemental E-1 Item 14 are received into evidence.)

(WHEREUPON, D'Ascendis Attachment A; Exhibits DWD-1 through DWD-7; Rebuttal Exhibits DWD-1 through DWD-25; Supplemental Rebuttal Exhibits DWD-1 through DWD-8; Settlement Exhibit DWD-1, and Young Rebuttal Exhibits 1 - 8 are received into evidence.)

(WHEREUPON, the prefiled direct, amended rebuttal and Appendix A, supplemental rebuttal and settlement supporting testimony of Dylan D'Ascendis; direct, rebuttal and settlement supporting testimony of Karl Newlin; rebuttal testimony of Steven Young, and direct testimony of John Panizza is copied into the record as if given orally from the stand.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1219

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

I. INTRODUCTION AND PURPOSE

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

A. My name is Dylan W. D'Ascendis. I am a Director at ScottMadden, Inc. My business address is 3000 Atrium Way, Suite 241, Mount Laurel, New Jersey 08054.

Q. ON WHOSE BEHALF ARE YOU SUBMITTING THIS TESTIMONY?

A. I am submitting this direct testimony ("Direct Testimony") before the North Carolina Utilities Commission ("Commission") on behalf of Duke Energy Corporation, doing business in North Carolina as Duke Energy Progress, LLC ("DE Progress" or the "Company").

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A. I am a graduate of the University of Pennsylvania, where I received a Bachelor of Arts degree in Economic History. I also hold a Masters of Business Administration from Rutgers University with a concentration in Finance and International Business, which was conferred with high honors. I am a Certified Rate of Return Analyst ("CRRA") and a Certified Valuation Analyst ("CVA").

Q. PLEASE DESCRIBE YOUR EXPERIENCE IN THE ENERGY AND UTILITY INDUSTRIES.

A. I offer expert testimony on behalf of investor-owned utilities on rate of return issues and class cost of service issues. I also assist in the preparation of rate filings, including but not limited to revenue requirements and original cost and lead/lag studies. A summary of my professional and educational background, including a list of my testimony in prior proceedings, is included as Attachment A to my Direct Testimony.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my Direct Testimony is to present evidence and provide the Commission with a recommendation regarding the Company's return on equity ("ROE").[1] My analysis and conclusions are supported by the data presented in Exhibit DWD-1 through Exhibit DWD-7, which have been prepared by me or under my direction.

II. SUMMARY OF KEY CONCLUSIONS

Q. WHAT ARE YOUR CONCLUSIONS REGARDING THE APPROPRIATE COST OF EQUITY FOR THE COMPANY?

A. Based on the quantitative and qualitative analyses discussed throughout my Direct Testimony, I conclude that an ROE in the range of 10.00 percent to 11.00 percent represents the range of equity investors' required return for investment in electric utilities like DE Progress in today's capital markets. Within that range, I believe an ROE of 10.50 percent is reasonable and appropriate. As described in greater detail later in my testimony, that recommendation is based on the use of several widely accepted methods, and reflects the results of several analyses I have undertaken to estimate the effect of DE Progress' business risks on its Cost of Equity.

[1] Throughout my testimony, I interchangeably use the terms "ROE" and "Cost of Equity."

Q. PLEASE PROVIDE A BRIEF OVERVIEW OF THE ANALYSES THAT LED TO YOUR ROE DETERMINATION.

A. Because all financial models are subject to various assumptions and constraints, equity analysts and investors tend to use multiple methods to develop their return requirements. I therefore relied on three widely accepted approaches to develop my ROE determination: (1) the Constant Growth Discounted Cash Flow ("DCF") model; (2) the traditional and empirical forms of the Capital Asset Pricing Model ("CAPM"); and (3) the Bond Yield Plus Risk Premium approach. Those analyses indicate the Company's Cost of Equity currently to be in the range of 10.00 percent to 11.00 percent. That range is corroborated by the Expected Earnings approach which, as I discuss later in my Direct Testimony, is supported by recent FERC Orders.

In addition to the methods noted above, I considered: (1) the risks associated with certain aspects of the Company's generation portfolio and (2) the Company's significant capital expenditure plan. I also calculated the costs of issuing common stock (that is, "flotation" costs), and considered evolving capital market and business conditions, including changes in Federal Reserve monetary policy. Although those factors are very relevant to investors, their effect on the Company's Cost of Equity cannot be directly quantified. Therefore, although I did not make explicit adjustments to my ROE estimates, I considered those factors in determining where the Company's Cost of Equity falls within the range of analytical results. In light of those analyses, I believe that my recommended range is reasonable and appropriate.

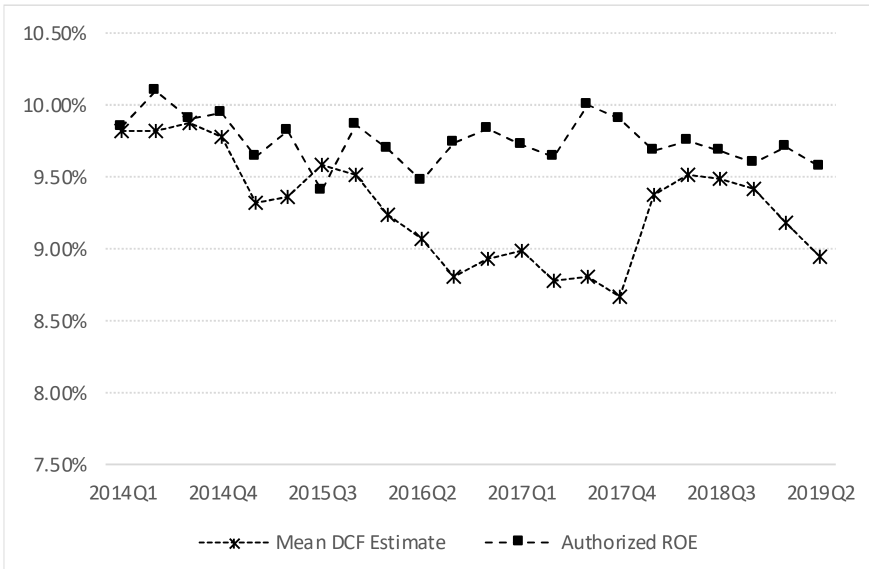
My analyses recognize that estimating the Cost of Equity is an empirical, but not entirely mathematical exercise; it relies on both quantitative and qualitative data and analyses, all of which are used to inform the judgment that inevitably must be applied. No single model is more reliable than all others under all market conditions, and all require the use of reasoned judgment in their application, and in interpreting their results. Therefore, the results of each ROE model must be assessed in the context of current and expected capital market conditions, and relative to other appropriate benchmarks.

In developing my recommendation, I recognized that the low end of the range of results (set by the low end of the range of Constant Growth DCF model results) is not likely to be a reasonable estimate of the Company's Cost of Equity. In large measure, that is the case because those results are far removed from the returns recently authorized in other jurisdictions and fail to adequately reflect evolving capital market conditions. Because Risk Premium-based methods directly reflect measures of capital market risk, they are more likely than other approaches (such as the Constant Growth DCF method) to provide reliable estimates of the Cost of Equity during periods of market instability.

Q. WHAT IS THE BASIS OF YOUR VIEW THAT THE CONSTANT GROWTH DCF METHOD RECENTLY HAS FAILED TO PROVIDE RELIABLE ROE ESTIMATES?

A. Since 2014, the model has produced results (*i.e.*, mean results) consistently and meaningfully below authorized returns (*see* Chart 1, below). That data suggests state regulatory commissions have recognized the model's results are not necessarily reliable estimates of the Cost of Equity, and that other methods should be given meaningful weight in determining the ROE.

Chart 1: Mean DCF Results vs. Authorized ROE Over Time[2]



For example, in Baltimore Gas and Electric Company's 2016 rate case, the Maryland Public Service Commission discussed the importance of considering multiple analytical methods, given the complexity of determining the investor-required ROE:

> The ROE witnesses used various analyses to estimate the appropriate return on equity […] including the DCF model, the IRR/DCF, the traditional CAPM, the ECAPM, and risk premium methodologies. Although the witnesses argued strongly over the correctness of their

[2] DCF results based on quarterly average stock prices, Earnings Per Share growth rates from Value Line, Zacks, and First Call; assumes my proxy group. Authorized ROEs are quarterly averages for vertically integrated electric utilities; source: S&P Global Market Intelligence. Please note that 2016 Q2 and 2017 Q3 included only one ROE decision.

> competing analyses, we are not willing to rule that there can be only one correct method for calculating an ROE. Neither will we eliminate any particular methodology as unworthy of basing a decision. The subject is far too complex to reduce to a single mathematical formula. That conclusion is made apparent, in practice, by the fact that the expert witnesses used discretion to eliminate outlier returns that they testified were too high or too low to be considered reasonable, even when using their own preferred methodologies.[3]

The FERC also has addressed its longstanding focus on the DCF method. In its November 15, 2018 *Order Directing Briefs*, FERC found that "in light of current investor behavior and capital market conditions, relying on the DCF methodology alone will not produce a just and reasonable ROE."[4] In its October 16, 2018 *Order Directing Briefs*, FERC found that although it "previously relied solely on the DCF model to produce the evidentiary zone of reasonableness…", it is "…concerned that relying on that methodology alone will not produce just and reasonable results."[5] As FERC explained, it is important to understand "how investors analyze and compare their investment opportunities."[6] FERC also explained that, although certain investors may give some weight to the DCF approach, other investors "place greater weight on one or more of the other methods…"[7] Those methods include the CAPM and the

[3] *In the matter of the application of Baltimore Gas and Electric Company for adjustments to its electric and gas base rates, Public Service Commission of Maryland*, Case No. 9406, Order No. 87591, at 153. Citations omitted.

[4] Docket Nos. EL14-12-003 and EL15-45-000, *Order Directing Briefs*, 165 FERC ¶ 61,118 (November 15, 2018) at para. 34.

[5] Docket No. EL11-66-001, *et al.*, *Order Directing Briefs* 165 FERC ¶ 61,030 (October 16, 2018) at para. 30.

[6] *Ibid*., at para. 33.

[7] *Ibid*., at para. 35; *see*, also, Docket No. PL19-4-000, *Inquiry Regarding the Commission's Policy for Determining Return on Equity*, March 21, 2019.

Risk Premium method, which I have applied in this proceeding.

Since the FERC issued its *Orders Directing Briefs*, the South Carolina Public Service Commission came to a similar finding, explaining that "it is appropriate and reasonable to consider a range of estimates under various methodologies in order to more accurately estimate [South Carolina Electric & Gas's] cost of equity", and relying on a single analytical method is "inconsistent with decisions reached by regulatory commissions over the past several years and departs from the normal practice of estimating the Cost of Equity for utilities."[8]

Q. HAS THE COMMISSION PREVIOUSLY DECLINED TO RELY ON THE DCF MODEL RESULTS?

A. Yes. In the Commission's February 2018 *Order Accepting Stipulation* for the Company, the Commission noted it "carefully evaluated the DCF analysis recommendations" of the ROE witnesses (which ranged from 8.25 percent to 9.00 percent) and determined that "all of these DCF analyses in the current market produce unrealistic low results."[9]

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[8] Public Service Commission of South Carolina, Docket Nos. 2017-207-E, 2017-305-E, and 2017-370-E, Order No. 2018-804, Order Addressing South Carolina Electric & Gas Nuclear Dockets, at 89-90. [clarification added]

[9] North Carolina Utilities Commission, Docket No. E-2, Sub 1142, *In the Matter of Application of Duke Energy Progress, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina*, Order Accepting Stipulation, Deciding Contested Issues, and Granting Partial Rate Increase, February 23, 2018, at 84-85.

Q. ARE THERE ASPECTS OF THE CONSTANT GROWTH DCF MODEL THAT MAY EXPLAIN WHY REGULATORY COMMISSIONS CURRENTLY DO NOT RELY PRINCIPALLY ON IT WHEN DETERMINING THE COST OF EQUITY?

A. Yes. Quite simply, the model's underlying structure and assumptions are not compatible with the recent capital market and economic environment. That can most easily be seen by recognizing that the model's fundamental structure requires the assumption of constancy in perpetuity. It assumes there will be no change in growth rates, dividend payout ratios, Price/Earnings ratios, Market/Book ratios, or in the economic and market conditions that support those variables. Equally important, the model assumes the Cost of Equity estimated today will remain unchanged, also in perpetuity. That is, the model requires that the Cost of Equity estimate produced today will be the same forward-looking return equity investors will require every day in the future, in perpetuity.

At issue is whether we reasonably can assume the market conditions created by federal policies will stay in place over the long run. For example, we know that the Federal Reserve is continuing to "assess" market information as it evaluates future monetary policy decisions.[10] Regardless of its eventual disposition, neither the Federal Reserve's unconventional monetary policy initiatives, nor the capital market conditions they supported, will remain in

[10] Minutes of the Federal Open Market Committee, July 30-31, 2019, at 13.

place in perpetuity, as the Constant Growth DCF model requires. On that basis alone, we should be cautious about the weight given the DCF method.

The model also assumes investors use its fundamental structure to find the "intrinsic" value of stock, that is, the price they are willing to pay.[11] In practice, investors also consider relative valuation multiples – Price/Earnings, Market/Book, Enterprise Value/EBITDA[12] – in their buying and selling decisions. They do so because no single financial model produces the most accurate measure of fundamental value, or the most reliable estimate of the Cost of Equity, at all times.

Q. IS IT YOUR VIEW THAT THE DCF MODEL SHOULD BE GIVEN NO WEIGHT IN DETERMINING THE COMPANY'S COST OF EQUITY?

A. No, it is not. It is my view, however, that we should carefully consider the range of results the model produces in arriving at ROE recommendations. As discussed later in my Direct Testimony, doing so fully supports my ROE range and recommendation.

Q. PLEASE SUMMARIZE THE RESULTS OF THE ANALYSES, AND HOW THEY CONTRIBUTED TO YOUR ROE RECOMMENDATION.

A. The range of results produced by the three primary approaches noted above are summarized in Tables 1a and 1b, below.

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11 *See*, Equations [4] and [5], in Appendix A below; *see also* finance.zacks.com/difference-between-market-value-intrinsic-value-2991.html

12 Earnings Before Interest, Taxes, Depreciation, and Amortization.

Table 1a: Summary of Discounted Cash Flow Model Results[13]

	Mean	Mean High
30-Day Average	8.78%	9.67%
90-Day Average	8.84%	9.73%
180-Day Average	8.97%	9.85%

Table 1b: Summary of Risk Premium Results[14]

CAPM	**Bloomberg Derived Market Risk Premium**	**Value Line Derived Market Risk Premium**
Average Bloomberg Beta Coefficient		
Current 30-Year Treasury (2.43%)	8.44%	8.52%
Near Term Projected 30-Year Treasury (2.65%)	8.66%	8.74%
Average Value Line Beta Coefficient		
Current 30-Year Treasury (2.43%)	9.32%	9.41%
Near Term Projected 30-Year Treasury (2.65%)	9.54%	9.62%
Empirical CAPM	**Bloomberg Derived Market Risk Premium**	**Value Line Derived Market Risk Premium**
Average Bloomberg Beta Coefficient		
Current 30-Year Treasury (2.43%)	9.95%	10.04%
Near Term Projected 30-Year Treasury (2.65%)	10.17%	10.26%
Average Value Line Beta Coefficient		
Current 30-Year Treasury (2.43%)	10.61%	10.71%
Near Term Projected 30-Year Treasury (2.65%)	10.83%	10.93%
Bond Yield Plus Risk Premium Approach		
Current 30-Year Treasury (2.43%)	9.91%	
Near Term Projected 30-Year Treasury (2.65%)	9.90%	
Long-Term Projected 30-Year Treasury (3.70%)	10.06%	

13 *See also* Exhibit DWD-1, which includes the Mean Low estimates.

14 Exhibit DWD-4 and Exhibit DWD-5.

Based on those estimates, it is my view that a reasonable range of estimates is from 10.00 percent to 11.00 percent, and within that range, an ROE of 10.50 percent is reasonable and appropriate. That range is supported by the Expected Earnings approach, which results in an average ROE estimate of 10.47 percent and a median ROE estimate of 10.54 percent.

Q. HOW IS THE REMAINDER OF YOUR DIRECT TESTIMONY ORGANIZED?

A. The remainder of my Direct Testimony is organized as follows:

- Section III – Provides an overview of the Cost of Equity analyses;
- Section IV – Provides a discussion of specific business risk and other considerations that have a direct bearing on DE Progress' Cost of Equity;
- Section V – Discusses the economic conditions in North Carolina;
- Section VI – Highlights the current capital market conditions and their effect on DE Progress' Cost of Equity;
- Section VII – Summarizes my conclusions; and
- Section VIII – Appendix A provides the technical details of my analytical approaches.

III. COST OF EQUITY ESTIMATION

Regulatory Guidelines and Financial Considerations

Q. BEFORE ADDRESSING THE SPECIFIC ASPECTS OF THIS PROCEEDING, PLEASE PROVIDE AN OVERVIEW OF THE ISSUES SURROUNDING THE COST OF EQUITY IN REGULATORY PROCEEDINGS, GENERALLY.

A. In general terms, the Cost of Equity is the return that investors require to make an equity investment in a firm. That is, investors will provide funds to a firm only if the return that they *expect* is equal to, or greater than, the return that they *require* to accept the risk of providing funds to the firm. From the firm's perspective, that required return, whether it is provided to debt or equity investors, has a cost. Individually, we speak of the "Cost of Debt" and the "Cost of Equity" as measures of those costs; together, they are referred to as the "Cost of Capital."

The Cost of Capital (including the costs of both debt and equity) is based on the economic principle of "opportunity costs." Investing in any asset, whether debt or equity securities, implies a forgone opportunity to invest in alternative assets. For any investment to be sensible, its expected return must be at least equal to the return expected on alternative, comparable risk investment opportunities. Because investments with like risks should offer similar returns, the opportunity cost of an investment should equal the return available on an investment of comparable risk. In that important respect, the returns required by debt and equity investors represent a cost to the Company.

Although both debt and equity have required costs, they differ in certain fundamental ways. Most noticeably, the Cost of Debt is contractually defined and can be directly observed as the interest rate or yield on debt securities.[15] The Cost of Equity, on the other hand, is neither directly observable nor a contractual obligation. Rather, equity investors have a claim on cash flows only after debt holders are paid; the uncertainty (or risk) associated with those residual cash flows determines the Cost of Equity. Because equity investors bear the "residual risk," they take greater risks and require higher returns than debt holders. In that basic sense, equity and debt investors differ: they invest in different securities, face different risks, and require different returns.

Whereas the Cost of Debt can be directly observed, the Cost of Equity must be estimated or inferred based on market data and various financial models. As discussed throughout my Direct Testimony, each of those models is subject to specific assumptions, which may be more or less applicable under differing market conditions. In addition, because the Cost of Equity is premised on opportunity costs, the models typically are applied to a group of "comparable" or "proxy" companies. The choice of models (including their inputs), the selection of proxy companies, and the interpretation of the model results all require the application of reasoned judgment. That judgment should

[15] The observed interest rate may be adjusted to reflect issuance or debt directly observable costs.

consider data and information that is not necessarily included in the models themselves. In the end, the estimated Cost of Equity should reflect the return that investors require in light of the subject company's risks, and the returns available on comparable investments.

Practitioners and academics recognize that financial models are approximations of investor behavior, not precise quantifications of it. They appreciate that models are tools to be used in the ROE estimation process, and that strict adherence to any single approach, or to the specific results of any single approach, can lead to flawed or misleading conclusions. That position is consistent with the *Hope* and *Bluefield* principle that it is the analytical result, as opposed to the method employed, that is controlling in arriving at just and reasonable rates. A reasonable ROE estimate therefore appropriately considers alternative methods and the reasonableness of their individual and collective results in the context of observable, relevant market information.

As discussed earlier, FERC has found that no individual model is more reliable than all others under all market conditions, and that the application of judgment is important in developing ROE estimates. Commissions in other regulatory jurisdictions, such as Hawaii, Maryland, Massachusetts, and South

Carolina have made similar findings.[16] As those decisions suggest, it is both prudent and appropriate to use multiple methods to mitigate the effects of assumptions and inputs associated with any single approach. I therefore have considered the results of the Constant Growth DCF model, the traditional and empirical forms of the Capital Asset Pricing Model, and the Bond Yield Plus Risk Premium approach. I also have provided an Expected Earnings analysis, which I have applied as a corroborating method.

Q. PLEASE PROVIDE A BRIEF SUMMARY OF THE GUIDELINES ESTABLISHED BY THE UNITED STATES SUPREME COURT (THE "COURT") FOR THE PURPOSE OF DETERMINING THE RETURN ON EQUITY.

A. The Court established the guiding principles for establishing a fair return for capital in two cases: (1) *Bluefield Water Works and Improvement Co. v. Public Service Comm'n.* ("*Bluefield*");[17] and (2) *Federal Power Comm'n v. Hope Natural Gas Co.* ("*Hope*").[18] In *Bluefield*, the Court stated:

A public utility is entitled to such rates as will permit it to earn

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[16] *See, e.g.*, (1) Public Utilities Commission of the State of Hawaii, Docket No. 7700, Order No. 13704 in Docket No. 7700, *In the Matter of the Application of Hawaiian Electric Company, Inc. For Approval of Rate Increases and Revised Rate Schedules and Rules*, December 28, 1994 at 92; (2) The Public Service Commission of Maryland, Case No. 9418, *In the Matter of the Application of Potomac Electric Power Company for Adjustments to its Retail Rates for the Distribution of Electric Energy*, Order No. 87884, at 97; (3) The Commonwealth of Massachusetts Department of Public Utilities, *Investigation by the Department of Public Utilities*, Docket D.P.U. 15-155, September 30, 2016, at 376-378; and (4) Public Service Commission of South Carolina, Docket Nos. 2017-207-E, 2017-305-E, and 2017-370-E, Order No. 2018-804, Order Addressing South Carolina Electric & Gas Nuclear Dockets, at 88-89.

[17] *See Bluefield Water Works and Improvement Co. v. Public Service Comm'n*. 262 U.S. 679, 692 (1923).

[18] *See Federal Power Comm'n v. Hope Natural Gas Co*., 320 U.S. 591, 603 (1944).

> a return upon the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit, and enable it to raise the money necessary for the proper discharge of its public duties.[19]

The Court therefore recognized that: (1) a regulated public utility cannot remain financially sound unless the return it is allowed to earn on its invested capital is at least equal to the Cost of Capital (the principle relating to the demand for capital); and (2) a regulated public utility will not be able to attract capital if it does not offer investors an opportunity to earn a return on their investment equal to the return they expect to earn on other investments of similar risk (the principle relating to the supply of capital).

In *Hope*, the Court reiterated the financial integrity and capital attraction principles of the *Bluefield* case:

> From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock... By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to

[19] *Bluefield Water Works and Improvement Co. v. Public Service Comm'n*. 262 U.S. 679, 692 (1923).

maintain its credit and to attract capital.[20]

In summary, the Court clearly has 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.

Q. HAS THE COMMISSION ALSO LOOKED TO THE HOPE AND BLUEFIELD STANDARDS AS GUIDANCE FOR SETTING RATES?

A. Yes, it has. For example, in Docket No. E-7, Sub 1026, the Commission noted:

> First, there are, as the Commission noted in the DEP Rate Order, constitutional constraints upon the Commission's return on equity decision, established by the United States Supreme Court decisions in Bluefield Waterworks & Improvement Co., v. Pub. Serv. Comm'n of W. Va., 262 U.S. 679 (1923) (Bluefield), and Fed. Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591 (1944) (Hope):
>
> To fix rates that do not allow a utility to recover its costs, including the cost of equity capital, would be an unconstitutional taking. In assessing the impact of changing economic conditions on customers in setting an ROE, the Commission must still provide the public utility with the opportunity, by sound management, to (1) produce a fair profit for its shareholders, in view of current economic conditions, (2) maintain its facilities and service, and (3) compete in the marketplace for capital. State ex rel. Utilities Commission v. General Telephone Co. of the Southeast, 281 N.C. 318, 370, 189 S. E.2d 705, 757 (1972). As the Supreme Court held in that case, these factors constitute "the test of a fair rate of return declared" in Bluefield and Hope. *Id.*[21]

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20 *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944).

21 North Carolina Utilities Commission, Docket No. E-7, Sub 1026, Order Granting General Rate Increase, September 24, 2013, at 23; *see also* North Carolina Utilities Commission,

Based on those standards, the authorized ROE should provide the Company with the opportunity to earn a fair and reasonable return, and should enable efficient access to external capital under a variety of market conditions.

Q. WHY IS IT IMPORTANT FOR A UTILITY TO BE ALLOWED THE OPPORTUNITY TO EARN A RETURN ADEQUATE TO ATTRACT CAPITAL AT REASONABLE TERMS?

A. A return that is adequate to attract capital at reasonable terms enables the utility to provide service while maintaining its financial integrity. As discussed above, and in keeping with the *Hope* and *Bluefield* standards, that return should be commensurate with the returns expected elsewhere in the market for investments of equivalent risk. The consequence of the Commission's order in this case, therefore, should be to provide DE Progress with the opportunity to earn an ROE that is: (1) adequate to attract capital at reasonable terms; (2) sufficient to ensure its financial integrity; and (3) commensurate with returns on investments in enterprises having corresponding risks. To the extent DE Progress is provided a reasonable opportunity to earn its market-based Cost of Equity, neither customers nor shareholders should be disadvantaged. In fact, a return that is adequate to attract capital at reasonable terms enables DE Progress to provide safe, reliable electric utility service while maintaining its financial integrity, all to the benefit of both investors and ratepayers.

Docket No. E-22, Sub 479, Order on Remand, July 23, 2015, at 12-16 (discussing the *Hope* and *Bluefield* decisions) ("Dominion Remand Order").

Proxy Group Selection

Q. AS A PRELIMINARY MATTER, WHY IS IT NECESSARY TO SELECT A GROUP OF PROXY COMPANIES TO DETERMINE THE COST OF EQUITY FOR DE PROGRESS?

A. First, it is important to bear in mind that the Cost of Equity for a given enterprise depends on the risks attendant to the business in which the company is engaged. According to financial theory, the value of a given company is equal to the aggregate market value of its constituent business units. The value of the individual business units reflects the risks and opportunities inherent in the business sectors in which those units operate. In this proceeding, we are focused on estimating the Cost of Equity for the North Carolina operations of DE Progress, whose parent is Duke Energy Corporation ("Duke Energy"). Because the ROE is a market-based concept, and DE Progress is not a separate entity with its own stock price, it is necessary to establish a group of companies that are both publicly traded and comparable to the Company in certain fundamental respects to serve as its "proxy" in the ROE estimation process. Even if the Company were a publicly traded entity, short-term events could bias its market value during a given period of time. A significant benefit of using a proxy group is that it moderates the effects of anomalous, temporary events associated with any one company.

Q. DOES THE SELECTION OF A PROXY GROUP SUGGEST THAT ANALYTICAL RESULTS WILL BE TIGHTLY CLUSTERED AROUND AVERAGE (*I.E.*, MEAN) RESULTS?

A. Not necessarily. For example, the Constant Growth DCF approach defines the Cost of Equity as the sum of the expected dividend yield and projected long-term growth. Despite the care taken to ensure risk comparability, market expectations with respect to future risks and growth opportunities will vary from company to company. Therefore, even within a group of similarly situated companies, it is common for analytical results to reflect a seemingly wide range. Consequently, at issue is how to estimate the Cost of Equity from within that range. Such a determination necessarily must consider a wide range of both quantitative and qualitative information.

Q. PLEASE PROVIDE A SUMMARY PROFILE OF DE PROGRESS.

A. DE Progress, which is a wholly owned subsidiary of Duke Energy, provides electric generation, transmission and distribution services to approximately 1.60 million residential, commercial, and industrial customers in portions of North Carolina and South Carolina.[22] Duke Energy's long-term issuer credit ratings are A- (Outlook: Negative) from Standard & Poor's ("S&P") and Baa1 (Outlook: Stable) from Moody's Investors Service ("Moody's"). The Company's long-term and senior unsecured credit ratings are A- (S&P, Outlook:

[22] Duke Energy Corp., SEC Form 10-K for the fiscal year ended December 31, 2018, at 23.

Negative) and A2 (Moody's, Outlook: Stable).[23]

Q. HOW DID YOU SELECT THE COMPANIES INCLUDED IN YOUR PROXY GROUP?

A. I began with the universe of companies that Value Line classifies as Electric Utilities, and applied the following screening criteria:

- I excluded companies that do not consistently pay quarterly cash dividends;
- I excluded companies that were not covered by at least two utility industry equity analysts;
- I excluded companies that do not have investment grade senior unsecured bond and/or corporate credit ratings from S&P;
- I excluded companies that were not vertically-integrated, i.e. utilities that own and operate regulated generation, transmission and distribution assets;
- I excluded companies whose regulated operating income over the three most recently reported fiscal years composed less than 60.00 percent of the respective totals for that company;
- I excluded companies whose regulated electric operating income over the three most recently reported fiscal years represented less than 60.00 percent of total regulated operating income; and

[23] Source: S&P Global Market Intelligence.

- I eliminated companies that are currently known to be party to a merger or other significant transaction.

Q. DID YOU INCLUDE DUKE ENERGY IN YOUR ANALYSIS?

A. No. To avoid the circular logic that otherwise would occur, it is my practice to exclude the subject company, or its parent holding company, from the proxy group.

Q. WHAT COMPANIES MET THOSE SCREENING CRITERIA?

A. The criteria discussed above resulted in a proxy group of the following 19 companies:

Table 2: Proxy Group Screening Results

Company	Ticker
ALLETE, Inc.	ALE
Alliant Energy Corporation	LNT
Ameren Corporation	AEE
American Electric Power Company, Inc.	AEP
Avangrid, Inc.	AGR
CMS Energy Corporation	CMS
DTE Energy Company	DTE
Evergy, Inc.	EVRG
Hawaiian Electric Industries, Inc.	HE
NextEra Energy, Inc.	NEE
NorthWestern Corporation	NWE
OGE Energy Corp.	OGE
Otter Tail Corporation	OTTR
Pinnacle West Capital Corporation	PNW
PNM Resources, Inc.	PNM
Portland General Electric Company	POR
Southern Company	SO
WEC Energy Group, Inc.	WEC
Xcel Energy Inc.	XEL

Cost of Equity

Q. HOW HAVE YOU DETERMINED THE INVESTOR-REQUIRED ROE?

A. As noted earlier, because the Cost of Equity is not directly observable, it must be estimated based on both quantitative and qualitative information. Although several empirical models have been developed for that purpose, all are subject to limiting assumptions or other constraints. Consequently, many finance texts recommend using multiple approaches to estimate the Cost of Equity, as discussed in Appendix A.[24] When faced with the task of estimating the Cost of Equity, analysts and investors are inclined to gather and evaluate as much relevant data as reasonably can be analyzed and, therefore, rely on multiple analytical approaches. As noted earlier, the use of multiple methods, and the consideration given to them, recently was addressed by FERC.

Consistent with that approach, I have considered the results of the Constant Growth DCF model, the traditional and empirical forms of the Capital Asset Pricing Model, and the Bond Yield Plus Risk Premium approach. I also have provided an Expected Earnings analysis, which I have applied as a corroborating method. FERC has provided similar guidance, using the Expected Earnings analysis in its determination of the "zone of reasonableness", observing that "*investors use those models*".[25]

Q. PLEASE BRIEFLY DESCRIBE THE CONSTANT GROWTH DCF MODEL.

A. The Constant Growth DCF approach defines the Cost of Equity as the sum of (1) the expected dividend yield, and (2) expected long-term growth. As explained in Appendix A, the model often is expressed in the familiar form $k = \frac{D(1+g)}{P_0} + g$, where the expected dividend yield generally equals the expected annual dividend divided by the current stock price, and the growth rate is based

24 *See, e.g.*, Eugene Brigham, Louis Gapenski, Financial Management: Theory and Practice, 7th Ed., 1994, at 341, and Tom Copeland, Tim Koller and Jack Murrin, Valuation: Measuring and Managing the Value of Companies, 3rd ed., 2000, at 214.

25 Docket No. EL11-66-001, *et al.*, *Order Directing Briefs* 165 FERC ¶ 61,030 (October 16, 2018) at para. 44 (italics in original).

on analysts' expectations of earnings growth. The Constant Growth DCF formula, which falls from the longer "present value" structure,[26] requires several simplifying assumptions, including the constancy of inputs in perpetuity.

Under the model's strict assumptions, the growth rate equals the rate of capital appreciation (that is, the growth in the stock price).[27] Given that assumption, it does not matter whether the investor holds the stock in perpetuity, or whether they hold the stock for some period of time, collect the dividends, then sell at the prevailing market price. That result also requires that the ROE result reached today will remain unchanged in perpetuity. So, if market conditions are such that the model produces an unreasonably low (or high) ROE estimate today, it assumes that estimate will be the same ROE investors require every day in the future, regardless of whether or how market conditions change.

Q. PLEASE BRIEFLY DESCRIBE THE CAPITAL ASSET PRICING MODEL.

A. Whereas DCF models focus on expected cash flows,[28] Risk Premium-based models such as the CAPM focus on the additional return that investors require for taking on greater risk. In finance, "risk" generally refers to the variation in

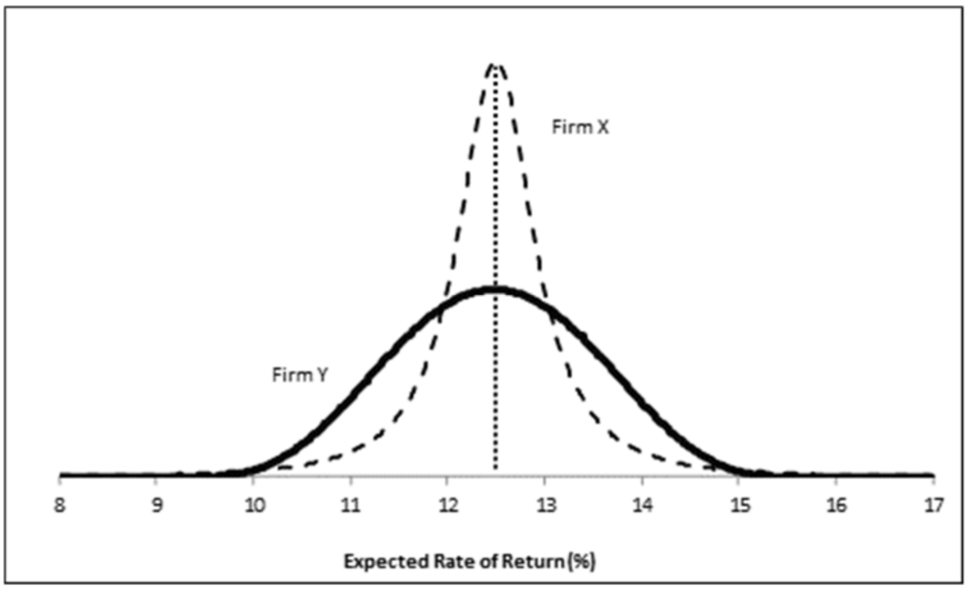
[26] *See* Appendix A, part A.

[27] As discussed in Appendix A, part A, the model assumes that earnings, dividends, book value, and the stock price all grow at the same constant rate in perpetuity. Additionally, academic research has indicated that analysts forecasts of growth are superior to other measures of growth (*see* Appendix A, part A).

[28] *See* Appendix A, part A.

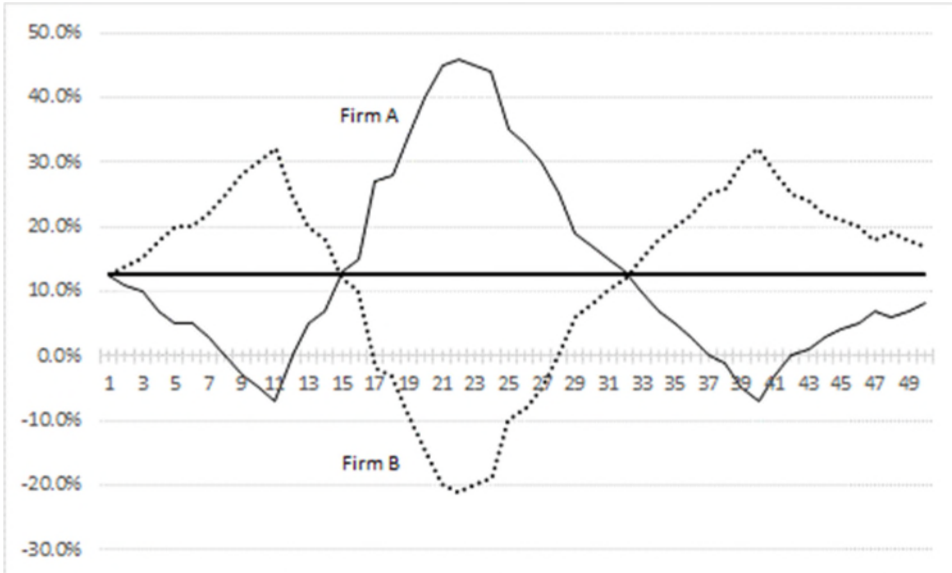
expected returns, rather than the expected return, itself. Consider two firms, X and Y, with expected returns, and the expected variation in returns noted in Chart 2, below. Although the two have the same expected return (12.50 percent), Firm Y's are far more variable. From that perspective, Firm Y would be considered the riskier investment.

Chart 2: Expected Return and Risk



Now consider two other firms, Firm A and Firm B. Both have expected returns of 12.50 percent, and both are equally risky as measured by their volatility. But as Firm A's returns go up, Firm B's returns go down. That is, the returns are negatively correlated.

Chart 3: Relative Risk



If we were to combine Firms A and B into a portfolio, we would expect a 12.50 percent return with no uncertainty because of the opposing symmetry of their risk profiles. That is, we can diversify the risk away. As long as two stocks are not perfectly correlated, we can achieve diversification benefits by combining them in a portfolio. That is the essence of the Capital Asset Pricing Model – because we can combine firms into a portfolio, the only risk that matters is the risk that remains after diversification, *i.e.*, the "non-diversifiable" risk.

The CAPM defines the Cost of Equity as the sum of the "risk-free" rate, and a premium to reflect the additional risk associated with equity investments. The "risk-free" rate is the yield on a security viewed as having no default risk, such as long-term Treasury bonds. The risk-free rate essentially sets the baseline of the CAPM. That is, an investor would expect a higher return than the risk-free rate to purchase an asset that carries risk. The difference between that higher return (*i.e.*, the required return) and the risk-free rate is the risk premium:

$$\text{Risk-Free Rate} + \text{Risk Premium} = \text{Cost of Equity} \quad [1]$$

The risk premium is defined as a security's Beta coefficient multiplied by the risk premium of the overall market (the "Market Risk Premium" or "MRP").[29] The Beta coefficient is a measure of the subject company's risk relative to the overall market, *i.e.*, the "non-diversifiable" risk. A Beta coefficient of 1.00 means the security is as risky as the overall market; a value below 1.00 represents a security with less risk than the overall market, and a value over 1.00 represents a security with more risk than the overall market. In general, the CAPM is expressed as follows:

$$\text{Risk-Free Rate} + (\text{Beta Coefficient} \times \text{MRP}) = \text{Cost of Equity} \quad [2]$$

As with the Constant Growth DCF model, it is important to understand the CAPM's inputs, assumptions, and results in the context of observable market data. Appendix A, part B explains that Beta coefficients reflect two aspects of stock price movements: (1) the variability of the subject company's returns relative to the market; and (2) the correlation of the subject company's returns to the market's returns. Both are important factors. When utility stock prices fall but the overall market increases, the correlation will fall. When that

[29] As discussed in Appendix A, part B, I have relied on a forward-looking measure of the MRP, using inputs from Value Line and Bloomberg to derive an *ex-ante* market return estimate.

happens (all else remaining equal), Beta coefficients also will fall. That is especially the case when they are calculated over relatively short periods, as Bloomberg does. The question then becomes whether those Beta coefficients are likely to reflect investors' views of utility risk going forward. Here again, a certain amount of judgment must be applied.

Because the correlation between the proxy group companies and the S&P 500 has declined since 2014, even as their relative risk increased,[30] the CAPM in the form presented here may not adequately reflect the expected systematic risk, and therefore, the returns required by investors in low-Beta companies. To address that concern, I considered the Empirical CAPM ("ECAPM") approach, which is a variant of the CAPM approach. The ECAPM adjusts for the CAPM's tendency to under-estimate returns for companies that (like utilities) have Beta coefficients less than one, and over-estimate returns for relatively high-Beta coefficient stocks.

Q. PLEASE BRIEFLY DESCRIBE THE BOND YIELD PLUS RISK PREMIUM APPROACH.

A. This approach is based on the basic financial principle that equity investors bear the risk associated with ownership and therefore require a premium over the return they would have earned as a bondholder. That is, because returns to equity holders are more risky than returns to bondholders, equity investors must be compensated for bearing that additional risk (that difference often is referred

[30] *See* Chart 16 in Appendix A, part B.

to as the "Equity Risk Premium"). Bond Yield Plus Risk Premium approaches estimate the Cost of Equity as the sum of the Equity Risk Premium and the yield on a particular class of bonds.[31]

$$\text{Bond Yield} + \text{Equity Risk Premium} = \text{Cost of Equity} \qquad [3]$$

Q. WHAT ARE THE RESULTS OF THE CONSTANT GROWTH DCF ANALYSIS?

A. The results of the Constant Growth DCF analysis described above are provided in Table 3, below.[32]

Table 3: Summary of DCF Results[33]

	Mean	Mean High
30-Day Average	8.78%	9.67%
90-Day Average	8.84%	9.73%
180-Day Average	8.97%	9.85%

Q. WHAT ARE THE RESULTS OF THE RISK PREMIUM-BASED ANALYSES?

A. The Risk Premium-based results, including the CAPM and Bond Yield Plus Risk Premium methods, are provided in Table 4 below.

31 Prior research has shown that the Equity Risk Premium is inversely related to the level of interest rates (*see* Appendix A, part C).

32 *See* Appendix A for a more detailed description of the models, assumptions, and inputs described in Section III.

33 Exhibit DWD-1.

Table 4: Summary of Risk Premium Results[34]

CAPM	Bloomberg Derived Market Risk Premium	Value Line Derived Market Risk Premium
Average Bloomberg Beta Coefficient		
Current 30-Year Treasury (2.43%)	8.44%	8.52%
Near Term Projected 30-Year Treasury (2.65%)	8.66%	8.74%
Average Value Line Beta Coefficient		
Current 30-Year Treasury (2.43%)	9.32%	9.41%
Near Term Projected 30-Year Treasury (2.65%)	9.54%	9.62%
Empirical CAPM	**Bloomberg Derived Market Risk Premium**	**Value Line Derived Market Risk Premium**
Average Bloomberg Beta Coefficient		
Current 30-Year Treasury (2.43%)	9.95%	10.04%
Near Term Projected 30-Year Treasury (2.65%)	10.17%	10.26%
Average Value Line Beta Coefficient		
Current 30-Year Treasury (2.43%)	10.61%	10.71%
Near Term Projected 30-Year Treasury (2.65%)	10.83%	10.93%
Bond Yield Plus Risk Premium Approach		
Current 30-Year Treasury (2.43%)	9.91%	
Near Term Projected 30-Year Treasury (2.65%)	9.90%	
Long-Term Projected 30-Year Treasury (3.70%)	10.06%	

Q. PLEASE BRIEFLY DESCRIBE THE EXPECTED EARNINGS ANALYSIS.

A. The Expected Earnings analysis is based on the principle of opportunity costs. By taking historical returns on book equity and comparing those authorized

34 Exhibit DWD-4 and Exhibit DWD-5.

ROEs, investors are able to directly compare returns from investments of similar risk. In addition to historical returns, Value Line also provides projected returns on book equity. Because the Cost of Equity is forward-looking, I relied solely on forward-looking projections in the Expected Earnings analysis.[35] The Expected Earnings analysis results in an average ROE estimate of 10.47 percent and median ROE estimate of 10.54 percent.[36] As noted earlier, I used those results to assess the reasonableness of the DCF, CAPM, and Bond-Yield Plus Risk Premium results.[37]

Flotation Costs

Q. WHAT ARE FLOTATION COSTS?

A. Flotation costs are the costs associated with the sale of new issues of common stock. These include out-of-pocket expenditures for preparation, filing, underwriting, and other costs of issuance.

Q. ARE FLOTATION COSTS PART OF THE UTILITY'S INVESTED COSTS OR PART OF THE UTILITY'S EXPENSES?

A. Flotation costs are part of capital costs, which are properly reflected on the balance sheet under "paid in capital" rather than current expenses on the income statement. Like investments in rate base or the issuance costs of long-term debt,

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35 As described more fully in Appendix A, part D, an adjustment is necessary to accurately reflect the average invested capital over the period in question.

36 Exhibit DWD-6.

37 *See also* Docket Nos. EL14-12-003 and EL15-45-000, *Order Directing Briefs,* 165 FERC ¶ 61,118 (November 15, 2018).

flotation costs are incurred over time. As a result, the great majority of flotation costs are incurred prior to the test year, but remain part of the cost structure during the test year and beyond.

Q. IS THE NEED TO CONSIDER FLOTATION COSTS ELIMINATED BECAUSE DE PROGRESS IS A WHOLLY OWNED SUBSIDIARY OF DUKE ENERGY?

A. No. Although the Company is a wholly owned subsidiary of Duke Energy, it is appropriate to consider flotation costs because wholly owned subsidiaries receive equity capital from their parents and provide returns on the capital that roll up to the parent, which is designated to attract and raise capital based on the returns of those subsidiaries. To deny recovery of issuance costs associated with the capital that is invested in the subsidiaries ultimately would penalize the investors that fund the utility operations and would inhibit the utility's ability to obtain new equity capital at a reasonable cost. This is important for companies such as DE Progress, that are planning continued capital expenditures in the near term, and for which access to capital to fund such required expenditures will be critical.

Q. HOW DID YOU ESTIMATE THE SIZE OF THE EFFECT OF FLOTATION COST ON INVESTOR RETURNS?

A. I modified the DCF calculation to provide a dividend yield that would reimburse investors for issuance costs. The estimate of flotation costs recognizes the costs of issuing equity that were incurred by Duke Energy and the proxy companies in their most recent two issuances. As shown in Exhibit DWD-7, an adjustment of 0.08 percent (*i.e.*, eight basis points) reasonably represents flotation costs for the Company.

Q. IS THE NEED TO CONSIDER FLOTATION COSTS RECOGNIZED BY THE ACADEMIC AND FINANCIAL COMMUNITIES?

A. Yes. The need to reimburse investors for equity issuance costs is recognized by the academic and financial communities in the same spirit that investors are reimbursed for the costs of issuing debt. For example, Dr. Morin notes that "[t]he costs of issuing [common stock] are just as real as operating and maintenance expenses or costs incurred to build utility plants, and fair regulatory treatment must permit the recovery of these costs."[38] Dr. Morin further notes that "equity capital raised in a given stock issue remains on the utility's common equity account and continues to provide benefits to ratepayers indefinitely."[39] This treatment is consistent with the philosophy of a fair rate of return. As explained by Dr. Shannon Pratt:

> Flotation costs occur when a company issues new stock. The business usually incurs several kinds of flotation or transaction costs, which reduce the actual proceeds received by the business. Some of these are direct out-of-pocket outlays, such as fees paid to underwriters, legal expenses, and prospectus preparation costs. Because of this reduction in proceeds, the business's required returns must be greater to compensate for the additional costs. Flotation costs can be accounted for either by amortizing the cost, thus reducing the net cash flow to discount, or by incorporating the cost into the cost of equity capital. Since

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[38] Roger A. Morin, New Regulatory Finance, Public Utility Reports, Inc., 2006, at 321.
[39] *Ibid.*, at 327.

> flotation costs typically are not applied to operating cash flow, they must be incorporated into the cost of equity capital.[40]

Similarly, Morningstar has commented on the need to reflect flotation costs in the cost of capital:

> Although the cost of capital estimation techniques set forth later in this book are applicable to rate setting, certain adjustments may be necessary. One such adjustment is for flotation costs (amounts that must be paid to underwriters by the issuer to attract and retain capital).[41]

Q. ARE YOU PROPOSING TO ADJUST YOUR RECOMMENDED ROE BY EIGHT BASIS POINTS TO REFLECT THE EFFECT OF FLOTATION COSTS ON THE COMPANY'S ROE?

A. No. Rather, I have considered the effect of flotation costs, in addition to the Company's other business risks (discussed below) in determining where the Company's ROE falls within the range of results.

IV. BUSINESS RISKS AND OTHER CONSIDERATIONS

Q. DO THE MEAN MODEL RESULTS FOR THE PROXY GROUP PROVIDE AN APPROPRIATE ESTIMATE FOR THE COST OF EQUITY FOR DE PROGRESS?

A. No. The mean results of these models do not necessarily provide an appropriate estimate of DE Progress' Cost of Equity. In my view, there are additional factors that must be taken into consideration when determining where DE

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40 Shannon P. Pratt, Roger J. Grabowski, Cost of Capital: Applications and Examples, 4th Ed. (John Wiley & Sons, Inc., 2010), at 586.

41 Morningstar, Inc. Ibbotson SBBI 2013 Valuation Yearbook, at 25.

Progress' Cost of Equity falls within the range of results. Those factors include: (1) the risks associated with certain aspects of the Company's generation portfolio and (2) the Company's significant capital expenditure plan. Those factors, which are discussed below, should be considered in terms of their overall effect on the Company's Cost of Equity.

A. Environmental Regulations

Q. HOW DO THE RISKS OF ENVIRONMENTAL REGULATIONS AFFECT DE PROGRESS' ACCESS TO AND COST OF CAPITAL?

A. Environmental regulations, in particular those relating to coal-fired generation (including coal-ash basin closure), nuclear generation, and regulations motivating distributed generation and net metering, have a direct bearing on the Company's operating and financial risk, and therefore, its Cost of Equity. In general, capital-intensive generation assets, such as coal-fired or nuclear generation facilities, are subject to certain risks including the recovery of investors' capital in the event of a change in market structure or a plant failure, and the recovery of replacement power and repair costs in the event of extended or unplanned outage. I discuss each of those issues in turn, below.

Coal-Fired Generation

Q. PLEASE PROVIDE AN OVERVIEW OF THE RISKS ASSOCIATED WITH DE PROGRESS' GENERATION PORTFOLIO AND CURRENT ENVIRONMENTAL REGULATIONS.

A. DE Progress' operations are dependent on coal-fired generation, which represented approximately 40.60 percent of its 2018 reported owned operating capacity.[42] In particular, DE Progress and its investors face the risk that environmental regulations will require them to invest additional capital or face closure or curtailment of generating capacity. These risks are compounded in the current regulatory environment as a result of the uncertainty investors, utilities, and the economy as a whole, face in light of the change in administration following the 2016 election, and, in particular, the uncertain fate of Obama-era environmental regulations targeting greenhouse gas emissions and climate change in general, such as the Clean Power Plan, which is currently being challenged in the courts.

Most recently, the U.S. Environmental Protection Agency ("EPA") unveiled a proposal to replace the Clean Power Plan with the Affordable Clean Energy ("ACE") rule. The ACE rule would allow utilities to make heat efficiency upgrades to coal-fired power plants without triggering further environmental controls and would exclude natural gas-fired power plants from

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[42] Duke Energy Corporation., SEC Form 10-K for the Period Ending December 31, 2018, at 33.

emissions limits.[43] Because investors consider those risks when establishing their return requirements, the Commission likewise should consider the effect of the additional risk associated with DE Progress' generating portfolio in determining its authorized ROE.

Q. PLEASE SUMMARIZE THE IMPLICATIONS OF COAL ASH BASIN CLOSURE AND COMPLIANCE ACTIVITIES IN DUKE ENERGY'S PROGRESS OPERATIONS FOR THE COMPANY'S COST OF EQUITY.

A. By way of background, on September 20, 2014, the North Carolina Coal Ash Management Act ("CAMA") became law. CAMA (as subsequently amended) was supplemented by the EPA's rule, published on April 17, 2015, which regulated the disposal of coal combustion residuals ("CCRs") from electric utilities as solid waste. The EPA's CCR rule established requirements regarding operational and reporting procedures to ensure the safe disposal and management of CCRs.[44] CAMA and the EPA CCR rule subjected most of Duke Energy's coal ash impoundments in North Carolina to scrutiny.

Pursuant to CAMA, Duke Energy was ordered to take immediate action, and to excavate and close four high-priority sites with multiple coal ash basins around the state (including two DE Progress sites) by August 2019. In addition, following publication of the EPA CCR rule in April 2015, DE Progress and the

43 S&P Global Market Intelligence, "EPA's Affordable Clean Energy rule: How it would work," August 21, 2018.

44 Duke Energy Corporation., SEC Form 10-K for the Period Ending December 31, 2018, at 80.

South Carolina Department of Health and Environmental Control ("SCDHEC") executed a consent agreement in July 2015, requiring the excavation of all CCRs at the Robinson Plant site. In a petition to the North Carolina Utilities Commission on December 30, 2016, Duke Energy indicated that it had recorded asset retirement obligations ("AROs") of $2.4 billion for DE Progress and $2.1 billion for Duke Energy Carolinas, in compliance with CAMA, the CCR rule and the consent agreements.[45]

In the Company's last rate case, the Commission approved recovery of $232.39 million of coal ash basin closure costs, and allowed the Company to defer costs recorded on and after September 1, 2017 until its next general rate case.[46] However, the North Carolina Attorney General filed an appeal challenging the Commission's Order allowing the Company to recover those costs.[47] The Public Staff and Sierra Club similarly filed appeals challenging the recovery of the coal ash basin closure costs. I also understand that on April 1, 2019, the North Carolina Department of Environmental Quality ("NCDEQ") ordered Duke Energy to excavate all remaining coal ash impoundments in North Carolina, and to submit final excavation closure plans to the NCDEQ by

45 *Ibid.*, Paragraph 11.

46 North Carolina Utilities Commission, Docket No. E-2, Sub 1142, *In the Matter of Application of Duke Energy Progress, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina*, Order Accepting Stipulation, Deciding Contested Issues, and Granting Partial Rate Increase, February 23, 2018, at 18-19.

47 *See* S&P Global Market Intelligence, "NC attorney general appeals orders allowing Duke to recover coal ash costs," April 29, 2019.

August 1, 2019.[48] The uncertainty surrounding the appeal of the last rate case order, the eventual cost of deferred coal ash compliance costs, and the timing and extent of recovery of those costs therefore remains a significant risk to investors.[49]

Q. ARE THERE ANY OTHER CONCERNS FOR INVESTORS WITH RESPECT TO COAL GENERATION?

A. Yes. On January 25, 2016, California Insurance Commissioner Dave Jones introduced a new requirement for the disclosure of carbon-based investments held by insurance companies, and called on California insurance companies to divest investments in coal and companies that use coal, including electrical utilities.[50] Although California's is the first insurance commission to call for such divestitures, it is the largest insurance commission in the United States, and sixth largest insurance commission in the world.[51] Given the large percentage of institutional ownership among the proxy companies,[52] the potential of divestiture represents a significant source of risk for investors.

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48 *See* North Carolina Department of Environmental Quality, Press Release, "DEQ Orders Duke Energy to Excavate Coal Ash at Six Remaining Sites," April 1, 2019.

49 *See* Duke Energy Corporation., Cautionary Statement Regarding Forward-Looking Information, SEC Form 10-K for the Period Ending December 31, 2018 at 5.

50 *See* California Department of Insurance, January 25, 2016 Press Release.

51 *Ibid*.

52 The average institutional ownership for the proxy group is 73.38 percent. Duke Energy Corporation's institutional ownership is 60.73 percent. Source: S&P Global Market Intelligence.

Nuclear Generation Portfolio

Q. PLEASE BRIEFLY DESCRIBE THE RISKS ASSOCIATED WITH THE OWNERSHIP OF NUCLEAR GENERATING RESOURCES.

A. Nuclear generating resources are regulated by the U.S. Nuclear Regulatory Commission ("NRC"). As such, DE Progress is subject to NRC mandates to meet licensing and safety related standards that may require increased capital spending and incremental operating costs. As Duke Energy noted:

> Revised security and safety requirements promulgated by the NRC, which could be prompted by, among other things, events within or outside the control of Duke Energy Carolinas, Duke Energy Progress and Duke Energy Florida, such as a serious nuclear incident at a facility owned by a third-party, could necessitate substantial capital and other expenditures, as well as assessments to cover third-party losses. In addition, if a serious nuclear incident were to occur, it could have a material adverse effect on the results of operations and financial condition and reputation of the Duke Energy Registrants.[53]

Q. DOES THE COMPANY'S GENERATION PORTFOLIO INCLUDE NUCLEAR GENERATING ASSETS?

A. Yes. DE Progress' generation portfolio includes 3,543 megawatts ("MW") of owned nuclear generating capacity. Specifically, the Company owns 1,870 MW at the Brunswick facility in North Carolina, 932 MW at the Harris facility in North Carolina, and 741 MW at the Robinson facility in South Carolina.[54]

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[53] Duke Energy Corporation., SEC Form 10-K for the Period Ending December 31, 2018, at 31.

[54] DE Progress owns 3,543 MW of nuclear capacity out of a total owned capacity of 12,747 MW, or 27.79 percent of the total. *See,* Duke Energy Corp., SEC Form 10-K for the fiscal year ended December 31, 2018, at 33.

Q. ARE THERE EXAMPLES OF THE INCREASED RISK OF NEW REGULATORY REQUIREMENTS THAT NUCLEAR GENERATION PLANT OPERATORS FACE?

A. Yes. One example is the increased oversight and regulatory requirements put in place following a March 11, 2011 earthquake and tsunami, which caused significant damage to the Fukushima Daiichi nuclear complex and threatened the public health. After the Fukushima accident, the NRC assembled a task force to assess current regulation and determine if new measures were required to ensure safety. The task force issued a report in July 2011 that included a set of recommendations for NRC consideration. Those recommendations continue to be modified and expanded by the NRC staff, and the first related regulatory requirements were issued in March 2012 with implementation guidance issued on August 30, 2012.[55] The evolving nature of these requirements from the NRC put nuclear operators at risk of incurring costly future capital expenditures.

Another example of nuclear risk is the ongoing and long-term uncertainty in regard to nuclear waste disposal. On June 8, 2012, the U.S. Court of Appeals vacated the NRC's rulemaking regarding storage and permanent disposal of nuclear waste. The Court of Appeals found the NRC rulemaking was deficient in that: (1) it "did not calculate the environmental effects of failing to secure permanent storage," and (2) "in determining that spent fuel can safely be stored on site at nuclear plants for sixty years after the expiration of a plant's

[55] *See* www.nrc.gov/reactors/operating/ops-experience/japan-info.html.

license, the [NRC] failed to properly examine future dangers and key consequences."[56] Nuclear operators therefore face future capital expenditures related to expansion of nuclear waste storage, and may face additional costs to meet safety standards that may be required when the NRC addresses the Court of Appeal's ruling.

To the extent further mandates are promulgated by the NRC, additional spending may be required. Absent full and timely recovery, increases in the Company's capital investment requirements will place additional pressure on its free cash flow and credit metrics.

North Carolina Renewable Energy and Energy Efficiency Portfolio Standard ("REPS")

Q. IS RETAIL NET METERING AVAILABLE TO DE PROGRESS' CUSTOMERS IN NORTH CAROLINA?

A. Yes. The Company has effective North Carolina retail net metering tariffs, and there is no aggregate limit on participation by retail customers.

Q. PLEASE DESCRIBE RETAIL NET METERING.

A. Simply put, net metering is a billing mechanism whereby, through the use of a bidirectional meter, the customer's usage of electricity and the production of electricity from the customer's generator are combined and netted on the customer bill. Under retail net metering, customers sell their generated electricity to the utility at the same price that the utility charges to the customer

[56] U.S. Court of Appeals for the District of Columbia Circuit, *On Petitions for Review of Orders of the Nuclear Regulatory Commission*, Case No. 11-1045, Decided June 8, 2012, at 3.

(a 1:1 ratio). This type of net metering is an embedded incentive to customers to invest in distributed generation in North Carolina.

Q. PLEASE EXPLAIN THE NORTH CAROLINA REPS AND THE COMPANY'S COMPLIANCE REQUIREMENTS.

A. Pursuant to North Carolina Session Law 2007-197 ("Senate Bill 3"), since 2012, utilities and other power suppliers have been required to meet stated percentages of their retail customers' energy needs (which escalates over time to 12.50 percent in 2021) through a combination of renewable energy resources, and energy reductions or savings from the implementation of energy efficiency and demand-side management programs. On July 27, 2017, North Carolina Governor Cooper signed HB 589 into law, which calls for a competitive procurement process by which the Company will pursue additional solar resources in both its North Carolina and South Carolina service territories. HB 589 targets 2,660 MW of competitively procured renewable resources over a 45-month period. The Company's "Base Case" forecast projects that the Company will have approximately 4,200 MW of renewable capacity by 2033 to comply with REPS and HB 589.[57]

57 Duke Energy Progress North Carolina 2018 Integrated Resource Plan, Docket No. E-100, Sub 157, September 5, 2018, at 29. Represents an incremental capacity of 1,175 MW over 2019 renewable capacity of approximately 3,025 MW.

Q. IS DE PROGRESS ALSO EXPERIENCING GROWTH IN RENEWABLE ENERGY PROJECTS IN NORTH CAROLINA RELATED TO ITS PUBLIC UTILITY REGULATORY POLICIES ACT OF 1978 ("PURPA") COMPLIANCE REQUIREMENTS?

A. Yes, it is. According to the Company's Joint Comments to the Federal Energy Regulatory Commission's Technical Conference Concerning Implementation Issues Under the Public Utility Regulatory Policies Act of 1978, submitted in Docket No. AD16-16-000 on June 7, 2016, "Duke Energy's utilities lead in and continue to grow deployment levels of PURPA qualifying facilities ("QF")…the Duke Progress and Duke Carolinas service territories are the nation's largest PURPA market, 'accounting for 60% of U.S. PURPA projects.'"[58] The following excerpt from the same filing further illustrates the PURPA compliance issues the Company faces in the Carolinas:

> From 2010 through 2015, 621 projects and 1246 MWs of QF generation have come online in the Carolinas, the vast majority of which are intermittent solar facilities. These mandatory purchases have resulted in over $1 billion in costs on customers – to date – and customers will continue to incur costs associated with these QF projects. Across Duke Energy's service territory in the Carolinas alone, transmission and distribution engineers have and are grappling with over 1,700 projects totaling over 9000 MWs of additional intermittent QF capacity. Engineers have to study all these projects, and they may not all be built. However, at this time there are over 1200 projects in the interconnection process that are viable and/or being built, totaling over 4400 MWs of additional intermittent capacity. These 1200 projects will mandate approximately $400 million

58 Colin Smith, Analyst, GTM Research, The Next Wave of U.S. Utility Solar, Procurement Beyond the RPS (Feb. 2016) at 28 (emphasis supplied).

> in costs each year or $6 billion in costs over a 15-year commitment period. The above do not include the QFs in the Carolinas that are interconnected with other systems and municipal/cooperative utilities that are selling or seeking to sell their output to Duke Progress and Duke Carolinas.[59]

The Company's North Carolina 2018 Integrated Resource Plan filed in Docket No. E-100, Sub 157 identified 462 projects totaling 7,586 MW in its combined Carolinas service territories, with 307 pending projects totaling 5,111 MW in capacity being located in North Carolina.[60]

Q. WHAT ARE THE POTENTIAL IMPLICATIONS OF RETAIL NET METERING FOR THE COMPANY'S BUSINESS RISK?

A. The Company currently is experiencing low growth in demand, and is projected to do so into the future.[61] The extension of retail net metering incentivizes continued or increased investment in distributed generation, which can begin a cycle in which customers with means leave the system, and the pool of remaining customers are left with increasing fixed costs until, ultimately, the utility has difficulties recovering its full cost of service.[62] At that point, credit quality may come under pressure.

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59 Comments of Duke Energy Corporation to the Federal Energy Regulatory Commission's Technical Conference Concerning Implementation Issues Under the Public Utility Regulatory Policies Act of 1978, Docket No. AD16-16-000, at 5.

60 Duke Energy Progress North Carolina 2018 Integrated Resource Plan, Docket No. E-100, Sub 157, September 5, 2018, at 202.

61 Duke Energy Corporation, SEC Form 10-K for the Period Ending December 31, 2018, at 10.

62 I understand that under House Bill 589, §62-126.4, utilities will file revised net metering rates for customers that own a renewable energy facility for their primary use, or are customer generator lessees, and that the Commission should establish non-discriminatory rates ensuring that retail net metering customers pay their full fixed costs. Those rates, and the Commission's analysis of the rates, are yet to be determined.

Q. DO CREDIT RATING AGENCIES RECOGNIZE RISKS ASSOCIATED WITH AN INCREASE IN DISTRIBUTED GENERATION RESOURCES?

A. Yes, they do. Although S&P noted the competitive threat from rooftop solar panels has not been significant enough to have an effect on credit quality to date, it has outlined the potential risks to the electric utility sector:

> …should solar rooftop use suddenly increase, a utility would be forced to recover its excess electric capacity costs from its remaining customers. The resulting higher bills to the remaining utility customers would only further drive those customers to install solar panels. This could, again, prevent the utility from fully recovering its costs and investments in a timely manner, potentially harming its credit quality.[63]

Moody's likewise noted that under certain conditions, there could be "large negative consequences" for utilities as a result of the widespread deployment of distributed generation resources. Under those conditions, when the regulatory structure does not address the effect of distributed generation, Moody's suggests that "the likelihood of negative credit events would rise due to the technological disruption."[64]

Similarly, a July 2014 article quoted Bernstein Research analysts regarding the risk of distributed generation from a utility's perspective, stating that "'[f]or the foreseeable future, distributed solar will exist in a parasitic

[63] Standard and Poor's Research, "Why U.S. Electric Utilities' Credit Quality Can Withstand the Rise of Rooftop Solar," November 15, 2013, at 6.

[64] Moody's also refers to distributed generation as a "form of technology event risk, where event risk is low or remote, but with high severity implications should the event actually materialize." *See* Moody's Investors Service, *Regulatory framework holds keys to risk and rewards associated with distributed generation*, April 23, 2014, at 2.

relationship to the grid, absorbing its revenues while continuing to rely upon it for economic viability,' the analysts said, noting two specific challenges distributed solar creates for utilities: lost sales volume and a 'foregone' need for new capacity."[65]

Q. ARE YOU AWARE OF ANY REGULATORY OFFICIAL THAT HAS QUANTIFIED THE POTENTIAL EFFECT OF DISTRIBUTED ENERGY SYSTEMS ON ELECTRIC UTILITIES?

A. Yes. On January 19, 2017, Commissioner Picker of the California Public Utilities Commission commented on the state of distributed energy in that state.[66] Commissioner Picker described an important development involving retail community clean aggregators ("CCA"), which are established by local governments. At the time of his comments, there were five operational, and fifteen CCAs in planning in California. Commissioner Picker noted that San Diego City's CCA would reduce San Diego Gas & Electric's customer base by 44.00 percent, and that Pacific Gas & Electric, where most of the existing CCAs are operational, was expected to see additional customer losses of 21.00 percent in 2017, alone. As described by Commissioner Picker, distributed energy is a very disruptive technology, with significant risks to incumbent electric utilities such as DE Progress.

65 Copley, Michael, "Despite distributed generation's buzz, grid power 'here to stay,' Bernstein says," SNL Financial, July 21, 2014.

66 *See* Commissioner Picker Comments at the Start of the New Year, January 19, 2017.

B. Capital Expenditures

Q. PLEASE SUMMARIZE DE PROGRESS' CAPITAL EXPENDITURE PLANS.

A. Based on Duke Energy's Summer 2019 Update, DE Progress plans to deploy approximately $10.43 billion in capital over the period 2019-2023.[67]

Q. WHAT ARE THE RISKS ASSOCIATED WITH THAT LEVEL OF INVESTMENT?

A. From a credit perspective, the additional pressure on cash flows associated with high levels of capital expenditures exerts corresponding pressure on credit metrics and, therefore, credit ratings. S&P has noted several long-term challenges for utilities' financial health, including: heavy construction programs to address demand growth; declining capacity margins; and aging infrastructure and regulatory responsiveness to mounting requests for rate increases.[68] More recently, S&P noted that:

> We assume that capital spending will remain a focus of most utility managements and strain credit metrics. It provides growth when sales are diminished by ongoing demanded efficiency from regulators and other trends, and it is welcomed by policymakers that appreciate the economic stimulus and the benefits of safer, more reliable service. The speed with which the regulatory process turns the new spending into higher rates to begin to pay for it is an important factor in our assumptions and the forecast. Any extended lag between spending and recovery can exacerbate the negative effect on credit metrics and

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67 Duke Energy Corporation, Summer Update 2019, at 29.

68 *See* Standard & Poor's, *Industry Report Card: Utility Sectors in the Americas Remain Stable, While Challenges Beset European, Australian, and New Zealand Counterparts*, RatingsDirect, June 27, 2008, at 4.

therefore ratings.[69]

The allowed ROE should enable the subject utility to finance capital expenditures and working capital requirements at reasonable rates, and to maintain its financial integrity in a variety of economic and capital market conditions. As discussed earlier in my direct testimony, a return that is adequate to attract capital at reasonable terms enables the utility to provide safe, reliable service while maintaining its financial soundness. To the extent a utility is provided the opportunity to earn its market-based cost of capital, neither customers nor shareholders should be disadvantaged.

The ratemaking process is based on the principle that, in order for investors and companies to commit the capital needed to provide safe and reliable utility services, the utility must have the opportunity to recover the return of, and the market-required return on, invested capital. Regulatory commissions recognize that because utility operations are capital intensive, their decisions should enable the utility to attract capital at reasonable terms; doing so balances the long-term interests of the utility and its ratepayers.

Further, the financial community carefully monitors the current and expected financial condition of utility companies, as well as the regulatory environment in which those companies operate. In that respect, the regulatory environment is one of the most important factors considered in both debt and

69 *See* Standard & Poor's Rating Services, *Industry Top Trends 2017: Utilities*, RatingsDirect, February 16, 2017, at 4.

equity investors' assessments of risk. That is especially important during periods in which the utility expects to make significant capital investments and, therefore, may require access to capital markets.

V. ECONOMIC CONDITIONS IN NORTH CAROLINA

Q. DID YOU CONSIDER THE ECONOMIC CONDITIONS IN NORTH CAROLINA IN ARRIVING AT YOUR ROE RECOMMENDATION?

A. Yes, I did. As a preliminary matter, I understand and appreciate that the Commission must balance the interests of investors and customers in setting the Return on Equity. As the Commission has stated, it "…is and must always be mindful of the North Carolina Supreme Court's command 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] In that regard, the return should be neither excessive nor confiscatory; it should be the minimum amount needed to meet the *Hope* and *Bluefield* Comparable Risk, Capital Attraction, and Financial Integrity standards.

The Commission also has found the role of Cost of Capital experts is to determine the investor-required return, not to estimate increments or decrements of return in connection with consumers' economic environment:

> … adjusting investors' required costs based on factors upon which investors do not base their willingness to invest is an

[70] North Carolina Utilities Commission, Docket No. E-7, Sub 1026, Order Granting General Rate Increase, Sept. 24, 2013 at 25; *see also*, North Carolina Utilities Commission, Docket No. E-7, Sub 989, Order on Remand, at 31 ("the Commission in every case seeks to comply with the N.C. Supreme Court mandate that the Commission establish rates as low as reasonably possible within Constitutional limits.").

> unsupportable theory or concept. The proper way to take into account customer ability to pay is in the Commission's exercise of fixing rates as low as reasonably possible without violating constitutional proscriptions against confiscation of property. This is in accord with the "end result" test of Hope. This the Commission has done.[71]

The Supreme Court agreed, and upheld the Commission's Order on Remand.[72] The Supreme Court also made clear, however, that "in retail electric 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."[73] The Commission made such additional findings of fact in its Order on Remand.[74] In light of the Cooper I decision, I appreciate the Commission's need to consider economic conditions in the state and, as such, I have undertaken several analyses to provide such a review.

Q. PLEASE SUMMARIZE YOUR ANALYSES AND CONCLUSIONS.

A. In its Order on Remand in Docket No. E-22, Sub 479, the Commission observed that economic conditions in North Carolina were highly correlated with national conditions, such that they were reflected in the analyses used to determine the Cost of Equity.[75] As discussed below, those relationships still hold: Economic conditions in North Carolina continue to improve from the recession following

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[71] North Carolina Utilities Commission, Docket No. E-7, Sub 989, Order on Remand, October 23, 2013, at 34 - 35; *see also* Dominion Remand Order, Docket No. E-22, Sub 479 at 26 (stating that the Commission is not required to "isolate and quantify the effect of changing economic conditions on consumers in order to determine the appropriate rate of return on equity").

[72] *State ex rel. Utils. Comm'n v. Cooper*, 366 N.C. 484,739 S.E.2d 541 (2013) ("Cooper I").

[73] *Cooper I*, 366 N.C. 484,739 S.E.2d 541 at 8.

[74] North Carolina Utilities Commission, Docket No. E-7, Sub 989, Order on Remand, October 23, 2013, at 13-16.

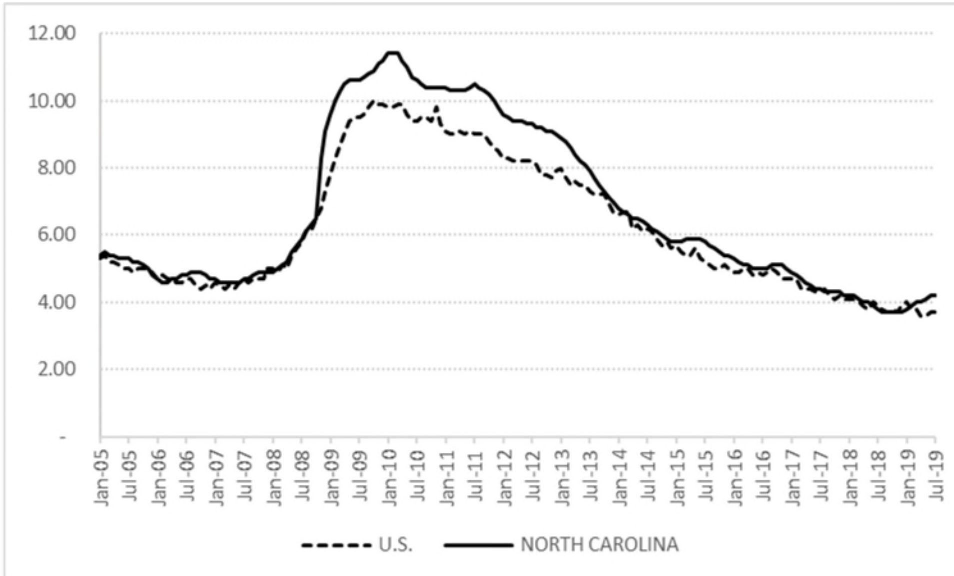
[75] *See* North Carolina Utilities Commission, Docket No. E-22, Sub 479, Order on Remand, July 23, 2015, at 39.

the 2008/2009 financial crisis, and they continue to be strongly correlated to conditions in the U.S., generally. In particular, unemployment, at both the state and county level, continues to fall and remains highly correlated with national rates of unemployment; real Gross Domestic Product ("GDP") also remains fairly well correlated with U.S. GDP growth; and median household income in North Carolina has grown at a rate consistent with the rest of the U.S., and remains strongly correlated with national levels. On balance, the correlations between state-wide measures of economic conditions noted by the Commission in Docket No. E-22, Sub 479 remain in place and, as such, they continue to be reflected in the models and data used to estimate the Cost of Equity.

Q. PLEASE NOW DESCRIBE THE SPECIFIC MEASURES OF ECONOMIC CONDITIONS THAT YOU REVIEWED.

A. Turning first to the rate of unemployment, as noted above it has fallen substantially in North Carolina and the U.S. since late 2009 and early 2010, when the rates peaked at 10.00 percent and 11.40 percent (seasonally adjusted), respectively. Although the unemployment rate in North Carolina exceeded the national rate during and after the 2008/2009 financial crisis, by the latter portion of 2013, the two were largely consistent. By July 2019, the unemployment rate (seasonally adjusted) had fallen by nearly two-thirds of those peak levels: to 3.70 percent nationally and 4.20 percent in North Carolina. (*see* Chart 4, below).

Chart 4: Unemployment Rate[76]



Since the Company's last rate filing in June 2017, the unemployment rate (seasonally adjusted) in North Carolina has fallen from 4.40 percent to 4.20 percent. Over the entire period of 2005 through 2019, the correlation between North Carolina's unemployment rate and the national rate was 99.30 percent. More broadly, economic growth at the national level is projected to generate 8.40 million new jobs from 2018-2028 (*i.e.*, 5.22 percent growth over that period).[77]

Looking to real Gross Domestic Product growth, there also has been a relatively strong correlation between North Carolina and the national economy (approximately 75.00 percent). Since the financial crisis, the national rate of growth at times outpaced North Carolina. Since the first quarter of 2015,

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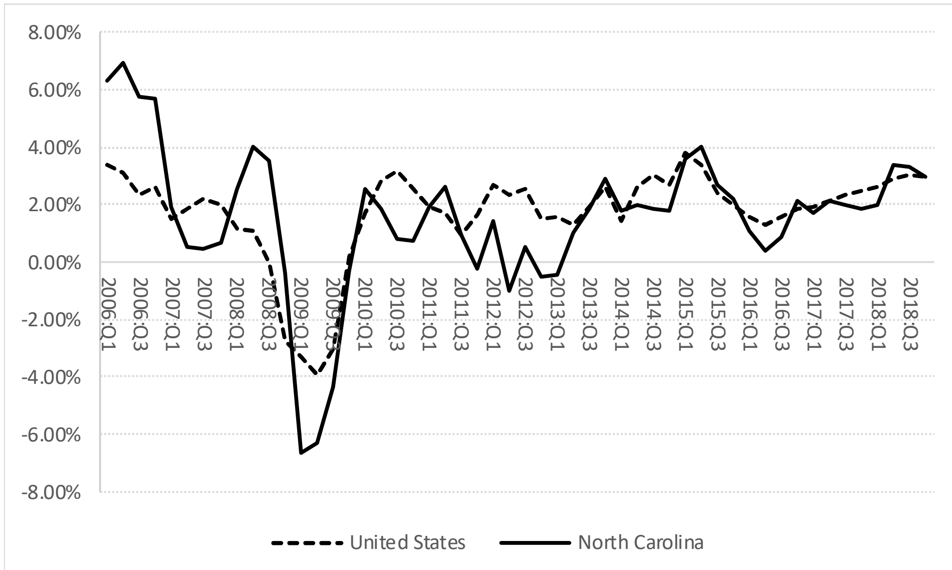
[76] Source: Bureau of Labor Statistics. Seasonally adjusted.
[77] *See* U.S. Bureau of Labor Statistics, *Employment Projections: 2018-2028*, September 4, 2019.

however, North Carolina's economic growth has been relatively consistent with U.S. economic growth.

Chart 5: Real Gross Domestic Product Growth Rate (Year over Year)[78]



As to median household income, the correlation between North Carolina and the U.S. is relatively strong (91.00 percent from 2005 through 2018). Since 2009 (that is, the years subsequent to the financial crisis), median household income (in nominal dollars) in North Carolina has grown at approximately the same annual rate as the national median income (2.72 percent vs. 2.68 percent, respectively; *see* Chart 6, below). To put household income in perspective, the Missouri Economic Research and Information Center reports that in the second quarter of 2019, North Carolina had the 20th lowest cost of living index among the 50 states and the District of Columbia.[79]

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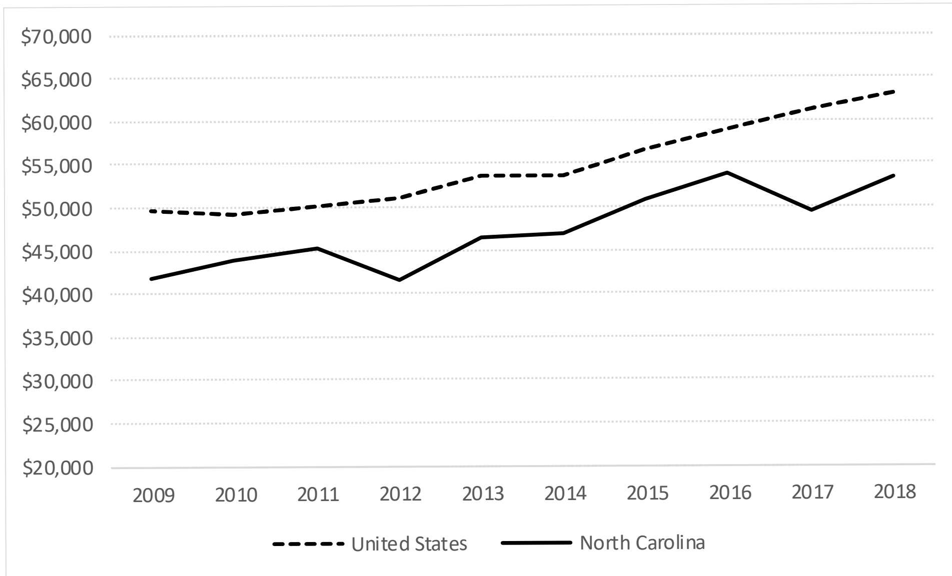
[78] Source: Bureau of Economic Analysis.
[79] Source: meric.mo.gov/data/cost-living-data-series accessed September 18, 2019.

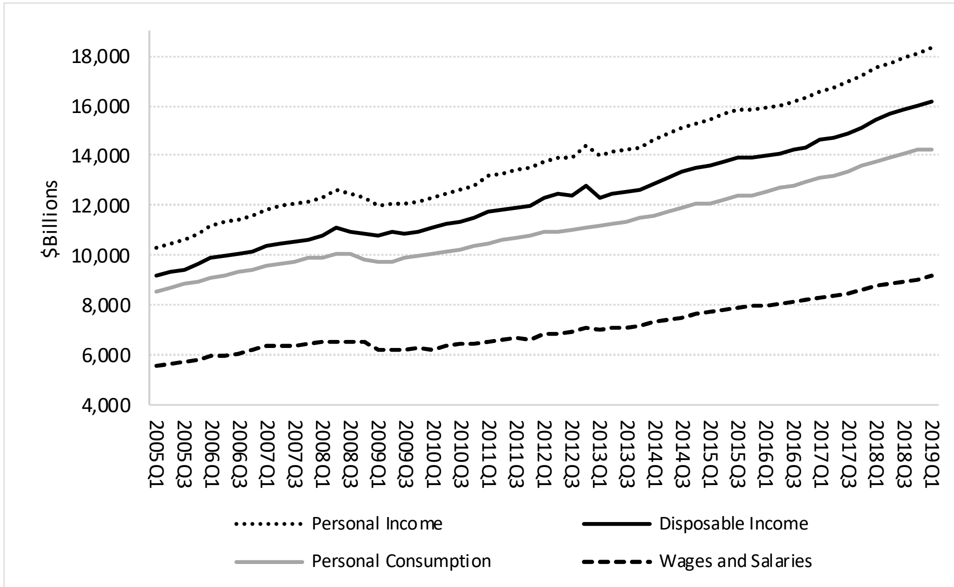
Chart 6: Median Household Income[80]



Similarly, as shown in Chart 7, below, since 2009 total personal income, disposable income, personal consumption, and wages and salaries have generally been on an increasing trend at the national level.

[80] Source: U.S. Census Bureau, Current Population Survey.

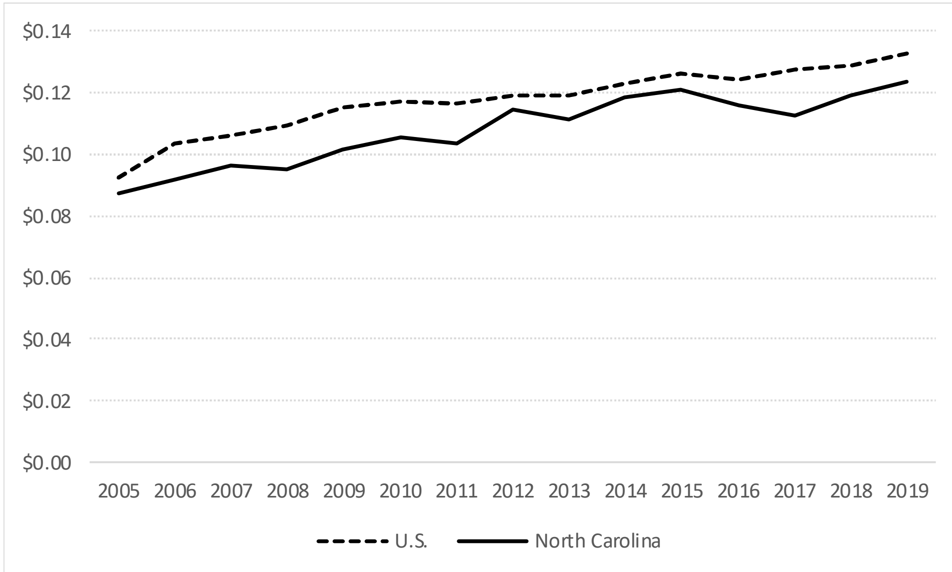
Chart 7: United States Income and Consumption[81]



Since 2005, residential electricity costs (measured in cents/kWh) in North Carolina remained approximately 8.28 percent (on average) below the national average. Even looking to the years 2012 through 2019, residential rates in North Carolina have been (on average) approximately 6.53 percent below the national average (*see* Chart 8, below). Over the longer period, residential rates remained highly correlated with the national average (approximately 95.40 percent).

81 Source: Bureau of Economic Analysis.

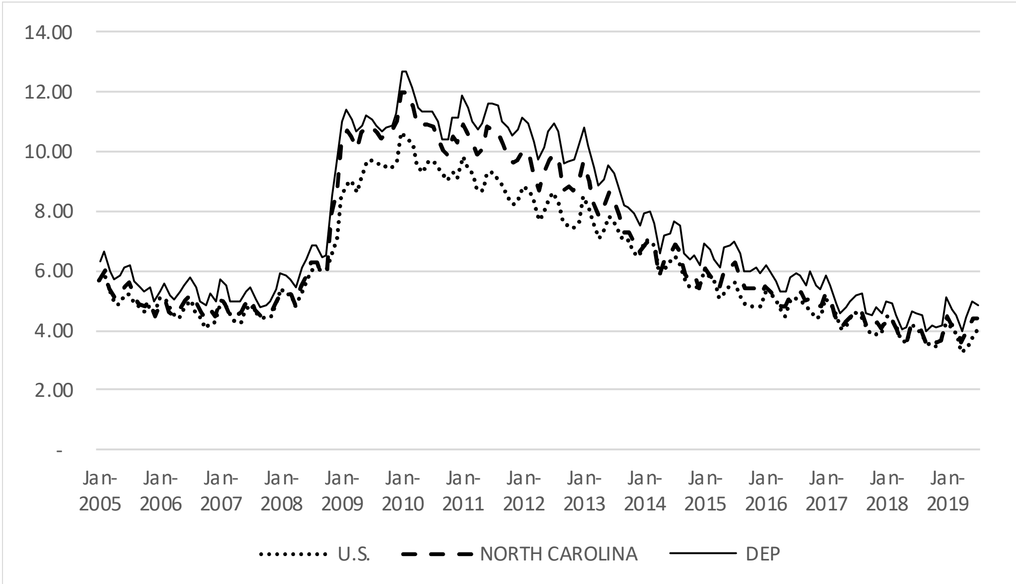
Chart 8: Residential Electricity Rates ($/kWh)[82]



Lastly, I reviewed (seasonally unadjusted) unemployment rates in the counties served by DE Progress. At its peak, which occurred in late 2009 into early 2010, the unemployment rate in those counties reached 12.66 percent (0.66 percentage points higher than the state-wide average); by July 2019 it had fallen to 4.87 percent. Since the Company's last rate filing in June 2017, the counties' unemployment has fallen by 10 basis points. From 2005 through 2019, the correlation in unemployment rates between the counties served by DE Progress, and the U.S. and North Carolina, respectively, were approximately 98.90 percent and 99.70 percent. In summary, county-level unemployment has fallen considerably since its peak in early 2010.

[82] Source: Energy Information Administration. As of April, each year.

Chart 9: Seasonally Unadjusted Unemployment Rates[83]



Based on the data presented above, I observe the following:

- North Carolina's unemployment rate has fallen by two-thirds since its peak in the 2009-2010 period; as of July 2019, it stood at 4.20 percent (seasonally adjusted). Although the current rate is slightly higher than the national average, it fell by 7.20 percentage points from its peak, whereas the national average rate fell by 6.30 percentage points.
- The unemployment rate in the counties served by DE Progress has fallen considerably since its peak in early 2010.[84]
- The State's Gross Domestic Product remains highly correlated with national GDP.
- Similarly, since 2005, median household income has grown in North

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83 Source: Bureau of Labor Statistics, St. Louis Federal Reserve.

84 Seasonally unadjusted. Source: Bureau of Labor Statistics, St. Louis Federal Reserve.

Carolina and has grown at a rate consistent with the national average. Additionally, the overall cost of living in North Carolina also is below the national average. Furthermore, at the national level, income has generally been increasing since the financial crisis.

- Residential electricity rates have been approximately 8.28 percent below the national average over the last fifteen years.

Q. HOW WOULD YOU SUMMARIZE THE ECONOMIC INDICATORS THAT YOU HAVE ANALYZED AND DISCUSSED IN YOUR TESTIMONY?

A. Based on the indicators discussed above, it is my opinion that North Carolina, and the counties contained within DE Progress' service area, continue to steadily emerge from the economic downturn that prevailed during 2009-2010, and have experienced significant economic improvement during the last several years.

Q. IN YOUR OPINION, IS AN ROE OF 10.50 PERCENT FAIR AND REASONABLE TO DE PROGRESS, ITS SHAREHOLDERS, AND ITS CUSTOMERS, AND NOT UNDULY BURDENSOME TO DE PROGRESS' CUSTOMERS CONSIDERING THE IMPACT OF THESE CHANGING ECONOMIC CONDITIONS?

A. Yes. Based on the factors I have discussed here, I believe that an ROE of 10.50 percent is fair and reasonable to DE Progress, its shareholders, and its customers in light of the effect of those changing economic conditions.

VI. CAPITAL MARKET ENVIRONMENT

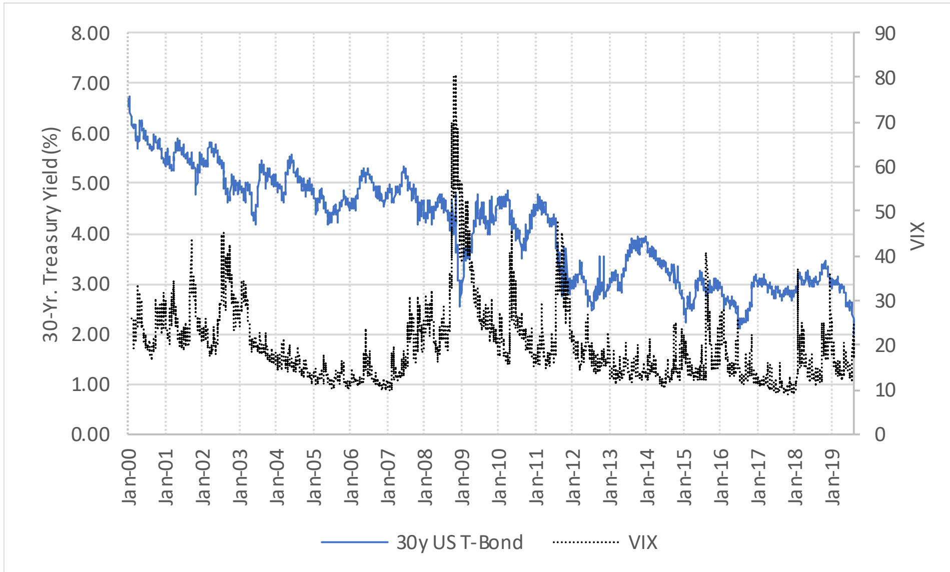
Q. DOES YOUR RECOMMENDATION CONSIDER THE CAPITAL MARKET ENVIRONMENT?

A. Yes, it does. From an analytical perspective, it is important that the inputs and assumptions used to arrive at an ROE recommendation, including assessments of capital market conditions, are consistent with the recommendation itself. Although all analyses require an element of judgment, the application of that judgment must be made in the context of the quantitative and qualitative information available to the analyst, and the capital market environment in which the analyses were undertaken.

Q. IS THERE A RELATIONSHIP BETWEEN EQUITY MARKET VOLATILITY AND INTEREST RATES?

A. Yes, there is. Significant and abrupt increases in volatility tend to be associated with declines in Treasury yields. That relationship makes intuitive sense; as investors see increasing risk their objectives may shift principally to capital preservation (that is, avoiding a capital loss). A means of doing so is to allocate capital to the relative safety of Treasury securities, in a "flight to safety." Because Treasury yields are inversely related to Treasury bond prices, as investors bid up the prices of bonds, they bid down the yields (see Chart 10, below, showing decreases in the 30-year Treasury yield coincident with significant increases in the VIX).

Chart 10: 30-Year Treasury Yields vs. VIX[85]



In those instances, the fall in yields does not reflect a reduction in required returns, it reflects an increase in risk aversion and, therefore, an increase in required equity returns.

Q. HAS MARKET VOLATILITY INCREASED IN RECENT MONTHS?

A. Yes, it has. A visible and widely reported measure of expected volatility is the Cboe Options Exchange ("Cboe") Volatility Index, often referred to as the VIX. As Cboe explains, the VIX is a calculation designed to produce a measure of constant, 30-day expected volatility of the U.S. stock market, derived from real-time, mid-quote prices of S&P 500® Index call and put options.[86] Simply, the VIX is a market-based measure of expected volatility. Because volatility is a measure of risk, increases in the VIX, or in its volatility, are a broad indicator

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85 Source: S&P Global Market Intelligence, Yahoo! Finance.

86 Source: www.cboe.com/vix

of expected increases in market risk.

Although the VIX is not expressed as a percentage, it should be understood as such. That is, if the VIX stood at 15.00, it would be interpreted as an expected standard deviation in annual market returns of 15.00 percent over the coming 30 days. Since 2000, the VIX has averaged about 19.20, which is highly consistent with the long-term standard deviation on annual market returns (19.80 percent, as reported by Duff & Phelps).[87]

Table 5, below, demonstrates the increase in market uncertainty from 2017 to 2019. As that table notes, the standard deviation (that is, the volatility of volatility) from 2018 through 2019 is about 3.20 times higher than its 2017 level (1.36).

Table 5: VIX Levels and Volatility[88]

Long-Term Average	19.20
2018-2019 Average	16.30
2018-2019 Maximum	37.32
2018-2019 Minimum	9.15
2018-2019 Standard Deviation	4.34
2017 Average	11.09
2017 Maximum	16.04
2017 Minimum	9.14
2017 Standard Deviation	1.36

The increase in volatility is not surprising as market participants reassess the Federal Reserve's long-term objective of monetary policy normalization, and the increasing risks associated with federal trade policy initiatives.

87 Source: Duff & Phelps, 2019 SBBI Yearbook, at 6-17.
88 Source: Yahoo! Finance.

Q. IS MARKET VOLATILITY EXPECTED TO INCREASE FROM ITS CURRENT LEVELS?

A. Yes, it is. One means of assessing market expectations regarding the future level of volatility is to review Cboe's "Term Structure of Volatility." As Cboe points out:

> The implied volatility term structure observed in SPX options markets is analogous to the term structure of interest rates observed in fixed income markets. Similar to the calculation of forward rates of interest, it is possible to observe the option market's expectation of future market volatility through use of the SPX implied volatility term structure.[89]

Cboe's term structure data is upward sloping, indicating market expectations of increasing volatility. The expected VIX value in December 2020 is about 19.82, suggesting investors see a reversion to long-term average volatility over the coming months.[90]

Q. HAVE RECENT DECLINES IN THE TREASURY YIELD BEEN ASSOCIATED WITH INCREASES IN MARKET VOLATILITY?

A. Yes, they have. Since November 2018, the periods during which Treasury yields fell coincided with increases in the VIX (*see* Chart 11, below).

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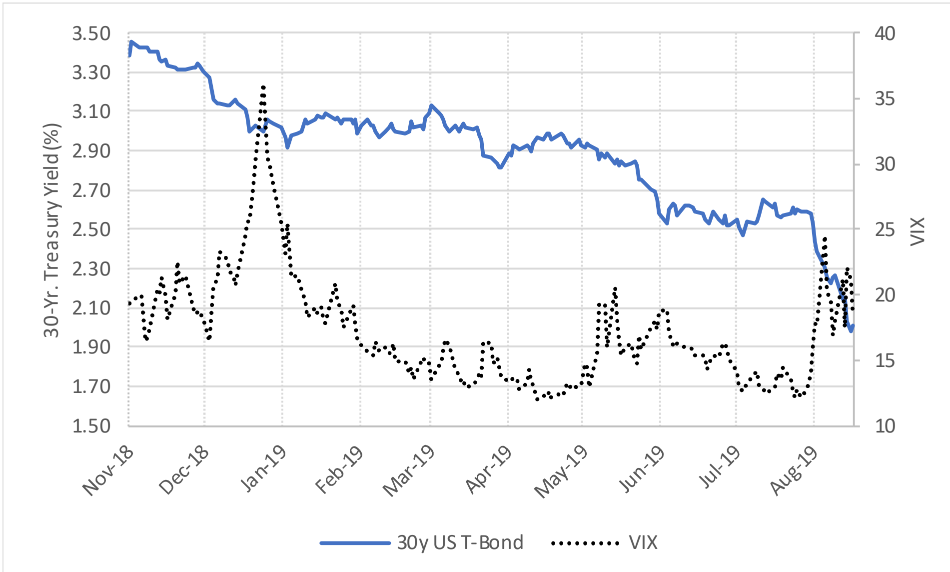
89 Source: www.cboe.com/trading-tools/strategy-planning-tools/term-structure-data.

90 Source: www.cboe.com/trading-tools/strategy-planning-tools/term-structure-data, accessed September 17, 2019.

Chart 11: 30-Year Treasury Yields vs. VIX (11/18 – 8/19)[91]

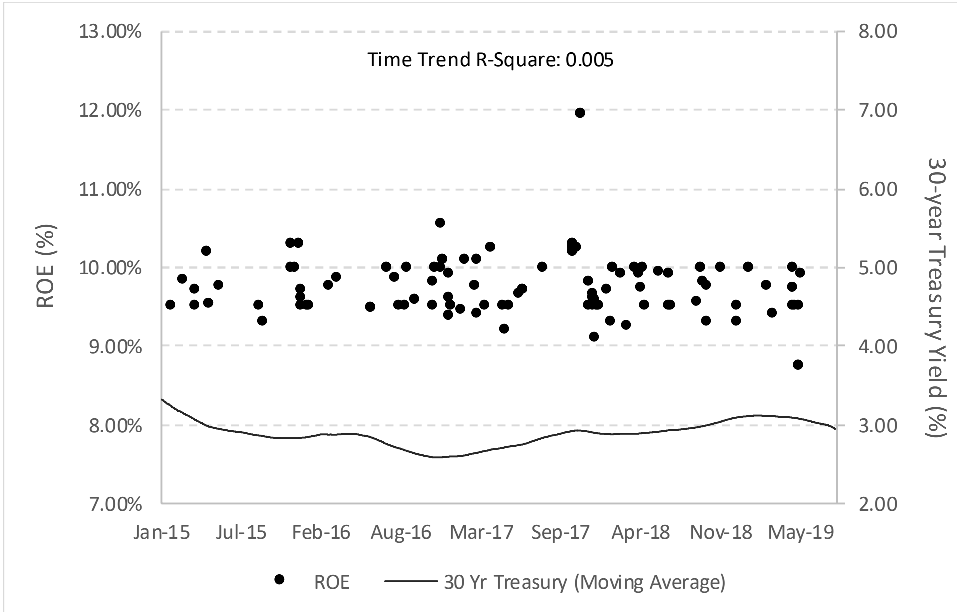


Q. HAVE AUTHORIZED RETURNS MOVED IN STEP WITH THE LOW INTEREST RATE ENVIRONMENT?

A. No, they have not. As Chart 12 (below) demonstrates, despite the decline in yields in 2015 and 2016, and again in late 2018 through 2019, regulatory commissions have not been inclined to reduce authorized returns. The constancy of authorized returns as interest rates fell also is consistent with widely accepted principle that the Equity Risk Premium increases as interest rates fall.

91 Source: S&P Global Market Intelligence, Yahoo! Finance.

Chart 12: Authorized Returns for Vertically Integrated Electric Utilities (2015 – 2019)[92]



Q. WHAT CONCLUSIONS DO YOU DRAW FROM THOSE ANALYSES?

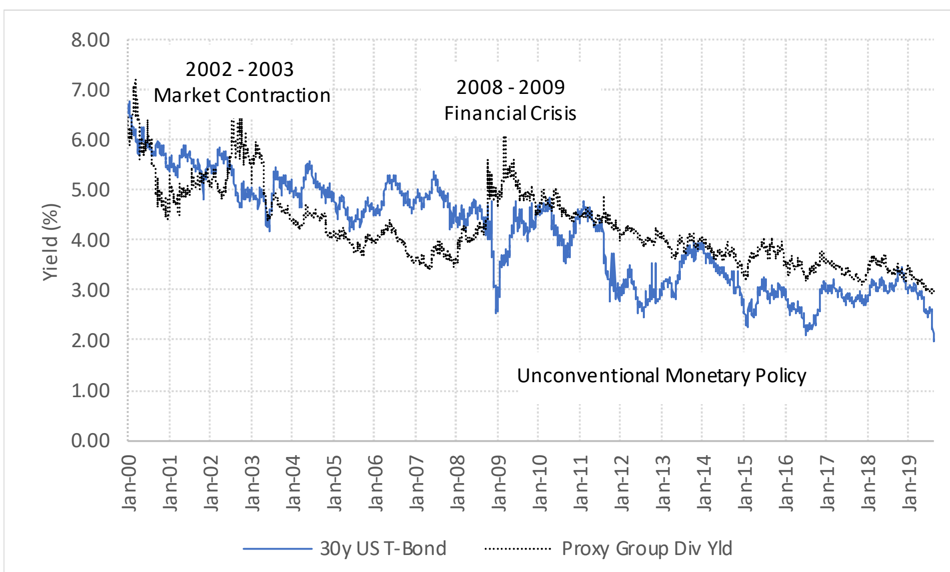
A. It is important to consider whether changes in long-term interest rates reflect fundamental changes in investor sentiment, or whether they reflect potentially transitory factors. The recent, sudden decline in interest rates appears to be related to the increase in equity market volatility, which may be event-driven rather than a fundamental change. Because the methods used to estimate the Cost of Equity are forward-looking it is important to consider those distinctions in assessing model results.

92 Excludes Limited Issue Rate Riders. Source: Regulatory Research Associates.

Q. HAVE ELECTRIC UTILITY DIVIDEND YIELDS CLOSELY FOLLOWED LONG-TERM TREASURY YIELDS?

A. Although they have been directionally related over time, the fundamental relationship between Treasury yields and utility dividend yields changed after the 2008/2009 financial crisis. From 2000 through 2008, Treasury yields generally exceeded dividend yields; the exception was the 2002-2003 market contraction. Then, as in 2008-2009, investors sought the safety of Treasury securities, accepting lower yields in exchange for a greater likelihood of capital preservation. Once the contraction ended (in latter half of 2003), the relationship was restored, and Treasury yields again exceeded dividend yields (*see* Chart 13, below).

Chart 13: Electric Utility Dividend Yields and 30-Year Treasury Yields[93]



During the 2008/2009 financial crisis, Treasury bond prices increased

[93] Source: S&P Global Market Intelligence.

(yields decreased), and utility stock prices decreased (dividend yields increased) such that the prior relationship inverted. As the Federal Reserve implemented and maintained "unconventional" monetary policies in reaction to the financial crisis (i.e., Quantitative Easing) with the intended consequence of lowering long-term interest rates, the now-inverted relationship between Treasury yields and utility dividend yields persisted.

Even though the "yield spread"[94] became inverted after the financial crisis, it has not been static. That is, as Treasury yields fell in response to central bank policies, dividend yields did not fall to the same degree; the yield spread widened (*see* Chart 13, above). That data suggests that, although utility prices are sensitive to long-term Treasury yields, the relationship is not unbounded.

Q. IS THAT RELATIONSHIP ALSO SEEN IN UTILITY PRICE/EARNINGS RATIOS?

A. Yes, it is. Looking to the period following the Federal Reserve's Quantitative Easing policy, the proxy group's P/E ratio has varied, often reverting once it has largely breached its 90-day moving average (*see* Chart 14, below).

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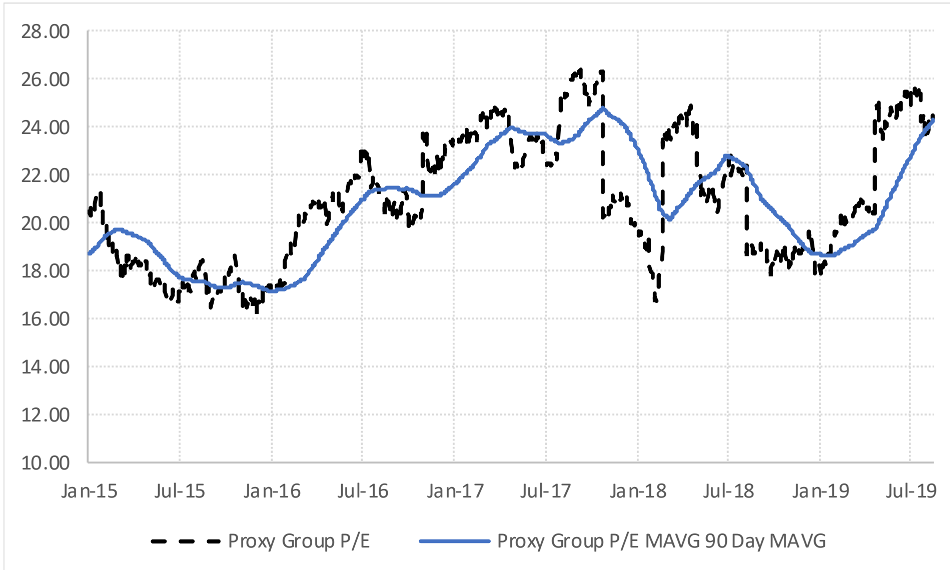
94 Defined here as dividend yields less Treasury yields.

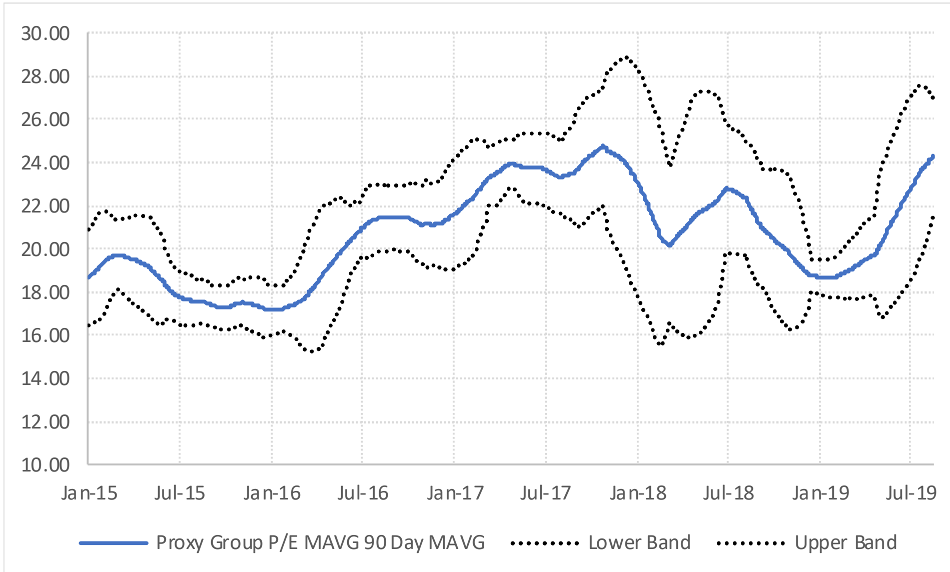
Chart 14: Proxy Group Average Price/Earnings Ratio[95]



From a somewhat different perspective, the proxy group's P/E ratio has traded within a two-standard deviation range, although that range recently has widened, indicating increasing variability in the group's valuation (*see* Chart 15, below).

95 Calculated as an index. Source: S&P Global Market Intelligence.

Chart 15: Proxy Group Average P/E Ratio Bands[96]



That data supports the conclusion discussed earlier, that utility stock prices are sensitive to changes in interest rates, but only to a point. The "reach for yield" that sometimes occurs when interest rates fall has a limit; investors will not accept the incremental risk of capital losses when utility valuation levels become "stretched". That also may be the case when investors see interest rates reacting to market volatility that is event-driven, rather than a fundamental change in the capital market environment or investor risk tolerances. The increasing variability can be seen in Chart 15 (above), when the bands around the 90-day moving average P/E ratios widen. During those periods, the risk of capital loss increases, implying a further limit on valuation levels.

96 Calculated as an index. Source: S&P Global Market Intelligence. Bands represent two standard deviations calculated over 90 days.

Q. DOES THE REDUCTION IN THE FEDERAL FUNDS TARGET RATE BY THE FEDERAL RESERVE OR AN INVERTED YIELD CURVE ALTER ANY OF THE CONCLUSIONS ABOVE?

A. No, it does not. As explained above, utility stock prices are sensitive to changes in interest rates, but only to a point. To the extent investors expect further reductions in the Federal Funds Target Rate or an inversion to the yield curve, the effects on utility stock prices are not certain to be directionally related. Further, although the Federal Open Market Committee ("FOMC") reduced the overnight Federal Funds rate by a quarter percentage point at each of the last two FOMC meetings, it noted that in determining the timing and size of future rate adjustments,

> "…the Committee will assess realized and expected economic conditions relative to its maximum employment objective and its symmetric 2 percent inflation objective. This assessment will take into account a wide range of information, including measures of labor market conditions, indicators of inflation pressures and inflation expectations, and readings on financial and international developments".[97]

As to the longer-term, the FOMC's September 2019 Projection Materials suggest an increase in the Federal Funds rate over the "longer-run".[98]

Regarding expectations of an inverted yield curve, whether an inverted

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97 *Federal Reserve Press Release*, September 18, 2019.

99 Federal Open Market Committee Meeting, *Table 1. Economic projections of Federal Reserve Board members and Federal Reserve Bank presidents, under their individual assumptions of projected appropriate monetary policy, September 2019*. The projection materials explain that "[l]onger-run projections represent each participant's assessment of the rate to which each variable would be expected to converge under appropriate monetary policy and in the absence of further shocks to the economy."

yield curve may cause a recession, the issue of causality is not settled. As the Federal Reserve Bank of Chicago (the "Chicago Fed") observed, the analyses discussed in its recent research on the topic "do not imply that a yield-curve inversion causes a recession." The Chicago Fed further explained that, "[r]ather, it could be that the slope itself fluctuates to reflect changing expectations about the economy, and these expectations are useful predictors of economic downturns."[99]

Lastly, the yield curve's ability to predict inflation has come under question since the Federal Reserve implemented its policy of Quantitative Easing. A May 2019 article in Barron's, for example, observed that by taking Treasury and mortgage-backed securities off the private market, the Federal Reserve "may be depressing the term premium and tilting the yield curve negatively."[100] In that case, a yield curve inversion may not be due to the macroeconomic factors that otherwise would suggest an impending recession.

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99 Chicago Fed Letter, *Why does the yield-curve slope predict recessions?*, Essays on Issues, 2018 Number 404, at 5.

101 Randall W. Forsyth, *An Inverted Yield Curve Is Usually Scary. Not this Time*. *Barron's*, May 31, 2019.

Q. HOW DOES THE CURRENT CAPITAL MARKET ENVIRONMENT COMPARE TO THE ENVIRONMENT IN PLACE DURING THE COMPANY'S LAST RATE CASE?

A. Although they are not perfect comparisons, there are similarities between the capital market during the pendency of the Company's last rate case[101] and the current market environment. As Table 6 (below) illustrates, utility P/E ratios,[102] the 30-year Treasury yield, and utility bond yields are similar. As discussed earlier, market volatility (as defined by the VIX) is notably higher in 2019 compared to 2017-2018.

Table 6: Capital Market Indices – 2017 and 2019[103]

	Average P/E Ratio	30-Year Treasury Yield	VIX Index	Moody's Utility A Index	Moody's Utility Baa Index
2019 Average	22.54	2.80	15.75	3.99	4.47
6/1/17 – 2/23/18	20.83	2.85	11.76	3.90	4.25

Given the similarities in interest rates and utility valuations, we cannot say that capital costs have fallen since the Commission's order in the Company's last rate case, particularly given the increase in market volatility.

[101] The Company filed its last rate case, Docket No. E-2, Sub 1142, on June 1, 2017. On February 23, 2018, the Commission authorized a 9.90 percent ROE for the Company.
[102] As defined by the proxy group.
[103] Source: Bloomberg Professional. P/E ratios calculated as a simple average. As of August 16, 2019.

Q. WHAT CONCLUSIONS DO YOU DRAW FROM YOUR ANALYSES OF THE CURRENT CAPITAL MARKET ENVIRONMENT, AND HOW DO THOSE CONCLUSIONS AFFECT YOUR ROE RECOMMENDATION?

A. Because certain models used to estimate the Cost of Equity require long-term assumptions, it is important to understand whether those assumptions hold. The current market environment is one in which changes in interest rates likely are associated with events, more than they are a function of fundamental economic conditions. Further, utility valuations have a limit, even when investors look to them for an alternate source of income as interest rates fall.

On balance, it remains important to consider changes in market conditions, the likely causes of those changes, and how model results are affected by them. Those assessments necessarily involve the application of reasoned and experienced judgment. Here, the capital market environment is largely similar to the market during the Company's last rate case, but with an increase in market volatility. As discussed throughout my testimony, that judgment supports my recommended range of 10.00 percent to 11.00 percent.

VII. CONCLUSION

Q. WHAT IS YOUR CONCLUSION REGARDING THE ROE FOR DE PROGRESS?

A. As discussed throughout my testimony, it is important to consider a variety of empirical and qualitative information in reviewing analytical results and arriving at ROE determinations. As a practical matter, the Constant Growth

DCF results are well below a highly observable and relevant benchmark, *i.e.*, the returns authorized for vertically integrated electric utilities. A more balanced approach therefore would be to consider the relative strengths and weaknesses of multiple methods, and give the appropriate weight to their results.

Based on that review, I believe that an ROE in the range of 10.00 percent to 11.00 percent represents the range of equity investors' required ROE for investment in integrated electric utilities in today's capital markets. Within that range, I conclude that 10.50 percent represents the Cost of Equity for DE Progress. That conclusion considers the cost associated with issuing common stock and the current capital market environment, as well as DE Progress' risk profile relative to the proxy group analytical results with respect to (1) the risks associated with certain aspects of the Company's generation portfolio and (2) the Company's significant capital expenditure plan. In light of those factors, it is appropriate to establish an ROE that is above the proxy group mean results. As such, an ROE of 10.50 percent reasonably represents the return required to invest in a company with a risk profile comparable to DE Progress.

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

A. Yes, it does.

VIII. APPENDIX A

A. Constant Growth DCF Model

Q. PLEASE DESCRIBE THE CONSTANT GROWTH DCF APPROACH.

A. The Constant Growth DCF approach is based on the theory that a stock's current price represents the present value of all expected future cash flows. In its simplest form, the Constant Growth DCF model expresses the Cost of Equity as the discount rate that sets the current price equal to expected cash flows:

$$P_0 = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \ldots + \frac{D_t}{(1+k)^t} \quad [4]$$

where P_0 represents the current stock price, $D_1 \ldots D_t$ represent expected future dividends, and k is the discount rate, or required ROE. Equation [4] is a standard present value calculation that can be simplified and rearranged into the familiar form:

$$k = \frac{D(1+g)}{P_0} + g \quad [5]$$

Equation [5] often is referred to as the "Constant Growth DCF" model, in which the first term is the expected dividend yield and the second term is the expected long-term growth rate.

Q. WHAT ASSUMPTIONS ARE REQUIRED FOR THE CONSTANT GROWTH DCF MODEL?

A. The Constant Growth DCF model assumes: (1) earnings, book value, and dividends all grow at the same, constant rate in perpetuity; (2) the dividend payout ratio remains constant; (3) the Price to Earnings ("P/E") multiple remains constant in perpetuity; and (4) the discount rate is greater than the expected growth rate, and remains constant over time.

Q. WHAT MARKET DATA DID YOU USE TO CALCULATE THE DIVIDEND YIELD IN YOUR DCF MODEL?

A. The dividend yield is based on the proxy companies' current annualized dividend and average closing stock prices over the 30-, 90-, and 180-trading day periods as of August 16, 2019.

Q. WHY DID YOU USE THREE AVERAGING PERIODS TO CALCULATE AN AVERAGE STOCK PRICE?

A. I did so to ensure the model's results are not skewed by anomalous events that may affect stock prices on any given trading day. At the same time, the averaging period should be reasonably representative of expected capital market conditions over the long term. In my view, using 30-, 90-, and 180-trading day averaging periods reasonably balances those concerns.

Q. DID YOU MAKE ANY ADJUSTMENTS TO THE DIVIDEND YIELD TO ACCOUNT FOR PERIODIC GROWTH IN DIVIDENDS?

A. Yes, I did. Because utilities tend to increase their quarterly dividends at different times throughout the year, it is reasonable to assume that dividend increases will be evenly distributed over calendar quarters. Given that assumption, it is appropriate to calculate the expected dividend yield by applying one-half of the long-term growth rate to the current dividend yield.[104]

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[104] Exhibit DWD-1.

That adjustment ensures that the expected dividend yield is, on average, representative of the coming twelve-month period, and does not overstate the dividends to be paid during that time.

Q. IS IT IMPORTANT TO SELECT APPROPRIATE MEASURES OF LONG-TERM GROWTH IN APPLYING THE DCF MODEL?

A. Yes. In its Constant Growth form, the DCF model (*i.e.*, as presented in Equation [5] above) assumes a single growth estimate in perpetuity. Accordingly, to reduce the long-term growth rate to a single measure, we must assume a fixed payout ratio, and the same constant growth rate for earnings per share ("EPS"), dividends per share, and book value per share. Because dividend growth can only be sustained by earnings growth, the model should incorporate a variety of measures of long-term earnings growth. That can be accomplished by averaging measures of long-term growth that tend to be least influenced by capital allocation decisions companies may make in response to near-term changes in the business environment. Because such decisions may directly affect near-term dividend payout ratios, estimates of earnings growth are more indicative of long-term investor expectations than are dividend growth estimates. For the purposes of the Constant Growth DCF model, therefore, growth in EPS represents the appropriate measure of long-term growth.

Q. PLEASE SUMMARIZE THE FINDINGS OF ACADEMIC RESEARCH ON THE APPROPRIATE MEASURE FOR ESTIMATING EQUITY RETURNS USING THE DCF MODEL.

A. The relationship between various growth rates and stock valuation metrics has been the subject of much academic research.[105] As noted over 40 years ago by Charles Phillips in The Economics of Regulation:

> For many years, it was thought that investors bought utility stocks largely on the basis of dividends. More recently, however, studies indicate that the market is valuing utility stocks with reference to total per share earnings, so that the earnings-price ratio has assumed increased emphasis in rate cases.[106]

Subsequent academic research has clearly and consistently indicated that measures of earnings and cash flow are strongly related to returns, and that analysts' forecasts of growth are superior to other measures of growth in predicting stock prices.[107] For example, Vander Weide and Carleton state that "[our] results … are consistent with the hypothesis that investors use analysts' forecasts, rather than historically oriented growth calculations, in making stock buy-and-sell decisions."[108] Other research specifically notes the importance of

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105 *See* Harris, Robert, *Using Analysts' Growth Forecasts to Estimate Shareholder Required Rate of Return*, Financial Management (Spring 1986).

106 Charles F. Phillips, Jr., The Economics of Regulation, at 285 (Rev. ed. 1969).

107 *See, e.g.*, Christofi, Christofi, Lori and Moliver, *Evaluating Common Stocks Using Value Line's Projected Cash Flows and Implied Growth Rate*, Journal of Investing (Spring 1999); Harris and Marston, *Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts*, Financial Management, 21 (Summer 1992); and Vander Weide and Carleton, *Investor Growth Expectations: Analysts vs. History*, The Journal of Portfolio Management (Spring 1988).

108 Vander Weide and Carleton, *Investor Growth Expectations: Analysts vs. History*, The Journal of Portfolio Management (Spring 1988). The Vander Weide and Carleton study was updated in 2004 under the direction of Dr. Vander Weide. The results of the updated study were consistent with the original study's conclusions.

analysts' growth estimates in determining the Cost of Equity, and in the valuation of equity securities. Dr. Robert Harris noted that "a growing body of knowledge shows that analysts' earnings forecasts are indeed reflected in stock prices."[109] Citing Cragg and Malkiel, Dr. Harris notes that those authors "found that the evaluations of companies that analysts make are the sorts of ones on which market valuation is based."[110] Similarly, Brigham, Shome, and Vinson noted that "evidence in the current literature indicates that (i) analysts' forecasts are superior to forecasts based solely on time series data, and (ii) investors do rely on analysts' forecasts."[111]

To that point, the research of Carleton and Vander Weide demonstrates that earnings growth projections have a statistically significant relationship to stock valuation levels, while dividend growth rates do not.[112] Those findings suggest investors form their investment decisions based on expectations of growth in earnings, not dividends. Consequently, earnings growth, not dividend growth, is the appropriate estimate for the purpose of the Constant Growth DCF model.

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[109] Robert S. Harris, *Using Analysts' Growth Forecasts to Estimate Shareholder Required Rate of Return*, Financial Management (Spring 1986) at 59.

[110] *Ibid*.

[111] Eugene F. Brigham, Dilip K. Shome, and Steve R. Vinson, *The Risk Premium Approach to Measuring a Utility's Cost of Equity*, Financial Management (Spring 1985) at 36.

[112] *See* Vander Weide and Carleton, *Investor Growth Expectations: Analysts vs. History*, The Journal of Portfolio Management (Spring 1988).

Q. PLEASE SUMMARIZE YOUR INPUTS TO THE CONSTANT GROWTH DCF MODEL.

A. I applied the DCF model to the proxy group of electric utility companies using the following inputs for the price and dividend terms:

- The average daily closing prices for the 30-trading days, 90-trading days, and 180-trading days ended August 16, 2019 for the term P_0; and
- The annualized dividend per share as of August 16, 2019 for the term D_0.

I then calculated the DCF results using each of the following growth terms:

- Zack's consensus long-term earnings growth estimates;
- First Call consensus long-term earnings growth estimates; and
- Value Line earnings growth estimates.

Q. HOW DID YOU CALCULATE THE DCF MODEL RESULTS?

A. For each proxy company, I calculated the mean, mean high, and mean low results. For the mean result, I combined the average of the EPS growth rate estimates reported by Value Line, Zacks, and First Call with the subject company's dividend yield for each proxy company and then calculated the average result for those estimates. I calculated the high DCF result by combining the maximum EPS growth rate estimate as reported by Value Line, Zacks, and First Call with the subject company's dividend yield. The mean high result simply is the average of those estimates. I used the same approach to calculate the low DCF result, using instead the minimum of the Value Line, Zacks, and First Call estimate for each proxy company, and calculating the average result for those estimates.

Q. WHAT ARE THE RESULTS OF YOUR DCF ANALYSES?

A. The Constant Growth DCF results are summarized in Table 7 below (*see also* Exhibit DWD-1).

Table 7: Constant Growth DCF Results

	Mean Low	Mean	Mean High
30-Day Average	7.90%	8.78%	9.67%
90-Day Average	7.96%	8.84%	9.73%
180-Day Average	8.08%	8.97%	9.85%

Q. DO YOU BELIEVE THAT THE CONSTANT GROWTH DCF MODEL CURRENTLY PROVIDES A REASONABLE ESTIMATE OF THE COMPANY'S COST OF EQUITY?

A. No, I do not. The Constant Growth DCF model is predicated on a number of assumptions, one of which is that the Price/Earnings ratio will remain constant, in perpetuity. Because utility sector P/E ratios have expanded to the point that they recently have exceeded both their long-term average and the market P/E ratio, the Constant Growth DCF model's results should be viewed with caution. As a practical matter, as shown in Chart 1 above, the mean Constant Growth DCF results are below a highly observable and relevant benchmark – the returns authorized for vertically integrated electric utilities.[113] As such, it is more appropriate to consider multiple methods in current market conditions, such as

[113] The average authorized ROE for vertically-integrated electric utilities since January 2015 is 9.74 percent. Excludes limited issue rider proceedings.

Risk-Premium based methods and the Expected Earnings approach.

Regardless of the method employed, however, an authorized ROE that is well below returns authorized for other utilities: (1) runs counter to the *Hope* and *Bluefield* "comparable risk" standard, (2) would place the Company at a competitive disadvantage, and (3) would make it difficult for the Company to compete for capital at reasonable terms.

Q. PLEASE SUMMARIZE THE REASONS YOU BELIEVE THE CONSTANT GROWTH DCF MODEL SHOULD NOT BE GIVEN UNDUE WEIGHT IN THIS PROCEEDING.

A. As explained earlier, the model assumes that the return estimated today will be the same return required in the future, even though the Federal Reserve only recently has completed the principal initiatives of its monetary policy normalization and is continuing to assess realized and expected economic conditions as it determines future adjustments,[114] introducing a degree of uncertainty regarding future monetary policy actions. As also discussed in my Direct Testimony, other methods more directly reflect the risk premium required by investors in response to market and industry risks. On balance, it is my view that the Constant Growth DCF method should be given less weight than other methods in establishing the Company's ROE.

[114] *Federal Reserve FOMC statement*, September 18, 2019.

Q. WITH THOSE POINTS IN MIND, HOW DID YOU REFLECT THE CONSTANT GROWTH DCF RESULTS IN YOUR ROE RANGE AND RECOMMENDATION?

A. I first recognized that the model's mean and mean low results are well below a reasonable estimate of the Company's Cost of Equity. For example, of the 1,594 electric utility rate cases provided by Regulatory Research Associates that disclosed the awarded ROE since 1980, only eleven included an authorized ROE below 9.00 percent.[115] On that basis alone, the mean low results are highly improbable.

I then considered why the Constant Growth model is producing such low estimates of the Company's Cost of Equity. In one sense, relatively low dividend yields should be associated with relatively high growth rates. That is, low dividend yields are the result of relatively high stock prices which, in turn, should be associated with relatively high growth rates. If those relationships do not hold, the model's results should be viewed with some caution.

I also recognize that, whereas the Constant Growth DCF model assumes existing capital market conditions will remain constant, Risk Premium-based methods (discussed later in this Appendix) directly reflect the changing capital market environment (*see* Section VI). Because it is important to reflect the

115 Source: Regulatory Research Associates. Eight of those eleven were the outcome of Illinois formula rate plans. Excluding Illinois formula rate plans, since 2015, only two electric utility rate cases included an authorized ROE below 9.00 percent, and only one of those two was for a vertically integrated electric utility.

results of different models, and the mean low Constant Growth DCF results are far-removed from recently authorized returns, I concluded that they should be given less weight than other methods in determining the Company's ROE.

B. CAPM Analyses

Q. PLEASE BRIEFLY DESCRIBE THE GENERAL FORM OF THE CAPM.

A. The CAPM is a risk premium method that estimates the Cost of Equity for a given security as a function of a risk-free return plus a risk premium (to compensate investors for the non-diversifiable or "systematic" risk of that security). As shown in Equation [6], the CAPM is defined by four components, each of which theoretically is a forward-looking estimate:

$$K_e = r_f + \beta(r_m - r_f) \quad [6]$$

where:

K_e = the required market ROE for a security;

β = Beta coefficient of that security;

r_f = the risk-free rate of return; and

r_m = the required return on the market, as a whole.

In Equation [6], the term (r_m – r_f) represents the Market Risk Premium.[116] According to the theory underlying the CAPM, because unsystematic risk can be diversified away by adding securities to investment

116 The Market Risk Premium is defined as the incremental return of the market portfolio over the risk-free rate.

portfolios, investors should be concerned only with systematic or non-diversifiable risk. Non-diversifiable risk is measured by the Beta coefficient, which is defined as:

$$\beta_j = \frac{\sigma_j}{\sigma_m} x\, \rho_{j,m} \quad [7]$$

where:

σ_j = the standard deviation of returns for company "j,"

σ_m = the standard deviation of returns for the broad market (as measured, for example, by the S&P 500 Index), and

$\rho_{j,m}$ = the correlation of returns in between company j and the broad market.

The Beta coefficient therefore represents both relative volatility (*i.e.*, the standard deviation) of returns and the correlation in returns between the subject company and the overall market. Intuitively, Beta coefficients approaching unity indicate the subject company's returns have moved in tandem with the overall market.

Q. WHAT ASSUMPTIONS DID YOU INCLUDE IN YOUR CAPM ANALYSIS?

A. Because utility equity is a long duration investment, I used two different measures of the risk-free rate: (1) the current 30-day average yield on 30-year Treasury bonds (*i.e.*, 2.43 percent);[117] and (2) the near-term projected 30-year

[117] Bloomberg Professional.

Treasury yield (*i.e.*, 2.65 percent).[118]

Q. WHY HAVE YOU RELIED ON THE 30-YEAR TREASURY YIELD FOR YOUR CAPM ANALYSIS?

A. In determining the security most relevant to the application of the CAPM, it is important to select the term (or maturity) that best matches the life of the underlying investment. As noted above, electric utilities typically are long-duration investments and, as such, the 30-year Treasury yield is more suitable for the purpose of calculating the Cost of Equity.

Q. PLEASE DESCRIBE YOUR *EX-ANTE* APPROACH TO ESTIMATING THE MARKET RISK PREMIUM.

A. The approach is based on the market-required return, less the current 30-year Treasury yield. To estimate the market required return, I calculated the market capitalization weighted average ROE based on the Constant Growth DCF model. To do so, I relied on data from two sources: (1) Bloomberg; and (2) Value Line.[119] With respect to Bloomberg-derived growth estimates, I calculated the expected dividend yield (using the same one-half growth rate assumption described earlier), and combined that amount with the projected earnings growth rate to arrive at the market capitalization weighted average DCF result. I performed that calculation for each of the companies for which

118 Blue Chip Financial Forecasts, Vol. 38, No. 8, August 1, 2019, at 2. Consensus projections of the 30-year Treasury yield for the six quarters ending December 2020.

119 Exhibit DWD-2.

Bloomberg provided both dividend yields and consensus growth rates. I then subtracted the current 30-year Treasury yield from that amount to arrive at the market DCF-derived *ex-ante* market risk premium estimate. In the case of Value Line, I performed the same calculation, again using all companies for which five-year earnings growth rates were available. The results of those calculations are provided in Exhibit DWD-2.

Q. HOW DID YOU APPLY YOUR EXPECTED MARKET RISK PREMIUM AND RISK-FREE RATE ESTIMATES?

A. I relied on the *ex-ante* Market Risk Premia discussed above, together with the current and near-term projected 30-year Treasury yields as inputs to my CAPM analysis.

Q. WHAT BETA COEFFICIENTS DID YOU USE IN YOUR CAPM MODEL?

A. As shown in Exhibit DWD-3, I considered the Beta coefficients reported by Value Line and Bloomberg, both of which adjust their calculated (or "raw") Beta coefficients to reflect the tendency of the Beta coefficient to regress to the market mean of 1.00. A notable difference between the two is that Value Line calculates the Beta coefficient over a five-year period, whereas Bloomberg's calculation is based on two years of data.

Q. WHAT ARE THE RESULTS OF YOUR CAPM ANALYSIS?

A. As shown in Table 8 (below) the CAPM analyses suggest an ROE range of 8.44

percent to 9.62 percent (*see also* Exhibit DWD-4).

Table 8: Summary of CAPM Results[120]

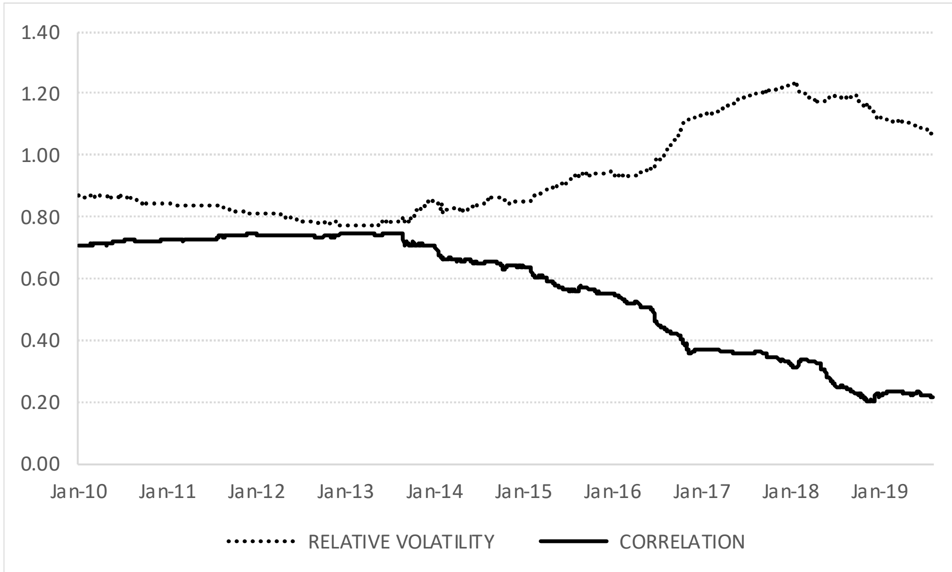
	Bloomberg Derived Market Risk Premium	**Value Line Derived Market Risk Premium**
Average Bloomberg Beta Coefficient		
Current 30-Year Treasury (2.43%)	8.44%	8.52%
Near Term Projected 30-Year Treasury (2.65%)	8.66%	8.74%
Average Value Line Beta Coefficient		
Current 30-Year Treasury (2.43%)	9.32%	9.41%
Near Term Projected 30-Year Treasury (2.65%)	9.54%	9.62%

Q. DOES THE RECENT DECLINE IN THE PROXY GROUP AVERAGE BETA COEFFICIENT IMPLY A DECREASE IN RISK RELATIVE TO THE MARKET?

A. Not necessarily. Although the proxy group average Beta coefficient reported by Bloomberg has fallen from approximately 0.76 in 2014 to 0.50 in August 2019, as Chart 16 below demonstrates, when the Beta coefficient is deconstructed into its components shown in Equation [7] above, we see that the correlation between the proxy group companies and the S&P 500 has declined, while the relative risk has increased. Given that the correlation between the proxy group companies and the S&P 500 has declined since 2014, while the relative risk has increased, the CAPM in the form presented here may not adequately reflect the expected systematic risk, and therefore, the returns required by investors in low-Beta coefficient companies such as utilities.

120 Exhibit DWD-4.

Chart 16: Components of Beta Coefficients Over Time[121]



Q. DID YOU CONSIDER ANOTHER FORM OF THE CAPM IN YOUR ANALYSIS?

A. Yes. I also included the ECAPM approach, which calculates the product of the adjusted Beta coefficient and the Market Risk Premium, and applies a weight of 75.00 percent to that result. The model then applies a 25.00 percent weight to the Market Risk Premium, without any effect from the Beta coefficient.[122] The results of the two calculations are summed, along with the risk-free rate, to produce the ECAPM result, as noted in Equation [8] below:

$$k_e = r_f + 0.75\beta(r_m - r_f) + 0.25(r_m - r_f) \qquad [8]$$

where:

k_e = the required market ROE.

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121 Source: S&P Global Market Intelligence. Calculated as an index.
122 *See, e.g.*, Roger A. Morin, *New Regulatory Finance* 189-90 (2006).

β = Adjusted Beta coefficient of an individual security.

r_f = the risk-free rate of return.

r_m = the required return on the market as a whole.

Q. WHAT IS THE BENEFIT OF THE ECAPM APPROACH?

A. The ECAPM addresses the tendency of the CAPM to under-estimate the Cost of Equity for companies, such as regulated utilities, with low Beta coefficients. As discussed below, the ECAPM recognizes the results of academic research indicating that the risk-return relationship is different (in essence, flatter) than estimated by the CAPM, and that the CAPM under-estimates the alpha, or the constant return term.[123]

Numerous tests of the CAPM have measured the extent to which security returns and Beta coefficients are related as predicted by the CAPM. The ECAPM method reflects the finding that the actual Security Market Line ("SML") described by the CAPM formula is not as steeply sloped as the predicted SML.[124] Fama and French state that "[t]he returns on the low beta portfolios are too high, and the returns on the high beta portfolios are too low."[125] Similarly, Morin states:

> With few exceptions, the empirical studies agree that . . . low-beta securities earn returns somewhat higher than the CAPM

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123 *Ibid.*, at 191 ("The ECAPM and the use of adjusted betas comprised two separate features of asset pricing. Even if a company's beta is estimated accurately, the CAPM still understates the return for low-beta stocks.").

124 *Ibid.* at 175. The Security Market Line plots the CAPM estimate on the Y-axis, and Beta coefficients on the X-axis.

125 Eugene F. Fama & Kenneth R. French, *The Capital Asset Pricing Model: Theory and Evidence*, Journal of Economic Perspectives, Vol. 18, No. 3, Summer 2004, at 33.

> would predict, and high-beta securities earn less than predicted. . . .
>
> Therefore, the empirical evidence suggests that the expected return on a security is related to its risk by the following approximation:
>
> $$K = R_F + x(R_M - R_F) + (1\text{-}x)\ \beta(R_M - R_F)$$
>
> where x is a fraction to be determined empirically. The value of x that best explains the observed relationship Return = 0.0829 + 0.0520 β is between 0.25 and 0.30. If x = 0.25, the equation becomes:
>
> $$K = R_F + 0.25(R_M - R_F) + 0.75\ \beta(R_M - R_F)$$ [126]

Some analysts claim that using adjusted Beta coefficients addresses the empirical issues with the CAPM by increasing the expected returns for low Beta coefficient stocks and decreasing the returns for high Beta coefficient stocks, concluding that there is no need for the ECAPM approach. I disagree with that conclusion. Beta coefficients are adjusted because of their general regression tendency to converge toward 1.00 over time, *i.e.*, over successive calculations. As also noted earlier, numerous studies have determined that at any given point in time, the SML described by the CAPM formula is not as steeply sloped as the predicted SML. To that point, Morin states:

> Some have argued that the use of the ECAPM is inconsistent with the use of adjusted betas, such as those supplied by Value Line and Bloomberg. This is because the reason for using the ECAPM is to allow for the tendency of betas to regress toward the mean value of 1.00 over time, and, since Value Line betas are already adjusted for such trend, an ECAPM analysis results

[126] Roger A. Morin, *New Regulatory Finance* 175, 190 (2006).

> in double-counting. This argument is erroneous. Fundamentally, the ECAPM is not an adjustment, increase or decrease, in beta. This is obvious from the fact that the expected return on high beta securities is actually lower than that produced by the CAPM estimate. The ECAPM is a formal recognition that the observed risk-return tradeoff is flatter than predicted by the CAPM based on myriad empirical evidence. The ECAPM and the use of adjusted betas comprised two separate features of asset pricing. Even if a company's beta is estimated accurately, the CAPM still understates the return for low-beta stocks. Even if the ECAPM is used, the return for low-beta securities is understated if the betas are understated. Referring back to Figure 6-1, the ECAPM is a return (vertical axis) adjustment and not a beta (horizontal axis) adjustment. Both adjustments are necessary. [127]

Therefore, it is appropriate to rely on adjusted Beta coefficients in both the CAPM and ECAPM. As with the CAPM, my application of the ECAPM uses the Market DCF-derived *ex-ante* Market Risk Premium estimate, the current yield on 30-year Treasury securities as the risk-free rate, and two estimates of the Beta coefficient. The results of my ECAPM analyses are shown in Exhibit DWD-4 and summarized in Table 9 below.

[127] *Ibid.*, at 191.

Table 9: Summary of ECAPM Results[128]

	Bloomberg Derived Market Risk Premium	Value Line Derived Market Risk Premium
Average Bloomberg Beta Coefficient		
Current 30-Year Treasury (2.43%)	9.95%	10.04%
Near Term Projected 30-Year Treasury (2.65%)	10.17%	10.26%
Average Value Line Beta Coefficient		
Current 30-Year Treasury (2.43%)	10.61%	10.71%
Near Term Projected 30-Year Treasury (2.65%)	10.83%	10.93%

C. Bond Yield Plus Risk Premium Analysis

Q. PLEASE DESCRIBE THE BOND YIELD PLUS RISK PREMIUM APPROACH.

A. This approach is based on the basic financial tenet that equity investors bear the residual risk associated with ownership and therefore require a premium over the return they would have earned as a bondholder. That is, because returns to equity holders have more risk than returns to bondholders, equity investors must be compensated for bearing that additional risk. Risk premium approaches, therefore, estimate the Cost of Equity as the sum of the Equity Risk Premium and the yield on a given class of bonds. Since the Equity Risk Premium is not directly observable, it typically is estimated using a variety of approaches, some of which incorporate *ex-ante*, or forward-looking estimates of the Cost of

128 Exhibit DWD-4.

Equity, and others that consider historical, or *ex-post*, estimates. An alternative approach is to use actual authorized returns for electric utilities to estimate the Equity Risk Premium.

Q. PLEASE EXPLAIN HOW YOU PERFORMED YOUR BOND YIELD PLUS RISK PREMIUM ANALYSIS.

A. As suggested above, I first defined the Equity Risk Premium as the difference between the authorized ROE and the then-prevailing level of the long-term (*i.e.*, 30-year) Treasury yield. I therefore gathered data for the ROE authorized in 1,594 electric utility rate proceedings between January 1980 and August 16, 2019. In addition to the authorized ROE, I also calculated the average period between the filing of the case and the date of the final order (the "lag period"). To reflect the prevailing level of interest rates during the pendency of the proceedings, I calculated the average 30-year Treasury yield over the average lag period (approximately 200 days).[129]

Because the data covers multiple economic cycles,[130] the analysis also may be used to assess the stability of the Equity Risk Premium. For example, prior research has shown that the Equity Risk Premium is inversely related to

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[129] Regulatory proceedings frequently retroactively apply the newly authorized ROE to a period preceding the decision date.

[130] *See,* National Bureau of Economic Research, *U.S. Business Cycle Expansions and Contractions*.

the level of interest rates.[131] That analysis is particularly relevant given the relatively low level of current Treasury yields.

Q. HOW DID YOU ANALYZE THE RELATIONSHIP BETWEEN INTEREST RATES AND THE EQUITY RISK PREMIUM?

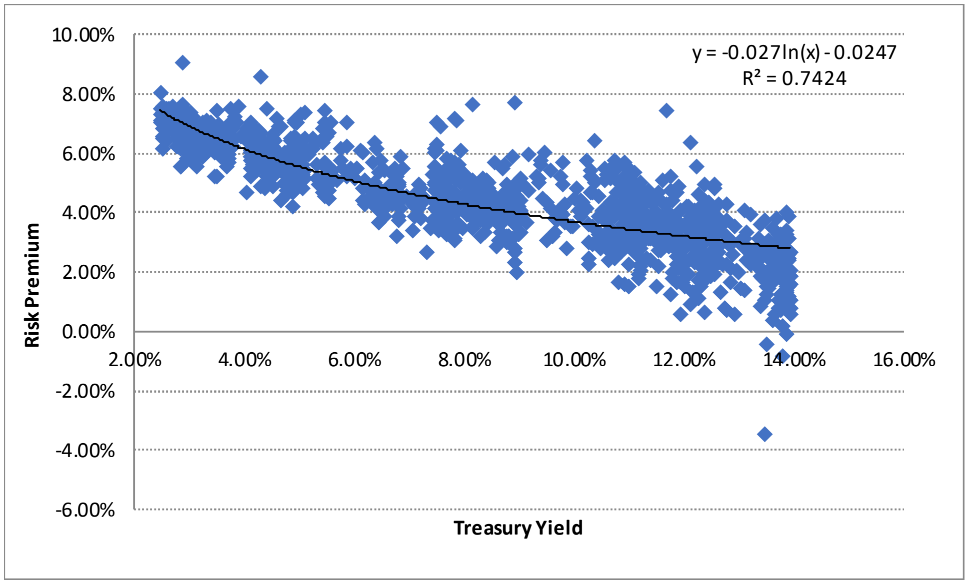
A. The basic method used was regression analysis, in which the observed Equity Risk Premium is the dependent variable, and the average 30-year Treasury yield is the independent variable. Relative to the long-term historical average, the analytical period includes interest rates and authorized ROEs that are quite high during one period (*i.e.*, the 1980s) and that are quite low during another (*i.e.*, the post-Lehman bankruptcy period). To account for that variability, I used the semi-log regression, in which the Equity Risk Premium is expressed as a function of the natural log of the 30-year Treasury yield:

$$\mathrm{RP} = \alpha + \beta(LN(T_{30})) \quad [9]$$

As shown on Chart 17 (below), the semi-log form is useful when measuring an absolute change in the dependent variable (in this case, the Risk Premium) relative to a proportional change in the independent variable (the 30-year Treasury yield).

131 *See, e.g.*, Robert S. Harris and Felicia C. Marston, *Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts*, Financial Management, (Summer 1992), at 63-70; Eugene F. Brigham, Dilip K. Shome, and Steve R. Vinson, *The Risk Premium Approach to Measuring a Utility's Cost of Equity*, Financial Management, (Spring 1985), at 33-45; and Farris M. Maddox, Donna T. Pippert, and Rodney N. Sullivan, *An Empirical Study of Ex Ante Risk Premiums for the Electric Utility Industry*, Financial Management, (Autumn 1995), at 89-95.

Chart 17: Equity Risk Premium[132]



As Chart 17 illustrates, over time there has been a statistically significant, negative (*i.e.*, inverse) relationship between the 30-year Treasury yield and the Equity Risk Premium. Consequently, simply applying the long-term average Equity Risk Premium of 4.68 percent would significantly understate the Cost of Equity and produce results well below any reasonable estimate. Based on the regression coefficients in Chart 17, however, the implied ROE is between 9.90 percent and 10.06 percent (*see* Table 10 and Exhibit DWD-5).

132 Exhibit DWD-5.

Table 10: Summary of Bond Yield Plus Risk Premium Results

	Return on Equity
Current 30-Year Treasury (2.43%)	9.91%
Near-Term Projected 30-Year Treasury (2.65%)	9.90%
Long-Term Projected 30-Year Treasury (3.70%)	10.06%

D. Expected Earnings

Q. PLEASE DESCRIBE THE EXPECTED EARNINGS ANALYSIS.

A. The Expected Earnings analysis is based on the principle of opportunity costs. Because investors may invest in and earn returns on alternative investments of similar risk, those rates of return can provide a useful benchmark in determining the appropriate rate of return for a firm. Further, because those results are based solely on the returns expected by investors, exclusive of market-data or models, the Expected Earnings approach provides a direct comparison.

Q. PLEASE EXPLAIN HOW THE EXPECTED EARNINGS ANALYSIS IS CONDUCTED.

A. The Expected Earnings analysis typically takes the actual earnings on book value of investment for each of the members of the proxy group and compares those values to the rate of return in question. Although the traditional approach uses data based on historical accounting records, it is common to use forecasted data in conducting the analysis. Projected returns on book investment are provided by various industry publications (*e.g.*, Value Line), which I have used in my analysis.

I relied on Value Line's projected Return on Common Equity for the period 2022-2024, and adjusted those projected returns to account for the fact that they reflect common shares outstanding at the end of the period, rather than the average shares outstanding over the course of the year.[133] The Expected Earnings analysis results in an average value of 10.47 percent and a median value of 10.54 percent (*see* Exhibit DWD-6).

[133] The rationale for that adjustment is straightforward: Earnings are achieved over the course of a year, and should be related to the equity that was, on average, in place during that year. *See,* Leopold A. Bernstein, Financial Statement Analysis: Theory, Application, and Interpretation, Irwin, 4th Ed., 1988, at 630.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1219

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

I. INTRODUCTION AND PURPOSE

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

A. My name is Dylan W. D'Ascendis. I am a Director at ScottMadden, Inc. My business address is 3000 Atrium Way, Suite 241, Mount Laurel, New Jersey 08054.

Q. ON WHOSE BEHALF ARE YOU SUBMITTING THIS TESTIMONY?

A. I am submitting this rebuttal testimony ("Rebuttal Testimony") before the North Carolina Utilities Commission ("Commission") on behalf of Duke Energy Corporation, doing business in North Carolina as Duke Energy Progress, LLC ("DE Progress" or the "Company").

Q. ARE YOU THE SAME DYLAN W. D'ASCENDIS THAT SUBMITTED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes, I am.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my Rebuttal Testimony is to respond to the direct testimony of the following Intervenor witnesses with respect to the Return on Equity ("ROE") and capital structure:

- Dr. J. Randall Woolridge, who testifies on behalf of Public Staff ("Staff");
- Mr. Richard A. Baudino, who testifies on behalf of the North Carolina Attorney General's Office ("AG");
- Mr. Kevin W. O'Donnell, who testifies on behalf of the Carolina Utility Customers Association ("CUCA");
- Mr. Steve W. Chriss, who testifies on behalf of the Commercial Group ("Commercial Group"); and
- Mr. Nicholas Phillips, Jr., who testifies on behalf of Carolina Industrial Group for Fair Utility Rates ("CIGFUR").

I refer to these witnesses collectively as the "Opposing Witnesses" as their testimony relates to the Company's ROE and capital structure. I also respond to the direct testimony of Staff Witness Mr. John R. Hinton, as his testimony relates to the Return on Equity assumptions in the Company's nuclear decommissioning trust fund ("NDTF"). My Rebuttal Testimony also updates many of the analyses contained in my Direct Testimony, and provides several additional analyses developed in response to the Opposing Witnesses.

II. SUMMARY AND CONCLUSIONS

Q. WHAT ARE YOUR SPECIFIC OBSERVATIONS REGARDING THE OPPOSING WITNESSES' RETURN ON EQUITY AND CAPITAL STRUCTURE RECOMMENDATIONS?

A. Quite simply, the Opposing Witnesses' recommendations are below any reasonable measure of the Company's Cost of Equity. As discussed throughout my Rebuttal Testimony, those recommendations (1) are far below those authorized for other utilities nationally and in North Carolina, (2) do not appropriately reflect the current capital market environment, and (3) do not recognize the risks faced by DE Progress.

There is no question the capital markets are undergoing a severe dislocation. The speed and severity of the increase in volatility and the loss in value has cut across all sectors, including utilities. As discussed below, during the period from mid-February through April 17, 2020, the utility sector lost as much as 34.00 percent of its value, and the correlation between utility stocks and the overall market approached 100.00 percent. In my opinion, recommended ROEs in the range of 8.40 percent (in the case of Dr. Woolridge's alternative recommendation) to 9.00 percent (in the case of Dr. Woolridge's primary recommendation, as well as Mr. Baudino's recommendation) would compound the significantly elevated risks utilities currently face.[1]

[1] Mr. O'Donnell's 8.75 percent ROE recommendation also falls within this range.

Based on the analyses discussed in my Direct and Rebuttal Testimony, I continue to believe the Company faces risks that fully support my ROE recommendation. Looking to all model results, and considering the quantitative and qualitative data presented throughout my Rebuttal Testimony, including the current capital market conditions, I continue to recommend an ROE in the range of 10.00 percent to 11.00 percent, with a point estimate of 10.50 percent.

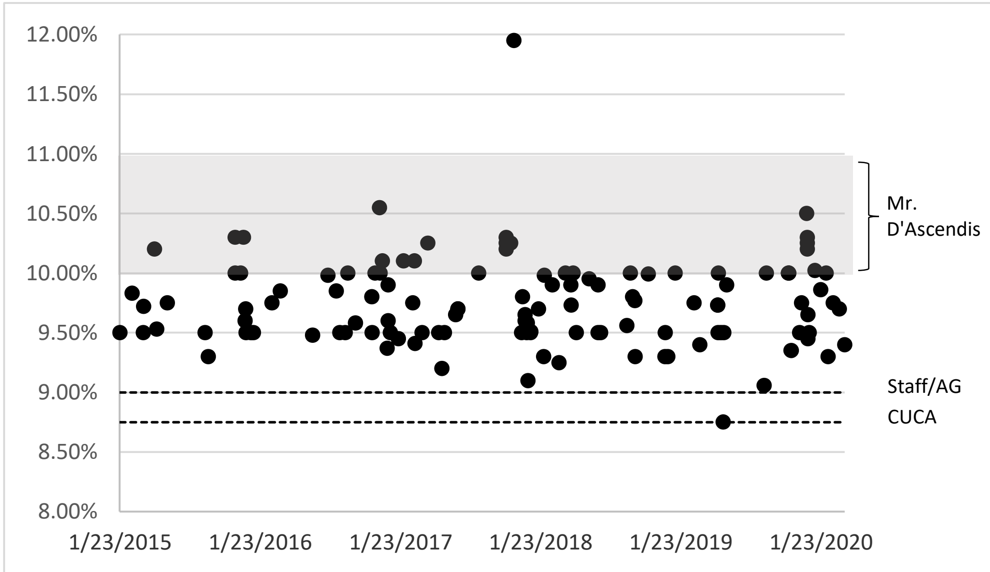
As to the Company's proposed capital structure, none of the Opposing Witnesses have explained why their proposals properly address the many and complicated financing objectives and constraints that operating utilities must manage. Rather, they inappropriately point to capital structures at the consolidated parent, without acknowledging the importance of matching the nature of utility assets and operations with the components of capital used to fund those assets. Further, although certain of the Opposing Witnesses suggest the Company should take on more financial risk to take advantage of debt costs below the Cost of Equity, they fail to acknowledge the costs and risks brought about by that increased financial risk. On balance, I believe the Opposing Witnesses' recommendations are overly simplistic, their analyses are partial, and their proposals should be rejected.

Q. PLEASE NOW PROVIDE AN OVERVIEW OF YOUR RESPONSE TO THE ROE RECOMMENDATIONS MADE BY THE OPPOSING WITNESSES.

A. Although the Opposing Witnesses believe their recommendations are reasonable and support the Company's financial integrity, nearly all authorized ROEs for vertically integrated electric utilities over the last five years have been above their recommendations (*see* Chart 1, below). Whereas the Opposing Witnesses' recommendations are far below those available to other utilities, my recommended range (10.00 percent to 11.00 percent), is within that range.[2]

[2] There have been 23 vertically integrated electric rate cases since January 1, 2017 in which the authorized ROE was 10.00 percent or greater. Of those, eleven were authorized in 2019-2020. *See*, Rebuttal Exhibit DWD-8.

Chart 1: Vertically Integrated Electric Utility Authorized ROEs (2015 – 2020) and Witness Recommendations[3]



That significant departure from the returns available to other utilities raises two concerns. First, DE Progress must compete with other companies, including utilities, for the long-term capital needed to provide safe and reliable utility service. Given the choice between two similarly situated utilities, one with a return that falls far below industry averages and another with a return that more closely aligns with returns available to other utilities, investors will choose the latter. That is a particular concern for the Company, given its risk profile, its need to access external capital, and the implication of Staff's overall recommendation. If the Commission were to approve an ROE in the range recommended by the Opposing Witnesses, investors would receive a lower

[3] Source: Regulatory Research Associates ("RRA"). Authorized ROEs for vertically integrated electric utilities from January 1, 2015 through April 15, 2020. ROEs authorized for limited issue rate rider proceedings are excluded.

return with greater risk than would be available from other utilities. A likely outcome would be increasing reluctance on the part of investors to provide capital at reasonable costs and terms.

Second, although no regulatory commission sets returns solely by reference to those authorized elsewhere, authorized returns do provide observable and measurable benchmarks against which return recommendations may be assessed. In my experience, regulatory commissions generally consider the same types of market, methodological, and risk factors at issue in this proceeding. They recognize that financial models are important tools in determining returns and understand that because all are subject to assumptions, no one method is most reliable at all times, or under all conditions.

As discussed throughout my Rebuttal Testimony, that holds true in this case. Even if we focus on a single method, it remains critically important to apply reasoned judgment to determine where the Cost of Equity falls within that model's range of results. Just as investors consider company-specific and general market factors in developing their return requirements, we should do the same. Those considerations, and that judgment, lead to the conclusion that the Opposing Witnesses' ROE recommendations are unduly low.

Q. HAS THE COMMISSION NOTED THE RISKS SURROUNDING SETTING AN ROE THAT MAY BE TOO LOW?

A. Yes, it has. In its Order in Docket No. E-7, Sub 1026, the Commission clearly stated it is well aware of the adverse effects of an unduly low ROE. Citing to its Order in Docket No. E-2, Sub 1023, the Commission noted that:

> Moreover, the Commission in establishing a rate of return on equity and other cost of service determinations is mindful that should it set the rate of return on equity too low, the impact on long term rates may be harmful to ratepayers. The utilities the Commission regulates compete in a market to raise capital. Financial analysts, rating agencies, and investors themselves scrutinize with great care the regulatory environment and decisions in which these utilities operate. The regulatory environment includes the utilities commissions, consumer advocates, the state legislature, the executive branch and the appellate courts. When regulatory risk is high, the cost of capital goes up. Should regulatory ratemaking decisions swing too far toward low consumer rates in a given case, the long term result may likely be higher rates in the future, irrespective of the now unknown economic conditions that will exist at such future time.[4]

I appreciate that the Commission has the difficult obligation of balancing the interests of investors and customers, such that rates are fair and reasonable, and the Company is allowed the opportunity to receive a reasonable return. As the Commission found, that balance is necessary for the Company to be "financially sound and capable of providing its customers with safe and reliable service".[5] That finding is particularly important during times of market volatility and uncertainty, as we currently are experiencing. I also appreciate the Commission's finding that the lowest rate of return does not necessarily achieve that balance; as the Commission observed, a return too low in the near-

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[4] North Carolina Utilities Commission, Docket No. E-7, Sub 1026, *Order Granting General Rate Increase*, Issued September 24, 2013, at 39 – 40.

[5] North Carolina Utilities Commission, Docket No. E-7, Sub 989, *Order on Remand*, Issued October 23, 2013, at 42.

term may produce higher customer rates in the future. In that important respect, I believe the Opposing Witnesses' recommendations do not strike the balance the Commission seeks to achieve.

Q. IS THERE REASON TO BE CONCERNED THAT THE FINANCIAL COMMUNITY WOULD REACT ADVERSELY IF AN ROE IN THE RANGE OF THE OPPOSING WITNESSES' RECOMMENDATIONS WAS TO BE ADOPTED?

A. Yes. Investors are aware of and are concerned with decisions that depart from regulatory practice. Here, the Opposing Witnesses' recommendations are far removed from recent regulatory decisions. In my view, that departure presents a risk that would cause investors to increase the return they would require to invest in the Company. If that were to occur, and its equity were to be further devalued, the Company's ability to compete for the capital needed to fund its utility investments would be further diminished.

Q. ARE YOU AWARE OF A RECENT RATE DECISION IN WHICH THE FINANCIAL COMMUNITY RESPONDED NEGATIVELY TO AN ADVERSE REGULATORY OUTCOME?

A. Yes, I am. In February 2020, following several months of regulatory deliberations, CenterPoint Energy Houston Electric, LLC ("CEHE") was authorized an ROE of 9.40 percent, together with an equity ratio of 42.50

percent.[6] By way of background, CEHE represents about 45.00 percent of CenterPoint Energy's ("CNP") combined net income.[7] The financial community closely followed the Public Utility Commission of Texas's ("PUCT") deliberations, which initially called for an ROE of 9.25 percent and an equity ratio of 40.00 percent. The real-time effect of those deliberations has been clear: CNP, significantly underperformed the utility sector, and its credit rating from FitchRatings ("Fitch") was downgraded by one credit "notch." The equally clear effect is that CEHE's cost of capital has increased, to the detriment of its customers. Please see Appendix A for further detail regarding CNP's stock price performance during the PUCT's deliberations.

III. CAPITAL MARKET CONDITIONS AND THE COMPANY'S COST OF EQUITY

Q. PLEASE BRIEFLY SUMMARIZE THE OPPOSING WITNESSES' POSITIONS REGARDING THE RECENT CAPITAL MARKET DISLOCATION, AND ITS IMPLICATIONS FOR THE COMPANY'S COST OF EQUITY.

A. Although the Opposing Witnesses recognize the significant instability arising from COVID-19, they do not see the pandemic, or its effect on capital markets, as meaningfully affecting the returns investors require for electric utilities. Dr.

[6] *See*, S&P Global Market Intelligence, *Texas PUC OKs CenterPoint rate case settlement, adds no dividend restrictions*, February 14, 2020.

[7] CenterPoint Energy, Inc. SEC Form 10-K for the fiscal year ended December 31, 2019, at 61, 63. As of December 2019, CEHE represented about 50.00 percent of CNP's combined pre-tax operating profit (75.00 percent as of December 2018).

Woolridge points to average annual authorized ROEs since 2000,[8] along with declines in Treasury yields[9] and "historically low" utility bond yields[10], concluding "[c]apital 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".[11]

Regarding the current market environment, Dr. Woolridge argues market prices have become so disconnected from "fundamentals" that we cannot rely on the models typically used to estimate the Cost of Equity.[12] Dr. Woolridge notes the dislocation's effect on models is uneven, noting an uncertain effect on the Discounted Cash Flow ("DCF") and Capital Asset Pricing Model ("CAPM") approaches, and no meaningful effect on the Risk Premium model.[13] Because those results remain highly uncertain, Dr. Woolridge bases his recommendation on data from early February, prior to the COVID-19 pandemic.

Although he "reserve[s] the right to update [his] testimony and recommendations",[14] Mr. Baudino's analyses rely on data through the end of February 2020, largely prior to the market dislocation associated with the

[8] Testimony of J. Randall Woolridge, at 31-32.
[9] Testimony of J. Randall Woolridge, at 17, B-2.
[10] Testimony of J. Randall Woolridge, at 95.
[11] Testimony of J. Randall Woolridge, at 98.
[12] Testimony of J. Randall Woolridge, at 25-28.
[13] Testimony of J. Randall Woolridge, at 27-29.
[14] Direct Testimony of Richard A. Baudino, at 5.

COVID-19 pandemic.[15] While Mr. O'Donnell's analyses use data into April 2020, he only briefly discusses the recent market disruption and does not draw any conclusions regarding the effect on the Company's Cost of Equity.[16]

Q. PLEASE DESCRIBE THE CURRENT CAPITAL MARKET CONDITIONS, AND THEIR IMPLICATIONS FOR ESTIMATING THE COMPANY'S COST OF EQUITY.

A. The recent, dramatic shifts in the capital markets brought about by the COVID-19 virus cannot be overstated. From February 12 to April 17, the S&P 500 lost about 15.00 percent of its value, and the utility sector lost about 12.00 percent.[17] During that time the broad market and the utility sector both had lost as much as 34.00 percent.[18] The VIX, which measures expected market volatility, increased six-fold (from 13.68 on February 14 to 82.69 on March 16); on March 9, the 30-year Treasury yield fell below 1.00 percent.[19]

Central banks have implemented multiple policies to address the financial market instability. On March 3, 2020, the Federal Reserve reduced the overnight lending rate by 50 basis points, to a target range of 1.00 percent to 1.25 percent. It did so in light of the "evolving risks to economic activity"

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15 Direct Testimony of Richard A. Baudino, at 2; Exhibit RAB-2, Exhibit RAB-3, Exhibit RAB-4.

16 Direct Testimony of Kevin W. O'Donnell, at 68-70. Exhibits KWO-1 through KWO-10.

17 Source: S&P Capital IQ. Utility sector measured by the XLU, and Dow Jones Utility Average.

18 Source: S&P Capital IQ. Utility sector measured by the XLU, and Dow Jones Utility Average. Largest losses occurred on March 23, 2020.

19 Source: Bloomberg Professional.

posed by the coronavirus, and despite its view that "[t]he fundamentals of the U.S. economy remain strong."[20] On March 12, 2020, the Federal Reserve Bank of New York ("FRBNY") released a statement regarding "Treasury Reserve Management Purchases and Repurchase Operations". In that statement, the FRBNY announced that from March 13 to April 13, 2020 it would repurchase $60 billion of Treasury securities "across a range of maturities". The FRBNY also stated it had updated its monthly schedule of repurchase agreement operations to "address temporary disruptions in Treasury financing markets." Together, the FRBNY's changes were meant to "address highly unusual disruptions in Treasury financing markets associated with the coronavirus outbreak."

Three days later, on March 15, 2020, the Bank of Canada, the Bank of England, the Bank of Japan, the European Central Bank, the Federal Reserve, and the Swiss National Bank announced "a coordinated action to enhance the provision of liquidity via the standing U.S. dollar liquidity swap line arrangements."[21] The same day, the Federal Reserve lowered the Federal Funds rate by an additional 100 basis points, to a target range of 0.00 percent to 0.25 percent, and announced its plan to increase holdings of Treasury securities and agency mortgage-backed securities by a total of $700 billion.[22]

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[20] Federal Reserve Press Release, March 3, 2020.

[21] Federal Reserve Press Release, *Coordinated Central Bank Action to Enhance the Provision of Global U.S. Dollar Liquidity*, March 15, 2020.

[22] Federal Reserve Press Release, March 15, 2020.

In late March, the Federal Reserve announced additional initiatives to support the capital markets, including a new method to measure counterparty credit risk derivatives contracts, an optional extension of the regulatory capital transition for the new credit loss accounting standard[23], and the establishment of a "temporary FIMA Repo Facility" intended to support "the smooth functioning of financial markets, including the U.S. Treasury market, and thus maintain the supply of credit to U.S. households and businesses."[24]

On March 23, the U.S. House of Representatives introduced a bill providing approximately $2.5 trillion of economic stimulus payments; on March 25, the U.S. Senate passed the Coronavirus Aid, Relief, and Economic Security Act, which was signed into law on March 27, 2020. On April 24, President Trump signed the Paycheck Protection Program and Health Care Enhancement Act that provided an additional $484 billion in emergency aid.[25]

On April 6, the Federal Reserve announced it would "establish a facility to facilitate lending to small businesses via the Small Business Administration's Paycheck Protection Program ("PPP") by providing term financing backed by PPP loans"[26]. On April 9, it "took additional actions to provide up to $2.3 trillion in loans to support the economy", explaining that the "funding will assist

[23] Joint Press Release, Board of Governors of the Federal Reserve System Federal Deposit Insurance Corporation Office of the Comptroller of the Currency, March 27, 2020.
[24] Federal Reserve Press Release, March 31, 2020.
[25] S&P Global Market Intelligence, *Trump signs $484B coronavirus relief package into law*, April 24, 2020.
[26] Federal Reserve Press Release, April 6, 2020.

households and employers of all sizes and bolster the ability of state and local governments to deliver critical services during the coronavirus pandemic."[27] By April 22, Securities Held Outright on the Federal Reserve's balance sheet increased to $5.45 trillion from $3.81 trillion on February 5, 2020.[28]

The April 10, 2020 edition of *Blue Chip Economic Indicators* ("*Blue Chip*") described the pandemic's effect on the general economy as follows:

> This month's Blue Chip Economic Indicators panel's forecast for real GDP in Q2 2020 is estimated to set a historical record – by far: a plunge of -24.5% SAAR [Seasonally Adjusted Annual Rate]. The previous record was -10.0% in Q1 1958; quarterly data began in Q1 1947. In its February forecast, the panel had projected Q2 growth to be 1.9% SAAR and in March 1.0%.[29]

Blue Chip further explained that it expects the "easing of the current outbreak of the disease and accompanying social distancing practices will support a visible recovery in the second half of this year and on into 2021." At the same time, *Blue Chip* cautioned that "the speed of the recovery would be nowhere near the magnitude of the drop", and according to its consensus forecast, "real GDP would not recover to its previous peak until the fourth quarter of 2021."[30]

According to the U.S. Department of Labor ("DOL"), the seasonally adjusted insured unemployment rate for the week ending April 4, 2020 was 8.20 percent. As DOL explained, "[t]his marks the highest level of the seasonally

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27 Federal Reserve Press Release, April 9, 2020.
28 Federal Reserve Schedule H.4.1
29 *Blue Chip Economic Indicators*, April 10, 2020, at 1. [clarification added]
30 *Ibid*.

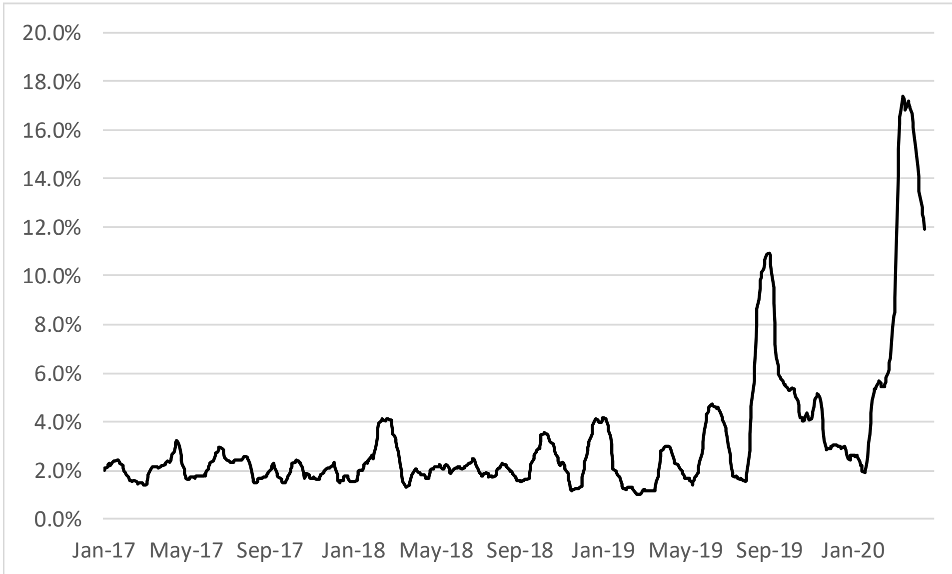
adjusted insured unemployment rate in the history of the seasonally adjusted series." The previous high, set in May 1975, was 7.00 percent.[31] By April 11th, the rate increased to 11.00 percent.[32] On April 29, 2020, the Bureau of Economic Analysis released its estimate for Gross Domestic Product ("GDP") for the first quarter of 2020, showing real GDP declined by 4.80 percent (annual rate) in the first three months of the year.[33]

It is within that broad context that on April 2, Standard & Poor's ("S&P") downgraded its outlook on the utility sector from "Stable" to "Negative", explaining that it expects a 12.00 percent contraction in GDP during the second quarter of 2020, reducing commercial and industrial usage.[34]

Despite central bank actions, the 30-Year Treasury bond yield has remained highly volatile, as seen in its Coefficient of Variation ("CoV"), (*see* Chart 2 below).

[31] U.S. Department of Labor News Release, April 16, 2020.
[32] U.S. Department of Labor News Release, April 23, 2020
[33] U.S. Bureau of Economic Analysis News Release, April 29, 2020.
[34] S&P Global Ratings, *COVID-19: The Outlook For North American Regulated Utilities Turns Negative*, April 2, 2020, at 1, 6-7.

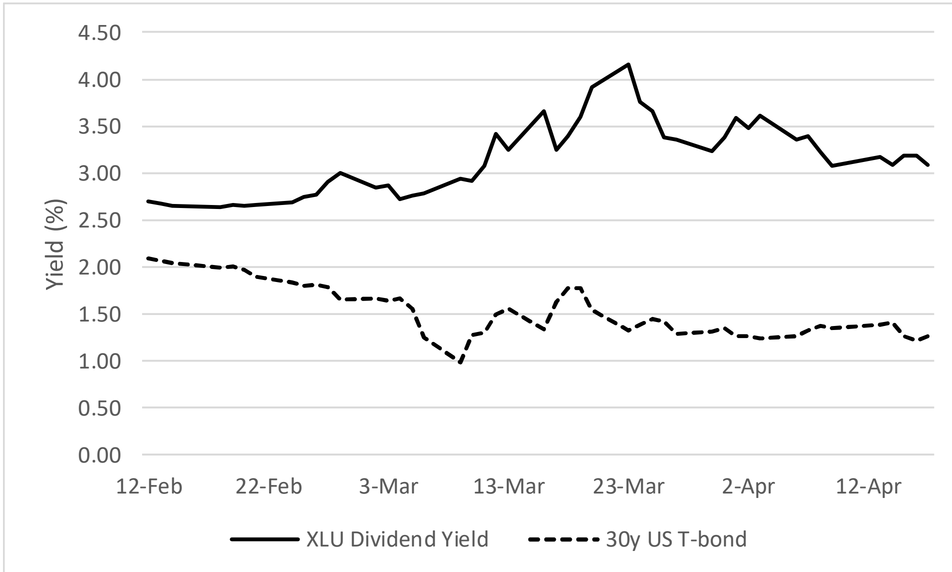
Chart 2: Coefficient of Variation in 30-Year Treasury Yields[35]



Investor reactions to the market instability also are reflected in the "yield spread", or the difference between dividend yields and long-term Government bond yields. As the 30-year Treasury yield fell, utility dividend yields increased, widening the yield spread (*see* Chart 3, below). That pattern, in which utility dividend yields move in the opposite direction of interest rates, reflects the disjointed capital market, and investors' reactions to it. Under more "normal" conditions, dividend yields tend to be directionally related to Treasury yields, such that the yield spread remains relatively constant. But that relationship has a limit. Investors will not continuously bid up utility prices as interest rates fall; the widening yield spread demonstrates as much.

35 Source: S&P Global Market Intelligence.

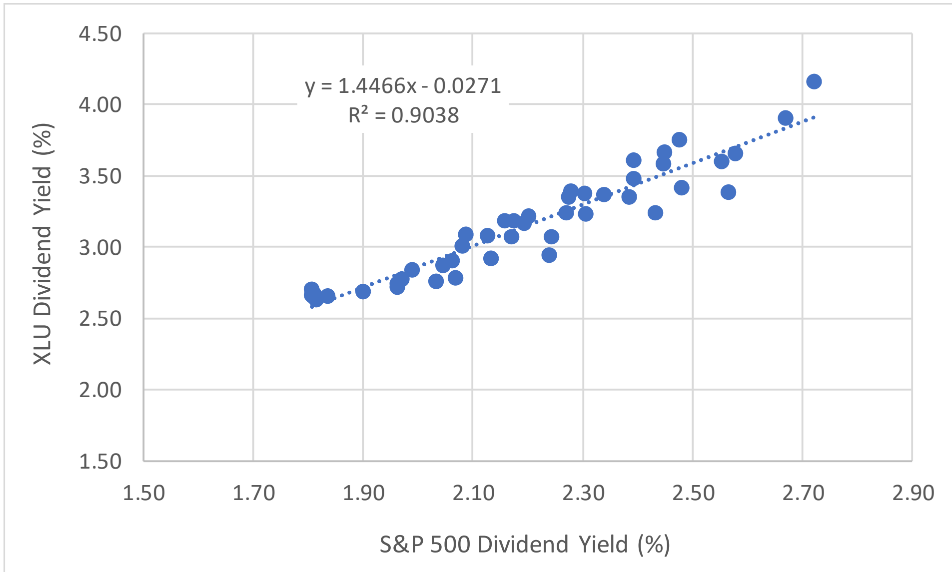
Chart 3: Utility Dividend Yields vs. 30-Year Treasury Yields[36]



From a slightly different perspective, from January 1 to February 11, 2020, the correlation between the S&P 500 dividend yield and the utility sector dividend yield was about 14.00 percent. From February 12 through April 17, 2020 it increased to 95.00 percent (*see* Chart 4, below). That increasing correlation is not surprising. As Morningstar recently explained, during volatile markets there often is little distinction in returns across assets or portfolios. That is, "correlations go to 1."[37] When that happens, utility stocks lose their "defensive" quality.

[36] Source: S&P Capital IQ.
[37] Morningstar, *Correlations Going to 1: Amid Market Collapse, U.S. Stock Fund Factors Show Little Differentiation*, March 6, 2020.

Chart 4: Utility Sector Dividend Yield vs. S&P 500 Dividend Yield (2/12/2020 – 4/17/2020)[38]



A direct consequence of stronger correlations is higher Beta coefficients.[39] That effect is demonstrated in Rebuttal Exhibit DWD-3, where Beta coefficients provided by Bloomberg have nearly doubled (from 0.499 to 0.995) since I filed my Direct Testimony (*see* Exhibit DWD-3). Under the CAPM, those higher Beta coefficients indicate a substantial increase in the Cost of Equity.

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38 Source: S&P Capital IQ. Utility sector represented by the XLU. Please note, R^2 of 0.9038 indicates a correlation coefficient (R) of 0.9507.

39 Direct Testimony of Dylan W. D'Ascendis, at 87, Equation 7.

Q. WITH THAT BACKGROUND, DO YOU AGREE WITH DR. WOOLRIDGE THAT THE BEST APPROACH TO INTERPRETING THE MARKET DISLOCATION IS TO REACH BACK TO THE PRE-COVID-19 ERA?

A. No, I do not. Dr. Woolridge's testimony provides a brief chronology of events associated with COVID-19, a review of certain financial measures and how they have changed since mid-February, and his interpretation of how those events have affected the models commonly used to estimate the Cost of Equity. Dr. Woolridge's principal position appears to be that capital markets are in a state of disequilibrium, and the DCF and CAPM methods provide unreliable measures of the Cost of Equity. Because the model results are highly uncertain, he chose to use data as of the first week of February.[40]

Dr. Woolridge's conclusion that the capital markets currently are in a state of disequilibrium rests on his view that "the emotions of the market and the great uncertainty over the future impact of the coronavirus have resulted in markets that have become disconnected from fundamentals."[41] By that he means the fundamental factors investors tend to consider – national and global macroeconomic factors, industry-specific factors, and company-specific factors[42] – have been supplanted by investor emotion arising from the "great

40 Testimony of J. Randall Woolridge, at 30-31.
41 Testimony of J. Randall Woolridge, at 25.
42 Testimony of J. Randall Woolridge, at 25

uncertainty involving the spread of the virus and its impact on the economy."[43] He concludes "there is not clear indication that these models would indicate that equity cost rates have increased or decreased since mid-February."[44]

As Dr. Woolridge notes, the duration and eventual effect of the pandemic are unknown, and the range of potential economic and capital market outcomes is highly uncertain. The consequence of that uncertainty, he argues, is that:

> … in the current environment, investors cannot rely on fundamental factors to value stocks and bonds based on traditional valuation procedures and measures. Instead, I believe that investors are reacting to daily news reports and updates on the virus as to whether the situation is getting better or worse and then allocating their investment funds accordingly.[45]

Dr. Woolridge then goes through each of the DCF, CAPM, and Risk Premium methods, finding the DCF and CAPM approaches are susceptible to some modeling error in the current environment, but the Risk Premium method less so.[46] He finds the "big increase in volatility in the markets suggests that the markets are not in equilibrium, and probably will not be in equilibrium until more is known about the virus and the associated economic implications", and concludes that "traditional financial models such as the DCF and CAPM models do not provide reliable estimates of the cost of equity capital in the

43 Testimony of J. Randall Woolridge, at 27-28.
44 Testimony of J. Randall Woolridge, at 31.
45 Testimony of J. Randall Woolridge, at 26.
46 Testimony of J. Randall Woolridge, at 27-29. I respond to Dr. Woolridge's assessment of these models in Section V.

coronavirus economic environment."[47] Dr. Woolridge's proposed solution is to use "data as of the first week of February, which is before the market meltdown associated with coronavirus."[48]

Q. WHAT IS YOUR GENERAL RESPONSE TO DR. WOOLRIDGE ON THOSE POINTS?

A. I agree that since mid-February, the capital markets have been historically unstable. I also agree, in part, with Dr. Woolridge's observation that when market prices diverge from some measure of intrinsic value, the disequilibrium affects the reliability of certain model results. That said, I disagree with Dr. Woolridge's implicit position that we cannot draw conclusions from models or market data as to whether the Cost of Equity has increased or decreased in connection with that instability. As discussed below, we certainly can look to parameters within the models themselves, or data on which they rely, to comfortably conclude the Cost of Equity is higher now than it was in early February. Although we cannot assign precise basis point increments to the increased market risk, we can infer with reasonable confidence that there has been a directional change in the Cost of Equity, and that change is upward. The fundamental risk/reward relationship tells us as much.

I also disagree that a proper remedy is to ignore COVID-19's current and possible effect on the economy and capital markets. As Dr. Woolridge

[47] Testimony of J. Randall Woolridge, at 30.
[48] Testimony of J. Randall Woolridge, at 30.

points out, the range of possible future economic outcomes created by the pandemic is significant. It is that uncertainty that has driven the unprecedented volatility in the capital markets. We therefore cannot say the post-COVID-19 environment, whenever that comes about, will resemble early February 2020.

Lastly, the proposed approach of looking back to early 2020 does not solve the problem of market prices that may be "disconnected from fundamentals". Rather, it looks to a period of unusually high valuations, and produces a series of unreasonably low ROE estimates.

Q. ARE YOU AWARE OF ANY GENERAL INDICATORS THAT THE COST OF CAPITAL FOR UTILITIES HAS INCREASED DURING THE RECENT MARKET DISLOCATION?

A. Yes. At page 37 of his Testimony, Dr. Woolridge refers to the Company's credit rating, arguing it demonstrates less risk than other electric utilities. That is, he argues credit ratings are a measure of equity risk. As noted earlier, S&P downgraded its outlook for the North American utility sector from stable to negative. In its review of how COVID-19 may affect the utility sector, S&P explained it expects a 12.00 percent contraction in GDP during the second quarter of 2020, reducing commercial and industrial usage. S&P further noted that although companies with decoupling structures may be able to offset some of that lower usage, bad debt expenses likely will increase. Even though some utilities may be able to defer those costs, S&P notes that in prior incidents utilities have negotiated with regulatory commissions to "write off some of these costs as part of a larger agreement."[49]

Regarding liquidity and capital access, S&P observes that "the industry continues to exhibit adequate liquidity and access to the debt markets, despite uneven performance of the commercial paper market for tier 2 issuers", but availability to equity markets "remains extraordinarily challenging."[50] S&P expects the negative discretionary cash flow associated with high capital investment commitments and the "lack of access to the equity markets" to "lead to a weakening of credit measures."[51]

Q. HAVE UTILITY CREDIT SPREADS REFLECTED THE CONCERNS NOTED BY S&P AND MOODY'S?

A. Yes, they have. As Chart 5 (below) demonstrates, credit spreads for, A, BBB+, and BBB rated utility debt increased significantly from February 19 to April 17, 2020, nearly 50.00 percent by the end of the period and more than doubling during the period. Looking back to 2007, before the 2008/2009 Financial Crisis, utility credit spreads as of April 17, 2020 were in the top 90th to 93rd percentile. Put another way, even considering the Financial Crisis, credit spreads currently are at historically high levels.

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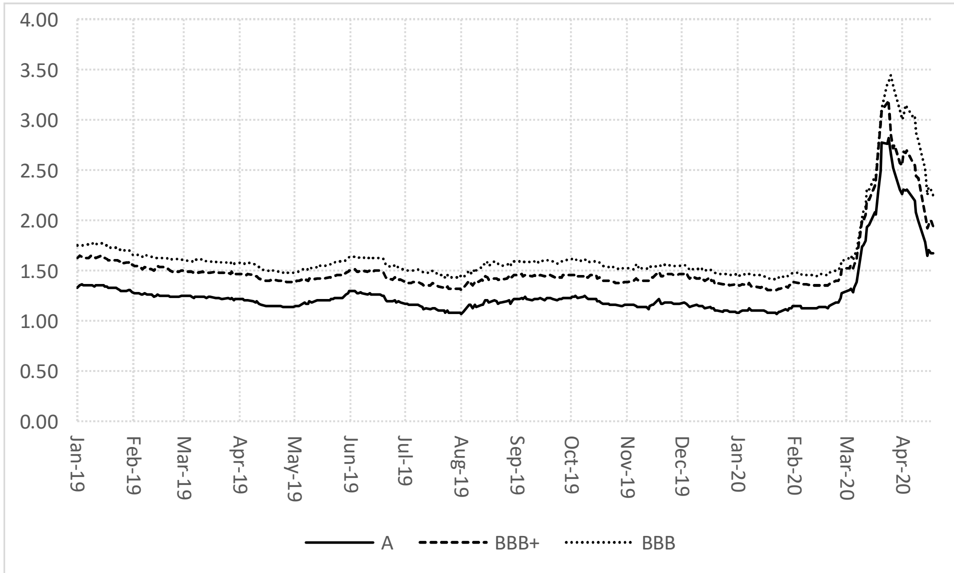
49 S&P Global Ratings, *COVID-19: The Outlook For North American Regulated Utilities Turns Negative*, April 2, 2020, at 7.
50 *Ibid.*
51 *Ibid.*

Chart 5: Utility Credit Spreads (January 1, 2020 to April 17, 2020)[52]



Q. WHAT CONCLUSIONS DO YOU DRAW FROM THOSE ANALYSES?

A. First, certain of the Opposing Witnesses look to debt cost rates as a measure of the Cost of Equity.[53] Because underlying Treasury yields have been depressed due to investors seeking the safety of Treasury securities, the relevant measure of incremental return requirements is the change in credit spreads. Debt investors have a contractual, senior claim on cash flows over a limited horizon whereas equity investors bear the residual risk of ownership in perpetuity. Despite those protections, the additional return required by debt investors approximately doubled during the current market dislocation. Given its lower priority claim on cash flows and its perpetual exposure to risk, we can assume

[52] Source: Bloomberg Professional. Data based on Fair Value Curves for 30-year maturities.

[53] Testimony of J. Randall Woolridge, at 16-17, 55; Direct Testimony of Richard A. Baudino, at 54-55; Direct Testimony of Kevin W. O’Donnell, CFA, at 68-69.

the increase in the Cost of Equity would be greater than the increase in credit spreads. Again, even if we cannot precisely measure the increase in the Cost of Equity associated with market dislocation, we reasonably can conclude it has increased, not decreased.

Second, S&P and Moody's both point to reducing the growth in dividends as a means of preserving credit quality in the event of a prolonged economic downturn. Doing so, however, comes at the expense of equity investors. The potential tension between maintaining credit quality and preserving dividends is another reason the Cost of Equity may increase more than credit spreads.

Lastly, rating agency discussions of the importance of cash flow demonstrate the risks the Opposing Witnesses' recommendations would create. The two principal sources of cash flow to utilities are net income and depreciation. By reducing the ROE, the Opposing Witnesses would reduce the Company's earnings, cash flow, and ability to internally fund capital investments and dividends, putting further downward pressure on stock prices.

If dividends are maintained despite lower earnings and cash flow, payout ratios will increase. As Moody's observed, over time companies with higher payout ratios are more likely to reduce dividends, which would put further downward pressure on stock valuations. And as S&P noted, reduced equity valuations diminish the ability to access external equity, further eroding credit quality.

In short, during a period of heightened and possibly prolonged market uncertainty, observable market information makes clear that utility investors now face greater risks and require higher returns. I therefore cannot agree that because certain models become less reliable under unusual market conditions, we should look to the pre-COVID-19 period as Dr. Woolridge suggests, or conclude the Cost of Equity has decreased. Rather, we reasonably can conclude risks and required returns have increased, even if not all models are able to precisely measure that increase.

Q. WITH THOSE CONSIDERATIONS IN MIND, DO YOU AGREE IT IS PROPER TO EXCLUDE THE CURRENT MARKET ENVIRONMENT IN DETERMINING THE COMPANY'S ROE?

A. No, I do not. As Dr. Woolridge notes, the potential range of economic and financial outcomes due to COVID-19 is wide; we cannot know at this time which path eventually will prevail. On that point, we agree. I also agree the assumptions underlying the models used to estimate the Cost of Equity may be disconnected from the current market. As discussed earlier, however, even if we cannot precisely measure its change, we can say with confidence the market-required Return on Equity has increased. In my opinion, there is no reason to believe investors, including the institutional investors that hold about 75.00 percent of the proxy companies' shares,[54] would assume the current market

[54] Source: S&P Global Market Intelligence; downloaded April 24, 2020.

instability and economic uncertainty has no meaning for the returns they require.

Lastly, as noted earlier, Dr. Woolridge's proposed remedy would have the Commission set rates based on a period of unusually high valuations. From January 2 to February 11, 2020, Dr. Woolridge's proxy group average Market/Book ratio was about 2.49x; by April 3 it had fallen to about 1.98x, a decline of more than 20.00 percent.[55]

Although the current Market/Book ratio is lower than its recent level, it is consistent with the long-term average. Dr. Woolridge's approach, however, would look to a period during which the Market/Book was in the top 93rd percentile of historical observations. If Dr. Woolridge is concerned with market prices that are disassociated with "fundamentals", that same concern should apply to the unusually high valuation multiples on which he bases his recommendation.

As discussed above, it is difficult to attribute basis points to the increased risks brought about by the COVID-19 pandemic. That does not mean those risks do not exist or should be disregarded. Rather, the risks to investors are real, and should be considered in some fashion. Further, if the Opposing Witnesses' ROE recommendations were adopted, it would compound those risks at a time when regulatory support is critically important.

55 Source: S&P Global Market Intelligence. Dr. Woolridge's proxy group calculated as an Index.

Although the Opposing Witnesses may take those concerns lightly, market participants such as S&P have not. Nor have the debt investors who require considerably higher credit spreads than they had as recently as early February 2020, the policy-makers that would add $2.5 trillion of liquidity to the economy, or economists that have noted the historic economic dislocation created by COVID-19. Taken in that broad context, I continue to support my 10.50 percent ROE recommendation.

IV. SUMMARY OF UPDATED ANALYSES

Q. PLEASE SUMMARIZE THE ANALYSES CONTAINED IN YOUR REBUTTAL TESTIMONY.

A. I have updated many of the analyses contained in my Direct Testimony, including the Constant Growth DCF analyses, the CAPM, the Empirical CAPM ("ECAPM"), the Bond Yield Plus Risk Premium approach, and the Expected Earnings approach. I also have updated my proxy group based on recent data. Lastly, I have provided additional analyses in response to the Opposing Witnesses.

Q. PLEASE DESCRIBE YOUR UPDATED PROXY GROUP.

A. I have included Avista Corporation ("Avista"), which had been party to a proposed acquisition by Hydro One Limited; that transaction was terminated on January 23, 2019.[56] Because Avista meets all my screening criteria and enough

[56] *See, Hydro One and Avista Mutually Agree to Terminate Merger Agreement*, Press Release, January 23, 2019.

time has passed that the model inputs no longer are affected by the proposed transaction, I included Avista in my proxy group. I refer to the resulting group as the "Updated Proxy Group" and is provided in Table 1, below.

Table 1: Updated Proxy Group

Company	**Ticker**
ALLETE, Inc.	ALE
Alliant Energy Corporation	LNT
Ameren Corporation	AEE
American Electric Power Company	AEP
Avangrid, Inc.	AGR
Avista Corporation	AVA
CMS Energy Corporation	CMS
DTE Energy Company	DTE
Evergy, Inc.	EVRG
Hawaiian Electric Industries, Inc.	HE
NextEra Energy, Inc.	NEE
NorthWestern Corporation	NWE
OGE Energy Corp.	OGE
Otter Tail Corporation	OTTR
Pinnacle West Capital Corporation	PNW
PNM Resources, Inc.	PNM
Portland General Electric Company	POR
Southern Company	SO
WEC Energy Group, Inc.	WEC
Xcel Energy Inc.	XEL

My updated analytical results based on the Updated Proxy Group are provided in Section XI, Table 15.

V. RESPONSE TO STAFF WITNESS DR. WOOLRIDGE

Q. PLEASE BRIEFLY SUMMARIZE DR. WOOLDRIDGE'S ROE ANALYSES AND RECOMMENDATIONS.

A. Although Dr. Woolridge asserts "an appropriate ROE for the Company is in the range of 6.90% to 8.40%", his "primary" recommendation is an ROE of 9.00 percent, assuming his 50.00 percent proposed common equity ratio.[57] He provides an "alternative" recommendation of 8.40 percent, based on the Company's December 31, 2019 equity ratio of 51.50 percent.[58] In each case, Dr. Woolridge's recommendation is based primarily on his Constant Growth DCF analysis, although he did provide a CAPM analysis, to which he gives less weight.[59]

Q. WHAT ARE THE SPECIFIC AREAS IN WHICH YOU DISAGREE WITH DR. WOOLRIDGE'S ANALYSES AND CONCLUSIONS?

A. There are several areas in which I disagree with Dr. Woolridge, including: (1) the interpretation of current capital market conditions; (2) the overall reasonableness of his ROE recommendation; (3) the selection of the proxy companies; (4) Dr. Woolridge's application of the Constant Growth DCF model; (5) Dr. Woolridge's application of the CAPM; (6) the applicability of the ECAPM; (7) the reasonableness of the Bond Yield Plus Risk Premium

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57 Testimony of J. Randall Woolridge, at 6.
58 Testimony of J. Randall Woolridge, at 7.
59 Testimony of J. Randall Woolridge, at 59.

method; (8) Dr. Woolridge's position that the Expected Earnings approach is not an accurate measure of investor expectations; (9) the relevance of Market/Book ("M/B") ratios in determining the ROE; (10) Dr. Woolridge's position that the Company is less risky than its peers; (11) the implications of economic conditions in North Carolina for the Company's Cost of Equity; and (12) the reasonableness of his capital structure proposal.

A. Capital Market Conditions

Q. PLEASE SUMMARIZE DR. WOOLRIDGE'S TESTIMONY AS IT RELATES TO CURRENT CAPITAL MARKET CONDITIONS.

A. Dr. Woolridge argues that my "analyses, ROE results, and recommendations reflect an assumption of higher interest rates and capital costs".[60] He goes on to state that "[d]espite 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"[61] and observes that "[i]n 2019, interest rates fell dramatically with slow economic growth and low inflation."[62] On that basis, Dr. Woolridge suggests the Commission "set an equity cost rate based on indicators of market-cost rates rather than speculating on the future direction of interest rates"[63] based on his conclusion that "it is practically impossible to accurately forecast interest rates and prices of investments that are determined in financial

60 Testimony of J. Randall Woolridge, at 9.
61 Testimony of J. Randall Woolridge, at 9.
62 Testimony of J. Randall Woolridge, at 9.
63 Testimony of J. Randall Woolridge, at 20.

markets".[64]

Q. DO YOU AGREE WITH DR. WOOLRIDGE'S CONCLUSION THAT THE CAPITAL MARKET ENVIRONMENT SUGGESTS A LOWER COST OF EQUITY FOR THE COMPANY?

A. No, I do not. As Chart 2 (above) indicates, one means of viewing the increasing volatility of Treasury yields is to view the CoV over time. As that chart demonstrates, long-term Treasury yields have become increasingly variable through mid-April 2020. At issue is the extent to which that volatility should be considered in assessing the relationship between Treasury yields and the Cost of Equity. If the variability in yields relates to something other than long-term fundamental market factors, we should question the extent to which changes in bond yields reflect changes in investor return requirements.

As noted in my Direct Testimony, over time, significant and abrupt declines in Treasury yields have been associated with increases in equity market volatility.[65] That relationship makes intuitive sense; as investors see increasing risk their objectives may shift to capital preservation (that is, avoiding a capital loss), rather than capital appreciation. Consistent with that objective, investors may allocate capital to the relative safety of Treasury yields, in a "flight to safety." Because bond yields are inversely related to bond prices, as investors bid up the prices of bonds, they bid down the yields. That pattern is seen in

64 Testimony of J. Randall Woolridge, at 23.
65 Direct Testimony of Dylan W. D'Ascendis at 62.

Chart 10 in my Direct Testimony, in which decreases in the 30-year Treasury yield coincided with increases in the VIX. In those instances, the fall in yields does not reflect a reduction in required returns, it reflects an increase in risk aversion and, therefore, an increase in investor-required returns.

As explained in Section III, February and March 2020, the VIX increased six-fold. That increase corresponded with the increasing volatility in Treasury yields. And as noted in Chart 3 (above), the recent decline in Treasury yields also corresponded with an increase in utility dividend yields. To summarize, the recent decline in interest cannot be seen as indicating a decrease in the Cost of Equity. Rather, the fall in interest rates is the result of safety-seeking behavior on the part of investors facing an extraordinarily volatile market.

Q. PLEASE BRIEFLY SUMMARIZE APPENDIX B TO DR. WOOLRIDGE'S TESTIMONY.

A. Appendix B generally provides a chronology of events associated with the Coronavirus, a review of certain financial measures and how they have changed since mid-February, and Dr. Woolridge's interpretation of how those events are reflected in the models commonly used to estimate the Cost of Equity. Dr. Woolridge's principal position appears to be straightforward: The capital markets are in a state of disequilibrium, and the DCF and CAPM methods provide unreliable measures of the Cost of Equity.[66]

Dr. Woolridge then goes through each of the DCF method, the CAPM approach, and the Risk Premium model, finding the DCF and CAPM methods are susceptible to some modeling error in the current environment, but the Risk Premium method is not.[67] He concludes "security prices are disconnected from fundamentals, and therefore traditional financial models such as the DCF and CAPM models do not provide reliable estimates of the cost of equity capital."[68]

In the end, Dr. Woolridge argues "the volatility of the markets since mid-February suggests that the markets are not in equilibrium and therefore traditional models, using the current market data, do not provide reliable estimates of the cost of equity capital".[69] His proposed solution is to use "data as of the first week of February, which is before the market meltdown associated with coronavirus occurred."[70]

Q. WHAT IS YOUR GENERAL RESPONSE TO DR. WOOLRIDGE'S APPENDIX B?

A. First, there is no question that since mid-February, the capital markets have become historically unstable. As discussed in Section III, the utility sector has

66 Testimony of J. Randall Woolridge, at B-13.
67 Testimony of J. Randall Woolridge, at B-10 – B-12. As to the Risk Premium approach, Dr. Woolridge describes a method very similar to that included in my Direct Testimony (*see*, Direct Testimony of Dylan W. D'Ascendis, at 95-99), concluding it is not affected by the current environment.
68 Testimony of J. Randall Woolridge, at B-13.
69 Testimony of J. Randall Woolridge, at B-14.
70 Testimony of J. Randall Woolridge, at B-14.

not been immune to that risk. As also discussed in Section III, when market prices diverge from some measure of intrinsic value, the disequilibrium affects the reliability of certain model results, including the DCF method.

That said, I disagree with Dr. Woolridge's conclusion that we cannot draw conclusions from the models or market data as to whether the Cost of Equity has increased or decreased in connection with that instability. As discussed below, we certainly can look to readily identifiable data to conclude the Cost of Equity increased during the market dislocation. The fundamental risk/reward relationship tells us as much.

I also disagree that a proper remedy is to ignore COVID-19's current and possible effect on the economy and capital markets. As Dr. Woolridge points out, the range of possible future economic outcomes created by COVID-19 is significant. It is that uncertainty that has driven the unprecedented volatility in the capital markets. We therefore cannot say the post-COVID-19 environment, whenever that comes about, will resemble February 2020.

Even though we cannot quantify the risk created by the coronavirus, neither should we ignore it, as Dr. Woolridge's proposed remedy requires. The fact that we cannot rely on models to tell us precisely how much the Cost of Equity has changed since mid-February does not mean we cannot infer from them, and from other relevant data, that it has increased.

Lastly, Dr. Woolridge's proposed approach of looking to February 2020 does not solve the problem of market prices that may be "disconnected from fundamentals". Rather, it looks to a period of anomalously high valuations and produces a series of unreliably low ROE estimates.

Q. TURNING NOW TO DR. WOOLRIDGE'S ASSESSMENT OF THE DCF, CAPM, AND RISK PREMIUM METHODS, DO YOU AGREE WITH HIS REVIEW AND CONCLUSIONS?

A. Not entirely. As noted earlier, my principal disagreement is with Dr. Woolridge's conclusion that we cannot rely on the models in any sense to draw conclusions regarding how the current market instability has affected the Cost of Equity.

Turning first to the DCF method, I agree utility dividend yields have increased. As discussed in Section III, that increase corresponds with the increase in market volatility, and the decrease in Treasury yields. As risk increased, investors allocated their capital away from equity securities, including utility stocks, toward the relative safety of Treasury securities. The increasing dividend yields and decreasing Treasury yields indicate investors have become less tolerant of equity risk, and require higher returns to bear that risk.

As to the growth rate component, I agree it is difficult to determine what they might be going forward. Nonetheless, if the DCF model is in equilibrium, further decreases in growth rates would put downward pressure on stock prices and, therefore, upward pressure on dividend yields. But for now, we safely can say dividend yields have increased by about 54 basis points since the filing of my Direct Testimony (based on the 30-day average), and we reasonably can conclude that increase is a directional indicator that the Cost of Equity has increased.

Q. TURNING TO THE CAPM, DO YOU AGREE WITH DR. WOOLRIDGE THAT WE CANNOT DRAW CONCLUSIONS REGARDING THE CHANGES IN THE COST OF EQUITY FROM THAT METHOD?[71]

A. No, I do not. Dr. Woolridge looks to the model's three components, finding that: (1) the 30-year Treasury yield decreased by about 40 basis points "primarily in response to the market's appetite for risk"[72]; (2) Beta coefficients are not likely to have changed much, given that they are measured using "periods up to five years"[73]; and (3) the Market Risk Premium would change only by reference to changes in expected market return which, he argues is very "indeterminate"[74].

As discussed earlier, I agree Treasury yields are depressed in response to investor risk appetites. For that reason, I believe it is proper to consider projected Treasury yields. Even if we continue to focus on recently observed yields, the CAPM and ECAPM results have increased approximately 175 basis points on average since I filed my Direct Testimony.[75]

71 Testimony of J. Randall Woolridge, at B-7 – B-9, B-11.

72 Testimony of J. Randall Woolridge, at B-7.

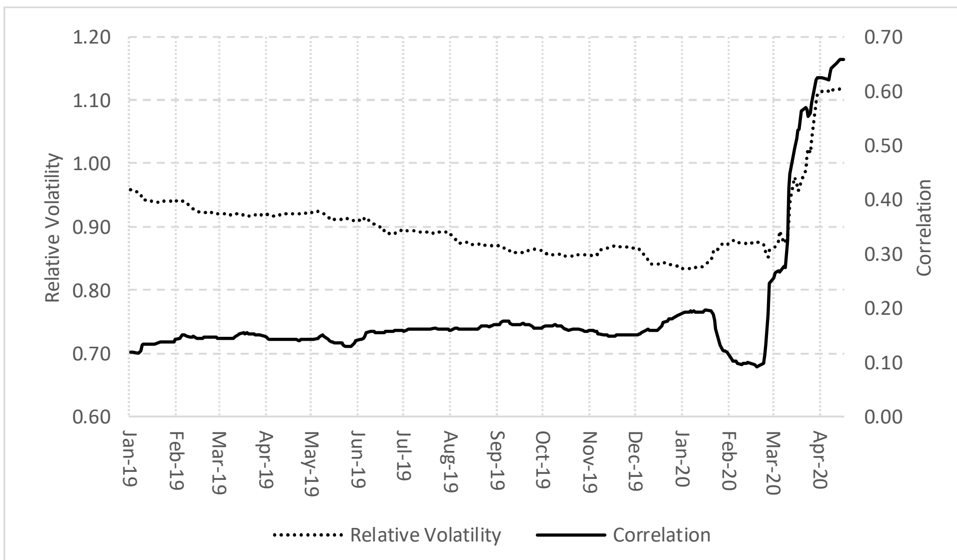
73 Testimony of J. Randall Woolridge, at B-8.

74 Testimony of J. Randall Woolridge, at B-9, B-11. Dr. Woolridge notes Market Risk Premium estimates based on historical data or surveys would not be affected by the current market dislocation.

75 Exhibit DWD-4 and Rebuttal Exhibit DWD-4.

As explained in my Direct Testimony, Beta coefficients are a function of two parameters: (1) relative volatility (the standard deviation of the subject company's returns relative to the standard deviation of the market return; and (2) the correlation between the subject company's returns and the market return.[76] Applying Bloomberg's two-year calculation convention, the increase in correlations, and in relative volatility, since mid-February 2020 is apparent (*see* Chart 6, below).

Chart 6: Components of Proxy Group (Two-Year) Beta Coefficients[77]



Not surprisingly, the increased correlation and relative volatility combine to produce significantly increased (adjusted) Beta coefficients.

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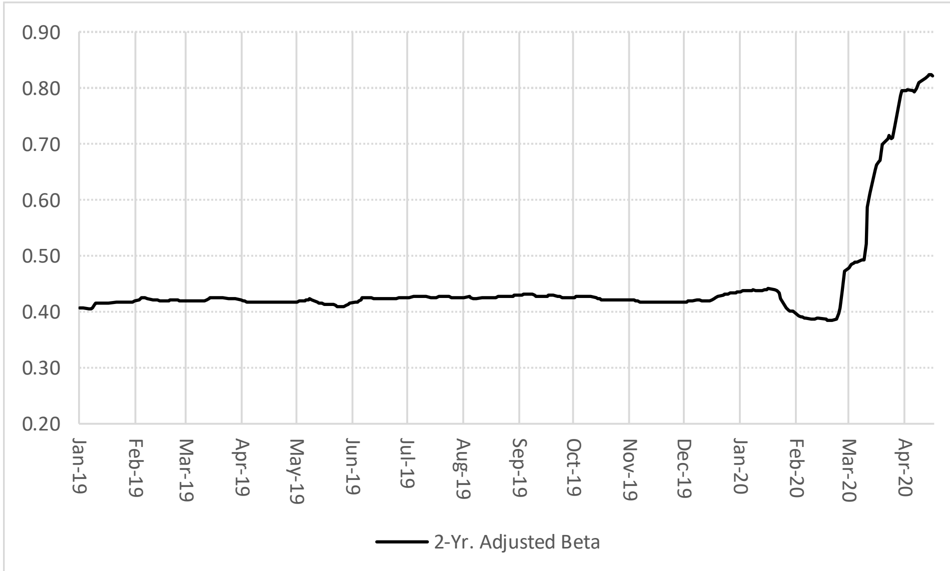
76 Direct Testimony of Dylan W. D'Ascendis, at 87, Equation [7].

77 Source: S&P Global Market Intelligence. Weekly returns calculated over 24 months.

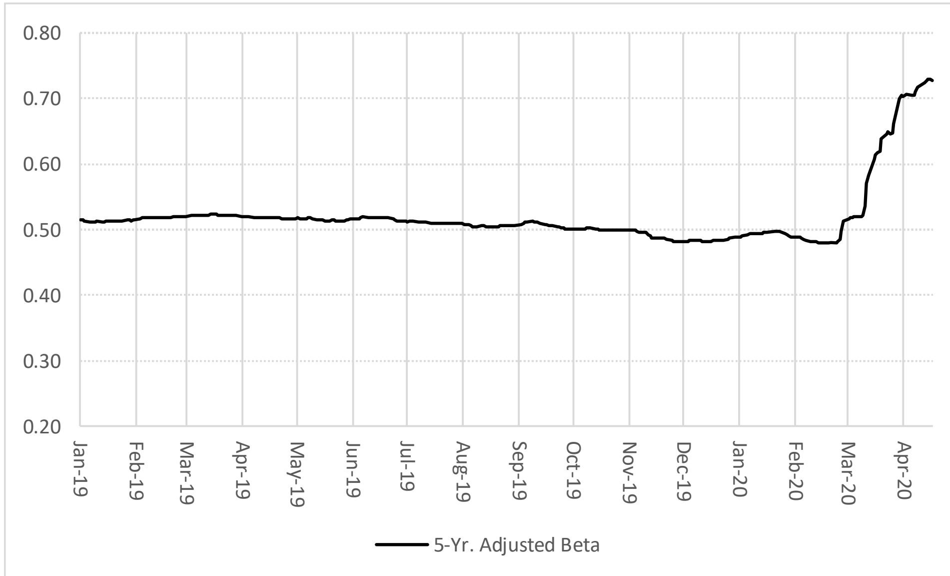
Chart 7: Proxy Group (Two-Year) Beta Coefficient Over Time[78]



Even if we extend the calculation period to five years, the increase in correlations increases calculated Beta coefficients well above their January and February 2020 levels (see Chart 8, below).

[78] Source: S&P Global Market Intelligence. Beta coefficients based on weekly returns calculated over 24 months.

Chart 8: Proxy Group (Five-Year) Beta Coefficient Over Time[79]



I understand Beta coefficients are one component of the CAPM. Nonetheless, as Dr. Woolridge notes, long-term Treasury yields remain highly variable. Even if we hold constant the risk-free rate, and assume (for the sake of discussion) the Market Risk Premium also remains constant, the increase in systematic risk manifested in elevated Beta coefficients is another observable indicator that directionally, the Cost of Equity has increased during the recent market dislocation.

[79] Source: S&P Global Market Intelligence. Beta coefficients based on weekly returns calculated over 60 months.

Q. AT PAGES 89 AND 90 OF HIS TESTIMONY DR. WOOLRIDGE REFERS TO MARKET RISK PREMIUM ESTIMATES BY DUFF & PHELPS AND PROFESSOR DAMODARAN. ARE YOU AWARE OF WHETHER EITHER OR BOTH THOSE SOURCES HAVE INCREASED THEIR ESTIMATES DURING THE RECENT MARKET DISLOCATION?

A. Yes. Although Dr. Woolridge notes that Duff & Phelps decreased its Market Risk Premium estimate in the fourth quarter of 2019 to 5.00 percent,[80] on March 27, 2020 (the date Dr. Woolridge's direct testimony was filed), Duff & Phelps increased its estimate of the Market Risk Premium by 100 basis points to 6.00 percent.[81] Similarly, Dr. Woolridge noted Professor Damodaran's estimate of the Market Risk Premium generally has been between 5.00 percent and 6.00 percent.[82] On April 1, 2020 Professor Damodaran's risk premium estimate increased to 6.52 percent, higher than any annual value provided in Dr. Woolridge's Figure 5.[83]

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80 Testimony of J. Randall Woolridge, at 90.

81 Harrington, James P. and Nunes, Carla, *Duff & Phelps Recommended U.S. Equity Risk Premium Increased from 5.0% to 6.0% Effective March 25, 2020*, March 27, 2020.

82 Testimony of J. Randall Woolridge, at 89.

83 http://pages.stern.nyu.edu/~adamodar/, accessed April 24, 2020. I recognize that Professor Damodaran has also presented an adjusted Equity Risk Premium, which he calls the "COVID Adjusted" Equity Risk Premium of 6.02 percent.

Q. DO YOU AGREE WITH DR. WOOLRIDGE'S VIEW THAT THE BOND YIELD PLUS RISK PREMIUM METHOD IS LARGELY UNAFFECTED BY CURRENT MARKET CONDITIONS[84]?

A. No, I do not. As explained in my Direct Testimony, the Bond Yield Plus Risk Premium method makes use of the finding that the Equity Risk Premium is inversely related to interest rates. The semi-log form of the regression analysis quantifying that relationship is well-suited to environments in which Treasury yields have fallen due to the "risk appetite" of investors. In that case, the Equity Risk Premium increases at a somewhat faster rate when Treasury yields become unusually depressed. Table 2, below, demonstrates that effect, as a decline in interest rates is more than offset by an increase in the Equity Risk Premium.

Table 2: Bond Yield Plus Risk Premium Results[85]

	30-Yr. Treasury Yield	Risk Premium	Return on Equity
Current 30-Year Treasury	1.37%	8.98%	10.35%
Near-Term Projected 30-Year Treasury	1.75%	8.33%	10.08%
Long-Term Projected 30-Year Treasury	3.45%	6.52%	9.97%

The model also can be expanded to directly reflect changes in expected market volatility, as measured by the VIX. Including the VIX as a second explanatory variable produces a positive, statistically significant coefficient (*see*, Rebuttal

84 Testimony of J. Randall Woolridge, at 29, B-12.

85 Source: S&P Global Market Intelligence. The 208-basis point negative change between 3.45 percent and 1.37 percent is more than offset by the 246-basis point positive change in the Equity Risk Premium. The result is an approximate 38-basis point increase in the Return on Equity. *See also*, Rebuttal Exhibit DWD-5.

Exhibit DWD-9). That finding is consistent with the fundamental theory that the Cost of Equity increases with uncertainty (that is, volatility). Back-testing the model demonstrates that from 2008 through 2019, the average annual difference between the authorized and projected ROE was four basis points. In 2008, during the peak of the financial crisis, the difference was nine basis points.

As Dr. Woolridge explains, during his review period the VIX increased from 15 to over 50, "a level which has not been seen since the financial crisis in 2008."[86] Assuming the VIX level of 50.00 Dr. Woolridge noted, the Cost of Equity increases by about 80 basis points (*see*, Table 3, below).

Table 3: Bond Yield Plus Risk Premium Results, Including VIX[87]

	30-Yr. Treasury Yield	VIX	Risk Premium	Return on Equity
Current 30-Year Treasury	1.37%	50.00	9.73%	11.10%
Near-Term Projected 30-Year Treasury	1.75%	50.00	9.10%	10.85%
Long-Term Projected 30-Year Treasury	3.45%	50.00	7.35%	10.80%

Q. WHAT DO YOU CONCLUDE FROM THOSE ANALYSES?

A. The Bond Yield Plus Risk Premium approach is well-suited to estimate the ROE, even during volatile markets. Including the VIX as an explanatory variable indicates that (at a VIX of 50) the ROE would be as high as 11.10 percent. Those results support my position that if the Commission were to

86 Testimony of J. Randall Woolridge, at 25. As noted in Section III, in late March 2020 the VIX exceeded 80.

87 Rebuttal Exhibit DWD-9.

consider the current market dislocation, it reasonably could support an ROE at, or above, the upper end of my recommended range.

Q. DO YOU AGREE WITH DR. WOOLRIDGE'S PROPOSED REMEDY, WHICH IS TO LOOK BACK TO EARLY FEBRUARY 2020, BEFORE THE CORONAVIRUS AFFECTED THE CAPITAL MARKETS, AS THE BASIS FOR HIS ROE ESTIMATES?

A. No, I do not. As noted earlier, I agree with Dr. Woolridge that the potential range of economic and financial outcomes due to the coronavirus is wide and we cannot know at this time which path will prevail. I also agree that certain assumptions underlying the models used to estimate the Cost of Equity may be disconnected from the current market.

As discussed earlier, I do not agree we should effectively disregard the market and economic risks created by the coronavirus by looking back to early February, before those risks emerged, to estimate the forward-looking Cost of Equity. In my opinion, there is no reason to believe investors would assume the current market instability and economic uncertainty has no meaning for the returns they require.

B. Recommended ROE

Q. ARE DR. WOOLRIDGE'S 8.40 PERCENT OR 9.00 PERCENT ROE RECOMMENDATIONS CONSISTENT WITH RETURNS RECENTLY AUTHORIZED IN NORTH CAROLINA?

A. No, they are not. On February 25, 2020, in Docket No. E-22, Sub 562, the Commission authorized an ROE of 9.75 percent for Dominion Energy North Carolina. Prior to that, the Commission authorized an ROE of 9.90 percent for the Company, Duke Energy Carolinas, and Piedmont Natural Gas.[88] That is, the Commission's most recent authorized return is 75 to 135 basis points above Dr. Woolridge's recommendations, and 285 basis points above the low end of his range. Dr. Woolridge has provided no evidence to support the conclusion the Company has become so less risky than its peers that investors would require a return so far below those recently authorized by this Commission.

Q. ARE DR. WOOLRIDGE'S ROE RECOMMENDATIONS CONSISTENT WITH RETURNS RECENTLY AUTHORIZED IN OTHER JURISDICTIONS CONSIDERED TO HAVE CONSTRUCTIVE REGULATORY ENVIRONMENTS?

A. No. As discussed in my response to Mr. Chriss, Regulatory Research Associates ("RRA") currently ranks North Carolina in the top third of all jurisdictions from investors' perspectives. Since 2016, the average and median

[88] *See,* NCUC Docket Nos. E-2, Sub 1142; E-7 Sub 1146; and G-9, Sub 743.

authorized ROE in jurisdictions similar to North Carolina was 9.93 percent and 9.95 percent, respectively (within a range of 9.37 percent to 10.55 percent).[89] Dr. Woolridge's recommendations are well below even the low end of that range. If adopted, Dr. Woolridge's 9.00 percent ROE recommendation would be only 25 basis points above the lowest authorized return for a vertically integrated electric utility since at least 1980.[90]

Q. DO YOU AGREE WITH DR. WOOLRIDGE'S POSITION THAT AUTHORIZED RETURNS FOR ELECTRIC AND NATURAL GAS UTILITIES HAVE DECLINED OVER THE PAST FIVE YEARS?[91]

A. No, I do not. In fact, Dr. Woolridge's own data contradicts that position. As shown in Table 4 below, according to Dr. Woolridge's data,[92] the average annual authorized ROE for electric utilities has been relatively stable over the past five years. If anything, Dr. Woolridge's data shows the average authorized ROE has increased slightly over the past five years.

89 Rebuttal Exhibit DWD-25 and Table 13.
90 Source: Regulatory Research Associates. As discussed in my response to Mr. O'Donnell, the market response after the South Dakota PUC's 8.75 percent ROE decision for Otter Tail Power was immediate and negative.
91 Testimony of J. Randall Woolridge, at 31.
92 Dr. Woolridge's source is Regulatory Research Associates.

Table 4: Dr. Woolridge's Reported Average Authorized ROE for Electric Utilities[93]

Year	Average
2015	9.58%
2016	9.60%
2017	9.68%
2018	9.56%
2019	9.64%

Moreover, Dr. Woolridge's data includes returns authorized for distribution-only electric utilities, in addition to vertically integrated electric utilities. Looking to the average and median ROE authorized for vertically integrated electric utilities only, the trend over the past five years also has been relatively stable (*see* Table 5, below). In either case, Tables 4 and 5 demonstrate that there has not been a downward trend in authorized ROEs, and the unreasonableness of Dr. Woolridge's recommendation.

Table 5: Average and Median Authorized ROE for Vertically Integrated Electric Utilities[94]

Year	Average	Median
2015	9.75%	9.70%
2016	9.77%	9.78%
2017	9.80%	9.65%
2018	9.68%	9.73%
2019	9.73%	9.73%

93 Testimony of J. Randall Woolridge, at 31.
94 Source: Regulatory Research Associates. Excludes Limited Issue Rate Rider proceedings.

Q. PLEASE SUMMARIZE DR. WOOLRIDGE'S REFERENCE TO A MARCH 2015 REPORT BY MOODY'S REGARDING THE EFFECT OF ROES ON UTILITIES' NEAR-TERM CREDIT PROFILES.

A. Dr. Woolridge points to the March 2015 Moody's report and concludes lower authorized ROEs are not impairing utilities' credit profiles and are not "deterring them from raising record amounts of capital."[95] He argues the Moody's article "supports the prevailing/emerging belief that lower authorized ROEs are unlikely to hurt the financial integrity of utilities or their ability to attract capital."[96]

Q. DO YOU AGREE WITH DR. WOOLRIDGE'S ASSESSMENT OF THAT ARTICLE?

A. No, I do not. The March 2015 Moody's article makes clear utilities' cash flow had benefited from increased deferred taxes, which themselves were due to bonus depreciation. In that report, Moody's noted the rise in deferred taxes eventually would reverse.[97] In January 2018, Moody's spoke to the effect of that reversal on utility credit profiles in the context of tax reform:

> Tax reform is credit negative for US regulated utilities because the lower 21% statutory tax rate reduces cash collected from customers, while the loss of bonus depreciation reduces tax deferrals, all else being equal. Moody's calculates that the recent changes in tax laws will dilute a utility's ratio of cash flow before changes in working capital to debt by approximately 150 - 250

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95 Testimony of J. Randall Woolridge, at 33.
96 Testimony of J. Randall Woolridge, at 34.
97 Moody's Investors Service, *Lower Authorized Returns Will Not Hurt Near-Term Credit Profiles,* March 10, 2015, at 4.

> basis points on average, depending to some degree on the size of the company's capital expenditure programs. From a leverage perspective, Moody's estimates that debt to total capitalization ratios will increase, based on the lower value of deferred tax liabilities.[98]

In June 2018, Moody's changed its outlook on the U.S. regulated sector to "negative" from "stable". Moody's explained that its change in outlook "…primarily reflects a degradation in key financial credit ratios, specifically the ratio of cash flow from operations to debt, funds from operations ("FFO") to debt and retained cash flow to debt, as well as certain book leverage ratios."[99] The sector's outlook could remain "negative" if cash flow-based metrics continue to decline, or if there emerge signs of a more "contentious" regulatory environment (which, Moody's notes, is not fully reflected in lower authorized returns). Dr. Woolridge's reference to a 2015 article does not consider Moody's more recent position.

Q. IN YOUR VIEW, IS THE S&P SECTOR DOWNGRADE DISCUSSED IN SECTION III A MORE RELEVANT VIEW OF RATING AGENCIES' ASSESSMENT OF UTILITY RISK THAN THE 2015 MOODY'S ARTICLE DR. WOOLRIDGE CITES?

A. Yes, it is.

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98 Moody's Investors' Service, *Rating Action: Moody's changes outlooks on 25 US regulated utilities primarily impacted by tax reform*, January 19, 2018.

99 Moody's Investors Service, *Announcement: Moody's changes the US regulated utility sector outlook to negative from stable,* June 18, 2018.

Q. DO YOU AGREE WITH DR. WOOLRIDGE'S PRIMARY RELIANCE ON A SINGLE MODEL (*I.E.*, THE CONSTANT GROWTH DCF MODEL) IN DEVELOPING HIS RECOMMENDED ROE?

A. No, I do not. I understand Dr. Woolridge applied the CAPM in addition to the DCF model. Nonetheless, he gives the DCF method primary weight in arriving at his ROE recommendation.[100] The relevant issue is whether investors use multiple methods in evaluating investment opportunities and making investment decisions. Nowhere has Dr. Woolridge demonstrated investors disregard other methods in favor of the Constant Growth DCF approach. Because no individual model is more reliable than all others at all times and under all conditions, it is important to use multiple methods to mitigate the effects of assumptions and inputs associated with any single approach. To that point, in its February 2018 *Order Accepting Stipulation* authorizing the 9.90 percent ROE for the Company, the Commission noted it "carefully evaluated the DCF analysis recommendations" of the ROE witnesses (which ranged from 8.25 percent to 9.00 percent) and found "all of these DCF analyses in the current market produce unrealistic low results."[101] As noted in my Direct Testimony, other regulatory commissions have come to similar conclusions.[102]

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100 Testimony of J. Randall Woolridge, at 59.

101 North Carolina Utilities Commission, Docket No. E-2, Sub 1142, *In the Matter of Application of Duke Energy Progress, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina*, Order Accepting Stipulation, Deciding Contested Issues, and Granting Partial Rate Increase, February 23, 2018, at 84-85.

102 Direct Testimony of Dylan W. D'Ascendis, at, 6-9, 15-16.

As to its use among investors, an article published in Financial Analysts Journal surveyed financial analysts to determine the analytical techniques that are used in practice, which included the CAPM.[103] That survey clearly indicated that the CAPM is used by practitioners. Similarly, a 2001 article by Professors Graham and Harvey demonstrated that industry practitioners are far more likely to use the CAPM than the DCF model.[104]

Q. IS THERE PUBLISHED SUPPORT FOR THE USE OF MULTIPLE METHODS IN ESTIMATING THE COST OF EQUITY?

A. Yes, there is. For example, Dr. Morin notes:

> Each methodology requires the exercise of considerable judgment on the reasonableness of the assumptions underlying the methodology and on the reasonableness of the proxies used to validate the theory. The inability of the DCF model to account for changes in relative market valuation, discussed below, is a vivid example of the potential shortcomings of the DCF model when applied to a given company. Similarly, the inability of the CAPM to account for variables that affect security returns other than beta tarnishes its use.
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> No one individual method provides the necessary level of precision for determining a fair return, but each method provides useful evidence to facilitate the exercise of an informed judgment. *Reliance on any single method or preset formula is inappropriate when dealing with investor expectations because of possible measurement difficulties and vagaries in individual*

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103 *See*, Stanley B. Block, *A Study of Financial Analysts: Practice and Theory*, Financial Analysts Journal, July/August, 1999.

104 *See*, John R. Graham, Campbell R. Harvey, *The Theory and Practice of Corporate Finance: Evidence from the Field*, Journal of Financial Economics, 2001. *See*, Robert S. Harris, Felicia C. Marston, *The Market Risk Premium: Expectational Estimates Using Analysts' Forecasts,* Journal of Applied Finance, 2001.

> *companies' market data*. [105]

In a similar fashion, Professor Eugene Brigham, a widely respected scholar and finance academician, recommends the CAPM, DCF, and Bond Yield Plus Risk Premium approaches:

> Three methods typically are used: (1) the Capital Asset Pricing Model (CAPM), (2) the discounted cash flow (DCF) method, and (3) the bond-yield-plus-risk-premium approach. These methods are not mutually exclusive – no method dominates the others, and all are subject to error when used in practice. Therefore, when faced with the task of estimating a company's cost of equity, *we generally use all three methods and then choose among them on the basis of our confidence in the data used for each in the specific case at hand*.[106]

Similarly, Dr. Morin (quoting, in part, Professor Stewart Myers), stated:

> Use more than one model when you can. Because estimating the opportunity cost of capital is difficult, only a fool throws away useful information. *That means you should not use any one model or measure mechanically and exclusively*. Beta is helpful as one tool in a kit, to be used in parallel with DCF models or other techniques for interpreting capital market data.
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> ***
>
> While it is certainly appropriate to use the DCF methodology to estimate the cost of equity, there is no proof that the DCF produces a more accurate estimate of the cost of equity than other methodologies. Sole reliance on the DCF model ignores the capital market evidence and financial theory formalized in the CAPM and other risk premium methods. The DCF model is one of many tools to be employed in conjunction with other

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[105] Roger A. Morin, New Regulatory Finance (Public Utility Reports, Inc., 2006), at 428. [*Emphasis added*]

[106] *Ibid*., at 430-431, citing Eugene Brigham, Louis Gapenski, Financial Management: Theory and Practice, 7th Ed., 1994, at 341. [*Emphasis added*]

> methods to estimate the cost of equity. It is not a superior methodology that supplants other financial theory and market evidence. The broad usage of the DCF methodology in regulatory proceedings in contrast to its virtual disappearance in academic textbooks does not make it superior to other methods. The same is true of the Risk Premium and CAPM methodologies.[107]

As those authors make clear, we should not mechanically apply models. Rather, as Brigham noted, we should choose among them based on our confidence in the data at hand. That is what I have done.

Lastly, we know investors consider multiple metrics – including Price/Earnings ("P/E"), M/B, and Enterprise Value/EBITDA[108] multiples – in their buying and selling decisions. They do so because no single financial model produces the most accurate and reliable measure of value at all times and under all conditions. That practice extends to the Cost of Equity which, like fundamental (or intrinsic) value, is unobservable and must be estimated.

Q. ARE THERE STRUCTURAL REASONS WHY THE CONSTANT GROWTH DCF MODEL MAY NOT ALWAYS PROVIDE RELIABLE ROE ESTIMATES?

A. Yes, there are. As explained in my Direct Testimony, the DCF model noted by the equation $k= \frac{D(1+g)}{P_0}+g$ is derived from the longer-form present value formula:

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[107] Roger A. Morin, New Regulatory Finance (Public Utility Reports, Inc., 2006), at 430-431. [*Emphasis added*]

[108] Earnings Before Interest, Taxes, Depreciation, and Amortization.

$$P_0 = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \cdots + \frac{D_\infty}{(1+k)^\infty} \qquad [1]$$

Using the DCF model as the principal method[109] to estimate the Cost of Equity fundamentally assumes investors use the present value structure alone to find the intrinsic value of common stock, and intrinsic value always equals market value.[110] The model therefore will not produce accurate estimates of the market-required ROE if the market price diverges from the present value-based estimate of intrinsic value. Differences between market prices and intrinsic valuations may arise when investors take short-term trading positions to hedge risk (*e.g.*, a "flight to safety"), to speculate (*e.g.*, momentum trades), or as temporary position to increase current income (*i.e.*, a "reach for yield"), much like the pre-COVID-19 market environment.[111]

The implications of market prices diverging from DCF-based estimates of intrinsic value was studied in an article published in the Journal of Applied Finance. That article, which focused on back-tests of the Constant Growth DCF model, found that even under "ideal" circumstances:

> … it is difficult to obtain good intrinsic value estimates in models stretching over lengthy periods of time. Shorter horizon models based on five or fewer years show more promise. Any model based on dividend streams of ten years or more, whether as a teaching tool or in practice, should be used with caution

109 At page 59 of his testimony, Dr. Woolridge refers to the DCF method as providing "the best measure of equity cost rates for public utilities."

110 Direct Testimony of Dylan W. D'Ascendis, at 10.

111 Some investors may select relatively high dividend yield companies as a "reach for yield" in response to the shortage of investment alternatives that provide adequate yield in today's capital market, rather than investing in stocks based on their long-term return potential.

since they are likely to produce low-quality estimates.[112]

In short, because the DCF model is derived from a valuation model that assumes constancy in perpetuity, it is likely to produce less reliable ROE estimates when market conditions are non-constant, and when investor practice is to consider multiple valuation methods.

Q. IS IT YOUR VIEW THAT THE DCF MODEL SHOULD BE GIVEN NO WEIGHT IN DETERMINING THE COMPANY'S COST OF EQUITY?

A. No, it is not. It is my view, however, that we should carefully consider the model's results relative to its underlying assumptions, and in the context of the recent market instability, and doing so fully supports my ROE range and recommendation and is consistent with the Commission's prior orders. As explained in my Direct Testimony, models are approximations of investor behavior; no one method best measures that behavior at all times and under all market conditions.[113] Because no sensible investor would systematically ignore relevant information, nor should we ignore models used by investors to estimate the Cost of Equity.

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112 P. McLemore, G. Woodward, and T. Zwirlein, *Back-tests of the Dividend Discount Model using Time-varying Cost of Equity*, Journal of Applied Finance, No. 2, 2015, at 19.

113 Direct Testimony of Dylan W. D'Ascendis, at 5.

Q. DO YOU AGREE WITH DR. WOOLRIDGE'S PROPOSED REDUCTION TO HIS ROE RECOMMENDATION TO 8.40 PERCENT IF THE COMMISSION ACCEPTS THE COMPANY'S CAPITAL STRUCTURE AS OF DECEMBER 31, 2019?[114]

A. No, I do not. Dr. Woolridge's recommendation is based on his view that holding company capital structures are the proper benchmark.[115] Because they can be directly observed and reflect the common practice of matching permanent assets with permanent capital, operating company capital structures should be used as the measure of industry practice. Dr. Woolridge fails to perform such an analysis. Consequently, there is no basis for a 60-basis point adjustment to the Company's ROE in connection with the Company's actual capital structure.

Q. WHAT ARE YOUR CONCLUSIONS RELATED TO DR. WOOLRIDGE'S ROE RECOMMENDATION?

A. Dr. Woolridge's 8.40 percent and 9.00 percent recommendations are unduly low and inconsistent with authorized returns by this Commission and in other constructive jurisdictions. In large measure, Dr. Woolridge's recommendations are driven by his focus on the Constant Growth DCF method. Even under more stable conditions, relying principally on a single method may lead to unreliable ROE estimates.

There is little question investors' motivations change during volatile

114 Testimony of J. Randall Woolridge, at 7, 49.
115 Testimony of J. Randall Woolridge, at 40-41.

markets; capital preservation becomes a principal objective. The DCF model, which requires us to assume constancy in perpetuity, is particularly susceptible to estimation error during those periods. It requires us to assume the motivations underlying investor decisions in that environment, including capital preservation, are the same motivations that will persist, every day, forever. Because that assumption is not likely to hold, we should be very cautious about giving the Constant Growth DCF method undue weight.

Q. IS THERE "A DISCONNECT" BETWEEN YOUR RECOMMENDED ROE OF 10.50 PERCENT AND YOUR ROE STUDIES?[116]

A. No, there is not. Dr. Woolridge states "the vast majority of [my] equity cost rate results point to a lower ROE" and "the only results that point to an ROE as high as 10.50% are some of [my] CAPM/ECAPM results".[117] As discussed in my Direct Testimony, practitioners and academics recognize that financial models are simply tools to be used in the ROE estimation process, and that strict adherence to any single approach, or to the specific results of any single approach, can lead to flawed or misleading conclusions.[118] My ROE recommendation considers all my analyses, not a single method.

Further, Dr. Woolridge is incorrect in stating that only my CAPM results point to an ROE as high as 10.50 percent. For example, in Exhibit DWD-1 in

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116 Testimony of J. Randall Woolridge, at 10, 99.

117 Testimony of J. Randall Woolridge, at 99. [clarification added]

118 Direct Testimony of Dylan W. D'Ascendis, at 15.

my Direct Testimony, my DCF method produces a range of ROE results from a low of 5.79 percent to a high of 13.71 percent. My recommended ROE of 10.50 percent fits squarely within this range. Exhibit DWD-6 in my Direct Testimony also corroborates my recommended ROE. The Expected Earnings approach in Exhibit DWD-6 in my Direct Testimony produces a range of results from a low of 6.00 percent to a high of 14.06 percent. Again, my recommended ROE of 10.50 percent fits squarely within this range.

C. Proxy Group Selection

Q. PLEASE DESCRIBE THE SCREENING CRITERIA BY WHICH DR. WOOLRIDGE DEVELOPED HIS PROXY GROUP.

A. Dr. Woolridge relied on six screening criteria to develop his proxy group of 31 companies:

1. Received at least 50.00 percent 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, or be the target of an acquisition; and
6. Has analysts' long-term EPS growth forecasts available from Yahoo or Zacks.[119]

[119] Testimony of J. Randall Woolridge, at 36.

Q. DO YOU AGREE WITH DR. WOOLRIDGE'S SCREENING CRITERIA?

A. Not entirely. Although we do have certain criteria in common (for example, we both exclude companies that are party to a significant corporate transaction or that do not consistently pay dividends), as explained below, Dr. Woolridge's screens do not render a group of companies that is sufficiently comparable to the Company.

Q. WHAT IS YOUR CONCERN WITH DR. WOOLRIDGE'S USE OF REVENUE, RATHER THAN INCOME, AS A SCREENING CRITERION?

A. Measures of income are far more likely to be considered by the financial community in making credit assessments and investment decisions than are measures of revenue. From the perspective of credit markets, measures of financial strength and liquidity are focused on cash from operations, which is directly derivative of earnings, as opposed to revenue. As part of its rating methodology, for example, Moody's assigns a 40.00 percent weight to measures of financial strength and liquidity, of which 22.50 percent specifically relates to the ability to cover debt obligations with cash from operations.[120]

Just as rating agencies focus on measures of cash from operations, equity analysts rely on measures of income in assessing equity valuation levels;

[120] *See,* Moody's Investors Service, Rating Methodology, *Regulated Electric and Gas Utilities,* June 23, 2017, at 4.

common measures of relative value include the P/E ratio, and the ratio of Enterprise Value to EBITDA. Revenue, however, may be several steps removed from the earnings and cash flows that form the basis of equity valuations. Focusing on revenue may mislead the analyst into assuming a given operating unit is the primary driver of expected growth, when the majority of earnings and cash flows are derived from other business segments. Here, we are considering whether the underlying utility is the principal source of long-term growth, and as such, focusing on revenue may obscure important elements of the analysis.

Q. DO YOU AGREE WITH DR. WOOLRIDGE'S CONSIDERATION OF DUKE ENERGY CORPORATION, DE PROGRESS' PARENT, IN HIS PROXY GROUP?

A. No, I do not. As noted in my Direct Testimony, it is my practice to exclude parent companies from the proxy groups of subsidiary utilities, as the inclusion of a parent involves circular logic.[121]

[121] Direct Testimony of Dylan W. D'Ascendis, at 23.

D. Constant Growth DCF Model

Q. PLEASE SUMMARIZE YOUR CONCERNS WITH THE CONSTANT GROWTH DCF MODEL AND DR. WOOLRIDGE'S APPLICATION OF THE MODEL.

A. There are several practical concerns with Dr. Woolridge's application of the model, and his interpretation of its results. For example, Dr. Woolridge's approach includes a degree of subjectivity that prevents us from replicating the fundamental inputs that drive his results. Moreover, Dr. Woolridge's judgment is to give "primary weight"[122] to growth rate projections produced by equity analysts, even though he argues those analysts knowingly and persistently produce biased growth rate forecasts.

Q. WHAT GROWTH RATES DID DR. WOOLRIDGE REVIEW IN HIS CONSTANT GROWTH DCF ANALYSIS?

A. Dr. Woolridge reviewed a number of growth rates, including historical and projected Dividends Per Share ("DPS"), Book Value Per Share ("BVPS"), and Earnings Per Share ("EPS") growth rates as reported by Value Line; analysts' consensus EPS growth rate projections from Yahoo!, Reuters, and Zacks; and an estimate of sustainable growth derived from data provided by Value Line.[123] Dr. Woolridge states that in arriving at his growth rate projections for the proxy

[122] Testimony of J. Randall Woolridge, at 75.
[123] Exhibit JRW-7.

group he gave "primary weight" to projected EPS growth rates.[124]

Table 6: Summary of Dr. Woolridge's Growth Rate Estimates[125]

	Dr. Woolridge's Proxy Group	D'Ascendis Proxy Group
Value Line Historical Growth Rates (DPS, BVPS, EPS)	4.40%	5.00%
Value Line Projected Growth Rates (DPS, BVPS, EPS)	5.30%	5.20%
Sustainable Growth	3.60%	3.50%
Analyst Projected EPS Growth Rates (Yahoo! And Zacks) – Mean/Median	5.00% / 4.80%	5.40% / 5.40%
Dr. Woolridge's Assumed DCF Growth Rate	5.00%	5.40%

Q. DO YOU AGREE WITH DR. WOOLRIDGE'S POSITION THAT ANALYSTS' EARNINGS GROWTH PROJECTIONS ARE CONSISTENTLY BIASED?

A. No, I do not. Dr. Woolridge argues analysts' earnings growth estimates are "overly optimistic and upwardly biased",[126] and believes relying on such estimates is a methodological error. He further argues that, due to that bias, "the DCF growth rate must be adjusted downward from the projected EPS growth rate".[127] Dr. Woolridge's position, however, is based on observations of the broad market; he has provided no evidence that any of the growth rates used in my (or his) DCF analyses are the result of a consistent and pervasive bias on the part of the analysts providing those projections. Notably, despite his view

124 Testimony of J. Randall Woolridge, at 75.
125 Testimony of J. Randall Woolridge, at 75; Exhibit JRW-7, at 1, 6.
126 Testimony of J. Randall Woolridge, at 70.
127 Testimony of J. Randall Woolridge, at 72.

that they are biased, it was by "[g]iving primary weight to the projected EPS growth rate of Wall Street analysts" that Dr. Woolridge arrived at his assumed growth rates.[128]

Q. WHAT IS YOUR RESPONSE TO DR. WOOLRIDGE ON THAT POINT?

A. There is no reason to believe the analyst growth rates used in my DCF analyses are biased. As a practical matter, the October 2003 Global Research Analyst Settlement required financial institutions to insulate investment banking from analysis, prohibited analysts from participating in "road shows," and required the settling financial institutions to fund independent third-party research.[129] I have reviewed the Letters of Acceptance, Waiver and Consent signed by financial institutions that were party to the Global Settlement, and found no reference to misconduct by analysts following the utility sector.

Moreover, pursuant to Regulation AC, which became effective in April 2003, analysts must certify that "…the views expressed in the report accurately reflect his or her personal views, and disclose whether or not the analyst received compensation or other payments in connection with his or her specific recommendations or views."[130] I further understand industry practice is to avoid conflicts of interest by ensuring that compensation is not directly or

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128 Testimony of J. Randall Woolridge, at 75.

129 The 2002 Global Financial Settlement resolved an investigation by the U.S. Securities and Exchange Commission and the New York Attorney General's Office of a number of investment banks related to concerns about conflicts of interest that might influence the independence of investment research provided by equity analysts.

130 Securities and Exchange Commission, 17 CFR PART 242 [Release Nos. 33-8193; 34-47384; File No. S7-30-02], RIN 3235-AI60 Regulation Analyst Certification.

indirectly linked to the opinions contained in those reports. Dr. Woolridge has not explained why any of the analysts covering our respective proxy companies would bias their projections despite those certification requirements.

Lastly, Dr. Woolridge argues utilities generally are in the "mature" stage of their industry life cycle.[131] Key characteristics of a mature industry include predictable cash flows and earnings, both of which would enable more stable, less "biased" earnings estimates. Dr. Woolridge has not reconciled those two largely competing points.

Q. IS THE USE OF ANALYSTS' EARNINGS GROWTH PROJECTIONS IN THE DCF MODEL SUPPORTED BY FINANCIAL LITERATURE?

A. Yes, it is. Several published articles support the use of analysts' earnings growth projections in the DCF model. Dr. Robert Harris, for example, found financial analysts' earnings forecasts (referred to in the article as "FAF") to be appropriate in calculating the expected Market Risk Premium:[132]

> ... a growing body of knowledge shows that analysts' earnings forecasts are indeed reflected in stock prices. Such studies typically employ a consensus measure of FAF calculated as a simple average of forecasts by individual analysts.[133]

Dr. Harris further noted that:

> Given the demonstrated relationship of FAF to equity prices and

[131] Testimony of J. Randall Woolridge, at 63.

[132] *See,* Robert S. Harris, *Using Analysts' Growth Forecasts to Estimate Shareholder Required Rates of Return*, Financial Management, 1986, at 66.

[133] *Ibid.*, at 59. As noted in my Direct Testimony, Zacks and First Call, the sources of earnings growth projections that Dr. Woolridge uses in addition to Value Line, are consensus forecasts.

> the direct theoretical appeal of expectational data, it is no surprise that FAF have been used in conjunction with DCF models to estimate equity return requirements.[134]

Similarly, in *Estimating Shareholder Risk Premia Using Analysts Growth Forecasts*, Harris and Marston presented "estimates of shareholder required rates of return and risk premia which are derived using forward-looking analysts' growth forecasts."[135] As Harris and Marston reported:

> ... in addition to fitting the theoretical requirement of being forward-looking, the utilization of analysts' forecasts in estimating return requirements provides reasonable empirical results that can be useful in practical applications.[136]

Here again, the finding was clear: Analysts' earnings forecasts are highly related to stock price valuations and are appropriate inputs to stock valuation and ROE estimation models.[137]

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134 *Ibid*., at 60.

135 Robert S. Harris, Felicia C. Marston, *Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts*, Financial Management, Summer 1992, at 63.

136 *Ibid*.

137 In *the Risk Premium Approach to Measuring a Utility's Cost of Equity*, published in Financial Management, Spring 1985, Brigham, Shome and Vinson noted that "evidence in the current literature indicates that (i) analysts' forecasts are superior to forecasts based solely on time series data; and (ii) investors do rely on analysts' forecasts."

Q. DO YOU AGREE WITH DR. WOOLRIDGE'S POSITION THAT "THE DCF GROWTH RATE MUST BE ADJUSTED DOWNWARD FROM THE PROJECTED EPS GROWTH RATE TO REFLECT THIS UPWARD BIAS"?[138]

A. No, I do not. If current stock prices (and therefore the dividend yield) reflect some measure of assumed bias,[139] it would not be necessary to adjust the growth rate. Although Dr. Woolridge argues "…long-term EPS growth-rate forecasts of Wall Street securities analysts are overly optimistic and upwardly biased"[140], he has not demonstrated that to be the case for the electric companies in the proxy groups. To that point, I reviewed quarterly earnings presentations of companies in the proxy groups and found analysts' growth rate projections to be within the long-term growth rate ranges provided by the companies' management teams (*see* Table 7, below). I therefore do not believe the earnings projections included in our respective analyses are likely to be systemically biased.

138 Testimony of J. Randall Woolridge, at 72.
139 Testimony of J. Randall Woolridge, at 72.
140 Testimony of J. Randall Woolridge, at 70.

Table 7: Analysts' Earnings Growth Projections Relative to Management Presentations[141]

Company	Ticker	Zacks Earnings Growth	First Call Earnings Growth	Investor Presentation Earnings Growth Range
ALLETE, Inc.	ALE	NA	7.00%	5.00% - 7.00%
American Electric Power	AEP	5.80%	6.15%	5.00% - 7.00%
CMS Energy Corp.	CMS	7.10%	7.50%	6.00% - 8.00%
DTE Energy Company	DTE	6.00%	6.00%	5.00% - 7.00%
NextEra Energy, Inc.	NEE	7.60%	7.59%	6.00% - 8.00%
WEC Energy Group	WEC	6.20%	6.23%	5.00% - 7.00%
Xcel Energy Inc.	XEL	6.00%	6.10%	5.00% - 7.00%

Q. DO YOU AGREE WITH DR. WOOLRIDGE THAT HISTORICAL GROWTH RATES ARE APPROPRIATE MEASURES OF EXPECTED GROWTH FOR THE CONSTANT GROWTH DCF MODEL?[142]

A. No, I do not. As Dr. Woolridge notes, the growth component of the Constant Growth DCF model is a forward-looking measure of investors' expectations.[143] To the extent historical growth influences expectations of future growth, it already will be reflected in analysts' consensus earnings growth estimates. Carlton and Vander Weide found "overwhelming evidence that consensus analysts' forecast of future growth is superior to historically oriented growth

141 Source: Zacks, Yahoo! Finance (*see*, Rebuttal Exhibit DWD-1), and individual company investor presentations released in Q1 2020 and early Q2 2020.

142 Testimony of J. Randall Woolridge, at 67.

143 Testimony of J. Randall Woolridge, at 67-68.

measures in predicting the firm's stock price."[144] Consequently, I do not believe historical growth rates are appropriate for the Constant Growth DCF model.

Q. WHY DO YOU DISAGREE WITH DR. WOOLRIDGE'S POSITION THAT DIVIDEND AND BOOK VALUE GROWTH RATES ARE APPROPRIATE INPUTS TO THE CONSTANT GROWTH DCF MODEL?[145]

A. Earnings growth enables both dividend and book value growth. Under the strict assumptions of the Constant Growth DCF model, earnings, dividends, book value, and stock prices all grow at the same, constant rate in perpetuity.

Book value increases with the amount of earnings not distributed as dividends (that is, retained earnings), and the price at which new equity is issued is a function of the EPS and the then-current P/E ratio. Similarly, the ability to pay dividends depends fundamentally on expected earnings.[146] Because dividend policy contemplates additional factors, including the disproportionately negative effect on prices resulting from dividend cuts, as opposed to dividend increases, in the short-run dividend growth may be disconnected from earnings growth.[147] In the long run, however, dividends cannot be increased without earnings growth.

144 Vander Weide and Carleton, *Investor Growth Expectations: Analysts vs History*, The Journal of Portfolio Management (Spring 1988).

145 Testimony of J. Randall Woolridge, at 66-67.

146 *See,* Jing Liu, Doron Nissim, and Jacob Thomas, *Is Cash Flow King in Valuations?*, Financial Analysts Journal, Volume 63, Number 2, 2007.

147 *See,* Servaes and Tufano, *Corporate Dividend Policy: The Theory and Practice of Corporate Dividend and Share Repurchase Policy*, Deutsche Bank, February 2006.

As Rebuttal Exhibit DWD-10 demonstrates, under those assumptions the assumed growth rate equals the rate of capital appreciation (*i.e.*, the stock price growth rate). Because investors often assess stock values on the basis of P/E ratios, it is important to consider whether the growth rates used in the DCF model are related to those valuations.

Q. HAVE YOU UNDERTAKEN ANY ANALYSES TO DETERMINE WHICH MEASURES OF GROWTH ARE STATISTICALLY RELATED TO THE PROXY COMPANIES' STOCK VALUATION LEVELS?

A. Yes, I have. My analysis is based on the methodological approach used by Professors Carleton and Vander Weide, who compared the predictive capability of historical growth estimates and analysts' forecasts on the valuation levels of sixty-five utility companies.[148] I structured the analysis to understand whether projected and historical earnings, dividend, book value, or retention growth rates best explain utility stock valuations. In particular, my analysis examined the statistical relationship between the P/E ratios of the natural gas and electric utilities as classified by Value Line, and the projected EPS, DPS, BVPS, and the "BxR" retention growth[149] rates as reported by Value Line, as well as the historical EPS, DPS, and BVPS as reported by Value Line. To determine which, if any, of those growth rates are statistically related to utility stock valuations, I

148 Vander Weide and Carleton, *Investor Growth Expectations: Analysts vs History*, The Journal of Portfolio Management (Spring 1988).

149 As discussed below, Dr. Woolridge reviews the more limiting "BxR" form of the retention growth rate.

performed a series of regression analyses in which the projected growth rates were explanatory variables and the P/E ratio was the dependent variable. The results of those analyses are presented in Rebuttal Exhibit DWD-11.

In that analysis, I performed ten separate regressions with the P/E as the dependent variable, and historical EPS, DPS, and BVPS; projected EPS, DPS and BVPS; and the sustainable growth rate, respectively, as the independent variable. I also performed a separate regression with all ten growth rates as independent variables. I then reviewed the T- and F-Statistics to determine whether the variables and equations were statistically significant.[150]

Q. WHAT DID THOSE ANALYSES REVEAL?

A. As shown in Rebuttal Exhibit DWD-11, the only growth rate that was statistically significant and positively related to the P/E ratio was projected Earnings Per Share. Because EPS growth is the only growth rate that is both statistically and positively related to utility valuation, earnings is the proper measure of growth in the Constant Growth DCF Model.

Q. DO YOU HAVE ANY CONCERNS WITH DR. WOOLRIDGE'S SPECIFICATION OF THE RETENTION GROWTH RATE?

A. Yes, I do. The full form of the model assumes growth is a function of its expected earnings, and the extent to which it retains earnings to invest in the

[150] In general, a T-Statistic of 2.00 or greater indicates that the variable is likely to be different than zero, or "statistically significant." The F-Statistic is used to determine whether the model as a whole has statistically significant predictive capability.

enterprise. The form of the model on which Dr. Woolridge relies is its simplest form, which defines growth solely as a function of internally generated funds. Although I do not believe it is appropriate to use the Retention Growth rate to estimate the Cost of Equity in this proceeding, if Dr. Woolridge is going to consider a form of Retention Growth, he should use the "BR + SV" form of the model, which reflects growth both from internally generated funds *(i.e.*, the "BR" term) and from issuances of equity (*i.e.*, the "SV" term). As noted above, the first term is the product of the retention ratio (*i.e.*, "B", or the portion of net income not paid in dividends) and the expected ROE (*i.e.*, "R"), which represents the portion of net income that is "plowed back" into the company as a means of funding growth. The "SV" term is represented as:

$$\left(\frac{m}{b} - 1\right) x\ Common\ shares\ growth\ rate \quad [2]$$

where:

$$\left(\frac{m}{b}\right) = \text{ the Market} - \text{to} - \text{Book ratio.}$$

In that form, the "SV" term reflects an element of growth as the product of (1) the growth in shares outstanding, and (2) that portion of the M/B ratio that exceeds unity.

E. Capital Asset Pricing Model

Q. PLEASE BRIEFLY DESCRIBE DR. WOOLRIDGE'S CAPM ANALYSIS AND RESULTS.

A. Dr. Woolridge's CAPM analysis produces an estimated Cost of Equity of 6.70 percent for both his and my proxy group.[151] I strongly disagree with the position that 6.70 percent is a reasonable measure of the Company's Cost of Equity. As discussed below, Dr. Woolridge's unduly low CAPM estimate principally falls from his estimated Market Risk Premium.

Dr. Woolridge combines a risk-free rate of 3.50 percent and a Market Risk Premium ("MRP") of 5.75 percent to the average Beta coefficient of his and my proxy groups (0.55). In estimating his MRP, Dr. Woolridge reviews a series of studies that calculate the MRP using different methodologies; he also considers the results of his "Building Blocks" approach. Based on that review, Dr. Woolridge argues the MRP ranges from 4.00 percent to 6.00 percent and, within that range, 5.75 percent is "conservatively high".[152]

Q. DOES DR. WOOLRIDGE EXPRESS ANY CONCERNS REGARDING YOUR CAPM ANALYSIS?

A. Dr. Woolridge's disagreement with my CAPM analysis includes: (1) the Market Risk Premium component of the model; and (2) the applicability of the

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151 Testimony of J. Randall Woolridge, at 92, Exhibit JRW-8.
152 Testimony of J. Randall Woolridge, at 91-92.

Empirical form of the CAPM.[153]

Q. PLEASE BRIEFLY SUMMARIZE DR. WOOLRIDGE'S CONCERNS REGARDING YOUR USE OF EXPECTED MARKET RETURNS.

A. Regarding the use of expected market returns, Dr. Woolridge states that the result is "excessive."[154] Dr. Woolridge also points to the long-term EPS growth rates for the S&P 500 based on the data from Bloomberg and Value Line, respectively, and notes that they "are inconsistent with both historic and projected economic and earnings growth in the U.S".[155] He also points to MRPs provided in academic studies, assumed by investment banks and management consulting firms, and found in surveys of financial professionals as support for his position that the MRP is in the range of 4.00 percent to 6.00 percent.[156]

Q. WHAT IS YOUR RESPONSE TO DR. WOOLRIDGE ON THOSE POINTS?

A. Dr. Woolridge refers to two surveys of financial professionals in support of his MRP: the Duke Chief Financial Officer ("Duke CFO") survey and the Philadelphia Federal Reserve Survey of Professional Forecasters.[157] Looking to the Federal Bank of Philadelphia's First Quarter 2020 survey, only 17 of 37 participants responded to the question regarding the expected return for the S&P 500 over the next ten years, and 23 of 37 responded to the question regarding

[153] Testimony of J. Randall Woolridge, at 116.
[154] Testimony of J. Randall Woolridge, at 130.
[155] Testimony of J. Randall Woolridge, at 116.
[156] Testimony of J. Randall Woolridge, at 87-91, 112-113.
[157] Testimony of J. Randall Woolridge, at 83-84.

expected return on ten-year Treasury bonds.[158]

Even if all 37 economists provided expected market returns and Treasury yields, Dr. Woolridge gives economists' interest rate projections little weight, going so far as to note that in a 2014 Bloomberg survey, "100% of the economists were wrong".[159] Despite that conviction, Dr. Woolridge gives economists' forecasts of market returns and GDP considerable weight in supporting his ROE recommendation. It is unclear why Dr. Woolridge finds economists' estimates appropriate for his analyses, but improper for mine.

Regarding the Duke CFO survey, Dr. Woolridge's 8.40 percent and 9.00 percent ROE recommendations, which apply to a company that is less risky than the overall market,[160] are 159 to 219 basis points above the expected market return suggested by the survey results. If the survey was a reasonable method of determining the expected market return, Dr. Woolridge's ROE recommendation would be no higher than 6.81 percent.[161] Lastly, over time the survey results have rather significantly underestimated actual market performance (*see* Table 8, below).

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158 *See*, Federal Reserve Bank of Philadelphia, Survey of Professional Forecasters, First Quarter of 2020 at 19.

159 Testimony of J. Randall Woolridge, at 20-21.

160 Dr. Woolridge agrees that Beta coefficients for our proxy companies are less than 1.0.

161 6.81 percent equals the expected annual average market return over the next 10 years suggested by the Duke CFO survey. Duke/CFO Magazine Global Business Outlook survey – U.S., Fourth Quarter 2019, at 38. *See also*, Testimony of J. Randall Woolridge, at 83.

Table 8: S&P 500 Market Return: Accuracy of Survey Estimates[162]

	Actual	Survey Estimate
2019	31.49%	4.59%
2018	-4.38%	6.57%
2017	21.83%	5.00%
2016	11.96%	4.32%
2015	1.38%	6.07%
2014	13.69%	5.00%
2013	32.39%	3.40%
2012	16.00%	4.00%
2011	2.11%	5.30%
2010	15.06%	6.28%
Average	14.15%	5.05%

The Duke CFO Survey authors also have noted a distinction between the expected market return on one hand, and the "hurdle rate" on the other. In the Third Quarter 2017 survey, the authors reported an average hurdle rate, which is the return required for capital investments, of 13.50 percent. The authors further reported the average Weighted Average Cost of Capital, which includes the cost of debt, was 9.20 percent even though the expected market return was 6.50 percent.[163] In my view, Dr. Woolridge's reference to a 4.99 percent[164] expected MRP estimate based on the Duke CFO Survey should be given little weight.

162 Source: Duff & Phelps, 2020 SBBI Yearbook Appendix A-1; http://www.cfosurvey.org (One-year return estimates as of fourth quarter of the previous year).
163 Duke/CFO Magazine Global Business Outlook survey – U.S., Third Quarter 2017.
164 Testimony of J. Randall Woolridge, at 88.

Q. AT PAGE 91 OF HIS TESTIMONY, DR. WOOLRIDGE REFERS TO THE WEBSITE MARKET-RISK-PREMIA.COM, WHICH SUGGESTS A RISK-FREE RATE OF 1.51 PERCENT, AND AN MRP OF 4.14 PERCENT. DO YOU HAVE ANY OBSERVATIONS REGARDING THOSE DATA POINTS?

A. Yes, I do. First, as Dr. Woolridge points out, those estimates combine to suggest an expected market return of 5.65 percent. Because that estimate falls 125 basis points below the low end of his recommended range (6.90 percent),[165] it is unclear what, if any, weight Dr. Woolridge gives that data. Second, I reviewed the website, and it is unclear how the service calculates the expected market return, or the Market Risk Premium.[166] In any case, if Dr. Woolridge believed the website's 5.65 percent expected market return was proper, his CAPM estimate would be 4.68 percent,[167] only 53 basis points above the Company's 4.15 percent embedded cost of debt.

Q. DO YOU AGREE WITH DR. WOOLRIDGE'S REFERENCE TO STUDIES THAT REPORT MRP ESTIMATES BASED ON EXPECTED GEOMETRIC RETURNS?

A. No, I do not. The MRP should reflect the expected arithmetic average return. The important distinction between the arithmetic and geometric averages is that

165 Testimony of J. Randall Woolridge, at 93.
166 http://www.market-risk-premia.com/theoretical-background.html
167 4.68% = 3.50% + (0.55 x (5.65% - 3.50%)).

the arithmetic mean assumes that each periodic return is an independent observation and, therefore, incorporates uncertainty into the calculation of the long-term average. The geometric mean, on the other hand, is a backward-looking calculation that equates a beginning value to an ending value. Although geometric averages provide a standardized basis of review of historical performance across investments or investment managers, they do not reflect forward-looking uncertainty. That is why investors and researchers commonly use the arithmetic mean when estimating the risk premium over historical periods to estimate the Cost of Equity. As Morningstar notes:

> The arithmetic average equity risk premium can be demonstrated to be the most appropriate when discounting future cash flows. For use as the expected equity risk premium in either the CAPM or the building block approach, the arithmetic mean or the simple difference of the arithmetic means of the stock market returns and riskless rates is the relevant number.[168]

Lastly, investment risk, or volatility, typically is measured based on the standard deviation. The standard deviation, in turn, is a function of the arithmetic mean, not the geometric mean. In that regard, the Beta coefficients applied in CAPM analyses are a function of the standard deviation of returns.[169]

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168 Morningstar, Inc., 2013 Ibbotson SBBI Valuation Yearbook, at 56.
169 Direct Testimony of Dylan W. D'Ascendis, at 87.

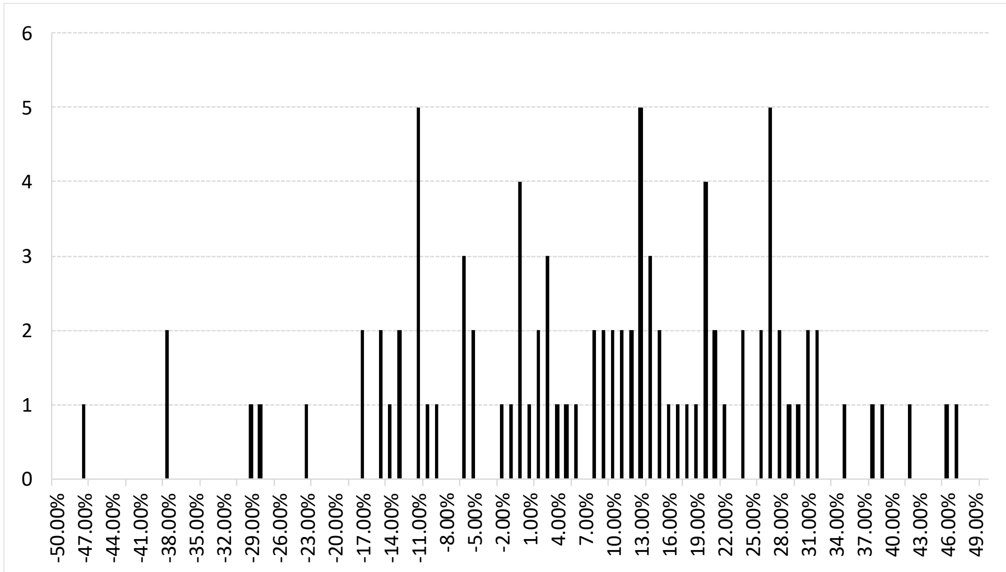
Q. TURNING TO DR. WOOLRIDGE'S POSITION THAT THE EPS GROWTH RATES USED TO DEVELOP YOUR ESTIMATED MARKET RETURN ARE TOO HIGH,[170] DID YOU CONSIDER WHERE YOUR ESTIMATE FALLS WITHIN THE RANGE OF HISTORICAL OBSERVATIONS?

A. Yes. I gathered the annual capital appreciation[171] return on Large Company Stocks reported by Morningstar for the years 1926 through 2018, produced a histogram of those observations (*see* Chart 9, below), and calculated the probability that a given capital appreciation return estimate would be observed. The results of that analysis demonstrate that capital appreciation rates of 12.50 percent to 12.53 percent (as Dr. Woolridge calculates) and higher actually occurred quite often, representing approximately the 57th percentile.

170 Testimony of J. Randall Woolridge, at 113-114.

171 Under the Constant Growth DCF model's assumptions, the growth rate equals the rate of capital appreciation.

Chart 9: Frequency Distribution of Capital Appreciation Returns, 1926-2019[172]

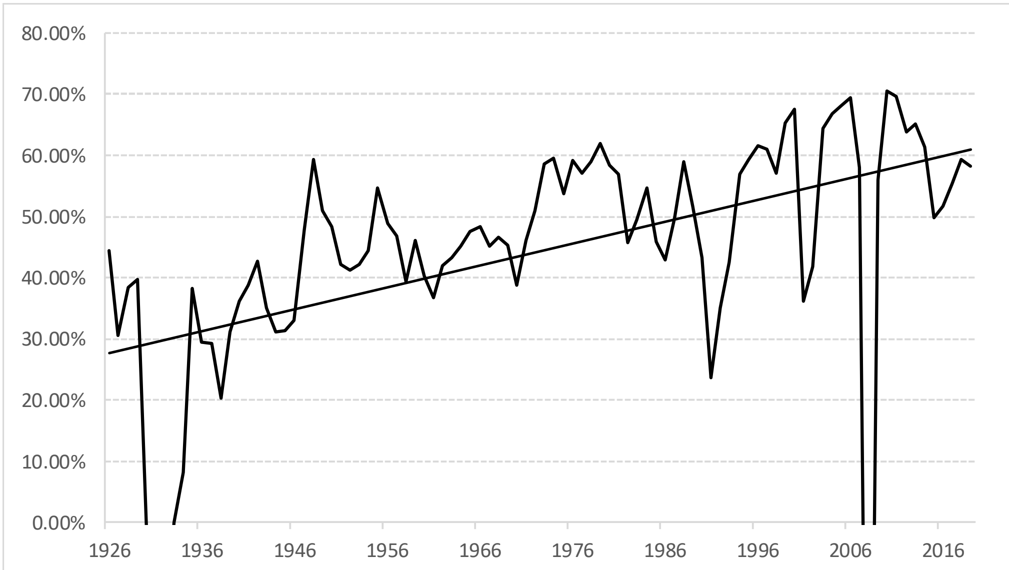


Regarding Dr. Woolridge's analysis of the S&P 500 EPS and GDP growth rates (in his Table 9), his conclusion that net income of the S&P 500 would grow to represent approximately 75.78 of GDP[173] is substantially driven by his unduly low GDP growth rate. Under the Sustainable Growth model, if the retention ratio is higher now than it historically has been, there would be reason to believe that expected growth rates would be higher than historical growth rates. To determine whether that has been the case, I calculated the annual retention ratio from 1926 to 2019 using earnings and dividends data published by Dr. Robert J. Shiller. As shown in Chart 10 (below), that data indicates the S&P 500 earnings retention has trended upward over time and is currently well above its

172 Duff & Phelps, 2020 SBBI Yearbook, at A-3.
173 Testimony of J. Randall Woolridge, at 127.

historical average. Consequently, the Sustainable Growth model included in Dr. Woolridge's DCF analysis suggests that the future growth of the S&P 500 could outpace its historical growth.

Chart 10: S&P 500 Annual Earnings Retention Ratio, 1926 – 2019[174]



Q. HAVE ANY REGULATORY COMMISSIONS CONSIDERED THE SUSTAINABILITY OF GROWTH RATES IN THE MARKET RISK PREMIUM?

A. The Federal Energy Regulatory Commission ("FERC") has found the DCF-based growth rates used to calculate the Market Risk Premium in the CAPM need not meet a sustainability threshold because, although an individual company may not be expected to sustain high short-term growth rates in

[174] Source: http://www.econ.yale.edu/~shiller/data.htm.

perpetuity, the same cannot be said for a stock index like the S&P 500 that is regularly updated to contain only companies with high market capitalization. As the FERC stated in Opinion 531-B (March 3, 2015):

> The rationale for incorporating a long-term growth rate estimate in conducting a two-step DCF analysis of a specific group of utilities does not necessarily apply when conducting a DCF study of the companies in the S&P 500. That is because the S&P 500 is regularly updated to include only companies with high market capitalization. While an individual company cannot be expected to sustain high short-term growth rates in perpetuity, the same cannot be said for a stock index like the S&P 500 that is regularly updated to contain only companies with high market capitalization, and the record in this proceeding does not indicate that the growth rate of the S&P 500 stock index is unsustainable.[175]

In my view, Dr. Woolridge's concern regarding sustainability of growth rates in the S&P 500 is misplaced.

Q. WHAT IS THE BASIS OF DR. WOOLRIDGE'S CONCERN WITH YOUR MRP ESTIMATE AS IT RELATES TO HISTORICAL NOMINAL GDP GROWTH RATES?

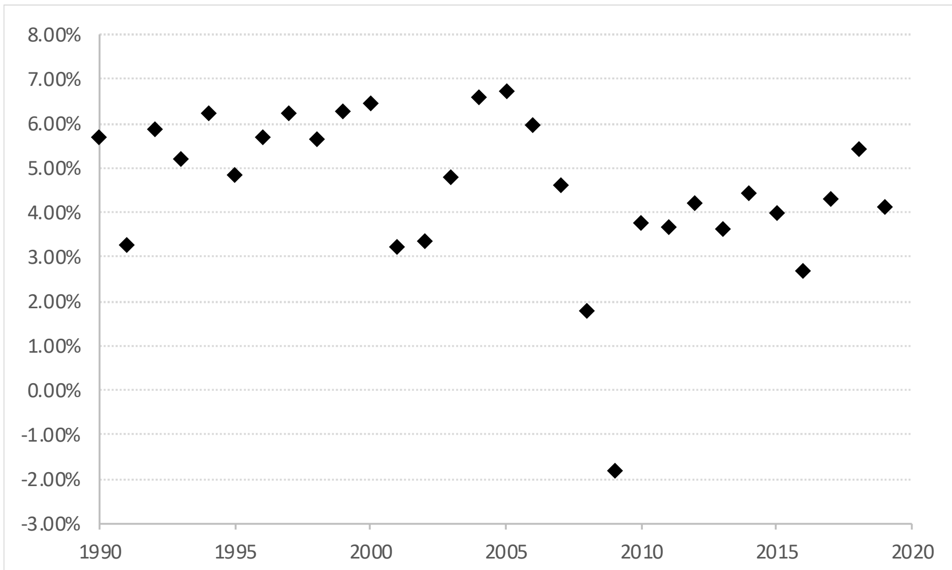
A. Dr. Woolridge argues "nominal GDP growth in recent decades has slowed and that a figure in the range of 4.0% to 5.0% is more appropriate today for the U.S. economy."[176] To support his position, Dr. Woolridge reviews average nominal GDP growth over periods of ten to 50 years. As shown on Chart 11 (below), however, since 1990 (*i.e.*, in "recent decades") the annual nominal growth rate

[175] Docket No. EL11-66-002, *Opinion 531-B Order on Rehearing*, 150 FERC ¶ 61,165 (March 3, 2015), at Para. 113.

[176] Testimony of J. Randall Woolridge, at 119.

in GDP has remained relatively stable, but for the period 2008 to 2012, which includes the recent recession. Over that time, annual nominal GDP growth rates greater than 5.00 percent (the high end of Dr. Woolridge's suggested range) occurred in 13 of 30 years.

Chart 11: Annual Nominal GDP Growth Rates (1990 – 2019)[177]



Q. AT PAGE 122 OF HIS TESTIMONY, DR. WOOLRIDGE REFERS TO A 2015 STUDY BY MCKINSEY & CO. ("MCKINSEY") AND ARGUES THAT REAL GDP GROWTH MAY FALL BY 40.00 PERCENT. DO YOU AGREE WITH DR. WOOLRIDGE'S CONCLUSION?

A. No, I do not. Dr. Woolridge argues future real global economic growth will fall to 2.10 percent, principally due to slow growth in the working age population. He suggests that is the case "even if productivity remains at the rapid rate of the

[177] Source: Bureau of Economic Analysis, March 30, 2020 update.

past 50 years of 1.8%".[178] McKinsey, however, also points to five "sector case studies", that find "more than enough productivity-acceleration scope to counter slower labor growth."[179] Based on those studies, McKinsey finds sufficient potential for productivity growth to reach 4.00 percent. Of note, about three-quarters of that global potential "would come from the broader adoption of existing best practices", which the firm would characterize as "catch-up" productivity improvements."[180] As to the remainder, McKinsey states:

> The remaining one-quarter, or about one percentage point a year, could come from technological, operational, or business innovations that go beyond today's best practices and that "push the frontier" of the world's GDP potential. In contrast to some observers, we do not find that a drying up of technological or business innovations will act as a constraint to growth. On the contrary, we see a strong innovation pipeline in both developed and developing economies in the sectors we studied. Our estimate of the potential here is based only on the innovations that we can foresee. It is quite possible that waves of innovation may, in reality, push the frontier far further than we can ascertain based on the current evidence.[181]

In short, the McKinsey study does not conclude the declining workforce necessarily means lower real global GDP growth. Rather, the potential for meaningful productivity increases may provide greater avenues for global real economic growth well greater than Dr. Woolridge assumes.

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178 Testimony of J. Randall Woolridge, at 122.

179 McKinsey Global Institute, *Global Growth: Can Productivity Save the Day In An Aging World?*, January 2015, at PDF 9.

180 *Ibid.*, at 53 (PDF 63).

181 *Ibid.*

Q. WHAT IS YOUR RESPONSE TO DR. WOOLRIDGE'S REFERENCE TO GDP FORECASTS PROVIDED BY THE *SURVEY OF PROFESSIONAL FORECASTERS,* THE ENERGY INFORMATION ADMINISTRATION ("EIA"), AND THE CONGRESSIONAL BUDGET OFFICE ("CBO")?[182]

A. First, Dr. Woolridge has not demonstrated investors rely on the surveys cited in his testimony. Second, as Dr. Woolridge points out, the *Survey of Professional Forecasters* relates to the years 2019 to 2029; given Dr. Woolridge's concern with my growth rates over the coming period of three-to-five years, his use of the *Survey of Professional Forecasters* does not address that issue. As to the CBO and EIA forecasts, those forecasts cover only fifteen to 25 years of a perpetual period and are not consensus forecasts. Lastly, because the EIA's GDP growth forecast is an input to its annual energy projections, the assumptions and methods underlying its GDP forecast are for that specific purpose.

The CBO provides updates regarding its forecasting record. In that context, the CBO has noted that comparisons to other forecasts are not always appropriate, at least in part because forecasts may be based on different assumptions and used for different purposes.[183] The CBO also observes it is required to assume future fiscal policy generally will reflect current law, so that

[182] Testimony of J. Randall Woolridge, at 120.
[183] *See, CBO's Economic Forecasting Record: 2019 Update,* October 2019, at 8.

it may provide a benchmark against which proposed changes in law may be assessed.[184] The CBO goes on to explain that "[d]ifferent assumptions about monetary policy can also make it difficult to compare CBO's forecasts with other forecasts. CBO's forecasts incorporate the assumption that monetary policy will reflect the economic conditions that the agency expects to prevail under the fiscal policy specified in current law."[185] The CBO also notes that among its two-year forecasts (since the early 1980s), the forecast error for "growth of real output" and inflation (measured by the Consumer Price Index) has been 1.30 percentage points and 0.90 percentage points, respectively.[186]

As to the accuracy of the EIA's GDP forecast, the agency reviews its projections in its *Annual Energy Outlook ("AEO") Retrospective Review*. There, the EIA has noted "[t]he projections in the AEO are not statements of what will happen but of what may happen given assumptions in the underlying National Energy Modeling System (NEMS)."[187]

As EIA makes clear, the reference case projections assume current laws

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184 *Ibid*. "CBO is required by statute to assume that future fiscal policy will generally reflect the provisions in current law, an approach that derives from the agency's responsibility to provide a benchmark for lawmakers as they consider proposed legislative changes. When the Administration prepares its forecasts, however, it assumes that the fiscal policy in the President's proposed budget will be adopted…Forecast errors may be affected by those different fiscal policy assumptions, especially when forecasts are made while policymakers are considering major legislative changes."

185 *Ibid*.

186 *Ibid.*, at 2. Root mean square error.

187 U.S. Energy Information Administration, *Annual Energy Outlook Retrospective Review: Evaluation of AEO2018 and Prior Reference Case Projections*, December 2018, at 1. Clarification added.

and regulations remain unchanged throughout the projection period.[188] The agency's projections, therefore, are based on the economic environment at the time of the forecast. As shown in Table 3 of the *AEO Retrospective Review*, the EIA compares its past real GDP growth projections to actual real GDP growth. In its 1994 forecast of GDP growth – a time during which the U.S. was coming out of a recession – the agency generally underestimated GDP growth. During the stronger economic times of the 2000s, the agency generally overestimated GDP growth into the future.[189] The agency's 2020 to 2050 reference case is based on the current economic environment of below average GDP growth, inflation, and interest rates.[190]

Q. PLEASE DESCRIBE DR. WOOLRIDGE'S CONCERNS WITH THE EMPIRICAL CAPITAL ASSET PRICING MODEL.

A. Dr. Woolridge believes the ECAPM is an "ad hoc version of the CAPM and has not been theoretically or empirically validated in refereed journals."[191] That point aside, he does not agree with the use of adjusted Beta coefficients in the ECAPM.[192] For the reasons discussed below, I disagree with Dr. Woolridge's concerns.

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188 U.S. Energy Information Administration, Annual Energy Outlook 2020 with Projections to 2050, January 2020, at 4.

189 U.S. Energy Information Administration, *Annual Energy Outlook Retrospective Review: Evaluation of AEO2018 and Prior Reference Case Projections*, December 2018, Table 3.

190 U.S. Energy Information Administration, Annual Energy Outlook 2020 with Projections to 2050, January 2020, at Table 20.

191 Testimony of J. Randall Woolridge, at 130.

192 Testimony of J. Randall Woolridge, at 131.

Q. WHY DID YOU INCLUDE THE ECAPM IN YOUR ANALYSES?

A. As discussed in my Direct Testimony, numerous tests have measured the extent to which security returns and Beta coefficients are related as predicted by the CAPM. Empirical studies have found that returns on low-Beta securities are higher than the CAPM would predict and lower than the CAPM would predict for high-Beta securities.[193] Simply, the ECAPM method addresses the tendency of the CAPM to underestimate the Cost of Equity for low-Beta coefficient companies such as regulated utilities. In its text on cost of capital analysis for regulated industries, for example, the Brattle Group summarizes a number of studies estimating the alpha component of the ECAPM.[194]

193 Direct Testimony of Dylan W. D'Ascendis, at 92-93.

194 Villadsen, Vilbert, Harris, and Kolbe, Risk and Return for Regulated Industries, 2017, Table 4.1 at 83. Alpha is an adjustment to the security market line that increases the intercept and lowers the slope of the line.

Q. HAS THE ECAPM METHOD BEEN RECOGNIZED IN OTHER REGULATORY JURISDICTIONS?

A. Yes, it has been accepted in Minnesota, Mississippi, and New York.[195] Additionally, the Commission recently found the ECAPM to be "credible, probative, and entitled to substantial weight."[196]

Q. HAVE YOU UNDERTAKEN ANY INDEPENDENT ANALYSES TO DETERMINE WHETHER THERE IS A RELATIONSHIP BETWEEN BETA COEFFICIENTS AND EXCESS RETURNS PRODUCED BY THE CAPM AND ECAPM?

A. Yes, I performed an analysis of excess returns produced by the CAPM, by Beta coefficient decile, over the eleven years ended 2019. The analysis compared the observed returns of the companies in the S&P 500 Index to expected returns based on the CAPM. Observed returns were calculated as the total return for each company from the first day of a given year to the end of that year. The

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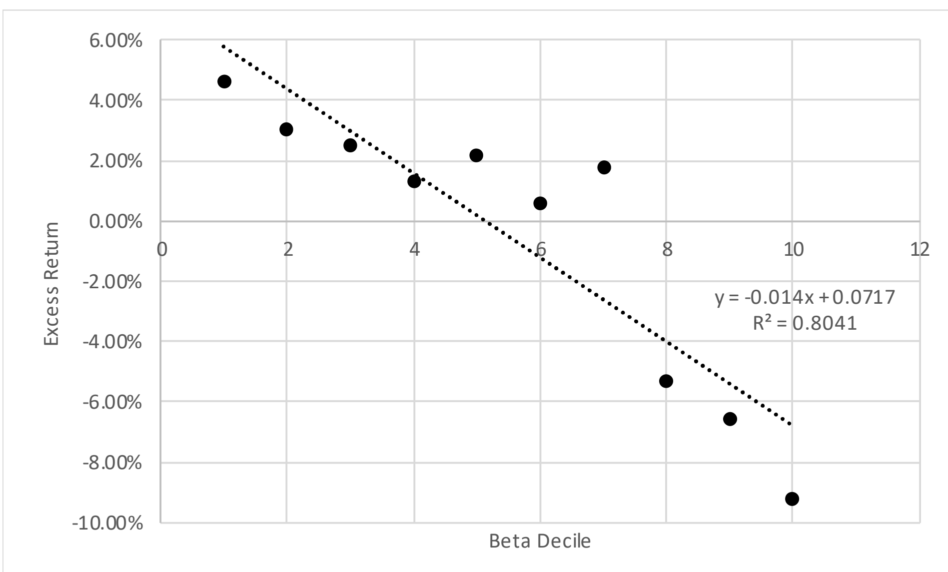
195 Minnesota Public Utilities Commission, MPUC Docket No. G011/GR-15-736, *In the Matter of the Application of Minnesota Energy Resources Corporation for Authority to Increase Rates for Natural Gas Service in Minnesota, Findings of Fact, Conclusions of Law, and Recommendation*, August 19, 2016, at 29; Mississippi Public Service Commission, Docket No. 01-UN-0548, *Notice of Intent of Mississippi Power Company to Change Rates for Electric Service in its Certificated Areas in the Twenty-Three Counties of Southeast Mississippi*, Final Order, December 3, 2001, at 19; New York Public Service Commission, Case 16-G-0058, P*roceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of KeySpan Gas East Corporation d/b/a National Grid for Gas Service*, Order Adopting Terms of Joint Proposal and Establishing Gas Rate Plans, December 16, 2016, at 32.

196 *In the Matter of Application of Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina*, Docket No. E-22, Sub 562 Order Accepting Public Staff Stipulation in Part, Accepting CIGFUR Stipulation, Deciding Contested Issues, and Granting Partial Rate Increase, February 24, 2020, at 40.

expected return for each company was calculated using the CAPM as applied to the following annual data: (1) a risk-free rate equal to the average 30-year Treasury yield for that year; (2) an adjusted Beta coefficient as of the beginning of the year using Bloomberg's standard calculation method (two years of weekly return data, using the S&P 500 Index as the comparison benchmark); and (3) a market return equal to the S&P 500 Index total return for that year. The companies were grouped into deciles each year based on their Beta coefficients, and the median excess return (or return deficiency) was calculated for each decile group. Excess returns were calculated as the observed return less the return implied by the CAPM. Chart 12 (below) summarizes those results.

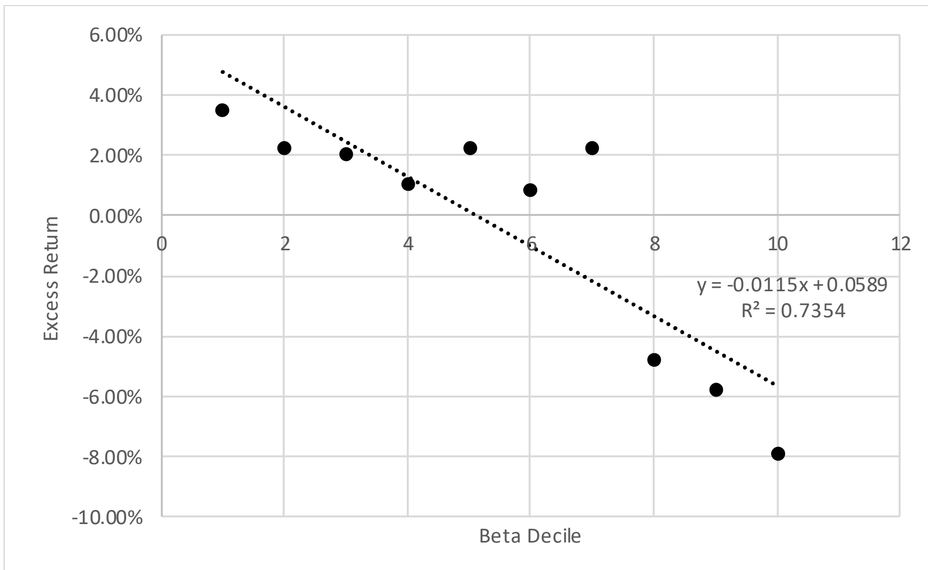
Chart 12: Excess Returns Under CAPM[197]



197 Source: Bloomberg Professional Services.

As Chart 12 demonstrates, the relationship between excess return and Beta coefficient deciles is strong, with deciles explaining approximately 80.00 percent of the excess return. Using the same data and calculating the excess return by reference to the ECAPM, produces the same downward sloping relationship, but not to the same degree (*see* Chart 13, below).

Chart 13: Excess Returns Under ECAPM[198]



There are two principal observations to be drawn from the data presented in Charts 12 and 13. First, under the ECAPM the slope coefficient is somewhat less negative (relative to the CAPM), suggesting a flatter relationship between Beta coefficient deciles and the excess return. The flatter slope moves closer to the point at which the excess return is zero across all deciles. Second, the excess return values are somewhat moderated under the ECAPM; the high

198 Source: Bloomberg Professional Services.

excess returns are lower than under the CAPM, and the low excess returns are higher. Again, that finding suggests the ECAPM mitigates, but does not solve the issue of the CAPM underestimating returns for low-Beta coefficient firms.

In summary, Charts 12 and 13 support the position that the CAPM tends to underestimate returns for low-Beta coefficient firms, and the ECAPM moderates that effect to some extent, but it does not appear to eliminate it. Because the ECAPM mitigates the drift in Beta coefficients, I believe it is a reasonable method.

Q. WHAT IS YOUR RESPONSE TO DR. WOOLRIDGE'S CONCERN WITH THE USE OF ADJUSTED BETA COEFFICIENTS IN THE ECAPM APPROACH?

A. As discussed in my Direct Testimony, the use of adjusted Beta coefficients is not equivalent to the use of the ECAPM.[199] Beta coefficients are adjusted because of their general regression tendency to converge toward 1.00 over time, *i.e.*, over successive calculations. Numerous studies have determined that at any given point in time the Security Market Line ("SML") described by the CAPM formula is not as steeply sloped as the predicted SML.[200] As noted by Dr. Morin, "[t]he ECAPM is a formal recognition that the observed risk-return tradeoff is flatter than predicted by the CAPM based on myriad empirical

[199] Direct Testimony of Dylan W. D'Ascendis, at 93-94.
[200] Direct Testimony of Dylan W. D'Ascendis, at 92-93.

evidence."[201]

F. Bond Yield Plus Risk Premium Analysis

Q. PLEASE SUMMARIZE DR. WOOLRIDGE'S RESPONSE TO YOUR BOND YIELD PLUS RISK PREMIUM ANALYSIS.

A. Dr. Woolridge argues the Risk Premium derived from the analysis is "inflated" and "is a gauge of *commission* behavior and not *investor* behavior."[202] Dr. Woolridge further notes that the Risk Premium approach results reflect "other utility- and rate case-specific information in setting ROEs"[203] and points to what he views as a potential discrepancy between settled and litigated cases.[204] Dr. Woolridge also suggests the analysis overstates the actual ROE because the estimated risk premium is based on historical Treasury yields, whereas the model is applied to current and expected yields.[205]

Q. WHAT IS DR. WOOLRIDGE'S POSITION REGARDING THE RISK-FREE RATES APPLIED IN YOUR BOND YIELD PLUS RISK PREMIUM ANALYSIS?

A. Dr. Woolridge finds the Treasury bond yields used in my Bond Yield Plus Risk Premium analysis "excessive", and argues they must not be accurate because if they were, "investors would not be buying long-term Treasury bonds at their

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201 Roger A. Morin, *New Regulatory Finance*, at 191 (2006).
202 Testimony of J. Randall Woolridge, at 133. [*Emphasis included in original*]
203 Testimony of J. Randall Woolridge, at 133.
204 Testimony of J. Randall Woolridge, at 133-134.
205 Testimony of J. Randall Woolridge, at 133.

current yields if they expected interest rates to suddenly increase".[206]

Q. WHAT IS YOUR RESPONSE TO DR. WOOLRIDGE ON THAT POINT?

A. Dr. Woolridge's argument is misplaced. In his CAPM analysis, Dr. Woolridge relies on a 3.50 percent risk-free rate,[207] which is higher than the three risk-free rates presented in my updated Bond Yield Plus Risk Premium analysis and over 200 basis points above the current 30-day average risk-free rate.[208] Still, Dr. Woolridge argues investors give such projections no weight in their decision to purchase bonds at current yields. I disagree. The Cost of Equity is fundamentally forward-looking, and the use of expected Treasury yields (such as the 3.50 percent Dr. Woolridge uses) is consistent with that principle.

Lastly, Dr. Woolridge's argument that investors would not acquire Treasury securities if they felt interest rates were to increase (because the price would decrease) appears to assume investors take short-term trading positions. Although that may be the case for some, I do not believe it is for all Treasury bond investors. In my experience, Treasury securities often are "immunized", by matching their duration to the duration of a corresponding liability (for example, in a benefit plan). In that case, reductions in the price brought about by higher interest rates are offset by the higher interest income associated with those rates. Because many investors in Treasury securities are institutions,

206 Testimony of J. Randall Woolridge, at 132.
207 Testimony of J. Randall Woolridge, at 79; Exhibit JRW-8.
208 Rebuttal Exhibit DWD-5.

whose objectives and strategies may go beyond short-term trading positions, we cannot say there is no implied risk of future rate increases.

Q. WHAT IS YOUR RESPONSE TO DR. WOOLRIDGE'S POSITION THAT THE RISK PREMIUM ANALYSIS IS A STUDY OF UTILITY COMMISSION BEHAVIOR RATHER THAN INVESTOR BEHAVIOR?

A. Those cases, and their associated decisions, reflect the same type of market-based analyses at issue in this proceeding. Because authorized returns are publicly available (the proxy companies disclose authorized returns, by jurisdiction, in their 2019 SEC Forms 10-K),[209] it therefore is reasonable to conclude that data is reflected, at least to some degree, in investors' return expectations and requirements. From that perspective, ROE recommendations that are far removed from prevailing levels, such as Dr. Woolridge's, should be reconciled by reference to differences in risk. I do not believe Dr. Woolridge's recommendation reasonably does so.

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209 *See*, *for example*, American Electric Power Company, Inc., SEC Form 10-K for the year ended December 31, 2019, at 4; ALLETE Inc., SEC Form 10-K for the year ended December 31, 2019, at 14-15; Duke Energy Corporation, SEC Form 10-K for the year ended December 31, 2019, at 16; WEC Energy Group, Inc., SEC Form 10-K for the year ended December 31, 2019, at 129-131.

Q. WHAT IS YOUR RESPONSE TO DR. WOOLRIDGE'S POSITION THAT YOUR ANALYSIS APPLIES AN HISTORICAL RISK PREMIUM TO PROJECTED RATES AND, AS SUCH, OVERSTATES THE COST OF EQUITY?[210]

A. I applied both historical and projected interest rates to the regression coefficients developed in the Risk Premium analysis, not to an average historical risk premium. As discussed in my Direct Testimony, the regression coefficients specifically recognize that as interest rates decrease, the Equity Risk Premium increases.[211] A consequence of that relationship is that interest rates and the Cost of Equity generally move in the same direction, although not on a one-to-one basis. As projected interest rates increase, the Cost of Equity also increases, but not to the same degree. Dr. Woolridge's concern that I applied projected interest rates to an historical risk premium is misplaced, in that: (1) the analysis does not rely on an historical risk premium; and (2) because the estimated risk premium does not increase in lock step with interest rates, the resulting ROE estimate does not overstate the Cost of Equity.

[210] Testimony of J. Randall Woolridge, at 133.
[211] Direct Testimony of Dylan W. D'Ascendis, at 96-97.

Q. WHAT IS YOUR RESPONSE TO DR. WOOLRIDGE'S POSITION THAT YOUR RISK PREMIUM ANALYSIS MUST TAKE INTO CONSIDERATION THE SPECIFIC ASPECTS OF THIS PROCEEDING RELATIVE TO ALL OTHERS?[212]

A. There is no disagreement that every case has its unique set of issues and circumstances. Reviewing over 1,600 cases over many economic cycles and using that data to develop the relationship between the Equity Risk Premium and interest rates mitigates that concern.

Q. IS IT A CONCERN, AS DR. WOOLRIDGE ARGUES, TO INCLUDE BOTH FULLY LITIGATED AND SETTLED RATE CASES IN YOUR RISK PREMIUM ANALYSIS?[213]

A. No, it is not. Of the more than 1,600 rate cases in my updated Risk Premium analysis (*see* Rebuttal Exhibit DWD-5), 1,162 were fully litigated and 462 were settled. More recently (from January 2015 through April 17, 2020), 80 cases were fully litigated and 101 were settled. Over the same period, the difference in average authorized returns between the two, however, was approximately 13 basis points. Further, the same inverse relationship between interest rates and the Equity Risk Premium is present, whether the analysis includes fully litigated rate cases, settled rate cases, or both.[214] I therefore disagree with Dr.

[212] Testimony of J. Randall Woolridge, at 133-134.
[213] Testimony of J. Randall Woolridge, at 133-134.
[214] Rebuttal Exhibit DWD-12.

Woolridge's concern.

G. Expected Earnings Analysis

Q. PLEASE SUMMARIZE DR. WOOLRIDGE'S CONCERNS WITH YOUR EXPECTED EARNINGS ANALYSIS.

A. Dr. Woolridge argues the Expected Earnings approach is inappropriate because: (1) it is accounting-based and does not measure market-based investor return requirements; (2) book equity does not change with investor return requirements as do market prices; (3) the approach is circular; and (4) the data partially reflect earnings of non-regulated operations.[215]

Q. WHAT IS YOUR RESPONSE TO DR. WOOLRIDGE?

A. Although I agree economic and financial factors and the market-based models that depend on them are important, those factors do not invalidate the Expected Earnings approach. As discussed in my Direct Testimony, no single method best captures investor expectations at all times and under all conditions.[216] Market-based models necessarily require us to draw inferences from market data based on the assumptions and construction of methods such as the DCF and CAPM approaches. The simplicity of the Expected Earnings approach is a benefit, not a detriment.

Although many factors affect stock returns and M/B ratios, the

[215] Testimony of J. Randall Woolridge, at 135-137.
[216] Direct Testimony of Dylan W. D'Ascendis, at 5.

accounting-based ROE is one of them and cannot be ignored.[217] As a practical matter, the Economic Value Added consulting practices[218] and related value-based-management systems[219] encourage financial managers to focus on elements of the Return on Net Assets, and Return on Invested Capital.

In addition, the standard revenue requirements formula applied by the Commission explicitly recognizes the validity of the book value of equity by choosing to measure capital structures based on book values, rather than market value. The Expected Earnings approach provides a direct measure of the book-based return comparable-risk utilities are expected to earn. In that sense, it is a direct measure of the expected opportunity cost on the book value of equity. Equally important, because it looks to the earnings expected of comparable-risk companies, the approach is consistent with the *Hope* and *Bluefield* "comparable return" standard. As Dr. Morin notes, the method "is easily understood, and is firmly anchored in regulatory tradition," concluding that "because the investment base for ratemaking purposes is expressed in book value terms, a rate of return on book value, as is the case with [Expected] Earnings, is highly meaningful."[220]

Lastly, among the growth rates Dr. Woolridge considers in his DCF

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217 I am not suggesting the M/B ratio necessarily will equal 1.00 when the accounting-based ROE equals the Cost of Equity.

218 *See*, G. Bennett Stewart, The Quest for Value, HarperCollins Publishers, Inc., 1990.

219 *See,* Institute of Management Accountants, *Measuring and Managing Shareholder Value Creation*, 1997.

220 Roger A. Morin, New Regulatory Finance, Public Utilities Reports, Inc., 2006 at 395. [clarification added].

analyses is the "sustainable growth" method. Under that method, expected growth depends on the expected return on the book value of common equity, and the extent to which that return is retained (that is, not paid in dividends). Although he does not adjust them to reflect average book value balances, Dr. Woolridge reports both mean and median expected returns of 10.50.[221]

Q. HAS THE COMMISSION ACCEPTED THE EXPECTED EARNINGS ANALYSIS IN PAST CASES?

A. Yes. In the Company's prior rate case (Docket No. E-2, Sub 1142), the Commission found the Comparable Earnings analysis, which is similar to my Expected Earnings Analysis, to be "credible".[222] The Commission also has noted the reasonableness of the Comparable Earnings analysis in prior orders, stating that it is "credible and deserving of great weight."[223]

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[221] Exhibit JRW-7, page 4. Mean and median of Dr. Woolridge's proxy group.

[222] North Carolina Utilities Commission, Docket No. E-2, Sub 1142, *Order Accepting Stipulation, Deciding Contested Issues, and Granting Partial Rate Increase*, February 23, 2018, at 74, 81, 82.

[223] North Carolina Utilities Commission, Docket No. E-2, Sub 1023, *Order Granting General Rate Increase*, May 30, 2013, at 39.

H. Market/Book Ratios and the Cost of Equity

Q. PLEASE BRIEFLY SUMMARIZE DR. WOOLRIDGE'S POSITION REGARDING THE RELATIONSHIP BETWEEN M/B RATIOS AND THE COST OF EQUITY.

A. Dr. Woolridge suggests M/B ratios greater than one[224] indicate the subject company's earned Return on Equity exceeds its Cost of Equity.[225] In Dr. Woolridge's view, the relationship between M/B ratios and the Cost of Equity 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.[226]

In discussing normative economic models of firms, which he notes are "developed under very restrictive assumptions",[227] Dr. Woolridge explains that in a perfectly competitive market, firms will produce to the point that 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

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224 M/B ratios in excess of unity simply means that the firm is worth more as a going concern than the book value of its assets.
225 Testimony of J. Randall Woolridge, at 54-55.
226 Testimony of J. Randall Woolridge, at 53.
227 Testimony of J. Randall Woolridge, at 51.

equal the book value of the firm's securities.[228]

Dr. Woolridge suggests the same relationship holds in the utility sector, arguing "[g]iven 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."[229] In short, Dr. Woolridge's position is clear: If a utility's M/B ratio is greater than one, its earned return is greater than its investor-required return.

Q. HAS DR. WOOLRIDGE UNDERTAKEN HIS OWN ANALYSES OF THE RELATIONSHIP BETWEEN M/B RATIOS AND EARNED RETURNS?

A. Yes, Dr. Woolridge performs a regression analysis to examine the relationship between the earned Return on Equity and M/B ratios for all electric and gas utilities covered by Value Line.[230] Based on his analysis, Dr. Woolridge argues there is a strong relationship between the two variables. In fact, because he reports an R-Squared of 50.00 percent, Dr. Woolridge concludes there is a "statistically significant positive relationship between ROEs and market-to-book ratios for electric utilities and gas companies."[231]

228 Testimony of J. Randall Woolridge, at 51.
229 Testimony of J. Randall Woolridge, at 55.
230 Testimony of J. Randall Woolridge, at 54-55, Exhibit JRW-4.
231 Testimony of J. Randall Woolridge, at 54-55, Exhibit JRW-4.

Q. WHAT IS YOUR RESPONSE TO DR. WOOLRIDGE ON THOSE POINTS?

A. Although expected earned returns are a factor that weigh in M/B ratios, they are not the only factor. Dr. Woolridge's linear regression says as much; other variables account for 50.00 percent of the variation in M/B ratios. Based on Dr. Woolridge's regression analysis, we cannot conclude earned returns are greater than required returns whenever M/B ratios are greater than one.

Looking beyond Dr. Woolridge's analysis, there are fundamental reasons we should not rely on M/B ratios as the measure of excess returns. By way of background, the M/B ratio equals the market value (or stock price) per share, divided by the total common equity (or the book value) per share. Book value per share is an accounting construct that reflects historical costs. In contrast, market value per share (*i.e.,* the stock price) is forward-looking, and a function of many variables, including, but not limited to, expected earnings and cash flow growth, expected payout ratios, measures of "earnings quality," the regulatory climate, the equity ratio, expected capital expenditures, and the earned return on common equity.[232] As Dr. Morin states, it is rarely the case in cost of service-based regulation that M/B ratios equal 1.00:

> The third and perhaps most important reason for caution and skepticism is that application of the DCF model produces estimates of common equity cost that are consistent with

[232] *See*, Roger A. Morin, New Regulatory Finance, Public Utility Reports, Inc., 2006, at 366. Please note, Dr. Morin cites several academic articles that address the various factors that affect the M/B ratio for utilities.

> investors' expected return only when stock price and book value are reasonably similar, that is, when the M/B is close to unity. As shown below, application of the standard DCF model to utility stocks understates the investor's expected return when the market-to-book (M/B) ratio of a given stock exceeds unity. This was particularly relevant in the capital market environment of the 1990s and 2000s whose utility stocks are trading at M/B ratios well above unity and have been for nearly two decades. The converse is also true, that is, the DCF model overstates the investor's return when the stock's M/B ratio is less than unity. The reason for the distortion is that the DCF market return is applied to a book value rate base by the regulator, that is, a utility's earnings are limited to earnings on a book value rate base.[233]

Here, Dr. Woolridge argues that whenever the earned ROE is greater than the Cost of Equity ("*k*"), the M/B ratio will exceed one.[234] Under certain restrictive assumptions, the DCF model can be rewritten to express the M/B ratio[235] as follows:

$$\frac{M}{B} = \frac{\text{ROE} - g}{k - g} \qquad [3]$$

where ROE is the return on book equity, k is the Cost of Equity, and g is the long-term growth rate. Rearranging Equation [3] produces the familiar Gordon Growth model:

$$P = \frac{D}{k - g} \qquad [4]$$

and the Constant Growth DCF model:

233 *Ibid.*, at 434.
234 Testimony of J. Randall Woolridge, at 54.
235 B. Branch, A. Sharma, C. Chawla, and F. Tu, *An Updated Model of Price-to-Book*, Journal of Applied Finance, No. 1 (2014).

$$P = \frac{D}{P} + g \quad [5]$$

Dr. Woolridge's assumed relationship between the accounting Return on Equity and the Cost of Equity therefore directly relies on the Constant Growth DCF model; one cannot be assumed without the other. Any inferences drawn from relationships among M/B, ROE, and *k* from Equation [3] therefore rely on the explicit acceptance of all assumptions underlying the Constant Growth DCF model. That is, Equation [3] only can be drawn from the Constant Growth DCF model if we assume: (1) a constant dividend payout ratio in perpetuity; (2) no stock issuances or repurchases; (3) the P/E ratio and the M/B ratio will remain constant in perpetuity; and (4) the Cost of Equity estimated today will never change. Taken together, those assumptions are quite restrictive, especially in the currently unstable capital market. Consequently, I do not believe we can assume the definitive and permanent relationship among M/B, ROE, and *k* that Dr. Woolridge's position assumes.

Q. WHAT WOULD BE THE RESULT IF REGULATORY COMMISSIONS DID FORCE M/B RATIOS TOWARD UNITY?

A. Looking to Dr. Woolridge's Electric Proxy Group, the average capital loss for equity investors would be about 58.00 percent.[236] That loss would not just affect investors, it also would substantially diminish the ability of utilities to

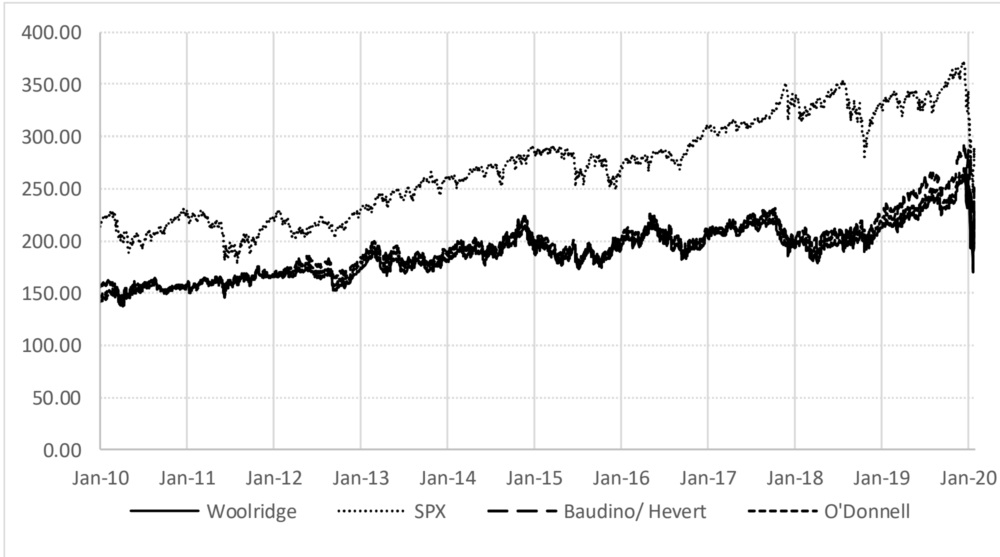
[236] Based on Dr. Woolridge's proxy group average M/B ratio of 237.00. (237.00 -100.00)/ 237.00 = 57.81 percent. Exhibit JRW-2, page 1.

attract external capital. To summarize, if regulatory commissions were to set rates with an eye toward moving the M/B ratio toward unity, that practice may well impede the ability to attract the capital required to support its operations, especially in markets during which the M/B ratio for the overall market is significantly greater than 100.00 percent.

Q. HAVE UTILITY M/B RATIOS GENERALLY EXCEEDED 1.00?

A. Yes, they have. Chart 14 (below) demonstrates that since 2010, the Opposing Witnesses' proxy group M/B ratios have exceeded 1.00, and generally have moved with the S&P 500 Index M/B ratio. If Dr. Woolridge is of the view that M/B ratios greater than 1.00 reflect earned returns greater than the Cost of Equity, it follows that utility commissions have long been incorrect in their ROE determinations. If, over many years and across many companies, investors felt the returns they expected had so significantly exceeded the returns they required, they would adjust their requirements. In Dr. Woolridge's construct, the difference between expected and required returns would dissipate, and take with it the difference between market and book values. That has not occurred.

Chart 14: Comparison Groups, S&P 500 Market/Book Ratios (2010 – 2020)[237]



Lastly, although the broad market represents a cross section of market sectors, of which the utility sector is just one, the observed variation in market-level M/B ratios speaks to the time-varying influence of general macroeconomic factors, not to any failure of regulation. The relationship between the Opposing Witnesses' proxy group M/B ratios and the S&P 500 M/B ratio is positive and statistically significant. That is the case even when we control for serial correlation.[238] We therefore reasonably can conclude that broad macroeconomic and capital market factors affect both utilities and non-regulated entities.

237 Source: S&P Global Market Intelligence, Bloomberg Professional.
238 Using the Prais-Winsten routine.

Q. HAVE M/B VALUES GENERALLY EXCEEDED 1.00 FOR THE BROAD EQUITY MARKET?

A. Yes, they have. As Chart 15 (below) demonstrates, since 1990 the average M/B ratio for the S&P 500 Index has been 2.89; it has never reached unity.

Chart 15: S&P 500 M/B Ratio Over Time[239]

Q. ARE YOU AWARE OF LITERATURE THAT HAS FOCUSED ON THE M/B RATIOS OF REGULATED UTILITIES?

A. Yes. Literature focusing on utilities has long concluded that regulation may not necessarily result in M/B ratios approaching unity. As noted by Phillips in 1993:

> Many question the assumption that market price should equal book value, believing that 'the earnings of utilities should be sufficiently high to achieve market-to-book ratios which are consistent with those prevailing for stocks of

239 Source: Bloomberg Professional Services.

unregulated companies.'[240]

In 1988 Bonbright stated:

> In the first place, commissions cannot forecast, except within wide limits, the effect their rate orders will have on the market prices of the stocks of the companies they regulate. In the second place, whatever the initial market prices may be, they are sure to change not only with the changing prospects for earnings, but with the changing outlook of an inherently volatile stock market. In short, market prices are beyond the control, though not beyond the influence, of rate regulation. Moreover, even if a commission did possess the power of control, any attempt to exercise it ... would result in harmful, uneconomic shifts in public utility rate levels.[241]

And in 1972 Stewart Myers came to the following conclusion:

> In short, a straightforward application of the cost of capital to a book value rate base does not automatically imply that the market and book values will be equal. This is an obvious but important point. If straightforward approaches did imply equality of market and book values, then there would be no need to estimate the cost of capital. It would suffice to lower (raise) allowed earnings whenever markets were above (below) book.[242]

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240 Charles F. Phillips, The Regulation of Public Utilities – Theory and Practice (Public Utility Reports, Inc., 1993) at 395.

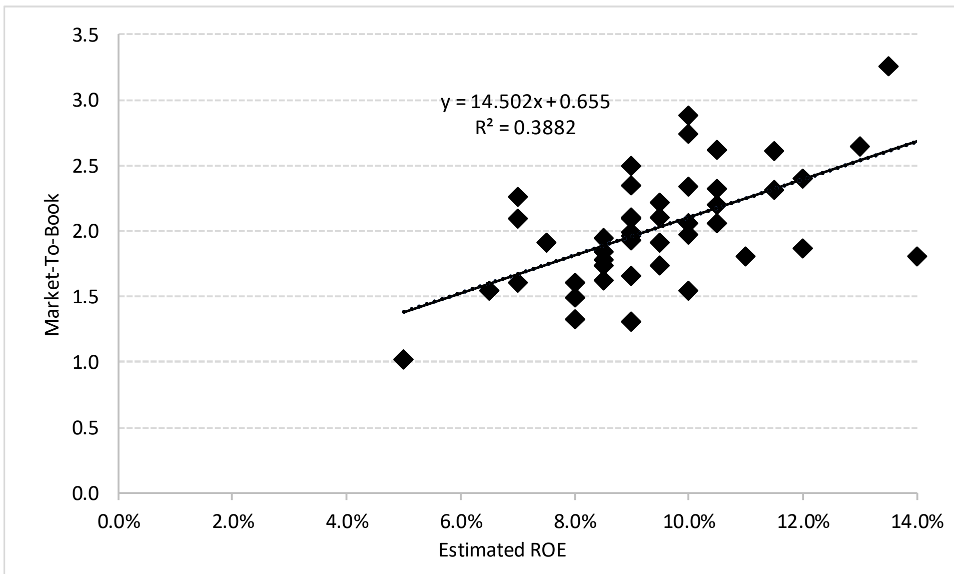
241 James C. Bonbright, Albert L. Danielsen and David R. Kamerschen, Principles of Public Utility Rates (Public Utilities Reports, Inc., 1988), at 334.

242 Stewart C. Myers, *The Application of Finance Theory to Public Utility Rate Cases*, The Bell Journal of Economics and Management Science, Vol. 3, No. 1 (Spring 1972), at 58-97.

Q. HAVE YOU REVIEWED THE ROE AND M/B RATIO DATA PROVIDED IN EXHIBIT JRW-4?

A. Yes, I have updated the chart contained in Exhibit JRW-4, including the regression coefficients, based on the method described by Dr. Woolridge[243] (*see* Chart 16, below).

Chart 16: Update of Exhibit JRW-4, With Regression Coefficients[244]



Based on Dr. Woolridge's approach, an M/B ratio of 1.00 is associated with an ROE of 2.38 percent,[245] a highly improbable condition. Even the one observation for which the M/B ratio is about 1.00 suggests an ROE of approximately 5.00 percent. Dr. Woolridge's data, therefore, do not support the theory that ROEs greater than 1.00 demonstrate earned returns exceed

243 Testimony of J. Randall Woolridge, at 54-55; Exhibit JRW-4.
244 Source: Value Line, accessed April 24, 2020.
245 1.00 = 0.655 + (14.502 x 2.38%).

investors' required returns.

Q. HAVE YOU ANALYZED WHETHER THE ACTUAL EARNED RETURN ON EQUITY EXPLAINS UTILITIES' M/B RATIOS?

A. Yes, I have. Using data provided by S&P Global Market Intelligence, I performed a regression analysis in which the M/B ratio was the dependent variable, and the Return on Average Common Equity ("ROACE") for 2019 was the explanatory variable. As shown in Rebuttal Exhibit DWD-13, the R-squared was approximately 17.60 percent. An R-squared of 17.60 percent means that factors other than ROACE explain up to 82.40 percent of M/B ratios in the proxy group.[246] Those results support the position that although the earned Return on Equity is a factor that explains M/B ratios, it is not the only factor. In any case, the regression equation indicates that an M/B ratio of 1.00 (that is, 100.00 percent) is associated with a Return on Common Equity of approximately -5.06 percent; an M/B ratio of 1.10 relates to an ROACE of approximately -3.88 percent. Because those estimates are nonsensical, I do not agree that M/B ratios greater than 1.00 demonstrate earnings in excess of investors' requirements.

[246] 0.824 = (1 – 0.176).

I. Relative Risk

Q. ON PAGE 38 OF HIS DIRECT TESTIMONY, DR. WOOLRIDGE ARGUES THAT THE COMPANY IS "LESS RISKY" THAN THE PROXY COMPANIES, BECAUSE ITS CREDIT RATING IS HIGHER THAN THE PROXY GROUP AVERAGE. DO YOU BELIEVE CREDIT RATINGS ARE A FULL MEASURE OF THE COMPANY'S EQUITY RISK COMPARED TO ITS PEERS?

A. No, I do not. Although over the long term credit ratings (and therefore credit spreads) may be directionally related to the Cost of Equity over the long-term, a change in one is not a direct measure of a change in the other. Debt and equity are entirely different securities with different risk/return characteristics, different lives, and different investors. Debt investors have a contractual, senior claim on cash flows not available to equity investors and as such, equity investors bear the residual risk of ownership. Moreover, debt investors' exposure to business and financial risk is finite (due to the finite life of debt), whereas equity investors are exposed to residual risk in perpetuity. Consequently, any inferences drawn from differences in credit ratings regarding the Company's Cost of Equity should be drawn with caution.

A visible measure of the distinction of the risks to which debt and equity investors are exposed is the difference in their respective Beta coefficients. Although I disagree with his conclusions, Dr. Woolridge recommends an average Beta coefficient of 0.55 for his proxy group.[247] Duff & Phelps notes that as of December 2019, Beta coefficients for A-rated debt was 0.04,[248] far below the equity Beta coefficient assumed by Dr. Woolridge. In fact, a debt Beta coefficient of 0.72 is associated with Caa-rated debt, which is considered below investment grade.[249] Those differences are a clear indication that the risks assumed by debt investors are far different than those assumed by equity investors.

Q. DOES THE DATA PROVIDED BY DR. WOOLRIDGE INDICATE A RELATIONSHIP BETWEEN COST OF EQUITY ESTIMATES AND CREDIT RATINGS?

A. No, they do not. Using the growth rates and dividend yields reported by Dr. Woolridge, I produced Constant Growth DCF results for each of the comparison companies.[250] Those results do not support Dr. Woolridge's conclusion. For example, Southern Company is rated A-, and Hawaiian Electric Industries, Inc. is rated BBB-, three credit "notches" apart. Yet, based on Dr. Woolridge's data, their DCF results are 6.79 percent and 6.56 percent, respectively, only 23 basis points apart. On the other hand, Consolidated Edison, Inc. and Evergy Inc. are both rated A-, but their DCF results differ by 412 basis points.[251] We cannot say, based on Dr. Woolridge's primary method, that there is a definitive

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247 Exhibit JRW-8, page 1.
248 Source: Duff & Phelps Cost of Capital Navigator, accessed April 24, 2020.
249 *Ibid*.
250 Rebuttal Exhibit DWD-14.
251 30-day average dividend yields.

relationship between credit rating notches and Cost of Equity estimates.

Q. DID YOU PERFORM ANY ANALYSES TO DETERMINE WHETHER DR. WOOLRIDGE'S DATA SUPPORTS THE ASSUMPTION THAT THERE IS A QUANTIFIABLE DIFFERENCE IN THE COST OF EQUITY FOR COMPANIES WITH DIFFERENT BOND CREDIT RATINGS?

A. Yes. Using the same Constant Growth DCF results for each of Dr. Woolridge's comparison companies discussed above, I applied "credit scores" to Dr. Woolridge's comparison companies by converting the S&P bond ratings reported in his direct testimony to a numerical value. If there is a quantifiable relationship between the proxy companies' credit ratings and Cost of Equity, there should be a positive, statistically significant relationship between the credit score and the DCF results. That is, as credit quality deteriorates (resulting in a higher score), the Cost of Equity should increase. Therefore, I performed a regression analysis in which the dependent variable was the DCF result and the explanatory variable was the credit score. As shown in Rebuttal Exhibit DWD-14, the regression analysis showed no significant statistical relationship between the two, and the relationship was negative. In fact, the highest R-squared of the regressions was only 0.00006, which indicates that credit ratings accounted for, at most, 0.006 percent of the change in the DCF-estimated Cost of Equity.[252]

Q. DO YOU HAVE ANY OTHER CONCERNS WITH DR. WOOLRIDGE'S REVIEW OF CREDIT RATINGS?

A. Yes, I do. My concern with Dr. Woolridge's comparison of DE Progress to the credit ratings of the proxy companies is that Moody's ratings methodology specifically considers the relationship between parent and operating companies, and typically rates parent companies lower than the operating company subsidiaries. As Moody's explains:

> Most HoldCos present their financial statements on a consolidated basis that blurs legal considerations about priority of creditors based on the legal structure of the family, and grid scoring is thus based on consolidated ratios. However, HoldCo creditors typically have a secondary claim on the group's cash flows and assets after OpCo creditors. We refer to this as structural subordination, because it is the corporate legal structure, rather than specific subordination provisions, that causes creditors at each of the utility and nonutility subsidiaries to have a more direct claim on the cash flows and assets of their respective OpCo obligors.[253]

Moody's further explains its assessment of structural subordination considers a variety of factors, such that "a formulaic approach is not practical".[254] Based on its review, Moody's may reduce the parent company rating up to three notches relative to the operating companies.

That relationship holds among the companies in Dr. Woolridge's proxy

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[252] The rank correlation coefficient between DCF results and credit ratings was approximately negative 0.0234, which is statistically insignificant at the 95.00 percent level.

[253] Moody's Investors Service, *Rating Methodology, Regulated Electric and Gas Utilities*, June 23, 2017, at 22.

[254] *Ibid*. at 23.

group. For example, Southern Company's Long-Term Corporate Rating from Moody's is Baa2, whereas Alabama Power's rating is A1. Similarly, whereas WEC Energy Group's rating is Baa1, Wisconsin Electric Power's rating is A2. A similar relationship applies to Duke Energy Corporation and DE Progress; the parent rating is Baa1, and DE Progress' rating is A2.[255] Rebuttal Exhibit DWD-15 provides the parent and operating subsidiary credit ratings for the 31 companies in Dr. Woolridge's proxy group. As that exhibit demonstrates, in each case the parent company credit rating is generally one to two notches below the utility operating company ratings.

Because Dr. Woolridge's comparison of DE Progress to parent companies does not reflect Moody's focus on structural subordination, it incorrectly suggests the Company is less risky than its peers. When we apply the proper comparison, operating companies to operating companies, we see that is not the case.

Q. DID DR. WOOLRIDGE STATE THE COMPANY'S OTHER UNIQUE RISK FACTORS CAN BE ATTRIBUTED TO THE COMPANY'S CREDIT RATING?

A. Yes, Dr. Woolridge believes the credit rating process reflects the unique risk factors I described in my Direct Testimony, including the Company's relatively high level of capital investment, its generation portfolio, and environmental

255 Source Direct: S&P Global Market Intelligence.

regulations.[256] I do not disagree with Dr. Woolridge that rating agencies may analyze those specific factors in their review. As explained above, however, I do not believe credit ratings are a full measure of equity risk.

J. Flotation Costs

Q. DID DR. WOOLRIDGE ADDRESS THE ISSUE OF FLOTATION COSTS IN HIS DIRECT TESTIMONY?

A. Yes, Dr. Woolridge devotes several pages of his testimony discussing various reasons why he believes such an adjustment is not necessary.[257] Dr. Woolridge does not account for flotation costs, reasoning that flotation costs for stock issuances are not out-of-pocket costs and, even if they were, current market conditions suggest that a *reduction* to the Cost of Equity is required to account for flotation costs.[258] Additionally, Dr. Woolridge asserts I did not identify any flotation costs for DEC and that North Carolina legal precedent precludes the Company from recovering flotation costs when it does not expect to issue stock in the near future.[259]

Q. PLEASE RESPOND TO DR. WOOLRIDGE IN THAT REGARD.

A. I disagree with Dr. Woolridge's position that flotation costs for stock issuances are different than issuance costs associated with long-term debt. Companies pay the same types of fees (both direct and indirect) regardless of whether they

[256] Testimony of J. Randall Woolridge, at 138.
[257] Testimony of J. Randall Woolridge, at 138-142.
[258] Testimony of J. Randall Woolridge, at 141-142.
[259] Testimony of J. Randall Woolridge, at 139.

are issuing equity or debt. As to Dr. Woolridge's observation that underwriter fees are not "out-of-pocket" expenses,[260] I view that to be a distinction without a meaningful difference. Whether paid directly or via an underwriting discount, the cost results in net proceeds that are less than the gross proceeds. I also disagree with Dr. Woolridge's position that flotation costs could represent a *reduction* in Cost of Equity. Flotation costs are true and necessary costs to the issuer, and represent funds that otherwise would be invested in long-lived assets. As explained in my Direct Testimony, to the extent flotation costs are not recovered, the issuing company is denied a portion of the opportunity to earn its expected (or required) return;[261] that point is further demonstrated in Rebuttal Exhibit DWD-16.

Q. HAS DUKE ENERGY CORPORATION RECENTLY ISSUED COMMON STOCK?

A. Yes, it has. Duke Energy Corporation issued 28.75 million shares of common stock on November 18, 2019, after the Company filed its rate case. As explained in my Direct Testimony, although the Company is a wholly owned subsidiary of Duke Energy, it is appropriate to consider flotation costs because wholly owned subsidiaries receive equity capital from their parents and provide returns on the capital that roll up to the parent, which is designated to attract and raise capital based on the returns of those subsidiaries. To deny recovery

260 Testimony of J. Randall Woolridge, at 141.
261 Direct Testimony of Dylan W. D'Ascendis at 34.

of issuance costs associated with the capital that is invested in the subsidiaries ultimately would penalize the investors that fund the utility operations and would inhibit the utility's ability to obtain new equity capital at a reasonable cost.[262] Consequently, Dr. Woolridge's position that the Company had no plans to issue stock is incorrect.

K. North Carolina Economic Conditions

Q. PLEASE BRIEFLY SUMMARIZE DR. WOOLRIDGE'S RESPONSE TO YOUR ASSESSMENT OF ECONOMIC CONDITIONS IN NORTH CAROLINA.

A. In my Direct Testimony I reviewed several measures of economic conditions, including the rate of unemployment, real Gross Domestic Product growth, median household income, residential electricity rates, and broad measures of income and consumption.[263] Based on that review, I found economic conditions in North Carolina have improved during the last several years; Dr. Woolridge generally agrees with that conclusion.[264] Dr. Woolridge argues, however, that although economic conditions generally have improved, certain measures do not support the Company's proposed Rate of Return, including my recommended ROE.[265]

262 Direct Testimony of Dylan W. D'Ascendis, at 34.
263 Direct Testimony of Dylan W. D'Ascendis, at 52-61.
264 Testimony of J. Randall Woolridge, at 144.
265 Testimony of J. Randall Woolridge, at 144-145.

Q. WHAT IS YOUR RESPONSE TO DR. WOOLRIDGE ON THAT POINT?

A. For the reasons discussed in my response to Mr. Baudino, I disagree with Dr. Woolridge's position regarding my review of the economic conditions in North Carolina. I recognize we do not yet know the extent of the effect of the pandemic on North Carolina's economy, however, as discussed in my response to Mr. Baudino, the unemployment rate in March 2020 for North Carolina was equal to the unemployment rate for the overall U.S. While real GDP declined at an annual rate of 4.80 percent in the first quarter of 2020, we will not know how North Carolina's GDP fared in the first quarter of 2020 until early July.

I appreciate there seems to be no fundamental disagreement that conditions have improved over the last several years. I also recognize the extent of the effect of the pandemic on North Carolina's economy is unclear. I further appreciate that the Commission has the difficult task of considering those conditions as it balances the interests of investors and consumers. In my view, Dr. Woolridge's recommendation is unduly low and unsupported by the data available.

L. Capital Structure

Q. PLEASE BRIEFLY SUMMARIZE DR. WOOLRIDGE'S RECOMMENDATION REGARDING THE COMPANY'S CAPITAL STRUCTURE.

A. Dr. Woolridge suggests that because Duke Energy's equity ratio is lower than DE Progress, the Company is engaging in double leverage.[266] On that basis, Dr. Woolridge's primary recommendation is a hypothetical capital structure consisting of 50.00 percent long-term debt and 50.00 percent common equity.[267] To support his recommendation, Dr. Woolridge compares the Company's capital structure to electric utility capital structures at the holding company level. That review suggests the Company's peers finance their utility assets with as little as 24.70 percent common equity.[268]

Q. DO YOU AGREE WITH DR. WOOLRIDGE'S APPROACH AND CONCLUSIONS?

A. No, I do not. As explained below, companies (including subsidiary companies) are financed in light of the specific risks and funding requirements associated with their individual operations. As such, the proper point of comparison is the mix of long-term capital (common equity, preferred stock, and long-term debt) in place at utility operating companies, not utility holding companies. The

[266] Testimony of J. Randall Woolridge, at 42-47.
[267] Testimony of J. Randall Woolridge, at 47-48.
[268] Exhibit JRW-2, page 1.

nature of utility operations, and the corresponding nature of the assets providing utility service, create common financing objectives and constraints addressed by financing practices at the operating company level. Instead, Dr. Woolridge's recommendation to increase the Company's financial leverage by reference to holding company capital structures would increase its financial risk and, therefore, its cost of capital.

Q. WHAT FACTORS DO UTILITIES GENERALLY CONSIDER IN DEVELOPING THEIR TARGET CAPITAL STRUCTURES?

A. Capital structure management is dynamic and complex, looking to satisfy multiple objectives subject to multiple constraints. Utilities must focus on the nature of the assets providing utility service, and recognize the constraints brought about by the obligation to serve. It therefore is important to understand utility financing practice, including the principles and constraints that drive financing decisions, and how that practice is reflected in the cost of capital.

In many ways, the nature of regulation determines the nature of utility assets, and how they are financed. In exchange for the obligation to serve, equity investors expect utilities to have the opportunity to earn a fair return on prudent investments. As the regulated rate of return granted to utilities is below that expected from unregulated enterprises, the nature of regulation is such that the variation in returns (that is, the expected risk) for utilities is expected to be less than those of unregulated companies. It is the nature of regulation that enables utilities to finance large, essentially irreversible, investments that are recovered over decades. Financing practice therefore must address the nature of investments made under the regulatory compact.

It also is important to keep in mind that capital structures, and the financial strength they support, are set not only to ensure capital access during normal markets, but to enable access when markets are constrained. The reason is straightforward: The obligation to serve is not contingent on capital market conditions. When markets are constrained, only those utilities with sufficient financial strength are able to attract capital at reasonable terms. That ability provides those utilities with critically important financing flexibility.

The requirement to access the capital markets in all market conditions can be contrasted with the financial needs of other entities without the legal obligation to serve. Because of that obligation, the financial flexibility brought about by the access to both long-term capital and short-term liquidity is critical for utilities' financial integrity, and their ability to continually attract capital. Unregulated firms have options to choose whether, where, and when to make investments; what services or products will be offered; whether to invest in expansions; and whether to cease operations in a given location. That is, unregulated companies may adjust the timing and amount of their major capital expenditures to align with economic cycles, and to defer decisions and investments to better match market conditions. Regulated companies have limited options to do so. Ensuring the financial strength to access capital because of the reduced spending flexibility therefore is critically important to utilities, their investors, and their customers.

As noted above, an appropriate capital structure is important not only to ensure long-term financial integrity, it also is critical to enabling access to capital during constrained markets, or when near-term liquidity is needed to fund extraordinary requirements. In that important respect, the capital structure, and the financial strength it engenders, must support both normal circumstances and periods of market uncertainty. Optimizing the capital structure therefore is a very complex process, which balances the need to maintain an appropriate financial profile while ensuring reasonable capital cost rates.

Q. IS THERE A GENERAL FINANCING PRACTICE TYPICALLY USED BY UTILITIES?

A. Yes, there is. Although capital structure optimization is complex, there are certain principles that commonly apply among utilities. In my experience, the financing practice sometimes referred to as "maturity matching" is chief among those principles. That practice aligns the average life of the securities in the capital structure with the average lives of the assets being financed.[269] As noted by Brigham and Houston, "[t]his strategy minimizes the risk that the firm will be unable to pay off its maturing obligations."[270]

[269] This is not to say that an individual dollar may be traced from its source to its use.
[270] Brigham, Eugene F. and Joel F. Houston, Fundamentals of Financial Management, Concise 4th Ed., Thomson South-Western, 2004, at 574.

The perpetual nature of common equity makes it an important component of the capital structure. Because long-term debt generally has a duration shorter than the average life of the rate base, common equity is needed to extend the capital structure's duration to more closely match that of the rate base. That is, owing to its perpetual life, common equity extends the weighted average life of the capital structure, and mitigates financing risk. Conversely, relying more heavily on debt increases the risk of refinancing maturing obligations during less accommodating market environments.

Q. IF COMPANIES MATCH THE LIVES OF THEIR ASSETS WITH THE TERM OF THE SECURITIES FINANCING THEM, CAN INDIVIDUAL SOURCES OF FINANCING BE TRACKED TO SPECIFIC ASSETS?

A. No. Because cash is fungible, it is not feasible to track a given dollar from its source to its use. Rather, companies tend to apply the more general maturity matching strategy under which short-term debt is borrowed to satisfy the overall, day-to-day, fluctuating, and somewhat unpredictable, cash needs, not to finance an individual utility function.

Q. DO YOU AGREE WITH DR. WOOLRIDGE'S CONCLUSION THAT THE COMPANY'S PROPOSED CAPITAL STRUCTURE "CONSISTS OF MORE COMMON EQUITY AND LESS FINANCIAL RISK"[271] THAN THE OTHER COMPANIES IN THE PROXY GROUP?

A. No, I do not. Dr. Woolridge's assessment focuses on the proxy group average, without considering differences within the group. As with all statistical analyses, a single metric – in this case a simple average – may not be meaningful in isolation. For example, the common equity ratio for my Updated Proxy Group ranges from 45.65 percent to 61.20 percent (*see* Rebuttal Exhibit DWD-7). The Company's proposed equity ratio of 53.00 percent is 8.20 percentage points below the high end of the range. Eleven of the 20 proxy companies have average common equity ratios above the Company's proposed equity ratio. Based on the Updated Proxy Group as a whole, it is apparent that a capital structure of 53.00 percent common equity and 47.00 percent long-term debt is consistent with industry practice.

Q. HAS THE COMMISSION RECENTLY AUTHORIZED COMMON EQUITY RATIOS IN LINE WITH THE COMPANY'S PROPOSED RATEMAKING CAPITAL STRUCTURE?

A. Yes, it has. In recent cases, the Commission has authorized common equity ratios of 52.00 percent for Dominion Energy North Carolina, the Company,

[271] Testimony of J. Randall Woolridge, at 48.

Duke Energy Carolinas, and Piedmont Natural Gas.[272]

Q. DO YOU AGREE WITH DR. WOOLRIDGE'S POSITION THAT IT IS APPROPRIATE TO LOOK TO THE PROXY GROUP CAPITAL STRUCTURE AT THE HOLDING COMPANY LEVEL?[273]

A. No, I do not. Dr. Woolridge's position is based on the fact that the operating subsidiaries are not publicly traded. Although there may not be market data at the operating subsidiary level on which to perform cost of capital analyses, Dr. Woolridge fails to acknowledge the proxy companies generally report capital structure data for its regulated operating subsidiaries.

Quite simply, when assessing the appropriate capital structure for ratemaking purposes for a regulated operating company, the relevant point of comparison is to the capital structure of the proxy group companies' *regulated* operations, *i.e.*, at the regulated operating company level. Because capital at the parent holding company level may finance non-regulated operations, comparisons to the parent company capital structure may lead to flawed and misleading conclusions.

[272] *See,* NCUC Docket Nos. E-22, Sub 562; E-2, Sub 1142; E-7, Sub 1146; and G-9, Sub 743.
[273] Testimony of J. Randall Woolridge, at 40-41.

Q. ARE THERE COMPANIES WITHIN DR. WOOLRIDGE'S PROXY GROUP THAT DEMONSTRATE WHY IT IS INAPPROPRIATE TO USE HOLDING COMPANIES TO SET OPERATING UTILITY CAPITAL STRUCTURES?

A. Yes, there are. As explained in my response to Mr. O'Donnell, NextEra Energy's capital structure, which includes debt not associated with utility operations, is an example of how comparisons to holding company capital structures can be misplaced. Another example is, Hawaiian Electric Industries ("HE"). In 2019, HE had approximately $13.75 billion of consolidated assets, of which $7.10 billion was associated with its commercial banking operations.[274] Only a small portion (9.30 percent) of the banking segment's assets were financed with equity;[275] the vast majority was supported by customer deposits.[276] Although it is common in the commercial banking industry to fund assets with customer deposits, that is not the case in the electric utility industry. The important point is that by looking to the operating utility capital structure, we can avoid those types of distortions.

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274 Hawaiian Electric Industries, Inc., SEC Form 10-K For the fiscal year ended December 31, 2019, at 55, 80.
275 *Ibid.*, at 55.
276 *Ibid.*, at 55.

Q. HAVE YOU REVIEWED THE OPERATING COMPANY CAPITAL STRUCTURES FOR DR. WOOLRIDGE'S PROXY GROUP?

A. Yes, I have. Rebuttal Exhibit DWD-17 which provides that data, shows quite clearly that over time and across companies, operating utility equity ratios tend to be higher than the parent company ratio. That finding makes sense, given the utility financing practices discussed above.

As Rebuttal Exhibit DWD-17 also makes clear, the Company's proposed equity ratio is highly consistent with those in place at the operating utilities held within his proxy group. In fact, the average equity ratio for Dr. Woolridge's proxy group is 53.52 percent, 52 basis points above the Company's proposed equity ratio. Among the operating utilities in my Updated Proxy Group, the average has been 53.69 percent,[277] again, quite consistent with the Company's proposal.

[277] Rebuttal Exhibit DWD-17.

Q. DR. WOOLRIDGE OBSERVES THAT THE COMPANY'S PROPOSED CAPITAL STRUCTURE IS "MUCH HIGHER"[278] THAN THE COMMON EQUITY RATIO OF ITS PARENT, DUKE ENERGY CORPORATION, AND FURTHER DISCUSSES THE "ISSUE OF PUBLIC UTILITY HOLDING COMPANIES SUCH AS DUKE ENERGY USING DEBT TO FINANCE THE EQUITY IN SUBSIDIARIES SUCH AS THE COMPANY."[279] WHAT IS YOUR RESPONSE?

A. Dr. Woolridge's position appears to suggest the Company is engaging in double leverage, to the detriment of customers.[280] I have several concerns with that position. First, as discussed above, in my experience utilities typically apply the prudent financing principle of maturity, or duration matching. Under that principle, long-lived assets are financed with correspondingly long-lived securities. As discussed earlier, due to its perpetual life, common equity has a long duration. Adding equity to the capital structure therefore extends the capital structure's weighted average duration, more closely aligning it with the assets that form the rate base.

Dr. Woolridge's position also runs counter to the widely accepted "stand-alone" regulatory principle, which treats each utility subsidiary as its own company. Under the stand-alone approach, the cost of capital is

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278 Direct Testimony of J. Randall Woolridge, at 42.
279 Testimony of J. Randall Woolridge, at 43-44.
280 Testimony of J. Randall Woolridge, at 43-46.

determined using the subsidiary's capital structure and cost of debt and equity; the Cost of Equity is generally estimated by reference to a proxy group of firms of comparable risk.

Consistent with the stand-alone principle, the ownership structure does not affect the operating utility's capital structure or cost of capital. Parent entities, like other investors, have capital constraints and must consider the attractiveness of the expected risk-adjusted return of each investment alternative as part of their capital budgeting process. This opportunity cost concept applies regardless of the source of the funding. When funding is provided by a parent entity, the return on that financing must still be sufficient to provide an incentive to the parent entity to allocate equity capital to the subsidiary or business unit rather than other internal or external investment opportunities. That is, the regulated subsidiary must compete for capital with its affiliates and with other, similarly situated utility companies.

From an external investor's perspective, the combined company must provide a return reflecting the risks of the company's constituent parts. Investors therefore value combined entities on a sum-of-the-parts basis, expecting each operating segment to provide its appropriate risk-adjusted return. That practical financial principle is consistent with the regulatory principle of treating utilities as stand-alone entities. From both perspectives, it is the utility's operating risk that defines the capital structure and cost of capital, not investors' sources of funds.

Contrary to those basic principles, Dr. Woolridge's double leverage argument assumes the required return depends on the source of financing, not on the risks of the underlying utility operations. The position that a company would have a different cost rate depending on how its investors fund their equity investments violates the widely acknowledged economic "law of one price", which states that in an efficient market, identical assets would have the same value. In other words, two utilities, identical in all respects but for their form of ownership, should have the same common equity cost rates.

Moreover, if the common equity of a subsidiary were held by both the parent and an external investor, the equity held by the parent would have one required return, and the equity held by outside investors would have another. To the extent the required returns differ, so would the value of the equity. But in an efficient market, identical assets must have the same price (value). If not, the difference quickly would be arbitraged away. As Dr. Roger Morin noted in New Regulatory Finance:

> Carrying the double leverage standard to its logical conclusion leads to even more unreasonable prescriptions. If the common shares of a subsidiary were held by both the parent and by individual investors, the equity contributed by the parent would have one cost under the double leverage computation while the equity contributed by the public would have another.[281]

The double leverage argument also requires every affiliate within the

[281] Roger A. Morin, New Regulatory Finance, Public Utility Reports, Inc., 2006, at 523.

corporate family to have the same cost of capital, regardless of differences in risk. Duke Energy Corporation reports four operating segments: electric utilities and infrastructure, gas utilities and infrastructure, commercial renewables, and other operations.[282] Because they are separately reported, we reasonably can assume those segments face different risks. And because they face different risks, we reasonably may assume they require different returns. Dr. Morin further noted:

> Just as individual investors require different returns from different assets in managing their personal affairs, why should regulation cause parent companies making investment decisions on behalf of their shareholders to act any differently? A parent company normally invests money in many operating companies of varying sizes and varying risks. These operating subsidiaries pay different rates for the use of investor capital, such as long-term debt capital, because investors recognize the differences in capital structure, risk, and prospects between the subsidiaries. Yet, the double leverage calculation would assign the same return to each activity, based on the parent's cost of capital. Investors recognize that different subsidiaries are exposed to different risks, as evidenced by the different bond ratings and cost rates of operating subsidiaries. The same argument carries over to common equity. If the cost rate for debt is different because the risk is different, the cost rate for common equity is also different, and the double leverage adjustment shouldn't obscure this fact.[283]

Longstanding academic literature has thoroughly discussed the flaws associated with the double leverage approach. For example:

[282] *See*, Duke Energy Corporation, SEC Form 10-K for the year ended December 31, 2019, at 9.
[283] Roger A. Morin, New Regulatory Finance, Public Utility Reports, Inc., 2006, at 524-525.

1. Pettway and Jordan (1983), and Beranek and Miles (1988) point out the flaws in the double leverage argument, particularly the excess return argument, and also demonstrate that the "stand-alone" method is the superior approach.[284]
2. Rozeff (1983) discusses the ratepayer cross-subsidies of one subsidiary by another when employing double leverage.[285]
3. Lerner (1973) concludes that the returns granted to equity investors must be based on the risks to which the investors' capital is exposed and not the investors' source of funds.[286]

Basic finance texts reach the same conclusions. In Principles of Corporate Finance, 8th edition, Brealey, Myers, and Allen state:

> In principle, each project should be evaluated at its own opportunity cost of capital; the true cost of capital depends on the use to which the capital is put. If we wish to estimate the cost of capital for a particular project, it is project risk that counts.[287]

Likewise, in Modern Corporate Finance, 1st edition, Shapiro states:

> Each project has its own required return, reflecting three basic elements: (1) the real or inflation-adjusted risk-free interest rate;

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[284] Richard H. Pettway and Bradford D. Jordan, *Diversification, Double Leverage, and the Cost of Capital*, The Journal of Financial Research, Vol. VI, No. 4, Winter 1983; William Beranek and James A. Miles, *The Excess Return Argument and Double Leverage,* The Financial Review, Vo. 23, No. 2, May 1988.

[285] Michael S. Rozeff, *Modified Double Leverage – A New Approach*, Public Utilities Fortnightly, March 31, 1983.

[286] Eugene M. Lerner, *What are the Real Double Leverage Problems?*, Public Utilities Fortnightly, June 7, 1973.

[287] Richard A. Brealey, Steward C. Meyers, Franklin Allen, Principles of Corporate Finance, McGraw-Hill Irwin, 8th Ed., 2006, at 234.

> (2) an inflation premium approximately equal to the amount of expected inflation; and (3) a premium for risk. The first two cost elements are shared by all projects and reflect the time value of money, whereas the third component varies according to the risks borne by investors in the different projects. For a project to be acceptable to the firm's shareholders, its return must be sufficient to compensate them for all three cost components. This minimum or required return is the project's cost of capital and is sometimes referred to as a hurdle rate.
>
> The preceding paragraph bears a crucial message: The cost of capital for a project depends on the riskiness of the assets being financed, not on the identity of the firm undertaking the project.[288]

Simply, the notion of double leverage runs counter to both financial and regulatory principles.

Lastly, double leverage arguments have been rejected by several regulatory commissions. As the Maryland Public Service Commission explained:

> We reject People's Counsel's proposed capital structure [reflecting a double leverage adjustment] because it suffers from numerous flaws. First, it assumes that the rate of return depends on the source of capital rather than the risks faced by the capital.[289]

In 2016, the FERC reiterated its previous position on "double leveraging,"[290] stating that "the motivations of a parent company are

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288 Alan C. Shapiro, Modern Corporate Finance, Wiley, 1st Ed., 1990, at 276.

289 Maryland Public Service Commission, Order No. 81517, Case No. 9092, *In the Matter of the Application of Potomac Electric Power Company for Authority to Revise its Rate and Charges for Electric Service and for Certain Rate Design Changes*, July 19, 2007, at 73. [Clarification added]

290 *See, Transcontinental Gas Pipe Line Corp.*, 80 FERC ¶ 61,157, 61,657 (1997) ("Opinion No. 414").

irrelevant"[291] so long as the operating company passes the FERC's three-part test: (1) it issues its own debt without guarantees; (2) it has its own bond rating; and (3) it has a capital structure within the range of capital structures approved by the commission.[292] Under FERC guidance, the capital structure of Duke Energy Corporation is not applicable to DE Progress.

The Washington Utilities and Transportation Commission ("WUTC") has cited to FERC's position on the use of double leverage in support of its decision in Docket No. UE 050684:

> The FERC does not embrace the concept of double leverage. For purposes of calculating rate of return for wholly owned subsidiaries, FERC uses the stand-alone capital structure and return on equity of the subsidiary so long as the subsidiary issues its own debt, maintains its own credit ratings and meets other standards related to equity ratio. The courts have upheld this policy. *See Missouri Pub. Serv. Comm'n v. Federal Energy Reg Comm'n, 215 F.3d 1, 342 U. S. App. DC. 1* (D.C. Cir. June 27, 2000).[293]

In that same Order, the WUTC considered the effects of ring fencing in protecting ratepayers against financial leverage at the parent level:

> The ring fencing provisions required by our final order in Docket UE-051090 insulate PacifiCorp and its customers from risks and financial distress at the MEHC level. Nonetheless, after having insulated PacifiCorp and its customers from the risks of leveraged financing at the parent, Staff and Public Counsel seek to secure for customers the cost and tax benefits of that

[291] *See*, 154 FERC ¶ 61,004, Docket No. ER15-945-001, at 15.

[292] *Ibid*. *See also, Transcontinental Gas Pipe Line Corp.*, 80 FERC ¶ 61,157, 61,657 (1997) ("Opinion No. 414").

[293] Washington Utilities and Transportation Commission, Docket No. UE 050684, Order No. 4, at 117.

> financing. The Company's expert witness argues this may violate the familiar principle in utility law that financial benefits should follow burden of risks. We agree. If the risks and costs of activities at the parent-level are born exclusively by shareholders—because customers are insulated from them by the ring fence—then it is fair and appropriate for the shareholders, and not the customers, to receive the benefits that result from those activities.[294]

Q. HAS THE COMMISSION NOTED THE REASONABLENESS OF THE DIFFERENCES BETWEEN THE CAPITAL STRUCTURES OF OPERATING COMPANIES AND PARENT COMPANIES?

A. Yes, it has. In Docket No. G-5, Sub 565, the Commission gave "significant weight" to my testimony regarding the differences in the financing needs of holding companies and operating companies, and concluded "[t]hus, the appropriate mix of debt and equity for a public utility operating company can be significantly different from that of its holding company."[295] In that case, the Commission approved a stipulated equity ratio of 52.00 percent,[296] similar to the equity ratio requested by the Company.

Q. WHAT IS YOUR CONCLUSION REGARDING THE APPROPRIATE CAPITAL STRUCTURE FOR THE COMPANY?

A. As shown in Rebuttal Exhibit DWD-7, the Company's proposed capital

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[294] *Ibid.*, at 54.

[295] North Carolina Utilities Commission Docket No. G-5, Sub 565, *Order Approving Rate Increase and Integrity Management Tracker*, October 28, 2016, at 24.

[296] As noted earlier, the Commission similarly authorized a 52.00 percent equity ratio for the Company in its last rate case, as well as for Duke Energy Carolinas and Dominion Energy North Carolina.

structure is in line with the capital structure in place at the proxy group companies and is consistent with the Commission's past decisions. Consequently, I disagree that Dr. Woolridge's recommended hypothetical capital structure of 50.00 percent long-term debt, and 50.00 percent common equity is appropriate for DE Progress. For the reasons noted earlier, I further disagree that the Company's ROE should be reduced if its proposed capital structure is adopted.

VI. RESPONSE TO AG WITNESS MR. BAUDINO

Q. PLEASE SUMMARIZE MR. BAUDINO'S ROE ANALYSES AND RECOMMENDATION IN THIS PROCEEDING.

A. Mr. Baudino recommends an ROE of 9.00 percent, which is based primarily on the results of his Constant Growth DCF analyses applied to the proxy group of 19 companies used in my Direct Testimony.[297] Mr. Baudino also performs two CAPM analyses, although he does not give those results substantial weight.[298]

[297] Direct Testimony of Richard A. Baudino, at 2-3.
[298] Direct Testimony of Richard A. Baudino, at 3, 35.

Q. WHAT ARE THE PRINCIPAL AREAS IN WHICH YOU DISAGREE WITH MR. BAUDINO'S ROE ANALYSES?

A. The principal areas in which I disagree with Mr. Baudino include: (1) our interpretations of current capital market conditions and their effect on the Company's Cost of Equity; (2) the growth rates applied in the Constant Growth DCF model; (3) his reliance on the Constant Growth DCF model to determine the Company's Cost of Equity; (4) the Market Risk Premium used in the CAPM; (5) the relevance of the ECAPM method; (6) whether the Bond Yield Plus Risk Premium analysis provides reasonable estimates of the Company's Cost of Equity; (7) the Expected Earnings analysis; (8) the relevance of flotation costs, (9) our respective assessments of the Company's level of business and financial risk; (10) our interpretations of North Carolina's current economic conditions; and (11) Mr. Baudino's proposed capital structure.

Q. AS A PRELIMINARY MATTER, DO YOU AGREE WITH MR. BAUDINO'S POSITION THAT HIS 9.00 PERCENT RECOMMENDATION "IS REASONABLY CLOSE TO RECENTLY ALLOWED ROES"[299]?

A. No, I do not. As shown in Rebuttal Exhibit DWD-8, the average and median authorized ROE for vertically integrated electric utilities since 2015 is 9.75 percent and 9.71 percent, respectively. On February 24, 2020 in Docket No. E-

[299] Direct Testimony of Richard A. Baudino, at 37-38.

22, Sub 562 the Commission authorized Dominion Energy North Carolina an ROE of 9.75 percent. Since January 2019, there have been eleven cases in which a regulatory commission authorized an ROE within my range of 10.00 percent to 11.00 percent. During that same time period, only two were "reasonably close"[300] to Mr. Baudino's recommendation of 9.00 percent (*see also* Chart 24 presented in my response to Mr. Phillips).

Q. MR. BAUDINO ASSERTS YOU IGNORE "A SIGNIFICANT PORTION" OF YOUR ROE ANALYSES.[301] WHAT IS YOUR RESPONSE?

A. As noted in my Direct Testimony and throughout my Rebuttal Testimony, all models are subject to limiting assumptions and no single model is more reliable than all others under all market conditions.[302] As also noted in my Direct Testimony, it is my view that the Constant Growth DCF model is subject to several assumptions that likely are not consistent with current market conditions, and therefore should be given less weight in the current capital market. To that point, authorized returns consistently have exceeded Constant Growth DCF estimates.[303] Further, as discussed in my Direct Testimony, regulatory commissions, including this Commission, have found it appropriate

[300] That is, within 25 basis points of Mr. Baudino's 9.00 percent ROE recommendation. The South Dakota PUC authorized an ROE of 8.75 percent for Otter Tail Power and the Vermont PUC authorized a 9.06 percent ROE for Green Mountain Power. I address the Otter Tail Power decision in my response to Mr. O'Donnell.
[301] Direct Testimony of Richard A. Baudino, at 4, 50-51.
[302] Direct Testimony of Dylan W. D'Ascendis, at 5.
[303] Direct Testimony of Dylan W. D'Ascendis, at 5.

to place less weight on the DCF model results.[304] As to Mr. Baudino's argument that I "reject" certain of my results, he disregards two of his three approaches, relying primarily on his Constant Growth DCF model results. Lastly, although Mr. Baudino argues that relying on the high DCF results is inappropriate, his 9.00 percent recommendation is based on his high DCF result.[305]

Q. AT PAGES 64-65 OF HIS TESTIMONY, MR. BAUDINO POINTS TO FERC OPINION NO. 569 REGARDING THE ORDER DIRECTING BRIEFS YOU REFER TO IN YOUR DIRECT TESTIMONY. WHAT IS YOUR RESPONSE?

A. If Mr. Baudino's point is FERC's Opinion No. 569 implies the Risk Premium and Expected Earnings approaches should be disregarded, I disagree. The revised approach under Opinion No. 569 is not settled policy. As FERC has acknowledged, there have been multiple requests for rehearing of Opinion No. 569.[306] Further, FERC recently has established a paper hearing to address the methods proposed in its prior Coakley Briefing Order, and MISO Briefing Order, the same Briefing Orders that proposed the DCF, CAPM, Risk Premium, and Expected Earnings approaches.[307] That process is ongoing, with no current resolution. Consequently, as a general proposition I do not agree Opinion No.

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304 Direct Testimony of Dylan W. D'Ascendis, at 6-9, 15-16.

305 Direct Testimony of Richard A. Baudino, at 36; Exhibit RAB-3, page 2.

306 *See*, Potomac-Appalachian Transmission Highline, LLC, Opinion No. 554-A, 170 FERC ¶ 61,050 (2020), Order on Rehearing, Directing Briefs, and Accepting in Part and Rejecting in Part Compliance Filings, at para. 5.

307 *Ibid*. *See also*, Direct Testimony of Dylan W. D'Ascendis, at 7-8.

569 "invalidates" my use of the Expected Earnings, and Risk Premium approaches.

A. Capital Market Environment

Q. DOES MR. BAUDINO ADDRESS THE CURRENT MARKET DISLOCATION ASSOCIATED WITH COVID-19?

A. Yes, Mr. Baudino briefly addresses the "unprecedented volatility, with steep and sharp declines in the stock market, including regulated utilities."[308] He further notes the decline in the 30-year Treasury yield and the increase in utility bond yields. Despite his brief summary, Mr. Baudino concludes it would not be "prudent" to "estimate the impact of the these changed conditions on [his] ROE recommendation".[309] Consequently, Mr. Baudino chooses to apply data as of the end of February in his analyses, and "reserve the right to update [his] testimony and recommendations to the Commission later in this proceeding."[310]

That brief summary aside, much of Mr. Baudino's testimony regarding the trend in interest rates and the implication for the Cost of Equity simply is not reflective of the current market. For example, Mr. Baudino discusses the trend in interest rates since 2007, noting that utilities are "interest rate sensitive" and therefore, the Cost of Equity moves directionally with changes in interest rates.[311] Based on that observation, Mr. Baudino concludes that the current low

308 Direct Testimony of Richard A. Baudino, at 5.
309 Direct Testimony of Richard A. Baudino, at 5.
310 Direct Testimony of Richard A. Baudino, at 5.
311 Direct Testimony of Richard A. Baudino, at 7-11.

interest rate environment "support[s] lower required ROEs for regulated utilities."[312] As noted earlier, the current low level of interest rates reflects investors' "flight to safety" suggesting an increase in equity risk, and therefore the Cost of Equity. The recent increase in utility bond yields and credit spreads that Mr. Baudino observes,[313] support that conclusion.

Q. DO YOU AGREE WITH MR. BAUDINO THAT IT IS APPROPRIATE TO USE DATA PRIOR TO THE MARKET DISLOCATION?

A. No, I do not. As discussed earlier, although we cannot precisely quantify the effect of the increased market risk on the Cost of Equity, we can infer with reasonable confidence that, directionally, the Cost of Equity has increased. I also disagree that the post-COVID-19 environment will resemble February 2020.

Q. WHAT IS YOUR RESPONSE TO MR. BAUDINO'S POSITION THAT "SECURITIES MARKETS ARE EFFICIENT AND MOST LIKELY REFLECT INVESTORS' EXPECTATIONS ABOUT FUTURE INTEREST RATES"?[314]

A. Mr. Baudino makes that argument in the context of "market efficiency", suggesting that if markets are efficient, expectations regarding the direction and level of interest rates already are embedded in stock prices and Treasury yields.

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312 Direct Testimony of Richard A. Baudino, at 11.
313 Direct Testimony of Richard A. Baudino, at 5.
314 Direct Testimony of Richard A. Baudino, at 12.

Mr. Baudino points to Dr. Morin's 2006 reference to the forecast accuracy of naïve extrapolations and "no-change" methods of projecting interest rates in support of his position that there is no need to consider projected interest rates in setting the current ROE.[315] I have several responses to Mr. Baudino on those points.

Regarding the suggestion that the "no-change" method of projecting interest rates is appropriate in the current market, I disagree. As Mr. Baudino acknowledges,[316] the Federal Reserve's Quantitative Easing program, which was initiated after 2006 (that is, after Dr. Morin's book was published), was designed to put downward pressure on long-term interest rates. Consequently, the observed Treasury yield in a given month likely would over-forecast the observed Treasury yield twelve months in the future. Conversely, when the Federal Reserve completed its Quantitative Easing program, it would be reasonable to assume the observed Treasury yield would under-forecast the yield twelve months in the future (as yields increase).

Mr. Baudino's data support that position. As shown in Table 9 below, from February 2007 through the end of Quantitative Easing (October 2015),[317] the 30-year Treasury yield over-forecast the twelve-month forward yield 71.00 percent of the time. After October 2015, current yields over-forecast future

315 Direct Testimony of Richard A. Baudino, at 12.

316 Direct Testimony of Richard A. Baudino, at 11.

317 Because the Treasury Department discontinued issuances of 30-year Treasury bonds from March 2002 to January 2006, February 2007 was the first month for which the forecast yield was available.

yields only 47.00 percent of the time; from 2017 through March 2020, in only 15 of 39 months (about 44.00 percent of the time). That is, from 2017 through March 2020, the "no-change" approach under-forecast Treasury yields in 22 of 39 months.

Table 9: "No-Change" Forecast Error Observations[318]

	Feb. 2007 – Oct. 2015	Nov. 2015 – March 2020	Jan. 2017 – March 2020
	Number of Observations		
Over-Forecast	75	25	17
Under-Forecast	30	28	22
Total	105	53	39
% Over-Forecast	71.00%	47.00%	44.00%
% Under-Forecast	29.00%	53.00%	56.00%

If Mr. Baudino wishes to consider current Treasury yields as measures of future rates, we can view the market's expectations based on the current yield curve. Those expected rates, often referred to as "forward yields" are derived from the "Expectations" theory, which states that (for example) the current 30-year Treasury yield equals the combination of the current five-year Treasury yield, and the 25-year Treasury yield expected in five years. That is, an investor would be indifferent to (1) holding a 30-year Treasury bond to maturity, or (2) holding a five-year Treasury note to maturity, then a 25-year Treasury bond, also to maturity.[319] Here, we can compare historical Treasury yield data to

318 Source: Mr. Baudino's workpapers; Federal Reserve Board Schedule H.15.

319 In addition to Expectations theory, there are other theories regarding the term structure of interest rates including: Liquidity Premium Theory, which asserts that investors require a premium for holding long term bonds; Market Segmentation Theory, which states that securities of different terms are not substitutable and, as such, the supply of and demand for

calculate the forward and current (interpolated) 25-year Treasury yield. If the forward 25-year Treasury yield exceeds the current 25-year yield, that relationship indicates expectations of future rate increases.

Based on the data from the Federal Reserve, forward yields generally exceeded current spot yields over the previous six months (*see* Table 10, below). The exceptions, of course, were in February and March, when current yields were pushed down as investors moved to the relative safety of Treasury securities. Nonetheless, just as economists' projections (such as *Blue Chip*) called for increased interest rates, so have forward Treasury yields.

Table 10: Forward vs. Interpolated 25-Year Treasury Yields[320]

	30-Year Treasury Yield	5-Year Treasury Yield	Forward 25-Year Treasury Yield	Interpolated 25-Year Treasury Yield
October 2019	2.19%	1.53%	2.32%	1.99%
November 2019	2.28%	1.64%	2.41%	2.04%
December 2019	2.30%	1.68%	2.42%	2.06%
January 2020	2.22%	1.56%	2.35%	2.15%
February 2020	1.97%	1.32%	2.10%	2.18%
March 2020	1.46%	0.59%	1.63%	2.09%
Average	2.07%	1.39%	2.21%	1.93%

Importantly, forward yields assume the current slope of the yield curve will remain constant going forward. They therefore assume the conditions

short-term and long-term instruments is developed independently; and Preferred Habitat Theory, which states that in addition to interest rate expectations, certain investors have distinct investment horizons and will require a return premium for bonds with maturities outside of that preference.

320 Source: Federal Reserve Board of Governors Schedule H.15.

supporting the current slope also will remain constant. Consequently, the current yield curve may not fully reflect market expectations. Nonetheless, implied forward yields certainly are known and considered by the professionals that contribute to the consensus long-term bond yield projections published by sources such as *Blue Chip Financial Forecasts*. In that case, forward yields would be reflected in economists' projections.

B. Constant Growth DCF Model

Q. PLEASE BRIEFLY DESCRIBE MR. BAUDINO'S CONSTANT GROWTH DCF ANALYSIS AND RESULTS.

A. Mr. Baudino calculates an average dividend yield of 2.88 percent by dividing each proxy company's annualized dividend by its monthly stock price for the six-month period ending February 2020,[321] noting that the average dividend yield for the proxy group ranged from 2.84 percent to 2.94 percent during the six-month period.[322] For the expected growth rate, Mr. Baudino relies on Earnings Per Share growth rate projections from Value Line, Zacks, and First Call, as well as Dividend Per Share growth rate projections from Value Line.[323] Mr. Baudino then calculates his DCF results based on the mean and median growth rate of the four sources noted above, producing eight ROE estimates, which range from 8.21 percent to 9.02 percent.[324]

321 Direct Testimony of Richard A. Baudino, at 24.
322 Direct Testimony of Richard A. Baudino, at 24.
323 Direct Testimony of Richard A. Baudino, at 25-26, Exhibit RAB-3.
324 Direct Testimony of Richard A. Baudino. at 26-27; Exhibit RAB-3, page 2.

Mr. Baudino refers to the DCF results produced using mean growth rates as "Method 1", and DCF results produced using median growth rates as "Method 2". The mean DCF results of his Methods 1 and 2 were 8.60 percent and 8.67 percent, respectively.[325]

Q. DO YOU AGREE WITH MR. BAUDINO THAT DIVIDEND GROWTH RATES ARE APPROPRIATE MEASURES OF EXPECTED GROWTH FOR THE CONSTANT GROWTH DCF MODEL?

A. No, I do not. As discussed in my Direct Testimony, academic literature supports the use of earnings growth rates in the DCF model.[326] Earnings growth is the fundamental driver of the ability to pay dividends. Further, as noted in my Direct Testimony, to reduce growth to a single measure we assume a fixed payout ratio, and a constant growth rate for Earnings Per Share, Dividend Per Share, and Book Value Per Share.[327] Because earnings are the fundamental driver of dividends, and knowing investors tend to value common equity on the basis of P/E ratios, the Cost of Equity is a function of the expected growth in earnings, not dividends. As discussed in my response to Dr. Woolridge, earnings growth rate projections are the only growth rates that are statistically and positively related to the P/E ratio.

Lastly, as discussed in my response to Mr. O'Donnell, Value Line is the

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325 Direct Testimony of Richard A. Baudino, at 27; Exhibit RAB-3, page 2.
326 Direct Testimony of Dylan W. D'Ascendis, at 80-81.
327 Direct Testimony of Dylan W. D'Ascendis., at 77-78. *See also,* Rebuttal Exhibit DWD-10.

only service that reports dividend growth projections. The fact that services such as Zacks and First Call provide earnings, but not dividend growth estimates indicates that they see little investor demand for such data.

C. DCF Model Assumptions

Q. PLEASE BRIEFLY DESCRIBE MR. BAUDINO'S CONCERNS WITH YOUR ARGUMENTS REGARDING THE ASSUMPTIONS OF THE DCF MODEL.

A. Mr. Baudino argues the industry's current P/E ratio's departure from its long-term average is not a valid concern because current stock prices reflect investors' required returns.[328]

Q. WHAT IS YOUR RESPONSE TO MR. BAUDINO'S CONCERN WITH YOUR ASSUMPTION REGARDING P/E RATIOS?

A. As explained in my response to Dr. Woolridge, the DCF model will not produce accurate estimates of the market-required ROE if the market price diverges from intrinsic value as defined by the present value formula. As also discussed in my response to Dr. Woolridge, recently elevated utility valuations likely arose from the "reach for yield" that sometimes occurs during periods of low Treasury yields. During those periods, some investors would turn to dividend-paying sectors, such as utilities, as an alternative source of income (that is, for

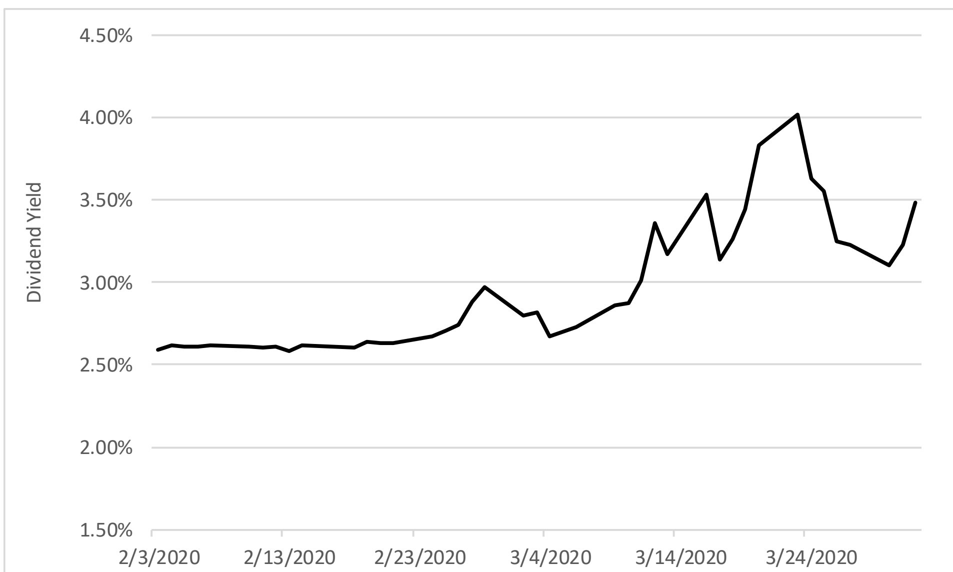
[328] Direct Testimony of Richard A. Baudino, at 53-54.

the dividend yield).[329] Then, when interest rates increased, investors rotated out of the utility sector, causing prices to fall.

The Constant Growth DCF model also assumes the dividend yield will remain constant, as stock prices and dividends grow at the same, constant rate. As the recent decline in utility prices demonstrates, the assumption of a constant dividend yield is limiting. For example, between the beginning of February 2020 and April 1, 2020, the dividend yield for Mr. Baudino's proxy group increased from 2.59 percent to 3.48 percent (*see* Chart 17 below).

Chart 17: Mr. Baudino's Proxy Group Dividend Yield

2/3/2020 – 4/1/2020[330]



Over the same time period, the P/E ratio of Mr. Baudino's proxy group fell significantly (*see* Chart 18 below).

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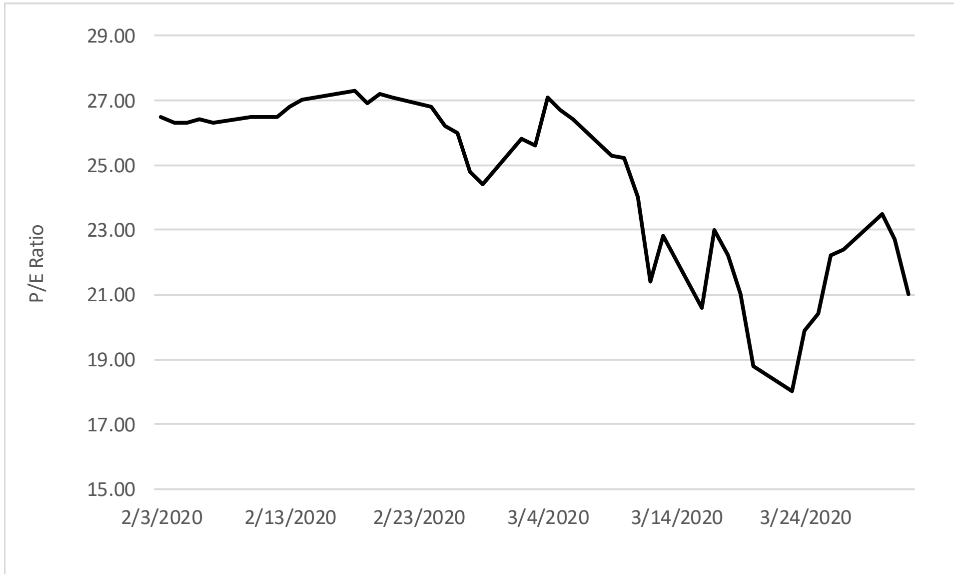
329 The relationship between utility prices and utility dividend yields is given in Equation [5], page 78 of my Direct Testimony.

330 Source: S&P Global Market Intelligence. Mr. Baudino's proxy group calculated as an index.

Chart 18: Mr. Baudino's Proxy Group P/E Ratio in February 2020[331]



Because the Constant Growth DCF model assumes a constant P/E ratio in perpetuity, during periods of elevated P/E ratios, it will underestimate the required return. I do not believe we should place significant weight on the Constant Growth DCF model's results during that time period, as Mr. Baudino recommends, when the assumptions underlying that model are plainly inconsistent with market expectations.

D. Capital Asset Pricing Model

Q. PLEASE SUMMARIZE MR. BAUDINO'S CAPM ANALYSES.

A. Mr. Baudino's CAPM analyses include two Market Risk Premium measures. His first set relies on the forecasted total market return as determined using Value Line projections, and the six-month average 30-year Treasury yield and

331 Source: S&P Global Market Intelligence. Mr. Baudino's proxy group calculated as an index.

Duff & Phelps' normalized risk-free rate (*i.e.*, 2.19 percent and 3.00 percent, respectively).[332] He assumes an expected growth rate for the market of 9.25 percent, using the average of the book value and earnings growth forecasts (8.00 percent and 10.50 percent, respectively) for all companies covered by Value Line. Mr. Baudino combines that average growth rate with Value Line's average expected dividend yield of 1.05 percent for the same group of companies, producing an estimated market return of 10.35 percent. He averages that estimate with Value Line's projected annual total return of 12.71 percent[333] to arrive at his final expected market return of 11.53 percent.[334]

Mr. Baudino's two forward-looking Market Risk Premium measures represent the difference between (1) his calculated expected market total return, and (2) the average yield over the past six months on 30-year Treasury securities (2.19 percent) and Duff & Phelps' normalized risk-free rate (3.00 percent). Mr. Baudino arrives at his CAPM results using the average Value Line Beta coefficient of 0.56 for his proxy companies.[335]

Mr. Baudino's second set of CAPM analyses calculate the arithmetic mean long-term annual returns on stocks, and long-term annual income returns on long-term government bonds, producing an historical measure of the Market

332 Direct Testimony of Richard A. Baudino, at 34; Exhibit RAB-4.
333 The average of Value Line's median and average projected annual total return of 12.00 percent and 13.42 percent, respectively.
334 Direct Testimony of Richard A. Baudino, at 32. Exhibit RAB-4.
335 Exhibit RAB-4.

Risk Premium.[336] He also considers an adjusted historical Market Risk Premium calculated by Dr. Roger Ibbotson and Dr. Peng Chen, and reported by Duff & Phelps.[337] Mr. Baudino uses those two Market Risk Premium measures in combination with the six month average 30-year Treasury bond yield, Duff and Phelps' normalized risk-free rate, and the average Value Line Beta coefficient to calculate four additional CAPM results. Although Mr. Baudino advises the Commission to consider only his DCF results in establishing the Company's ROE, he reports CAPM results ranging from 7.40 percent to 7.75 percent for his forward-looking return analysis and 5.61 percent to 6.85 percent for his historical return analysis.[338]

Q. DO YOU AGREE WITH MR. BAUDINO'S APPLICATION OF THE CAPM AND HIS INTERPRETATION OF ITS RESULTS?

A. No. My primary area of disagreement with Mr. Baudino's CAPM approach is his calculation of the Market Risk Premium.

Q. WHAT CONCERNS DO YOU HAVE WITH MR. BAUDINO'S *EX-ANTE* MARKET RISK PREMIUM CALCULATIONS?

A. Mr. Baudino calculates the expected market return using an average of earnings growth projections (10.50 percent) and book value growth projections (8.00 percent). As noted above, academic research indicates investors rely on

336 Direct Testimony of Richard A. Baudino, at 33. Exhibit RAB-5.
337 Direct Testimony of Richard A. Baudino, at 34. Exhibit RAB-5.
338 Direct Testimony of Richard A. Baudino, at 35.

estimates of earnings growth in arriving at their investment decisions. In that regard, Mr. Baudino did not include book value growth projections in his proxy group DCF analysis, nor has he explained why it is reasonable to include those growth rates in his Market Risk Premium analysis, but not his proxy company DCF analyses. Excluding book value growth estimates from Mr. Baudino's market return calculation would increase his Market Risk Premium estimate by approximately 63 basis points.[339]

Q. DO YOU AGREE WITH MR. BAUDINO'S USE OF HISTORICAL ESTIMATES OF THE MARKET RISK PREMIUM?

A. No, I do not. For the reasons discussed in my response to Dr. Woolridge, the Market Risk Premium is meant to be a forward-looking parameter. A Market Risk Premium calculated using historical market returns does not necessarily reflect investors' expectations or, for that matter, the relationship between market risk and returns. The relevant analytical issue in applying the CAPM is to ensure that all three components of the model (*i.e.*, the risk-free rate, Beta coefficient, and the Market Risk Premium) are consistent with market conditions and investor expectations. Therefore, *ex-ante* CAPM analyses are the more appropriate method to estimate DE Progress' Cost of Equity.

339 [(1.05% x (1+(0.5*10.50%)) + 10.50%) + 12.71%] / 2 = 12.16%. ((12.16% - 2.19%) – (11.53% - 2.19%)) = 0.63%

Q. PLEASE BRIEFLY SUMMARIZE MR. BAUDINO'S COMMENTS REGARDING YOUR *EX-ANTE* CAPM ANALYSES.

A. Mr. Baudino disagrees with my *ex-ante* Market Risk Premium, arguing that the market return estimates "are extraordinarily high."[340] He further disagrees with the use of forecasted Treasury bond yields applied in my CAPM analyses, but notes his and my risk-free rates "do not differ significantly in this proceeding."[341]

Q. WHAT IS YOUR RESPONSE TO MR. BAUDINO'S POSITION THAT YOUR MARKET RISK PREMIA ARE "EXTRAORDINARILY HIGH"[342]?

A. As shown in Rebuttal Exhibit DWD-18, the market return estimates presented in my Direct Testimony represent approximately the 51st percentile of actual returns observed from 1926 to 2019. Moreover, because market returns historically have been volatile, my market return estimates are statistically indistinguishable from the long-term arithmetic average market data on which Mr. Baudino relies.[343] Regarding the use of projected interest rates, it is important to remember that, as Mr. Baudino states, the "[r]eturn on equity analysis is a forward-looking process."[344] In that regard, I have considered

340 Direct Testimony of Richard A. Baudino, at 59.
341 Direct Testimony of Richard A. Baudino, at 58.
342 Direct Testimony of Richard A. Baudino, at 59.
343 Source: Duff & Phelps, 2020 SBBI Yearbook Appendix A-1. Even if we were to look at the standard error, my estimates are within two standard errors of the long-term average.
344 Direct Testimony of Richard A. Baudino, at 25.

forward-looking estimates of the risk-free rate. Because my analyses are predicated on market expectations, the expected increase in Treasury yields (as reflected in consensus projections) is a measurable and relevant data point.

E. Empirical Capital Asset Pricing Model

Q. PLEASE SUMMARIZE MR. BAUDINO'S POSITION REGARDING THE EMPIRICAL CAPITAL ASSET PRICING MODEL.

A. Mr. Baudino argues the ECAPM suggests Beta coefficients published by Value Line and Bloomberg are "incorrect and that investors should not rely on them".[345]

Q. IS MR. BAUDINO CORRECT?

A. No. The ECAPM reflects published research finding companies with lower Beta coefficients tend to have higher returns than those predicted by the CAPM, and those with higher Beta coefficients tend to have lower returns than expected.[346] Beta coefficient adjustments such as those used by Value Line on the other hand, address the tendency of "raw" Beta coefficients to regress toward the market mean of 1.00 over time. The two are different issues and are addressed with different methods.

Fama and French succinctly describe the empirical issue addressed by the ECAPM when they note that "[t]he returns on the low beta portfolios are

345 Direct Testimony of Richard A. Baudino, at 60.

346 Direct Testimony of Dylan W. D'Ascendis, at 92-93. *See also*, Roger A. Morin, New Regulatory Finance, Public Utility Reports, Inc., 2006, at 175-176.

too high, and the returns on the high beta portfolios are too low."[347] Fama and French further note:

> The early tests firmly reject the Sharpe-Lintner version of the CAPM. There is a positive relation between beta and average return, but it is too 'flat.'… The regressions consistently find that the intercept is greater than the average risk-free rate… and the coefficient on beta is less than the average excess market return… This is true in the early tests… as well as in more recent cross-section regressions tests, like Fama and French (1992).[348]
>
> * * *
>
> Confirming earlier evidence, the relation between beta and average return for the ten portfolios is much flatter than the Sharpe-Linter CAPM predicts. The returns on low beta portfolios are too high, and the returns on the high beta portfolios are too low. For example, the predicted return on the portfolio with the lowest beta is 8.3 percent per year; the actual return as 11.1 percent. The predicted return on the portfolio with the t beta is 16.8 percent per year; the actual is 13.7 percent.[349]

Similarly, Dr. Morin states:[350]

> With few exceptions, the empirical studies agree that … low-beta securities earn returns somewhat higher than the CAPM would predict, and high-beta securities earn less than predicted.
>
> * * *
>
> For an alpha in the range of 1%-2% and for reasonable values of the market risk premium and the risk-free rate, Equation 6-5 reduces to the following more pragmatic form:
>
> $$K = R_F + 0.25\ (R_M - R_F) + 0.75\ \beta(R_M - R_F) \quad (6\text{-}6)$$
>
> Over reasonable values of the risk-free rate and the market risk

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347 Eugene F. Fama and Kenneth R. French, T*he Capital Asset Pricing Model: Theory and Evidence*, Journal of Economic Perspectives, Vol. 18, No. 3, Summer 2004, at 33.

348 *Ibid.*, at 32.

349 *Ibid.*, at 33.

350 Roger A. Morin, New Regulatory Finance (Public Utility Reports, Inc., 2006), at 175 and 190.

> premium, Equation 6-6 produces results that are indistinguishable from the ECAPM of Equation 6-5.
>
> . . . Therefore, the empirical evidence suggests that the expected return on a security is related to its risk by the following approximation:
>
> $$K = R_F + x\,\beta(R_M - R_F) + (1\text{-}x)\ \beta(R_M - R_F)$$
>
> where x is a fraction to be determined empirically. The value of x that best explains the observed relationship Return = 0.0829 + 0.0520 β is between 0.25 and 0.30. If x = 0.25, the equation becomes:
>
> $$K = R_F + 0.25(R_M - R_F) + 0.75\ \beta(R_M - R_F)$$

Dianna R. Harrington summarizes studies on the predicted results of the CAPM versus the actual returns in her text <u>Modern Portfolio Theory & the Capital Asset Pricing Model</u>:

> So far we have learned some very interesting things about the CAPM and reality. Some of the earliest work tested realized data (history) against data generated by simulated portfolios. Early studies by Douglas (1969) and Lintner (Douglas [1969]) showed discrepancies between what was expected on the basis of the CAPM and the actual relationships that were apparent in the capital markets. Theoretically, the minimal rate of return from the portfolios (the intercept) and the actual risk-free rate for the period should have been equal. They were not.
>
> * * *
>
> Another study, now more famous than Lintner's was done by Black, Jensen, and Scholes (1972). Lintner had used what is called a cross-sectional method (looking at a number of stock returns during one time period), whereas Black, Jensen, and Scholes used a time-series method (using returns for a number of stocks over several time periods). To make their test, Black, Jensen, and Scholes assumed that what had happened in the past was a good proxy for the investor expectations (a frequent

assumption in CAPM tests). Using historical data, they generated estimates using what we call the market model:

$$R_{jt} = \alpha_j + \beta_j (R_{mt}) + \varepsilon_j$$

Where:

R = total returns

β = the slope of the line (the incremental return for risk)

α = the intercept or a constant (expected to be 0 over time and across all firms)

ε = an error term (expected to be random, without information)

m = the market proxy

j = the firm or portfolio

t = the time period

Instead of using single stocks, they formed portfolios in an effort to wash out one source of error; because betas of single firms are quite unstable. On the basis of the CAPM, they expected to find

1. That the intercept was equal to the risk-free rate (their proxy was the Treasury bill rate)
2. That the capital market line had a positive slope and that riskier (higher beta) securities provided higher return

Instead, they found

1. That the intercept was different from the risk-free rate
2. That high-risk securities earned less and low-risk securities earned more than predicted by the model
3. That the intercept seemed to depend on the beta of any asset: high-beta stocks had a different intercept than low-beta stocks

* * *

> Fama and MacBeth (1974) criticized the Black, Jensen, and Scholes study (hereafter called BJS). In a reformation of the study, they supported the first of the BJS findings. They found that the intercept exceeded the risk-free proxy, but did not find the evidence to support the other BJS conclusions.[351]

Harrington discusses Black's potential solution to this phenomenon:

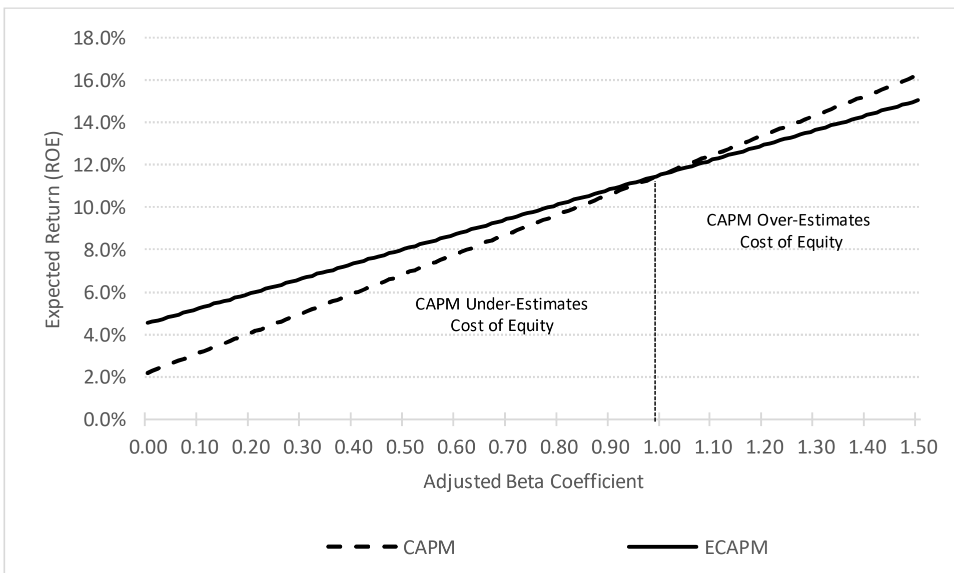
> Black's replacement for the risk-free asset was a portfolio that had no covariability with the market portfolio. Because the relevant risk in the CAPM is systematic risk, a risk-free asset would be the one with no volatility relative to the market – that is, a portfolio with a beta of zero. All investor-perceived levels of risk could be obtained from various linear combinations of Black's zero-beta portfolio and the market portfolio… Since R_z (the rate of return of the zero-beta asset) and R_m are uncorrelated (as R_f and R_m were assumed to be in the simple CAPM), the investor can choose from various combinations of R_z and R_m. On segment R_mY, R_z, is sold short and proceeds are invested in R_m. On segment R_zR_m, portions of the zero-beta portfolio are purchased. At R_m, the investor is fully invested in the market portfolio. The equilibrium CAPM was rewritten by Black as follows:
>
> $$E(R_i) = (1 - \beta_i) E(R_z) + \beta_i E(R_m)$$
>
> where:
>
> E indicates expected,
> $E(R_z)$ is less than $E(R_m)$, and
>
> R_z holdings over the whole market must be in equilibrium. That is, the number of short sellers and lenders of securities must be equal.
>
> Black's adaptation is intriguing. The result of using this model is a capital market line that has a less steep slope and a higher intercept than those of the simple CAPM. If Black's model is more correct in its description of investor behavior in the marketplace, then the use of the simple model would produce

[351] Dianna R. Harrington, Modern Portfolio Theory & the Capital Asset Pricing Model – A User's Guide, Prentice-Hall, Inc. 1983, at 43-45.

> equity return predictions that would be too low for sticks with betas greater than one and too high for stocks with betas of less than one.

The relationship between expected returns from the CAPM and ECAPM can be seen in Chart 19, below. That chart, which reflects Mr. Baudino's risk-free rate and MRP, illustrates the extent to which the CAPM under-states the expected return relative to the ECAPM when Beta coefficients, whether adjusted or unadjusted, are less than 1.00.

Chart 19: CAPM and ECAPM Expected Returns[352]



The ECAPM is an adjustment to the risk/return line which, as noted in Chart 19 above, is flatter than the CAPM assumes. That adjustment is required even with the use of adjusted Beta coefficients, such as those provide by Value

352 Rebuttal Exhibit DWD-19. The finding that the ECAPM is not an adjustment to the Beta coefficient also is clear in the equation ($k_e = R_f + \alpha + \beta(MRP - \alpha)$), in which the alpha coefficient increases the intercept (the expected return when the Beta coefficient equals zero), and reduces the Market Risk Premium.

Line. As Dr. Morin observes:

> Fundamentally, the ECAPM is not an adjustment, increase or decrease, in beta. This is obvious from the fact that the expected return on high beta securities is actually lower than that produced by the CAPM estimate. The ECAPM is a formal recognition that the observed risk-return tradeoff is flatter than predicted by the CAPM based on myriad empirical evidence. *The ECAPM and the use of adjusted betas comprised two separate features of asset pricing…Both adjustments are necessary*.[353]

Q. PLEASE EXPLAIN WHY VALUE LINE ADJUSTS ITS BETA COEFFICIENTS.

A. Value Line's adjustment is based on the research of Marshall Blume, who found that "[n]o economic variable including the beta coefficient is constant over time."[354] Consistent with that finding, Blume observed a tendency of raw Beta coefficients to change gradually over time:

> …there is obviously some tendency for the estimated values of the risk parameter [beta] to change gradually over time. This tendency is most pronounced in the lowest risk portfolios, for which the estimated risk in the second period is invariably higher than that estimated in the first period. There is some tendency for the high risk portfolios to have lower estimated risk coefficients in the second period than in those estimated in the first. Therefore, the estimated values of the risk coefficients in one period are biased assessments of the <u>future values</u>, and furthermore the values of the risk coefficients as measured by the estimates of β_1 tend to regress towards the means with this tendency stronger for the lower risk portfolios than the higher risk portfolios. (emphasis added)

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353 Roger A. Morin, <u>New Regulatory Finance,</u> Public Utility Reports, Inc., 2006, at 191 [*emphasis added*].

354 Marshall E. Blume, *On the Assessment of Risk*, <u>The Journal of Finance</u>, Vol. XXVI, No. 1, March 1971.

Blume proposed a correction for that "regression bias" to provide more accurate assessments of risk and, therefore, the Cost of Equity:

> For individual securities as well as portfolios of two or more securities, the assessments adjusted for the historical rate of regression are more accurate than the unadjusted or naïve assessments. Thus, an improvement in the accuracy of one's assessments of risk can be obtained by adjusting for the historical rate of regression even though the rate of regression over time is not strictly stationary.[355]

Based on Blume's results, Value Line adjusts its "raw" Beta coefficients according to the following formula:

$$\beta_{adjusted} = 0.35 + \left(0.67 \text{ x } \beta_{raw}\right) \quad [6]$$

Lastly, as discussed in my response to Dr. Woolridge, the ECAPM mitigates the CAPM's tendency to underestimate returns for relatively low Beta coefficient stocks, but does not eliminate that effect. That is the case assuming adjusted Beta coefficients.

F. Bond Yield Plus Risk Premium Approach

Q. WHAT CONCERNS DOES MR. BAUDINO EXPRESS REGARDING YOUR BOND YIELD PLUS RISK PREMIUM ANALYSIS?

A. Mr. Baudino suggests the Bond Yield Plus Risk Premium method is "imprecise and can only provide very general guidance," and notes that "[r]isk premiums can change substantially over time."[356] He suggests the approach is a "blunt

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355 *Ibid.*

356 Direct Testimony of Richard A. Baudino, at 62.

instrument".[357] Regarding its application, Mr. Baudino disagrees with the use of projected Treasury yields.

Q. WHAT IS YOUR RESPONSE TO MR. BAUDINO'S OBSERVATIONS?

A. Turning first to Mr. Baudino's point that the Risk Premium can change over time, I agree. As noted in my Direct Testimony, there is a statistically significant negative relationship between long-term Treasury yields and the Equity Risk Premium.[358] Given Mr. Baudino's observation that interest rates have declined since 2008,[359] the Bond Yield Plus Risk Premium analysis provides an empirically and theoretically sound method of quantifying the relationship between the Cost of Equity and interest rates. That is, it provides a method to quantify the change Mr. Baudino has observed.

As to Mr. Baudino's notion that the approach is a "blunt instrument," I disagree. As shown in Chart 17 in my Direct Testimony, the R-squared of the Bond Yield Plus Risk Premium regression analysis is approximately 0.74, indicating a rather high degree of explanatory value. More importantly, the relationship is highly statistically significant. Consequently, the Bond Yield Plus Risk Premium approach provides empirically and theoretically sound results that can be used, at a minimum, to assess the wide range of ROE results produced by Mr. Baudino's analyses in general, and his 9.00 percent

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[357] Direct Testimony of Richard A. Baudino, at 62.
[358] Direct Testimony of Dylan W. D'Ascendis, at 98.
[359] Direct Testimony of Richard A. Baudino, at 7.

recommendation in particular.

Q. DO YOU AGREE WITH MR. BAUDINO'S POSITION THAT YOUR BOND YIELD PLUS RISK PREMIUM RESULTS DO NOT ACCURATELY TRACK RECENTLY ALLOWED ROES?[360]

A. No, I do not. Although Mr. Baudino points to a 36-basis point difference between the model's result and the actual authorized ROE for one specific year (*i.e.*, 2018), as shown in Chart 20 below,[361] since 2000, the model has been quite accurate on average, underestimating the authorized ROE by about ten basis points, well within one standard deviation of the average error. Further, as discussed below, my approach has been considerably more accurate than using a constant historical average risk premium.

Q. HAVE YOU PERFORMED AN ANALYSIS TO DEMONSTRATE THE RELATIVE ACCURACY OF A RISK PREMIUM THAT REFLECTS THE INVERSE RELATIONSHIP BETWEEN BOND YIELDS AND THE EQUITY RISK PREMIUM COMPARED TO AN AVERAGE EQUITY RISK PREMIUM?

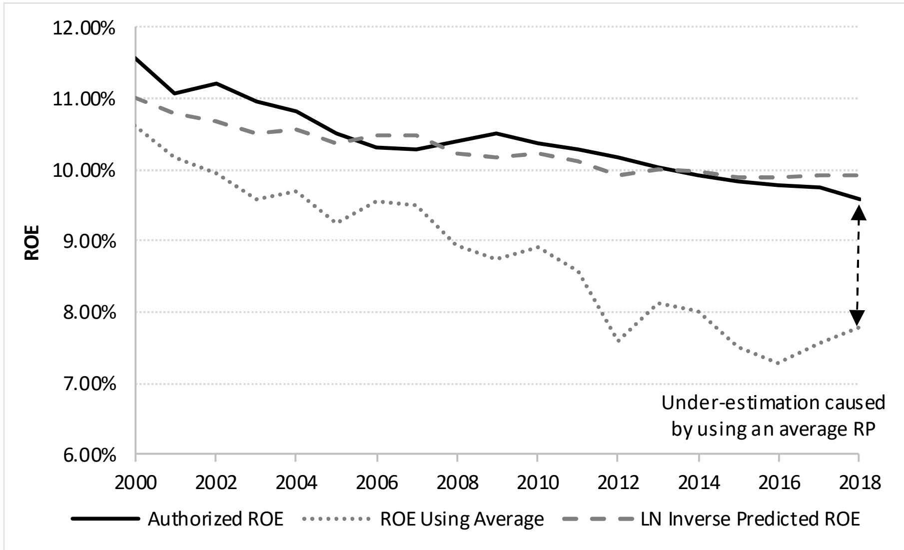
A. Yes, I have. I first calculated the ROE that an average 4.68 percent[362] "static" risk premium would predict using 2000-2019 annual average 30-year Treasury yields, and the error between the predicted ROE and the actual observed

[360] Direct Testimony of Richard A. Baudino, at 62.
[361] Rebuttal Exhibit DWD-20.
[362] The average Equity Risk Premium over the 1980 – 2019 time period calculated in Exhibit DWD-5.

average ROE. I then calculated the ROE predicted in each year using my methodology, which accounts for the log normal[363] relationship discussed in my Direct Testimony, and the error between the actual and predicted observations. As shown in Rebuttal Exhibit DWD-20, using an average Equity Risk Premium, produces estimates that are as much as 258 basis points removed from the actual observed ROE. Using a Risk Premium approach to reflect the inverse relationship between bond yields and the Equity Risk Premium, however, reduces the largest prediction error to 55 basis points. Chart 20 (*see also* Rebuttal Exhibit DWD-20) demonstrates that, contrary to Mr. Baudino's position, my approach produces generally accurate estimates of observed average authorized ROEs. That certainly is true for 2008, the last time the financial markets experienced a significant dislocation.

[363] Direct Testimony of Dylan W. D'Ascendis, at 97.

Chart 20: Accuracy of Risk Premium ROE Estimates



Q. DO YOU AGREE WITH MR. BAUDINO'S CLAIM THAT INCLUDING RATE CASE RESULTS SINCE 1980 IS "AN IRRELEVANT EXERCISE"?[364]

A. No, I do not. The model focuses on the relationship between interest rates and the Equity Risk Premium; it does not view the two in isolation. There is no evidence that excluding data from my analysis would improve the model's ability to estimate expected returns. In any event, an authorized ROE of 9.00 percent and lower for a vertically integrated electric utility has occurred very infrequently, even in the current lower interest rate environment. In fact, it has only occurred twice: in 2013 for Maui Electric Company in Hawaii[365] and in

364 Direct Testimony of Richard A. Baudino, at 55.

365 The 2013 order for Maui Electric included a 50-basis point reduction for "system inefficiencies". Hawaii PUC Docket No. 2011-0092, Decision and Order No. 31288, May 2013, at 107.

2019 for Otter Tail Power in South Dakota.[366] From that perspective, Mr. Baudino's recommendation is far below returns authorized for other vertically integrated electric utilities.

G. Expected Earnings Analysis

Q. PLEASE BRIEFLY SUMMARIZE MR. BAUDINO'S POSITION REGARDING THE EXPECTED EARNINGS ANALYSIS.

A. Mr. Baudino asserts that the "flaw" in the Expected Earnings approach is that "it measures forecasted accounting returns on book value, not investor required returns in the marketplace."[367]

Q. WHAT IS YOUR RESPONSE TO MR. BAUDINO ON THAT POINT?

A. Although I agree economic and financial factors, and the market-based models that depend on them are important, I do not agree those factors invalidate the Expected Earnings approach. As discussed in my response to Dr. Woolridge, no single method best captures investor expectations at all times and under all conditions. The simplicity of the Expected Earnings approach is a benefit, not a detriment. Further, The Expected Earnings method's relative stability during unusually volatile markets provides an important perspective not reflected in market-based methods. Lastly, utility rates are set based on the book value of equity and the Expected Earnings approach provides a direct measure of the book-based return comparable-risk utilities are expected to earn.

366 I discuss the Otter Tail Power order in my response to Mr. O'Donnell.
367 Direct Testimony of Richard A. Baudino, at 64.

H. Flotation Costs

Q. MR. BAUDINO ARGUES THAT FLOTATION COSTS SHOULD NOT BE CONSIDERED BECAUSE, IN HIS OPINION, "IT IS LIKELY THAT FLOTATION COSTS ARE ALREADY ACCOUNTED FOR IN CURRENT STOCK PRICES".[368] WHAT IS YOUR RESPONSE TO MR. BAUDINO ON THAT POINT?

A. I disagree. The models used to estimate the appropriate ROE assume no "friction" or transaction costs, as these costs are not reflected in the market price (in the case of the DCF model) or risk premium (in the case of the CAPM and the Bond Yield Plus Risk Premium model). Mr. Baudino provides no support for his opinion that current stock prices account for flotation costs, and his position should be disregarded.

I. Relative Risk

Q. WHAT IS YOUR RESPONSE TO MR. BAUDINO'S POSITION REGARDING THE COMPANY'S BUSINESS RISKS?

A. Mr. Baudino asserts my review of the Company's business risks is "one-sided"[369] and that its risks are accounted for in its credit rating. As explained in my response to Dr. Woolridge, although I do not disagree that rating agencies may analyze company-specific factors in their review, I do not believe credit ratings are a full measure of equity risk.

368 Direct Testimony of Richard A. Baudino, at 65-66.
369 Direct Testimony of Richard A. Baudino, at 66.

As to his position that my assessment is "one-sided", I disagree. As shown in Rebuttal Exhibit DWD-25, and discussed in my response to Mr. Chriss, my recommended range is consistent with the returns authorized in more constructive jurisdictions such as North Carolina. That is, my recommendation accounts for the Company's "constructive regulatory framework".[370]

J. North Carolina Economic Conditions

Q. PLEASE PROVIDE A SUMMARY OF MR. BAUDINO'S REVIEW OF YOUR NORTH CAROLINA ECONOMIC CONDITIONS.

A. Mr. Baudino observes the unemployment rate in North Carolina and the Company's service territory slightly higher in July 2019 than the national average, and the median income in North Carolina and in the Company's service territory are lower than the national average. He concludes that the Company's lower than average residential rates and the lower than average cost of living in North Carolina do not justify the Company's requested ROE.[371]

Q. WHAT IS YOUR RESPONSE TO MR. BAUDINO?

A. First, Mr. Baudino acknowledges that the difference in the unemployment rate between North Carolina and the U.S. overall narrowed since I filed my Direct Testimony.[372] In fact, the unemployment rate in North Carolina has declined

370 Direct Testimony of Richard A. Baudino, at 19.
371 Direct Testimony of Richard A. Baudino, at 45-46.
372 Direct Testimony of Richard A. Baudino, at 46.

by 0.60 percentage points from July 2019 to December 2019, whereas the U.S. unemployment rate has declined by 0.20 percentage points.[373] As Mr. Baudino acknowledges, North Carolina's unemployment rate is "now roughly equal to the national average."[374] As of March 2020, the seasonally adjusted. unemployment rate was 4.40 percent for both the U.S. and North Carolina.[375] Second, as noted in my Direct Testimony, since 2009, median household income in North Carolina has grown at a slightly faster compound annual rate (2.72 percent) than it has in the U.S. (2.68 percent compound annual rate).[376]

I recognize that economic conditions across the U.S. have deteriorated, as businesses have shut down to mitigate the spread of COVID-19. While North Carolina' GDP outpaced U.S. GDP in the fourth quarter of 2019,[377] we won't know how North Carolina's economy fared in the first quarter of 2020 (reflecting the beginning of the COVID-19 pandemic) until early July. Those points aside, the data available thus far indicate that the North Carolina economy has been generally consistent with the U.S. economy. Consequently, I continue to believe my recommended ROE is fair and reasonable in light of North Carolina's current economic conditions.

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373 Direct Testimony of Richard A. Baudino, at 46. Mr. Baudino notes the seasonally adjusted U.S. unemployment rate was 3.50 percent and the North Carolina unemployment rate was 3.60 percent.

374 Direct Testimony of Richard A. Baudino, at 47.

375 Source: Bureau of Labor Statistics: Table A-10, April 3, 2020; Local Area Unemployment Statistics, Unemployment Rates for States, April 17, 2020.

376 Direct Testimony of Dylan W. D'Ascendis, at 56.

377 https://www.bea.gov/news/2020/gross-domestic-product-state-4th-quarter-and-annual-2019

K. Capital Structure

Q. WHAT CAPITAL STRUCTURE DOES MR. BAUDINO RECOMMEND IN THIS PROCEEDING?

A. Mr. Baudino recommends a capital structure including 51.50 percent common equity and 48.50 percent long-term debt, consistent with his recommendation for DE Carolinas.[378] In Mr. Baudino's view, the Company's proposed 53.00 percent equity ratio is high relative to the actual equity ratios in 2018 at the consolidated parent company level among the proxy groups.[379]

Q. DO YOU AGREE WITH MR. BAUDINO'S CAPITAL STRUCTURE RECOMMENDATION?

A. No, I do not. As discussed throughout my Rebuttal Testimony, the Company's proposal is consistent with the capital structures in place at the proxy companies and with those recently approved by the Commission. Further, any comparison to the capital structures at the consolidated parent company level is inappropriate and should be disregarded.

[378] Direct Testimony of Richard A. Baudino, at 3, 40.
[379] Direct Testimony of Richard A. Baudino, at 41-42.

VII. RESPONSE TO CUCA WITNESS MR. O'DONNELL

Q. PLEASE PROVIDE A SUMMARY OF MR. O'DONNELL'S TESTIMONY AND RECOMMENDATION.

A. Mr. O'Donnell recommends an ROE of 8.75 percent[380] based on his application of the Constant Growth DCF method.[381] As to the Company's capital structure, he recommends 50.00 percent common equity and 50.00 percent long-term debt.[382] In performing his analyses, Mr. O'Donnell reviews data for his and my proxy groups. Regarding his assumed growth rates, Mr. O'Donnell reviews a variety of historical and prospective growth rates for each of his proxy companies. His DCF-based recommendation, which ranges from 7.00 percent to 10.00 percent, are based on his conclusion that a "proper" range of growth rates is from 4.00 percent to 6.00 percent.[383]

In his Comparable Earnings approach, Mr. O'Donnell reviews the actual and expected returns on equity for his and my proxy groups from 2017 to 2025, and finds ranges of 9.50 percent to 10.30 percent to be reasonable for both his and my proxy group.[384] He then concludes the proper range for his Comparable

380 Direct Testimony of Kevin W. O'Donnell, CFA, at 6.
381 Direct Testimony of Kevin W. O'Donnell, CFA, at 102.
382 Direct Testimony of Kevin W. O'Donnell, CFA, at 6, 116.
383 Direct Testimony of Kevin W. O'Donnell, CFA, at 86, 87.
384 Direct Testimony of Kevin W. O'Donnell, CFA, at 99, Exhibit KWO-3, Exhibit KWO-8. I note the range of results for his proxy group presented in Exhibit KWO-3 show a range of 9.90 percent to 10.60 percent.

Earnings approach is 9.25 percent to 10.25 percent, based on the trend of recent authorized ROEs and the forecasted earned returns of his proxy group.[385]

In developing his CAPM analyses, Mr. O'Donnell uses the current 30-year Treasury bond, together with Value Line Beta coefficients and MRP estimates of 4.00 percent and 6.00 percent, producing ROE estimates ranging from 3.17 percent to 6.74 percent for his proxy group and 3.15 percent to 6.69 percent for my proxy group.[386]

Q. WHAT ARE THE PRINCIPAL AREAS IN WHICH YOU DISAGREE WITH MR. O'DONNELL'S ROE ANALYSES, METHODOLOGIES, AND CONCLUSIONS?

A. My principal areas of disagreement include: (1) the interpretation of current capital market conditions; (2) the inclusion of Duke Energy Corporation in Mr. O'Donnell's proxy group; (3) certain aspects of Mr. O'Donnell's Constant Growth DCF analyses, particularly the growth rate component; (4) the application of the Comparable Earnings approach; (5) the application of the CAPM; (6) Mr. O'Donnell's criticisms of my Bond Yield Plus Risk Premium approach; (7) Mr. O'Donnell's concerns regarding the weight given certain model results; (8) Mr. O'Donnell's review of select orders from other regulatory commissions; and (9) his proposed capital structure consisting of 50.00 percent common equity and 50.00 percent long-term debt.

385 Direct Testimony of Kevin W. O'Donnell, CFA, at 101.
386 Direct Testimony of Kevin W. O'Donnell, CFA, at 97, and Exhibit KWO-5, Exhibit KWO-10.

Q. AT PAGE 64 OF HIS TESTIMONY, MR. O'DONNELL ASSERTS THAT THE NATURE OF REGULATION DOES NOT POSE ANY RISK TO A UTILITY. DO YOU AGREE WITH HIS POSITION?

A. No, I do not. Although I agree the nature of regulation may provide a "risk-reducing component"[387] relative to non-regulated businesses, I disagree with Mr. O'Donnell's position that the nature of regulation poses no risk at all (*i.e.*, that regulatory risk is non-existent). If that were the case, there would be no need for credit rating agencies to consider the regulatory environment in their rating assessments. To that point, the fact that utilities disclose regulatory risks in their SEC Form 10-Ks demonstrates such risks are present.

As Mr. O'Donnell acknowledges, the regulatory compact provides that a utility should be afforded a reasonable opportunity to recover its return of, and return on, its prudently incurred investments.[388] It does not guarantee that return. Statutes and commission precedents change.[389] As noted earlier in my Rebuttal Testimony and Appendix A, the risk of adverse regulatory outcomes is valid, and the financial community carefully monitors the regulatory environment. Consequently, Mr. O'Donnell's position that regulation does not pose any risk is misplaced.

387 Direct Testimony of Kevin W. O'Donnell, CFA, at 64.

388 Direct Testimony of Kevin W. O'Donnell, CFA, at 64.

389 For example, South Carolina recently repealed legislation that supported the construction and cost recovery of new nuclear generating plants. After the repeal, the regulatory environment in South Carolina deteriorated from the top third of regulatory environments to the bottom third, as evaluated by Regulatory Research Associates.

Lastly, as discussed in Section III, the correlation in returns between the utility sector and the overall market increased significantly during March and April, to approximately 95.00 percent. As a result, Beta coefficients also significantly increased. That data clearly demonstrates utilities are not immune to market dislocations, despite the nature of regulation.

A. Capital Market Conditions

Q. WHAT IS YOUR RESPONSE TO MR. O'DONNELL AS IT RELATES TO RECENT CAPITAL MARKET CONDITIONS?

A. Mr. O'Donnell's focus on the decrease in interest rates and his conclusion it implies a lower cost of capital[390] is misplaced. As described in Section III, the recent decline in interest rates is driven by investors seeking the safety of Treasury yields. Increases in the VIX, utility dividend yields, and credit spreads indicate an increasing, not decreasing, cost of capital. As also explained in Section III, utilities have not been immune to the recent market instability. The same holds for Mr. O'Donnell's proxy group, which lost about 22.50 percent of its value between February 12 and April 1, 2020.[391]

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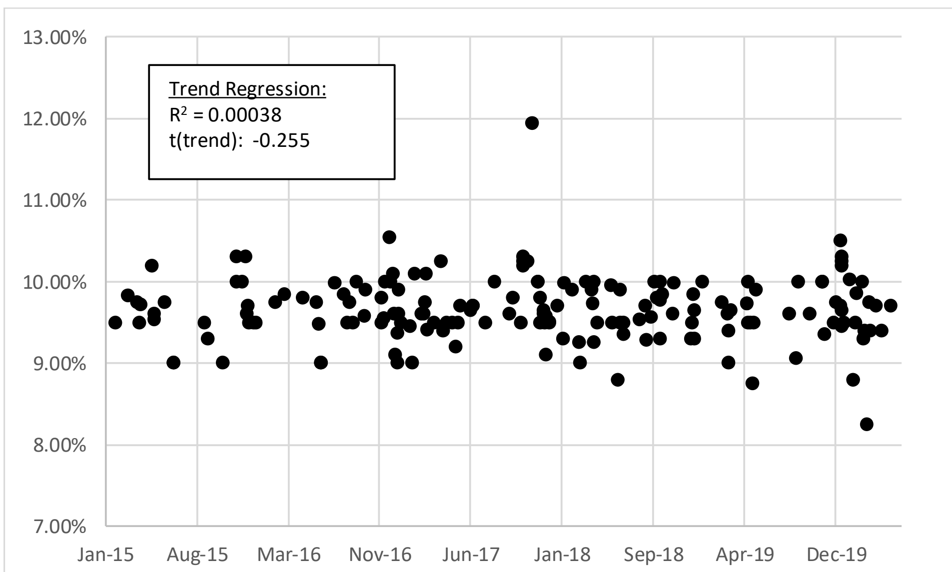
390 Direct Testimony of Kevin W. O'Donnell, CFA, at 68.

391 Source: S&P Global Market Intelligence. Calculated as an index.

Q. WHAT ARE YOUR OBSERVATIONS RELATED TO MR. O'DONNELL'S REVIEW OF AUTHORIZED RETURNS?[392]

A. It is difficult to draw any conclusions regarding trends in authorized returns based on so few observations and on a simple review of annual averages. However, as shown in Chart 21, below, if all authorized ROEs are charted (rather than the simple average), there has been no meaningful trend since 2015; time explains no more than 0.04 percent of the change in ROEs, and the trend is statistically insignificant.

Chart 21: Electric Authorized Returns (2015-2020)[393]



Mr. O'Donnell's assumption of a downward trend in authorized returns is demonstrably incorrect.

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[392] Direct Testimony of Kevin W. O'Donnell, CFA, at 71-72.

[393] Source: Regulatory Research Associates. Excludes Illinois formula rate plans.

Q. DO YOU HAVE ANY OBSERVATIONS REGARDING THE 8.75 PERCENT ROE AUTHORIZED TO OTTER TAIL POWER MR. O'DONNELL REFERS TO ON PAGE 61 OF HIS DIRECT TESTIMONY?

A Yes, the lowest authorized ROE for a vertically integrated electric utility (8.75 percent) was authorized for Otter Tail Power by the South Dakota Public Utilities Commission ("SDPUC") on May 30, 2019.[394] In considering the effect of that order, there are several points to keep in mind. First, South Dakota represents 10.00 percent of Otter Tail Corporation's ("OTTR") retail electric revenues.[395] From May 6 to May 31, 2019, OTTR lost about 5.20 percent of its market value, even though the Dow Jones Utility Average gained about 1.00 percent.[396] I recognize that is a limited observation, but it still appears OTTR meaningfully underperformed the utility sector around the time the SDPUC issued its order. My view that the SDPUC's order was anomalously low relative to returns authorized in other jurisdictions seems to be consistent with OTTR's price behavior.

In the case of Otter Tail Power, it appears the market reacted adversely to an unfavorable regulatory decision, even though the operations affected by that decision represented only a small portion of the company's consolidated

394 Public Utilities Commission of the State of South Dakota, In the Matter of the Application of Otter Tail Power Company Fore Authority to Increase its Electric Rates, Final Decision and Order; Notice of Entry, Docket No. EL18-021, May 30, 2019.

395 Otter Tail Corporation, SEC Form 10-K for the fiscal year ended December 31, 2019, at 5.

396 Source: Yahoo! Finance.

operations. As noted earlier, and discussed in more detail in Appendix A, the case of CenterPoint Energy is very clear, with its substantially underperforming stock price and credit rating downgrade.

Because utilities such as DE Progress invest in long-lived assets, the stability, predictability, and supportiveness of the regulatory environment is a key concern to investors. That concern is especially acute during periods of heightened market instability when utility stocks, like all stocks, are susceptible to market risk. If the Commission were to adopt Mr. O'Donnell's recommendation, the financial community's reaction would be adverse. Whether manifested in negative credit actions, or simply a perception on the part of investors and analysts that the regulatory environment has deteriorated, an adverse reaction would impede the Company's ability to raise capital at reasonable costs, to the detriment of customers.

To summarize, we have seen the financial community react negatively to adverse regulatory decisions. A consequence of those reactions is a diminished ability to compete for capital, and an increase in the cost of capital, to the detriment of customers. If Mr. O'Donnell's ROE recommendation, which is far removed from the returns available to other utilities, were adopted, the eventual result would be an increase in the Company's cost of capital.

B. Proxy Group Selection

Q. PLEASE DESCRIBE THE SCREENING CRITERIA BY WHICH MR. O'DONNELL DEVELOPED HIS PROXY GROUP.

A. Mr. O'Donnell relied on six screening criteria to develop his proxy group of 29 companies:

1. Followed by *Value Line Investment Survey* as an electric utility;
2. Derived at least 50.00 percent of 2018 revenues from regulated operations;
3. Has an investment-grade corporate credit and bond rating;
4. Is not in the midst of merger or acquisition discussions;
5. Have at least five years of historical data; and
6. Must have paid a dividend each quarter in the past year.[397]

Q. DO YOU AGREE WITH MR. O'DONNELL'S SCREENING CRITERIA?

A. Not entirely. As discussed in my response to Dr. Woolridge, I disagree with the use of revenue, rather than income as a screening criterion.

397 Direct Testimony of Kevin W. O'Donnell, CFA, at 72.

Q. DO YOU AGREE WITH MR. O'DONNELL'S INCLUSION OF DUKE ENERGY CORPORATION, DE PROGRESS' PARENT, IN HIS PROXY GROUP?

A. No, I do not. As noted earlier in my response to Dr. Woolridge, including parent companies creates circular logic.[398]

C. Constant Growth Discounted Cash Flow Model

Q. DO YOU AGREE WITH MR. O'DONNELL'S PRIMARY RELIANCE ON A SINGLE MODEL (*I.E.,* THE CONSTANT GROWTH DCF MODEL) IN DEVELOPING HIS RECOMMENDED ROE?

A. No, I do not. As explained in my response to Dr. Woolridge, the relevant issue is whether investors use multiple methods in evaluating investment opportunities and making investment decisions. Nowhere has Mr. O'Donnell demonstrated investors are inclined to disregard other methods in favor of the Constant Growth DCF model. As noted earlier, no one model is more reliable than all others at all times and under all conditions, including the DCF method. As to its use among investors, there is academic support for the use of multiple methods in estimating the Cost of Equity.

[398] Direct Testimony of Dylan W. D'Ascendis, at 23.

Q. AT PAGES 68 TO 70 OF HIS DIRECT TESTIMONY, MR. O'DONNELL SPEAKS TO CHANGES IN INTEREST RATES, AND THE INCREASE IN THE DOW JONES UTILITY AVERAGE. HOW DOES THAT DISCUSSION RELATE TO THE DCF METHOD AND MR. O'DONNELL'S DECISION TO GIVE THAT APPROACH PRIMARY WEIGHT?

A. It does so in several ways. First, Mr. O'Donnell asserts I "fail to acknowledge" the "mathematical certainty" that changes in equity prices result in changes in the Cost of Equity.[399] His argument is simplistic and misplaced. First, as Mr. O'Donnell surely understands, the Cost of Equity is not observable – it is not capable of precise "mathematical" quantification as are yields on debt securities. As Graham and Dodd long ago recognized, the investor sentiments that underlie market prices cannot be captured by a single analytical approach. Mr. O'Donnell's notion that the relationship between equity prices and the Cost of Equity are "a mathematical certainty" is inconsistent with years of financial research and practice.

Second, Mr. O'Donnell seems to suggest the relationship between utility stock valuations and interest rates is direct and unconstrained, arguing "investors are paying more and more for a given level of income."[400] Even that "reach for yield", however, has a limit; investors will not accept the incremental

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399 Direct Testimony of Kevin W. O'Donnell, CFA, at 56.
400 Direct Testimony of Kevin W. O'Donnell, CFA, at 56.

risk of capital losses when valuation multiples continually expand. That is, valuations do not strictly follow interest rates. The incremental risk of capital losses as valuations expand may be seen in the DCF model, and its derivative measure of "equity duration".

Q. PLEASE EXPLAIN THE CONCEPT OF "EQUITY DURATION", AND HOW IT MAY BE APPLIED IN THIS CIRCUMSTANCE.

A. In general, "duration" measures the security's price sensitivity to changes in the underlying discount rate. For bonds, duration measures the percent change in price relative to the percent change in the yield to maturity.[401] The same concept may be applied to equity investments, where equity duration measures the sensitivity of equity prices to changes in the Cost of Equity. In each case (that is, for both stocks and bonds), duration represents the weighted average time (in years) over which cash flows are received. Because it measures the sensitivity of prices to changes in yields, duration is an important measure of risk to investors.

Q. PLEASE GENERALLY DESCRIBE HOW DURATION IS CALCULATED.

A. Consistent with the Constant Growth DCF model, equity duration recognizes that equity cash flows (dividends) continue in perpetuity. Based on the Constant Growth DCF model's structure, duration may be defined as $d =$

[401] https://www.investopedia.com/terms/d/duration.asp

$\frac{1}{k-g}$ [7], where d is duration, k is the Cost of Equity, and g is the assumed growth rate.[402] Because the DCF model assumes the Cost of Equity is the sum of the dividend yield and the growth rate, the denominator equals the assumed dividend yield. Modified duration (d_m), sometimes considered a more precise measure, adjusts Equation [7] by the discount rate:

$$d_m = \frac{d}{1+k} \quad [8]$$

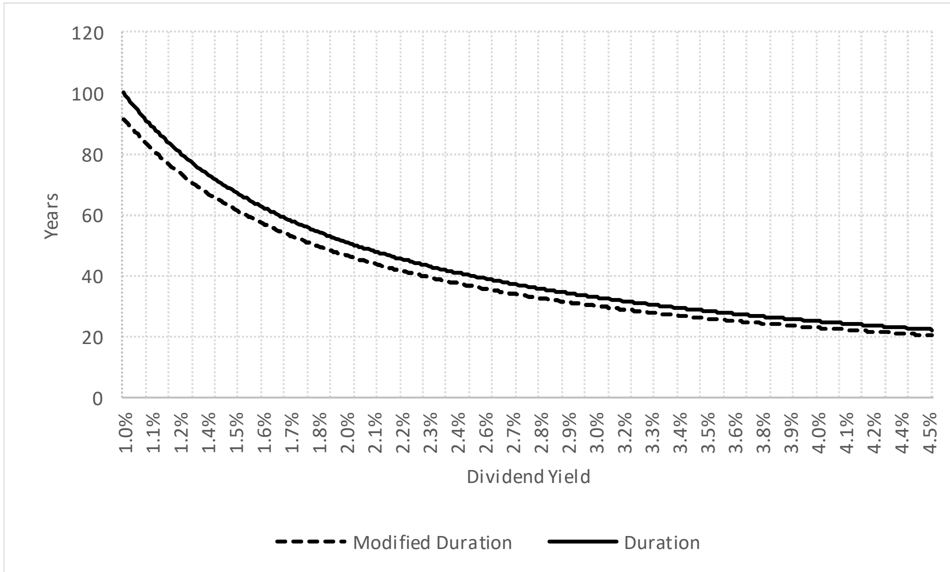
The percent change in stock prices (P) brought about by a change in the Cost of Equity is calculated as:

$$\frac{\Delta P}{P} = -d_m \text{ x } \Delta k \quad [9]$$

Two points bear particular attention. First, lower-yielding stocks will tend to have higher durations and, therefore, are more sensitive to changes in the Cost of Equity. The second, and related, point is that as the dividend yield decreases, duration, and duration-related risk, increases at an increasing rate (*see*, Chart 22, below).

402 James L. Farrell, Jr., *The Dividend Discount Model: A Primer*, Financial Analysts Journal, November/December 1985, at 23.

Chart 22: Duration and Dividend Yields



In this case, Mr. O'Donnell reports a current dividend yield of 3.50 percent for his proxy group,[403] indicating an equity duration of about 28.57 years.[404] Based on his 8.75 percent ROE recommendation, the modified duration is about 26.27 years.[405] There is no reason to assume investors would continuously follow interest rates down, continuously taking on increasing levels of duration risk. As discussed in Section III, that is what we recently have seen – utility dividend yields increased as interest rates decreased.

Q. WHAT CONCLUSIONS DO YOU DRAW FROM THOSE ANALYSES?

A. Mr. O'Donnell's assessments and recommendations do not consider the risks implied by them. Even if we assume investors rely principally on the DCF

403 Exhibit KWO-1.

404 $\frac{1}{.035} = 28.57$

405 $\frac{28.57}{1.0875} = 26.27$

method, and market prices always equal the estimate of intrinsic value produced by that method, we should not lose sight of the risk implied by extended equity durations. That being the case, we should be very cautious about accepting Mr. O'Donnell's position that the relationship between prices and the Cost of Equity is purely mathematical, or that yield-seeking behavior is a simple matter. Neither is the case in practice.

Q. HAS THE COMMISSION RECOGNIZED THE VALUE OF APPLYING MULTIPLE METHODS TO DETERMINING THE COST OF EQUITY?

A. Yes. In its prior Orders, the Commission has thoroughly considered the evidence presented by each ROE witness reflecting a variety of approaches, including the methods I present in this proceeding.

Q. WHAT ARE YOUR GENERAL CONCLUSIONS REGARDING MR. O'DONNELL'S PRINCIPAL RELIANCE ON HIS CONSTANT GROWTH DCF MODEL RESULTS?

A. Given the extreme volatility underlying the current capital markets, relying on a single method creates unnecessary modeling risk, and departs from investor practice. Because all models are subject to limiting assumptions, it is important to recognize that no model is appropriate under all market conditions. Mr. O'Donnell acknowledges his DCF results fall well below the returns authorized by other regulatory commissions.[406] That finding should raise concerns

[406] Direct Testimony of Kevin W. O'Donnell, at 102.

regarding the weight he gives that model. That is especially true since, as noted earlier, other commissions have not been inclined to give sole weight to a single method, including the DCF model.

Q. WHAT GROWTH RATES DID MR. O'DONNELL CONSIDER IN HIS CONSTANT GROWTH DCF ANALYSIS?

A. Mr. O'Donnell reviews a variety of growth rates, including: (1) the historical and projected "plowback ratio" (also referred to as "sustainable growth" rates or "Retention Growth" rates) as reported by Value Line; (2) the historical ten-year and five-year compound annual growth rates in EPS, BVPS, and DPS as reported by Value Line; (3) the Value Line projected EPS, BVPS, and DPS growth rates; and (4) consensus projected EPS growth rates, as reported by CFRA and Charles Schwab & Co.[407]

Q. DO YOU AGREE WITH MR. O'DONNELL THAT HISTORICAL GROWTH RATES ARE APPROPRIATE MEASURES OF EXPECTED GROWTH FOR THE CONSTANT GROWTH DCF MODEL?

A. No. For the reasons discussed in my response to Dr. Woolridge and Mr. Baudino, I do not believe historical growth rates are appropriate for the Constant Growth DCF model.

[407] Direct Testimony of Kevin W. O'Donnell, CFA, at 82-85; Exhibit KWO-1, Exhibit KWO-2, Exhibit KWO-6; Exhibit KWO-7.

Q. WHY DO YOU DISAGREE WITH MR. O'DONNELL'S POSITION THAT DIVIDEND OR BOOK VALUE GROWTH RATES ARE APPROPRIATE INPUTS TO THE CONSTANT GROWTH DCF MODEL?

A. As explained earlier in my response to Dr. Woolridge, earnings growth enables both dividend and book value growth. Under the strict assumptions of the Constant Growth DCF model, earnings, dividends, book value, and stock prices all grow at the same, constant rate.[408]

In addition, Value Line is the only service relied on by Mr. O'Donnell that provides either DPS or BVPS growth projections. The fact that services such as Zacks and First Call provide earnings, but not dividend or book value growth estimates indicates that they see little investor demand for such data. As Dr. Roger Morin notes:

> Casual inspection of the Zacks Investment Research, First Call Thompson, and Multex Web sites reveals that earnings per share forecasts dominate the information provided. There are few, if any, dividend growth forecasts. Only Value Line provides comprehensive long-term dividend growth forecasts. The wide availability of earnings forecast is not surprising. There is an abundance of evidence attesting to the importance of earnings in assessing investors' expectations. The sheer volume of earnings forecasts available from the investment community relative to the scarcity of dividend forecasts attests to their importance. The fact that these investment information providers focus on growth in earnings rather than growth in dividend indicates that the

[408] Direct Testimony of Dylan W. D'Ascendis, at 77. *See also*, Rebuttal Exhibit DWD-10.

> investment community regards earnings growth as a superior indicator of future long term growth.[409]

Moreover, Value Line estimates are available only via a subscription service and are attributable to a single analyst. Services such as Zacks and First Call, on the other hand, provide consensus growth estimates of multiple analysts and, as such, are less likely to be skewed in one direction or another by an individual analyst.

Q. DO YOU AGREE WITH MR. O'DONNELL'S POSITION THAT ANALYSTS' EARNINGS GROWTH FORECASTS ARE "UNREALISTICALLY HIGH"[410] AND INACCURATE[411]?

A. No, I do not. Mr. O'Donnell cites several studies to support his position regarding the "accuracy" of analysts' earnings forecasts.[412] His position, however, is based on observations of the broad market; Mr. O'Donnell has provided no evidence that any of the growth rates used in my DCF analyses are the result of a consistent and pervasive bias on the part of the analysts providing those projections. More importantly, the salient issue is the growth that investors *expect*, not what actually happens.

Further, and as discussed in my response to Dr. Woolridge, regulations implemented in 2003 insulated financial institutions' investment banking

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409 Roger A. Morin, PhD, New Regulatory Finance, (Public Utilities Reports, Inc., 2006), at 302-303.
410 Direct Testimony of Kevin W. O'Donnell, CFA, at 89.
411 Direct Testimony of Kevin W. O'Donnell, CFA, at 89.
412 Direct Testimony of Kevin W. O'Donnell, CFA, at 87-89.

functions from its analysis functions. In reviewing the Letters of Acceptance, Waiver and Consent signed by financial institutions that were party to the Global Settlement, I found no reference to misconduct by analysts following the utility sector.

Q. IS THE USE OF ANALYSTS' EARNINGS GROWTH PROJECTIONS IN THE DCF MODEL SUPPORTED BY FINANCIAL LITERATURE?

A. Yes, it is. As noted in my Direct Testimony[413] and discussed in my response to Dr. Woolridge, peer-reviewed, published articles support the use of analysts' earnings growth projections in the DCF model. Again, earnings growth, not dividend growth, is the appropriate estimate in the Constant Growth DCF model. As discussed in my response to Dr. Woolridge, and shown in Rebuttal Exhibit DWD-11, the only growth rate that is statistically significant and positively related to the P/E ratio is projected Earnings Per Share. Because EPS growth is the only growth rate that is both statistically and positively related to utility valuation, earnings growth is the proper measure of growth in the Constant Growth DCF Model.

Q. PLEASE SUMMARIZE YOUR CONCERNS WITH MR. O'DONNELL'S USE OF THE RETENTION GROWTH MODEL.

A. I have several concerns with Mr. O'Donnell's use of the Retention Growth model. First, as discussed below, the model's underlying premise is that future

[413] Direct Testimony of Dylan W. D'Ascendis, at 81-82.

earnings will increase as the retention ratio increases. That is, if future growth is modeled as "B x R" (where B is the retention ratio, and R is the earned return on book equity), growth will increase as B increases. There are several reasons, however, why that may not be the case. Management decisions to conserve cash for capital investments, to manage the dividend payout to minimize future dividend reductions, or to signal future earnings prospects can and do influence dividend payout (and therefore earnings retention) decisions in the near-term. Consequently, it is appropriate to determine whether the data relied on by Mr. O'Donnell supports the assumption that higher earnings retention ratios necessarily are associated with higher future earnings growth rates.

Q. DID YOU PERFORM ANY ANALYSES TO TEST THE RELATIONSHIP BETWEEN RETENTION RATIOS AND FUTURE GROWTH RATES?

A. Yes, I did. Using EPS and DPS data from Value Line (the source of the data Mr. O'Donnell used to calculate his earnings Retention Growth estimate), I calculated the historical dividend payout ratio, retention ratio, and subsequent five-year average earnings growth rate for each of his proxy companies with a consistent history of dividend payments. I then performed a regression analysis in which the dependent variable was the five-year earnings growth rate, and the explanatory variable was the earnings retention ratio. The purpose of that analysis was to determine whether Mr. O'Donnell's data empirically supports the assumption that higher retention ratios necessarily produce higher earnings growth rates.

Q. WHAT DID THAT ANALYSIS REVEAL?

A. As shown in Table 11 below (*see also* Rebuttal Exhibit DWD-21), there was a statistically significant negative relationship between the five-year average earnings growth rate and the earnings retention ratio. That is, based on Mr. O'Donnell's own data source, earnings growth actually *decreased* as the retention ratio increased. Those findings clearly call into question Mr. O'Donnell's reliance on his "Retention Growth" estimate.

Table 11: Regression Results - Retention Ratio / Earnings Growth[414]

	Coefficient	Standard Error	t-Statistic
Intercept	0.108	0.012	9.201
Retention Ratio	-0.166	0.023	-7.150

Q. ARE YOU AWARE OF INDEPENDENT RESEARCH THAT SUPPORTS YOUR FINDINGS?

A. Yes, I am. In 2006, for example, two articles in Financial Analysts Journal addressed the theory that high dividend payouts (*i.e.*, low retention ratios) are associated with low future earnings growth.[415] Both articles cite a 2003 study by Arnott and Asness,[416] who found that over the course of 130 years of data,

414 Rebuttal Exhibit DWD-21.

415 *See*, Ping Zhou, William Ruland, *Dividend Payout and Future Earnings Growth*, Financial Analysts Journal, Vol. 62, No. 3, 2006. *See also*, Owain ap Gwilym, James Seaton, Karina Suddason, Stephen Thomas, *International Evidence on the Payout Ratio, Earnings, Dividends and Returns*, Financial Analysts Journal, Vol. 62, No. 7, 2006.

416 *See*, Robert Arnott, Clifford Asness, *Surprise: Higher Dividends = Higher Earnings Growth*, Financial Analysts Journal, Vol. 59, No. 1, January/February 2003.

future earnings growth is associated with high, rather than low, payout ratios.[417] In essence, the findings of all three studies are consistent with my findings regarding the relationship between retention ratios and future earnings growth for Mr. O'Donnell's proxy companies: there is a negative, not a positive relationship between the two. In light of those articles, it appears my findings are reasonable. Given the strong statistical results of my analyses, and the corroborating research discussed above, I continue to believe Mr. O'Donnell's substantial reliance on the "B x R" approach is inappropriate.

Q. ARE VALUE LINE'S PROJECTIONS FOR THE PROXY COMPANIES' GROWTH IN EARNINGS PER SHARE CONSISTENT WITH THE RETENTION GROWTH ESTIMATE?

A. No, they are not. As shown in Rebuttal Exhibit DWD-22, I calculated the Retention Growth rate using Value Line's projected financial metrics for each company in our combined proxy group for the year 2019, and their respective three- to five-year projections. I then compared those estimates to Value Line's expected earnings growth for each company. As shown in Rebuttal Exhibit DWD-22, Value Line frequently expects actual earnings growth to exceed the growth rate indicated by the Retention Growth formula.[418] Consequently, the

[417] Because the payout ratio is the inverse of the retention ratio, the authors found that future earnings growth is negatively related to the retention ratio.

[418] To be conservative, I calculated the Retention Growth rate using the "BR + SV" approach described below; however, if I had used the "BxR" approach Mr. O'Donnell uses, there would have been more observations in which the Retention Growth rate underestimated the expected earnings growth rate. *See,* Rebuttal Exhibit DWD-22.

assumption that the Retention Growth estimate accurately reflects future growth may be too limiting.

Q. ASIDE FROM THOSE CONCERNS, DO YOU AGREE WITH MR. O'DONNELL'S SPECIFICATION OF THE RETENTION GROWTH RATE?

A. No, I do not. As discussed in my response to Dr. Woolridge, if Mr. O'Donnell is going to consider a form of Retention Growth, he should use the "BR + SV" form of the model, which reflects growth both from internally generated funds (*i.e.*, the "BR" term) and from issuances of equity (*i.e.*, the "SV" term).

Q. WHAT IS YOUR RESPONSE TO MR. O'DONNELL'S USE OF NEGATIVE GROWTH RATES IN HIS DCF ANALYSIS?[419]

A. Consideration of negative growth rates as Mr. O'Donnell has applied them is intuitively incorrect.[420] No rational investor would invest in an individual stock that is expected to decrease its earnings in perpetuity. Recall that under the Constant Growth DCF model's assumptions, the assumed growth rate equals the assumed rate of capital appreciation. By including negative growth rates, Mr. O'Donnell assumes investors knowingly and willingly would invest in a company that they expect to lose value every year, in perpetuity.

[419] Mr. O'Donnell includes negative growth rates in his review of historical EPS, BVPS, and DPS growth. *See*, Exhibit KWO-1.

[420] Applying negative growth rates to establish the expected market return is a different matter. There, investors understand that over time, the market will include companies that grow quickly, and others that recede.

Q. WHAT ARE YOUR CONCLUSIONS REGARDING THE APPROPRIATE GROWTH RATE FOR THE CONSTANT GROWTH DCF MODEL?

A. Based on the analyses and research noted above, I conclude projected EPS growth rates represent the appropriate measure of growth in the Constant Growth DCF model.

D. Comparable Earnings Method

Q. HOW DID MR. O'DONNELL DERIVE HIS 9.25 PERCENT TO 10.25 PERCENT ROE RANGE BASED ON THE COMPARABLE EARNINGS METHOD?

A. As Mr. O'Donnell states at page 101 of his direct testimony, the low end of his comparable earnings method range of results (*i.e.*, 9.25 percent) recognizes "the unmistakable downward trend of the average ROE allowed by state regulators for electric utilities dating back to 2005" and the high end (*i.e.*, 10.25 percent) "recognizes high forecasted earned returns on equity for the O'Donnell and [D'Ascendis] comparable groups".

Q. BEFORE DISCUSSING YOUR CONCERNS WITH MR. O'DONNELL'S COMPARABLE EARNINGS METHOD, PLEASE COMMENT ON MR. O'DONNELL'S DETERMINATION OF THE LOW-END OF HIS RANGE BASED ON THAT APPROACH.

A. As shown in Exhibits KWO-3 and KWO-8, Mr. O'Donnell's Comparable Earnings results range from 9.50 percent to 10.60 percent. The low end of his Comparable Earnings-based range, therefore, is 25 basis points below the low end of the range of his model results. As discussed earlier in my response to Mr. O'Donnell, authorized ROEs have been in a relatively narrow range since 2015; time explains less than 0.04 percent of the variation in returns.[421] There is no "unmistakable downward trend". Mr. O'Donnell's premise that recent years reflect lower authorized returns and capital costs is incorrect. That point aside, Mr. O'Donnell argues the average authorized ROE for all electric utilities in 2019 was 9.65 percent,[422] 40 basis points above the 9.25 percent low end of his Comparable Earnings range.

421 *See* Chart 21 above.

422 Direct Testimony of Kevin W. O'Donnell, CFA, at 100. The average for vertically integrated electric utilities in 2019 was 9.73 percent.

Q. PLEASE DISCUSS YOUR CONCERNS REGARDING THE USE OF HISTORICAL EARNED RATES OF RETURN IN THE COMPARABLE EARNINGS ANALYSIS.

A. Because the Cost of Equity is inherently forward-looking,[423] the only relevant earnings figures provided on Exhibit KWO-3 and Exhibit KWO-8 are the 2019 and 2022-2025 expected returns. Notably, the proxy groups' average expected return for 2019 and 2022-2025 range from 9.90 percent to 10.60 percent, 115 to 185 basis points above Mr. O'Donnell's estimate of the market required ROE, and overlapping my recommended range. Again, that inconsistency calls into question the relevance of Mr. O'Donnell's 8.75 percent ROE recommendation.

Q. MR. O'DONNELL SUGGESTS THE COMPARABLE EARNINGS ANALYSIS PRODUCES ESTIMATES HIGHER THAN INVESTORS ARE EXPECTING IN TODAY'S MARKETPLACE.[424] IS THAT SUGGESTION CORRECT?

A. No, it is not. Mr. O'Donnell's position is that because market values exceed book values, any analyses based on book value will overstate the market return investors require. He appears to largely dismiss the Comparable Earnings method on that basis, looking instead to a fifteen-year trend in authorized ROEs.[425]

423 Direct Testimony of Dylan W. D'Ascendis, at 33.
424 Direct Testimony of Kevin W. O'Donnell, CFA, at 98.
425 Direct Testimony of Kevin W. O'Donnell, CFA, at 99-100.

I appreciate there is a difference between market and book value. That does not mean, however, that book-based earnings are of no consequence to investors. Rather, accounting-based performance measures are related to market-based performance measures, such as market returns, and market to book ratios. Lehn and Makhija document a positive correlation between ROE and stock returns, significant at the 0.01 percent level.[426] In regressing market to book on factors including the excess of ROE over Cost of Equity (the "equity spread"), Varaiya, Kerin and Weeks find a positive and significant coefficient on the equity spread.[427] Nichols and Wahlen document a significant positive relationship between stock returns and earnings relative to assets measured at book value.[428] Taken together, these results suggest that although many factors may affect stock returns and market to book ratios, the accounting-based ROE is one of them, and should not be ignored.[429]

Alongside those peer-reviewed empirical investigations is a parallel body of literature based on the importance of managing ROE and other accounting-based metrics. Arzac proposes a value-creation model for managers

426 Kenneth Lehn, Anil Makhija, *EVA, Accounting Profits, and CEO Turnover: An Empirical Examination, 1985-1994*, Journal of Applied Corporate Finance, Vol 10.2, Summer 1997, at 90.

427 Nikhil Varaiya, Roger Kerin, David Weeks, *The Relationship Between Growth, Profitability, and Firm Value*, Strategic Management Journal, Vol. 8 No. 5, September-October 1987, at 487.

428 D. Craig Nichols, James M. Wahlen, *How Do Earnings Numbers Relate to Stock Returns? A Review of Classic Accounting Research with Updated Evidence*, Accounting Horizons, Vol 18, No. 4, December 2004, at 272 – 274, 285.

429 I am not suggesting the M/B ratio necessarily will equal 1.00 when the accounting-based ROE equals the Cost of Equity.

based on the equity spread.[430] As discussed in my response to Dr. Woolridge, the Economic Value Added consulting practices and related value-based-management systems encourage managers to focus on elements of return on net assets and return on invested capital.

Lastly, I have not suggested using the Expected Earnings approach as the sole measure of the appropriate ROE. Rather, I have used that method to corroborate the DCF, CAPM, ECAPM, and Risk Premium methods.

Q. ARE THE RESULTS OF MR. O'DONNELL'S COMPARABLE EARNINGS APPROACH SIMILAR TO THE RESULTS OF YOUR EXPECTED EARNINGS ANALYSIS?

A. Yes, they are. Mr. O'Donnell's projected earned returns produce ROE estimates of 10.00 percent and 10.60 percent for his proxy group, and 9.90 percent to 10.30 percent for my proxy group. Those results are within the range of results in my updated Expected Earnings analysis (*see* Rebuttal Exhibit DWD-6) and overlap with my recommended range and point estimate.

E. Capital Asset Pricing Model

Q. PLEASE SUMMARIZE MR. O'DONNELL'S CAPM ANALYSIS.

A. Mr. O'Donnell uses the range of the 30-year Treasury yield over the last year, Value Line Beta coefficients, and MRPs of 4.00 percent and 6.00 percent based on historical and investment professionals' forecasts to derive CAPM estimates

[430] *See*, Enrique R. Arzac, *Do Your Business Units Create Shareholder Value?*, Harvard Business Review, January – February 1986, at 122.

of 3.17 percent to 6.74 percent for his proxy group and 3.15 percent to 6.69 percent for my proxy group.[431] In Mr. O'Donnell's view, the Constant Growth "DCF model is superior to other approaches"[432] because the DCF incorporates "daily and ongoing market prices."[433]

Q. DO YOU AGREE WITH MR. O'DONNELL'S ASSESSMENT OF THE CAPM AND OTHER METHODS?

A. No, I do not. First, Mr. O'Donnell has provided no evidence that the DCF model is "superior" to other methods, or that investors prefer the DCF approach. The relevant issue is whether investors use multiple methods, including risk premium-based approaches, in evaluating investment opportunities and making investment decisions. Nowhere has Mr. O'Donnell demonstrated investors would disregard those methods in favor of the Constant Growth DCF approach. As discussed in my response to Dr. Woolridge, an article published in Financial Analysts Journal surveyed financial analysts to determine the analytical techniques that are used in practice, and this included the CAPM.[434] That survey clearly indicated that the CAPM is used by practitioners. Similarly, a 2001 article by Professors Graham and Harvey demonstrated that industry

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431 Direct Testimony of Kevin W. O'Donnell, CFA, at 97. Mr. O'Donnell concludes that the "proper" ROE range based on his CAPM results is 5.00 percent to 7.00 percent.

432 Direct Testimony of Kevin W. O'Donnell, CFA, at 77.

433 Direct Testimony of Kevin W. O'Donnell, CFA, at 77.

434 *See*, Stanley B. Block, *A Study of Financial Analysts: Practice and Theory*, Financial Analysts Journal, July/August, 1999.

practitioners are far more likely to use the CAPM than the DCF model.[435] As such, I strongly disagree with Mr. O'Donnell's assertion that the DCF approach is "superior" to other approaches such as the CAPM.

Q. ARE THERE OTHER REASONS YOU BELIEVE THE CAPM IS APPLICABLE IN THE CONTEXT OF SETTING THE ROE IN REGULATORY PROCEEDINGS?

A. Yes. As discussed in my Direct Testimony at page 19, the Commission applies the standards established under *Hope* and *Bluefield*, which includes the "comparability" standard. Although I am not an attorney, I understand that standard to recognize the authorized ROE should reflect the return investors require in light of the subject company's risks, and the returns available to investments of comparable risk. My Direct Testimony also noted that under the CAPM, the Beta coefficient reflects "systematic" risk, or the portion of market risk that cannot be diversified away.[436] That is, the Beta coefficient is a measure of relative risk. Because Beta coefficients provide a direct measure of relative risk, they address the "comparable risk" standard in a way that DCF-based methods do not. Putting aside the finding that the CAPM is regularly used in practice, its ability to address the "comparable risk" standard fully supports its use in regulatory proceedings.

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435 *See*, John R. Graham, Campbell R. Harvey, *The Theory and Practice of Corporate Finance: Evidence from the Field*, Journal of Financial Economics, 2001. *See*, Robert S. Harris, Felicia C. Marston, *The Market Risk Premium: Expectational Estimates Using Analysts' Forecasts,* Journal of Applied Finance, 2001.

436 Direct Testimony of Dylan W. D'Ascendis, at 86-87.

Q. WHAT CONCERNS HAS MR. O'DONNELL EXPRESSED REGARDING YOUR CAPM ANALYSES?

A. Mr. O'Donnell's concern is the market return estimates used in my *ex-ante* MRP calculation are higher than what is forecasted by some market participants.[437]

Q. PLEASE DESCRIBE HOW YOU DERIVED YOUR MARKET RISK PREMIUM ESTIMATE IN THIS PROCEEDING.

A. The Market Risk Premium represents the incremental return (over the risk-free rate) investors currently require for assuming the risk of equity ownership, as measured by the market as a whole. In my Direct Testimony, I calculated the expected market return using consensus analysts' projected growth rates and current expected dividend yields on a market capitalization-weighted basis for the S&P 500 Index.[438] That calculation was performed using earnings growth rate projections from two sources, Bloomberg and Value Line. From those estimates of the required market return, I calculated the MRP by subtracting the current 30-day average yield on 30-year Treasury securities.[439]

Q. IS THE MRP CONSTANT OVER TIME?

A. No, it is not. Mr. O'Donnell fails to recognize the MRP can be influenced by factors such as investors' changing levels of risk aversion, or changes in interest rates. Regarding the relationship between interest rates and the MRP, academic

[437] Direct Testimony of Kevin W. O'Donnell, CFA, at 59-60, 94-96.
[438] Direct Testimony of Dylan W. D'Ascendis, at 89-90.
[439] Direct Testimony of Dylan W. D'Ascendis, at 89; Exhibit DWD-2, Rebuttal Exhibit DWD-2.

studies found an inverse relationship between the two. Discussing that relationship, Dr. Morin notes:

> … [p]ublished studies by Brigham, Shome, and Vinson (1985), Harris (1986), Harris and Marston (1992, 1993), Carleton, Chambers, and Lakonishok (1983), Morin (2005), and McShane (2005), and others demonstrate that, beginning in 1980, risk premiums varied inversely with the level of interest rates - rising when rates fell and declining when interest rates rose.[440]

As such, increases in the MRP coincident with declining interest rates is consistent with financial theory.

Q. WHAT IS YOUR RESPONSE TO MR. O'DONNELL'S REFERENCE TO PROFESSIONAL INVESTOR FORECASTS AND MARKET SURVEYS THAT INDICATE EXPECTED MARKET RETURNS RANGE FROM NEGATIVE 4.40 PERCENT (REAL) TO 6.10 PERCENT (NOMINAL)?[441]

A. I have several concerns with his reference. First, Mr. O'Donnell's 8.75 percent ROE estimate is entirely at odds with the data he presents. In this instance, Mr. O'Donnell refers to the market forecasts summarized in Table 12, below.

Table 12: Summary of Mr. O'Donnell's Market Return Forecast References[442]

INSTITUTION	MARKET RETURN FORECAST
BlackRock Investment Institute	6.1% nominal (not inflation adjusted) return for US large caps over the next decade

[440] Roger A. Morin, New Regulatory Finance, Public Utilities Reports, Inc. 2006, at 128 [clarification added].
[441] Direct Testimony of Kevin W. O'Donnell, CFA, at 94-95.
[442] Direct Testimony of Kevin W. O'Donnell, CFA, at 94-95.

Grantham, Mayo, & van Otterloo (“GMO”)	-4.4% real (inflation adjusted) returns for US large caps over the next 7 years
JP Morgan Asset Management	5.6% nominal return for US equities over a 10-15 year horizon
Morningstar Investment Management	1.7% 10-year nominal returns for US stocks
Research Affiliates	0.3% real (inflation adjusted) returns for US large caps furring [*sic*] the next 10 years
Vanguard	Nominal equity market returns of 3.5% to 5.5% during the next decade

As Table 12 indicates, the expected market returns (on a nominal basis) range from 1.70 percent to 6.10 percent for U.S. equities. Mr. O’Donnell, however, estimates an ROE of 8.75 percent for a utility that, we agree, is less risky than the overall market. If Mr. O’Donnell believed these expected returns were meaningful measures of investor-required returns, which is the subject of his testimony, his recommendation would be no higher than 6.10 percent.[443]

Lastly, Mr. O’Donnell does not consider the limiting language often contained in documents providing expected market returns. For example, JP Morgan Asset Management’s *2020 Long-Term Capital Market Assumptions* (the source document for the 5.60 percent expected market return noted in Table 12, above) states:

> Please note that all information shown is based on qualitative analysis. Exclusive reliance on the above is not advised. This information is not intended as a recommendation to invest in any particular asset class or strategy or as a promise of future performance. Note that these asset class and strategy assumptions are passive only – they do not consider the impact of active management. References to future returns are not

443 Mr. O’Donnell also points to the results of the Duke University CFO Survey (“Duke University CFO Survey”), which, as discussed in my response to Dr. Woolridge, has consistently underestimated market returns.

> promises or even estimates of actual returns a client portfolio may achieve. Assumptions, opinions and estimates are provided for illustrative purposes only.[444]

Q. DO YOU AGREE WITH MR. O'DONNELL'S USE OF THE TOTAL RETURN ON LONG-TERM GOVERNMENT BONDS IN HIS CALCULATION OF THE HISTORICAL MRP?

A. No, I do not. The MRP should reflect the difference between the arithmetic average return on large company stocks and the income-only return on long-term government bonds as reported by Duff & Phelps (producing an estimated risk premium in 2018 of 6.90 percent).[445] Mr. O'Donnell, however, calculates the risk premium as the difference between the total return on those two asset classes, implying a risk premium of 4.10 percent to 5.60 percent in 2018.[446]

As Morningstar points out, the total return on a security is composed of three components: (1) the income return; (2) capital gains (or capital losses, if the value of the security falls); and (3) reinvestment return.[447] The income return is generally defined as the coupon, or interest rate on the security, which does not change over the life of the security. In contrast, the value of the security rises or falls as interest rates change, resulting in uncertain capital gains. As such, the income return is the only "riskless" component of the total

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444 JP Morgan Asset Management, *2020 Long-Term Capital Market Assumptions*, at PDF 116.
445 Duff & Phelps, 2019 SBBI Yearbook, at 6-17.
446 Direct Testimony of Kevin W. O'Donnell, CFA, at 94.
447 *See*, Duff & Phelps 2019 SBBI Yearbook, at 10-22.

return. Consequently, it is the income-only portion of the return, as opposed to the total return, that should be used in calculating the MRP.

Q. WHAT IS YOUR RESPONSE TO MR. O'DONNELL'S CONCERN THAT YOU USED AN EXPECTED MARKET RATE OF RETURN HIGHER THAN THE 12.00 PERCENT AVERAGE MARKET RETURN AS REPORTED BY DUFF & PHELPS (WHICH NOW PUBLISHES THE MORNINGSTAR DATA MR. O'DONNELL REFERS TO)?[448]

A. Although Mr. O'Donnell notes the arithmetic average is approximately 11.90 percent,[449] the standard deviation was approximately 19.80 percent.[450] One standard deviation around the long-term average through 2018 suggests a range of -7.90 percent to 31.70 percent.[451] As Rebuttal Exhibit DWD-18 demonstrates, and as noted in my response to Mr. Baudino, the expected returns included in my Direct Testimony are well within the range of historical results, especially when we consider the historical standard deviation.

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[448] Direct Testimony of Kevin W. O'Donnell, CFA, at 60.
[449] Direct Testimony of Kevin W. O'Donnell, CFA, at 94.
[450] Duff & Phelps, 2019 SBBI Yearbook, at 6-17.
[451] 11.90% - 19.80% = -7.90%; 11.90% + 19.80% = 31.70%.

Q. AT PAGE 59 OF HIS TESTIMONY, MR. O'DONNELL COMPARES THE MARKET RISK PREMIA APPLIED IN YOUR CAPM ANALYSES TO THE EQUITY RISK PREMIA APPLIED IN YOUR BOND YIELD PLUS RISK PREMIUM ANALYSIS. IS HIS COMPARISON APT?

A. No, it is not. Mr. O'Donnell appears to conflate the Market Risk Premium applied in the CAPM (calculated as the difference between the total expected return on the market and the current 30-year Treasury yield) with the Equity Risk Premium applied in the Bond Yield Plus Risk Premium analysis (calculated as the difference between the authorized ROE and the lagged 30-year Treasury yield). The two are different concepts and, therefore, are not comparable.

F. Bond Yield Plus Risk Premium Method

Q. DOES MR. O'DONNELL COMMENT ON YOUR BOND YIELD PLUS RISK PREMIUM ANALYSIS?

A. Other than his view that certain "flaws" he perceives in my CAPM analysis "flow through" to my Bond Yield Plus Risk Premium analysis,[452] Mr. O'Donnell does not comment on the model. Nor does he explain the particular "flaws" with which he seems to be concerned. Nonetheless, Mr. O'Donnell asserts the model is "biased upwards for [my] utility clients".[453]

452 Direct Testimony of Kevin W. O'Donnell, CFA, at 60, 61.
453 Direct Testimony of Kevin W. O'Donnell, at 60.

Q. WHAT IS YOUR RESPONSE TO MR. O'DONNELL?

A. First, the Bond Yield Plus Risk Premium analysis is empirically structured and data-driven – it does not require subjective assumptions or inputs. Mr. O'Donnell's assertion that it is "biased upwards" is incorrect. More important, the model captures the inverse relationship between interest rates and the Equity Risk Premium, an element of security pricing not addressed by the Constant Growth DCF model. As my Direct Testimony explained, longstanding research has shown the Equity Risk Premium is nonconstant, and varies with economic factors, including long-term interest rates.[454] Quantifying that relationship is particularly important when interest rates have been driven down by investors seeking the safety of Treasury securities, as currently is the case.

Second, Mr. O'Donnell's assertion that the Equity Risk Premiums included in the model "are nonsensical and have no fundamental basis in reality"[455] is fundamentally incorrect. As my Direct Testimony explained, those premiums are the observed difference between authorized ROEs and the prevailing 30-year Treasury yield. They are real. And they would be "nonsensical" only if the observed authorized returns and/or observed Treasury yields were "nonsensical". That may be Mr. O'Donnell's position, but he certainly has not explained why his judgment should prevail over the many

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[454] Direct Testimony of Dylan W. D'Ascendis at 96-97.
[455] Direct Testimony of Kevin W. O'Donnell, CFA at 60.

regulatory commissions that have authorized ROEs, or why his view is more sensible than the many investors that have determined Treasury yields.

Third, the Equity Risk Premium under the Bond Yield Plus Risk Premium approach is developed in a fundamentally different manner than it is under the CAPM. One is not "flowed through"[456] to the other, as Mr. O'Donnell seems to believe. The two models approach the Equity Risk Premium from different perspectives[457] and because they do, applying both provides a more robust estimate of the Company's Cost of Equity.

Q. CAN THE BOND YIELD PLUS RISK PREMIUM APPROACH CAPTURE OTHER VARIABLES BEYOND INTEREST RATES THAT AFFECT THE EQUITY RISK PREMIUM?

A. Yes, it can. Harris and Marston found expected market volatility and credit spreads to be positively related to the Equity Risk Premium.[458] Adopting that approach, I calculated the "credit spread", or the difference between the Moody's Baa-Utility Bond yield and the 30-Year Treasury yield. To reflect the risk of equity investments, I calculated the market volatility as measured by the VIX since 1990, the first year for which data was available. I then performed a regression analysis in which the Equity Risk Premium is the dependent variable,

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456 Direct Testimony of Kevin W. O'Donnell, CFA at 60.

457 Under the CAPM, the Equity Risk Premium is the product of the Beta coefficient and the Market Risk Premium. Under the Bond Yield Plus Risk Premium approach, it is the difference between authorized ROEs and observed 30-year Treasury yields. *See*, Direct Testimony of Dylan W. D'Ascendis at 96-97.

458 *See*, Robert S. Harris, Felicia C. Marston, *The Market Risk Premium: Expectational Estimates Using Analysts' Forecasts*, Journal of Applied Finance, 2001, at 11.

and Treasury yields, credit spreads, and the VIX are the explanatory variables (*see* Rebuttal Exhibit DWD-23).

Consistent with Harris and Marston's findings, credit spreads and the VIX are positively related to the Equity Risk Premium, and Treasury yields remain negatively related. At the same time, credit spreads and the VIX are strongly correlated, such that it is difficult to disentangle the effects of each on the Equity Risk Premium. Nonetheless, the findings make theoretical and intuitive sense; as measures of risk (*i.e*,, the VIX and credit spreads) increase, so does the Equity Risk Premium.

Using that expanded regression analysis, we can estimate the increased return required in the current market, with its elevated VIX and expanded credit spreads. As Rebuttal Exhibit DWD-23 demonstrates, the indicated Cost of Equity is 10.98 percent.

G. Weighting of Model Results

Q. MR. O'DONNELL ACCUSES YOU OF "DISAVOWING"[459] THE CONSTANT GROWTH DCF MODEL, IN PART BECAUSE YOU QUESTION WHETHER THE CONSTANT GROWTH DCF MODEL'S ASSUMPTIONS ARE CONSISTENT WITH THE CURRENT MARKET. IS HIS POSITION CORRECT?

A. No, it is not. My concern is not with the model itself. As discussed earlier, my concern is whether the model's fundamental assumptions reasonably hold in the current market. Given the DCF model's restrictive assumptions and the high level of market volatility, it not only is reasonable to consider and give weight to alternative methods, it is prudent to do so.

[459] Direct Testimony of Kevin W. O'Donnell, CFA, at 55. To be clear, I have not "disavowed" the DCF model, as Mr. O'Donnell suggests. Rather, I have considered the model and its results in the proper context. Mr. O'Donnell's use of the term "disavow", however, is ironic given the North Carolina Utility Commission's finding in Docket No. E-2, Sub 1023: "In complying with the Supreme Court's mandate in CUCA I that the Commission evaluate all of the testimony in determining the appropriate ROE, it remains for the Commission to consider the testimony of CUCA witness O'Donnell. As noted previously, O'Donnell's pre-filed direct testimony recommended an ROE of 9.25%. However, when testifying at the evidentiary hearing, witness O'Donnell in effect disavowed reliance upon those portions of his testimony except for rate design and Rider IER. Accordingly, the Commission gives only very limited weight to witness O'Donnell's ROE recommendation in the selection of an appropriate ROE." State of North Carolina Utilities Commission, Docket No. E-2, Sub 1023, Order Granting General Rate Increase, May 30, 2013, at 27.

H. Orders from Other Regulatory Commissions Cited by Mr. O'Donnell

Q. AT PAGES 60-61 OF HIS DIRECT TESTIMONY, MR. O'DONNELL REFERS TO AN ORDER FROM THE VIRGINIA CORPORATION COMMISSION REGARDING A DOCKET IN WHICH YOU PROVIDED TESTIMONY. WHAT IS YOUR RESPONSE TO MR. O'DONNELL ON THAT POINT?

A. Mr. O'Donnell fails to note orders that were supportive of [Mr. Robert B. Hevert's] analyses and conclusions. For example, Mr. O'Donnell refers to orders in May 2019 by the South Carolina Public Service Commission ("SCPSC"), and the SDPUC, pointing to the authorized return in those cases relative to [Mr. Robert B. Hevert's] recommendations.[460] Mr. O'Donnell neglects to point out, however, that in February 2019, the SCPSC reviewed [Mr. Robert B. Hevert's] testimony and found "there is ample evidence and reason to conclude that the analyses conducted by Mr. Hevert are accurate and reliable estimates of SCE&G's cost of equity."[461]

Regarding the SDPUC's order relating to Otter Tail Power, as noted earlier, OTTR meaningfully underperformed the utility sector around the time the SDPUC issued its order.

460 Direct Testimony of Kevin W. O'Donnell, CFA, at 61-62.

461 Public Service Commission of South Carolina, Docket Nos. 2017-207-E, 2017-305-E, and 2017-370-E, Order No. 2019-122, dated February 12, 2019, at 26.

I. Capital Structure

Q. WHAT CAPITAL STRUCTURE DOES MR. O'DONNELL RECOMMEND IN THIS PROCEEDING?

A. Mr. O'Donnell recommends a hypothetical capital structure including 50.00 percent common equity, and 50.00 percent long-term debt.[462] In Mr. O'Donnell's view, the Company's proposed 53.00 percent equity ratio is high relative to authorized equity ratios, the equity ratios at the consolidated parent company level among the proxy groups, and Duke Energy Corporation's consolidated equity ratio as of December 2018.[463]

Q. WHAT IS YOUR RESPONSE TO MR. O'DONNELL'S COMPARISON TO THE PROXY GROUP EQUITY RATIO AT THE HOLDING COMPANY LEVEL?

A. First, by relying on the parent capital structure, Mr. O'Donnell assumes all subsidiaries can and should be financed in the same proportions as the parent. That clearly is not the case – companies (including subsidiary companies) are financed in light of the specific risks and funding requirements associated with their individual operations.

The use of the operating subsidiary's actual capital structure – the capital funding the utility plant and equipment that enables utility service – also is consistent with FERC's precedent, under which the commission prefers to use

462 Direct Testimony of Kevin W. O'Donnell, CFA, at 116.
463 Direct Testimony of Kevin W. O'Donnell, CFA, at 115-116.

the applicant's capital structure, where possible.[464] As noted earlier, FERC will use the utility operating company's capital structure if it meets three criteria: (1) it issues its own debt without guarantees; (2) it has its own bond rating; and (3) it has a capital structure within the range of capital structures approved by the Commission.[465] FERC noted that if those conditions are not met, it may apply the consolidated capital structure.[466]

FERC also noted that it does not apply a specific cap to the equity ratio. Rather, the commission stated:

> [we] recognize that a utility may consider a range of factors beyond simple capital cost minimization in developing their capital structures. Such considerations include, but are not limited to, managing risk and cash flow.[467]

FERC therefore has recognized that the capital structure is tied to the assets being financed, and to the nature of utility operations.

Because vertically integrated electric utilities must finance similar types of assets (electric generation, transmission, and distribution infrastructure), it would be reasonable to expect those companies to have comparable capital structures. Although I do not agree with Mr. O'Donnell's view that the parent is the appropriate point of comparison for operating company capital structures, the Company's proposed common equity ratio of 53.00 percent is well within

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[464] *See, Transcontinental Gas Pipe Line Corp*, 80 FERC ¶ 61,157, 61,657 (1997) ("Opinion No. 414").

[465] 148 FERC ¶ 61,049 Docket No. EL14-12-000, at P 190.

[466] *Ibid.*, at P 191.

[467] *Ibid.*, at P 197.

the range of results presented in his Tables 10 and 11. In fact, the Company's proposed equity ratio is within approximately one standard deviation of the average.

Q. IS IT APPROPRIATE TO ASSUME THE PROXY GROUP AVERAGE CAPITAL STRUCTURE APPLIES TO DE PROGRESS?

A. No, it is not. Although utilities have certain factors in common, each has its own risk profile, which influences its target capital structure. In my view, although it is proper to review the range of operating utility equity ratios in assessing the Company's proposed capital structure, there is no reason to assume we should default to the average. Nonetheless, as noted above, the Company's proposal is within approximately one standard deviation from the proxy group average, as provided by Mr. O'Donnell's data.

Q. AT PAGES 111-112 OF HIS TESTIMONY, MR. O'DONNELL REVIEWS THE CONSOLIDATED PARENT CAPITAL STRUCTURES FOR THE COMPANIES IN HIS PROXY GROUP. DO YOU HAVE ANY OBSERVATION REGARDING MR. O'DONNELL'S REVIEW?

A. Yes, I do. As discussed in my response to Dr. Woolridge, if we are going to review capital structures in place at other utilities, the appropriate reference is to operating companies, not consolidated parent companies. The reason is quite straightforward: Parent company capital structures may reflect operations other than the rate base at issue in this proceeding. It therefore would not be surprising to see operating utility equity ratios that differ from the consolidated parent company equity ratio.

Q. HAVE YOU REVIEWED THE OPERATING COMPANY CAPITAL STRUCTURES FOR MR. O'DONNELL'S PROXY GROUP?

A. Yes, I have. Rebuttal Exhibit DWD-24 which provides that data, shows quite clearly that over time and across companies, operating utility equity ratios tend to be higher than the parent company ratio. That finding makes sense, given the utility financing practices discussed earlier in my Rebuttal Testimony. As Rebuttal Exhibit DWD-24 demonstrates, the average equity ratio for Mr. O'Donnell's proxy group is 53.05 percent, consistent with the Company's proposal.

Q. LOOKING TO MR. O'DONNELL'S PROXY GROUP, ARE THERE EXAMPLES OF WHY THE PARENT COMPANY CAPITAL STRUCTURE DOES NOT APPLY TO UTILITY OPERATING COMPANIES?

A. Yes, there are. For example, in addition to Florida Power & Light ("FPL"), NextEra Energy, Inc. ("NEE") holds NextEra Energy Resources, LLC, ("NEER") which develops, owns, and operates electric generating facilities in wholesale energy markets.[468] Among the vehicles used by NEER to fund those facilities are project-specific, limited, or non-recourse financing structures.[469]

468 NextEra Energy, Inc., SEC Form 10-K For the fiscal year ended December 31, 2019, at 11.
469 NextEra Energy, Inc., SEC Form 10-K For the fiscal year ended December 31, 2019, at 30.

Because they are not used to fund rate base assets, the debt associated with those financing structures should not be considered in assessing the Company's capital structure. In any event, whereas NEE's equity ratio has historically been approximately 45.00 percent on average,[470] FPL's equity ratio has been considerably higher, in the range of 62.00 percent.[471]

Again, the ratemaking capital structure should relate to utility operations, and the permanent assets that support those operations. Because, as in the case of NEE, parent company capital structures may contain debt not associated with utility operations, the parent company capital structure should not be used to assess the Company's proposed equity ratio.

Q. WHY IS THE CAPITAL STRUCTURE IMPORTANT TO UTILITIES' FINANCIAL INTEGRITY?

A. As explained earlier in my response to Dr. Woolridge, utility capital structures, and the financial strength they support, are set not only to ensure capital access during normal markets, but to enable access when markets are constrained. The reason is straightforward: A utility's obligation to serve is not contingent on capital market conditions. When markets are constrained, only those utilities with sufficient financial strength are able to attract capital at reasonable terms.

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470 Source: *Value Line Investment Survey*, NextEra Energy Inc., November 15, 2019 for the years 2009 - 2018.

471 Rebuttal Exhibit DWD-7.

That ability provides those utilities with critically important financing flexibility.

Q. WHAT IS YOUR RESPONSE TO MR. O'DONNELL'S REVIEW OF AUTHORIZED EQUITY RATIOS?

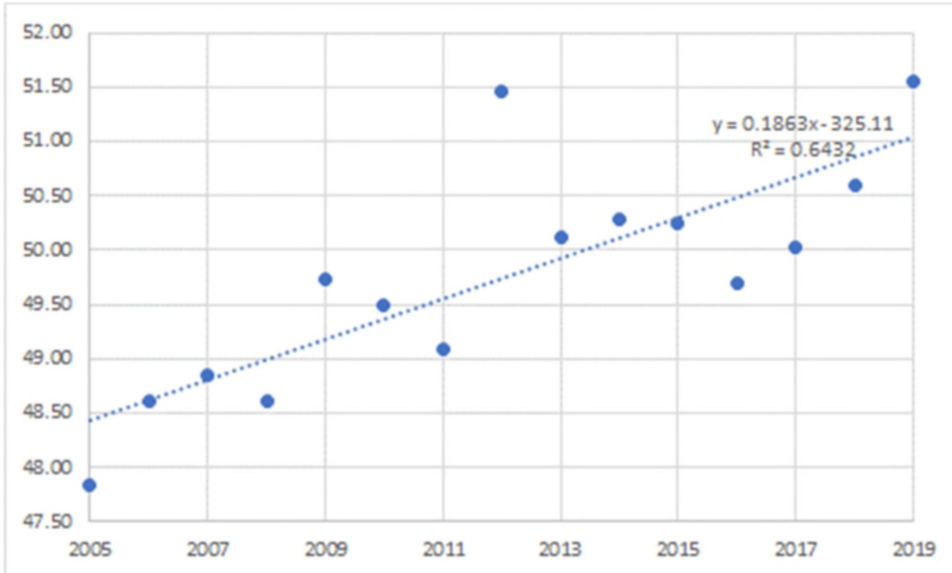
A. First, Mr. O'Donnell's reported 49.94 percent average equity ratio[472] includes distribution-only electric utilities. The more appropriate comparison is to vertically integrated electric utilities, for which the average and median authorized equity ratio in 2019 was 50.24 percent and 52.00 percent, respectively, within a range of 33.71 percent to 57.02 percent. Again, the Company's proposed 53.00 percent equity ratio is well within that range (and less than one standard deviation from the mean).

Q. HAVE AUTHORIZED EQUITY RATIOS CHANGED OVER TIME?

A. Yes, they generally have increased. Mr. O'Donnell's Chart 8 demonstrates as much. Excluding capital structures authorized in jurisdictions that include non-investor supplied sources of capital (principally, Accumulated Deferred Income Taxes), authorized equity ratios have increased over time (*see*, Chart 23, below).

[472] Direct Testimony of Kevin W. O'Donnell, CFA, at 113.

Chart 23: Average Authorized Equity for Electric Utilities[473]



The upward trend in equity ratios since 2005, in particular since 2008/2009, makes sense as the financial crisis focused attention on balance sheet strength and capital access. Now, as the capital markets undergo another severe dislocation, the balance sheet strength built over time has become extremely important. The Opposing Witnesses' capital structure recommendations not only would undo the financial strength needed during volatile capital markets, it would indicate a degree of regulatory risk that would further diminish the Company's financial profile, just as that profile is most needed.

473 Source: S&P Global Market Intelligence. Excludes equity ratios authorized in AR, FL, IN, and MI.

Q. DO YOU HAVE ANY ADDITIONAL OBSERVATIONS REGARDING MR. O'DONNELL'S REFERENCE TO AUTHORIZED EQUITY RATIOS?

A. Yes, I do. Mr. O'Donnell's review includes equity ratios authorized in jurisdictions that include non-investor supplied capital in the capital structure (*i.e.*, Arkansas, Florida, Indiana, and Michigan). If those jurisdictions are excluded, the average and median authorized equity ratio in 2019 was 52.08 percent and 52.00 percent, respectively, for vertically integrated utilities. Again, that review suggests the Company's proposed 53.00 percent equity ratio is consistent with authorized equity ratios.

VIII. RESPONSE TO COMMERCIAL GROUP WITNESS MR. CHRISS

Q. PLEASE SUMMARIZE MR. CHRISS' TESTIMONY REGARDING THE COMPANY'S ROE.

A. Mr. Chriss opposes the Company's proposed ROE based on his review of authorized ROEs since 2016 nationwide and within North Carolina.[474] He recommends the Commission "closely examine" the Company's proposed ROE:

> [I]n light of: (1) The customer impact of the resulting revenue requirement increase as discussed above; (2) recent rate case ROEs approved by the Commission; and (3) recent rate case

[474] Direct Testimony of Steve W. Chriss, at 9-12.

ROEs approved by commissions nationwide.[475]

However, Mr. Chriss did not undertake an independent, market-based analysis of the Company's Cost of Equity.

Q. ARE THERE OTHER DISTINCTIONS THAT ARE IMPORTANT TO CONSIDER WHEN REVIEWING AUTHORIZED RETURNS?

A. Yes, there are. The regulatory environment is one of the most important factors debt and equity investors factor in their assessment of risk. Further, utility credit ratings and outlooks depend substantially on the extent to which rating agencies view the regulatory environment credit supportive, or not. For example, Moody's finds the regulatory environment to be so important that 50.00 percent of the factors that weigh in its ratings determination are determined by the nature of regulation.[476] Given the Company's need to access external capital and the weight rating agencies place on the nature of the regulatory environment, I believe it is important to consider the extent to which the jurisdictions that recently have authorized ROEs for electric utilities are viewed as having constructive regulatory environments.

[475] Direct Testimony of Steve W. Chriss, at 4, 13.

[476] *See,* Moody's Investors Service Rating Methodology: Regulated Electric and Gas Utilities, June 23, 2017, at 4.

Q. HAVE YOU REVIEWED AND UPDATED THE INFORMATION CONTAINED IN MR. CHRISS' EXHIBIT 3?

A. Yes. As shown in Table 13 (below; *see also* Rebuttal Exhibit DWD-25), I analyzed the authorized ROE for electric utilities based on the jurisdiction's ranking by RRA. RRA, which is the source of Mr. Chriss' data, provides an assessment of the extent to which regulatory jurisdictions are constructive from investors' perspectives, or not. As RRA explains, less constructive environments are associated with higher levels of risk:

> RRA maintains three principal rating categories, Above Average, Average, and Below Average, with Above Average indicating a relatively more constructive, lower-risk regulatory environment from an investor viewpoint, and Below Average indicating a less constructive, higher-risk regulatory climate from an investor viewpoint, Within the three principal rating categories, the numbers 1, 2, and 3 indicate relative position. The designation 1 indicates a stronger (more constructive) rating; 2, a mid-range rating; and, 3, a weaker (less constructive) rating. We endeavor to maintain an approximately equal number of ratings above the average and below the average.[477]

The Commission currently is ranked "Average/1", which falls in the top third of the 53 jurisdictions ranked by RRA.

Across the 103 vertically integrated rate cases for which RRA reports an authorized ROE since 2016, there was a 45-basis point difference between the median return for jurisdictions ranked in the top third of all jurisdictions and jurisdictions ranked in the bottom third of all jurisdictions (the higher-ranked

477 Source: Regulatory Research Associates, accessed April 24, 2020.

jurisdictions providing the higher authorized returns, *see* Table 13, below). As Table 13 indicates, authorized ROEs for vertically integrated electric utilities in jurisdictions rated in the top third of all jurisdictions, including North Carolina, range from 9.37 percent to 10.55 percent, with an average of 9.93 percent, and a median of 9.95 percent.

Table 13: Vertically Integrated Authorized ROE by RRA Ranking[478]

Authorized ROE (%) Vertically Integrated Electric Utilities			
RRA Ranking	**Top Third**	**Middle Third**	**Bottom Third**
Mean	9.93%	9.53%	9.62%
Median	9.95%	9.50%	9.50%
Maximum	10.55%	10.30%	11.95%
Minimum	9.37%	8.75%	9.06%

My recommended range, 10.00 percent to 11.00 percent, is consistent with the returns authorized in more constructive jurisdictions.

Q. DO YOU AGREE WITH MR. CHRISS' CALCULATION OF THE AVERAGE AUTHORIZED ROE FOR ALL UTILITIES?[479]

A. No, I do not. Mr. Chriss's average authorized ROE reported in his Chriss Exhibit 3 for the 2016 to 2020 period for all utilities and for distribution only utilities includes ROEs authorized as part of the Illinois Formula Rate Plan

[478] Source: Regulatory Research Associates. "Top Third" includes Above Average/1,2,3 and Average/1; "Middle Third" includes Average/2; "Bottom Third" includes Average/3 and Below Average/1,2,3. The "Top Third" and "Bottom Third" groups each include 19 (of the 53 total) jurisdictions. The "Middle Third" group includes 15 jurisdictions. *See also*, Rebuttal Exhibit DWD-25. Excludes limited issue riders.

[479] Chriss Exhibit 3.

("FRP") proceedings,[480] which has resulted in the lowest ROEs in at least 30 years and biases his calculated average downward. Table 14 below illustrates the effect of removing the Illinois Formula Rate Plans from his average ROE calculations.[481]

Table 14: Average Authorized ROE Presented in Chriss Exhibit 3 Excluding Illinois Formula Rate Plan Proceedings

	All Electric Utility Rate Cases	
	Average Including Illinois FRPs	**Average Excluding Illinois FRPs**
Entire Period (2016-2020)	9.60%	9.67%
2016	9.60%	9.66%
2017	9.68%	9.74%
2018	9.54%	9.59%
2019	9.64%	9.69%

Q. HAS MR. CHRISS CONSIDERED THE EFFECT OF HIS RECOMMENDATION ON THE COMPANY'S FINANCIAL PROFILE?

A. No, he has not. The financial community carefully monitors utility companies' financial conditions, both current and expected, as well as the regulatory environment in which those companies operate. Here, Mr. Chriss suggests the

480 In Illinois, statutes require the ROEs for Commonwealth Edison and Ameren Illinois to be re-set annually, under a formula rate plan ratemaking paradigm where the allowed ROE is set by application of a 580 basis-point premium to the 12-month average 30-year Treasury Bond yield. In the historically low interest rate environment, this framework has resulted in the lowest ROEs in at least 30 years. Source: Regulatory Research Associates.

481 Source: Regulatory Research Associates. The average authorized ROE period for distribution-only electric utilities excluding Illinois FRPs over the 2016-2020 period is 9.45 percent.

Commission should reduce the Company's ROE by some unspecified amount without the benefit of market-based, comparative analyses to support that recommendation. The consequence of doing so would indicate an increased degree of regulatory risk.

IX. RESPONSE TO CIGFUR WITNESS MR. PHILLIPS

Q. PLEASE SUMMARIZE MR. PHILLIPS'S TESTIMONY REGARDING THE COMPANY'S ROE.

A. Mr. Phillips opposes the Company's proposed ROE based on his review of authorized ROEs during 2019, as reported by RRA.[482] Mr. Phillips reasons that because RRA reports the average authorized ROE for vertically integrated electric utilities to be 9.73 percent, that the Commission should not authorize an ROE above that level for the Company.[483] Further, Mr. Phillips recommends that Company's authorized capital structure "not exceed 52.00% equity."[484]

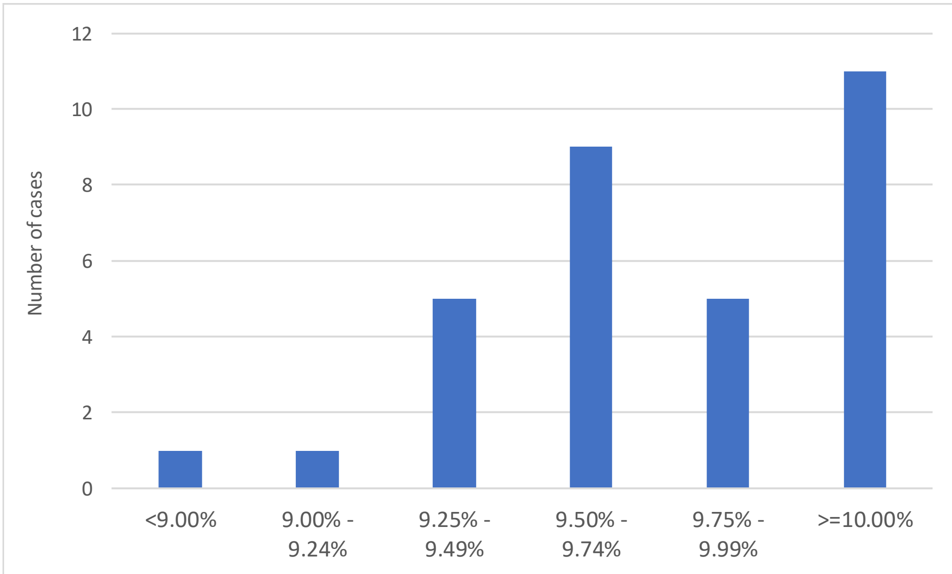
Q. HAVE YOU REVIEWED THE 9.73 PERCENT RETURN MR. PHILLIPS DISCUSSED IN HIS TESTIMONY?

A. Yes, I have. To gain another perspective regarding the returns authorized in 2019, I prepared a histogram of the returns authorized for vertically integrated electric utilities. As shown in Chart 24 below, nearly one-third (*i.e.*, eleven of 32) of the rate cases in 2019 through January 2020 awarded an ROE of 10.00

[482] Direct Testimony and Exhibits of Nicholas Phillips, Jr., at 26.
[483] Direct Testimony and Exhibits of Nicholas Phillips, Jr., at 26, 27.
[484] Direct Testimony and Exhibits of Nicholas Phillips, Jr., at 28.

percent and higher, within my recommended range.

Chart 24: Frequency of Vertically Integrated Electric Utility Authorized ROEs in 2019-2020[485]



As discussed in my response to Mr. Chriss, and as shown in Table 13 (above; *see also* Rebuttal Exhibit DWD-25), I analyzed the authorized ROE for vertically integrated electric utilities based on each jurisdiction's ranking by RRA. As discussed in my response to Mr. Chriss, authorized ROEs for vertically integrated electric utilities in jurisdictions rated in the top third of all jurisdictions range from 9.37 percent to 10.55 percent, with an average of 9.93 percent, and a median of 9.95 percent (*see* Table 13 above).

485 Source: Regulatory Research Associates. *See*, Rebuttal Exhibit DWD-8.

Q. ARE THERE OTHER DISTINCTIONS THAT ARE IMPORTANT TO CONSIDER WHEN REVIEWING AUTHORIZED RETURNS?

A. Yes, there are. Utility credit ratings and outlooks depend substantially on the extent to which rating agencies view the regulatory environment as credit supportive, or not. As noted in my response to Mr. Chriss, Moody's finds the regulatory environment to be so important that 50.00 percent of the factors that weigh in its ratings determination are determined by the nature of regulation. Given the Company's need to access external capital and the weight rating agencies place on the nature of the regulatory environment, it is important to consider the extent to which the jurisdictions that recently have authorized ROEs are viewed as having constructive regulatory environments.

Q. DO YOU AGREE WITH MR. PHILLIPS' RECOMMENDED EQUITY RATIO FOR RATEMAKING PURPOSES?

A. No, I do not. Mr. Phillips reviews authorized equity ratios nationally during 2019 and the Commission's authorized equity ratios for electric and natural gas utilities since 2009, and concludes the Company's proposed equity ratio of 53.00 percent is "inconsistent with broader electric industry trends and the Commission's recent decisions."[486] Based on that review, he recommends a capital structure no higher than 52.00 percent.[487]

Moreover, Mr. Phillips has not demonstrated an equity ratio of 53.00

[486] Direct Testimony and Exhibits of Nicholas Phillips, Jr., at 27-28.
[487] Direct Testimony and Exhibits of Nicholas Phillips, Jr., at 28.

percent is "inconsistent" with equity ratios authorized by other jurisdictions and by the Commission. Mr. Phillips refers to a January 2020 RRA publication percent that noted the average authorized equity ratio for electric utility cases nationwide was 51.55 percent (excluding jurisdictions that include cost-free items or tax credit balances in the capital structure). However, he fails to note that the range of authorized equity ratios for electric utilities in 2019 was 47.97 percent to 57.02 percent.[488] An equity ratio of 53.00 percent is squarely within that range. As such, I do not agree an equity ratio of 53.00 percent is "inconsistent with broader electric industry trends" as Mr. Phillips asserts.

X. RESPONSE TO STAFF WITNESS MR. HINTON

Q. PLEASE SUMMARIZE MR. HINTON'S TESTIMONY AS IT RELATES TO THE RETURN ON EQUITY ASSUMPTIONS IN THE COMPANY'S NUCLEAR DECOMMISSIONING TRUST FUND ("NDTF") COST AND FUNDING MODEL.

A. Mr. Hinton believes the Company's proposed rates of return for its qualified trust fund are "unreasonable and overly conservative" based on (1) his work with cost of equity for regulated utilities; (2) Dr. Woolridge's testimony filed in this proceeding; (3) the performance of the Company's qualified funds, pension funds, and other pension funds; and (4) Dominion Energy North Carolina's filed

488 S&P Global Market Intelligence, *RRA Regulatory Focus: Major Rate Case Decisions – January – December 2019*, Table 5, January 30, 2020.

2015 Decommissioning Cost and Funding report.[489] Based upon his review of those factors, Mr. Hinton recommends a 6.00 percent rate of return for the NDTF Cost and Funding model, which is based on a 9.50 percent expected Return on Equity (after taxes and fees).

Q. IS MR. HINTON'S ASSUMED 9.50 PERCENT MARKET RETURN APPROPRIATE FOR USE IN THE NDTF COST AND FUNDING MODEL?

A. No, it is not. Mr. Hinton believes his "expected return on the market" of 9.50 percent is "a more reasonable expected rate of return for these assets".[490] His conclusion is based on Dr. Woolridge's CAPM inputs consisting of a MRP of 5.75 percent, a risk-free rate of 3.75 percent,[491] and a Beta coefficient for the overall market of 1.0.[492] Mr. Hinton's position, however, turns on his assumption that there is no distinction between the expected returns assumed in the NDTF funding assumptions (and other managed asset funds such as pension funds) and the required returns that are the subject of my and Dr. Woolridge's testimony. As explained below, the expected return included in NDTF assumptions is distinct from the required return that is the subject of my testimony. Mr. Hinton's argument, therefore, is without merit.

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489 Testimony of John R. Hinton, at 18.
490 Testimony of John R. Hinton, at 18-19. Within his range of 9.00 percent to 9.50 percent.
491 I note that in this proceeding, Dr. Woolridge applies a risk-free rate of 3.50 percent in his CAPM analysis. Dr. Woolridge applied a risk-free rate of 3.75 percent in DE Carolina's pending proceeding. For the reasons discussed in my response to Dr. Woolridge, I disagree with Dr. Woolridge's estimate of the market return in his CAPM analysis.
492 Testimony of John R. Hinton, at 19.

Q. PLEASE EXPLAIN THE DISTINCTION BETWEEN EXPECTED AND REQUIRED RETURNS AND WHY MR. HINTON'S USE OF DR. WOOLRIDGE'S CAPM ESTIMATE OF THE REQUIRED RETURN ON THE MARKET IS INAPPROPRIATE.

A. Mr. Hinton inappropriately assumes the investor-required return on the market is equivalent to the expected market return estimates used by asset fund managers (such as nuclear decommissioning fund and pension funds), and that one can be substituted for the other. There is an important distinction between expected and required returns. As discussed below, investors may use a more conservative return estimate for asset fund management purposes than the required return that applies to individual equity investments.

The Cost of Equity is a measure of investors' required returns. An asset fund manager will match the expected returns available from various asset classes to the expected liabilities that must be funded. Investors seeking to maximize their risk-adjusted return will only invest in a security if the expected return is equal to or greater than the required return. If it is not, investors will look to alternative investments for which the expected return is compensatory relative to the expected risks. Because expected returns may or may not equal required returns, it is not clear that asset funding assumptions (that is, expected returns) and investors' required returns should be viewed as synonymous and used interchangeably.

From the perspective of an asset fund manager, asset allocation and investment decisions must be made based on expected risks and returns for various asset classes, and subject to the investment objective or expected timing and nature of the liabilities being funded by those investments. In the U.S., they must consider: (1) the diversification of the portfolio; (2) the liquidity and current return of the portfolio relative to the expected cash flow requirements under the plan; (3) the portfolio's projected return relative to the plan's funding objective; and (4) the return expected on alternative investments with similar risks.[493] Asset fund managers, therefore, are concerned with investing funds at an expected return to meet expected liabilities over a finite period.

An individual equity investor, on the other hand, decides whether to commit capital to a given security based on the return that they require to be compensated for the risks associated with the that security, in perpetuity. As noted earlier, if the expected return is less than the required return, the investor would not commit capital, but instead commit their capital to alternative investments with appropriate risk-adjusted returns.

Q. HAS THE COMMISSION RECOGNIZED THE DIFFERENCE BETWEEN EXPECTED AND REQUIRED RETURNS IN PRIOR PROCEEDINGS?

A. Yes, it has. In its Order on Remand in Docket No. E-7, Sub 989, the Commission found that:

493 29 CFR 2509.908-1, Interpretive bulletin relating to the fiduciary standard under ERISA in consider economically targeted investments, October 17, 2008.

> …there are aspects of witness O'Donnell's pre-filed testimony which lead the Commission to doubt its overall conclusions. For example, O'Donnell relies in part upon the assumed equity rate of return for the Company's pension expense, which he indicates is 8.5%. Tr. vol. 6, pp. 21-22. The Commission finds this reliance to be misplaced. In particular, the testimony ignores the crucial distinction between expected returns, which underlie pension expense, and required returns, which underlie the appropriate rate of return on equity.[494]

Although the Commission's finding relates to the relevance of expected returns in pension funding assumptions, the concept applies to the assumptions in the NDTF Cost and Funding model as well.

XI. CONCLUSION

Q. PLEASE SUMMARIZE THE ANALYSES AND CONCLUSIONS CONTAINED IN YOUR REBUTTAL TESTIMONY.

A. My updated analytical results applied to my Updated Proxy Group described above are provided in Table 15 below. Based on the analyses discussed throughout my Rebuttal Testimony, and the results summarized in Table 15, I continue to believe the reasonable range of ROE estimates is from 10.00 percent to 11.00 percent and within that range, 10.50 percent is a reasonable and appropriate estimate of the Company's Cost of Equity, particularly in light of current volatile capital market conditions. Although we do not yet know the extent of the effect of the pandemic on North Carolina's economy, based on the data available, North Carolina's economy has been generally consistent with

[494] North Carolina Utilities Commission, *Order on Remand*, Docket No. E-7, Sub 989, issued October 23, 2013, at 39.

that of the U.S.

Table 15: Summary of Updated Analytical Results

Discounted Cash Flow	**Mean Low**	**Mean**	**Mean High**
30-Day Constant Growth DCF	8.24%	9.00%	9.70%
90-Day Constant Growth DCF	7.82%	8.59%	9.28%
180-Day Constant Growth DCF	7.80%	8.56%	9.26%
CAPM Results		**Bloomberg Derived Market Risk Premium**	**Value Line Derived Market Risk Premium**
Average Bloomberg Beta Coefficient			
Current 30-Year Treasury (1.37%)		12.87%	14.75%
Near-Term Projected 30-Year Treasury (1.75%)		13.25%	15.13%
Long-Term Projected 30-Year Treasury (3.45%)		14.95%	16.83%
Average Value Line Beta Coefficient			
Current 30-Year Treasury (1.37%)		7.70%	8.74%
Near-Term Projected 30-Year Treasury (1.75%)		8.08%	9.11%
Long-Term Projected 30-Year Treasury (3.45%)		9.78%	10.81%
ECAPM Results		**Bloomberg Derived Market Risk Premium**	**Value Line Derived Market Risk Premium**
Average Bloomberg Beta Coefficient			
Current 30-Year Treasury (1.37%)		12.89%	14.77%
Near-Term Projected 30-Year Treasury (1.75%)		13.27%	15.15%
Long-Term Projected 30-Year Treasury (3.45%)		14.97%	16.85%
Average Value Line Beta Coefficient			
Current 30-Year Treasury (1.37%)		9.01%	10.26%
Near-Term Projected 30-Year Treasury (1.75%)		9.39%	10.64%
Long-Term Projected 30-Year Treasury (3.45%)		11.09%	12.34%
Bond Yield Risk Premium			
	Low	**Mid**	**High**
Bond Yield Risk Premium	10.35%	10.08%	9.97%
		Median	**Average**
Expected Earnings		10.30%	10.21%

Q. LASTLY, ARE YOU CONCERNED WITH THE DIFFERENCE IN CAPM RESULTS BASED ON BLOOMBERG AND VALUE LINE BETA COEFFICIENTS?

A. No, I am not. Because Bloomberg calculates Beta coefficients over two years, the ongoing market instability will be more acutely reflected in them than it would be in Value Line's Beta coefficients, which are calculated over five years. Further, because Value Line reports are provided on a periodic basis, they are not as current as the Bloomberg Beta coefficients, which may be calculated at any time. That said, as demonstrated in Chart 8, applying Value Line's method to current data indicates Beta coefficients calculated on that basis also have increased. From that perspective, the CAPM results based on the "Average Value Line Beta Coefficient" may be considered conservatively low.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

APPENDIX A

Q. EARLIER, YOU REFERRED TO THE FINANCIAL COMMUNITY'S REACTION TO THE PUCT'S DELIBERATIONS REGARDING CEHE'S[495] RECENT RATE PROCEEDING. HAVE YOU FURTHER ANALYZED THAT REACTION?

A. Yes, I have. By way of background, in April 2019, CEHE filed a rate case including a proposed ROE of 10.40 percent, and an equity ratio of 50.00 percent.[496] In their September 16, 2019 Proposal For Decision ("PFD"), the Administrative Law Judges recommended an ROE of 9.42 percent (including a three-basis point penalty for service complaints), and a capital structure including 45.00 percent equity (55.00 percent long-term debt).[497]

In its November 14, 2019 open meeting deliberations, the PUCT discussed authorizing an ROE of 9.25 percent, and a hypothetical equity ratio of 40.00 percent, both downward revisions to the PFD, and to the PUCT's previously authorized ROE of 10.00 percent and hypothetical equity ratio of 45.00 percent. The PUCT also discussed ordering a series of "ring-fencing" provisions, similar to those approved for Oncor Electric Delivery Company LLC ("Oncor") in connection with Oncor's acquisition by Sempra Energy,

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495 As of December 2018, CEHE represented about 75.00 percent of CNP's combined pre-tax operating profit.

496 Source: PUCT Docket No. 49421, Item Number: 1.

497 As a point of reference, in December 2018 the PUCT approved a settlement for Texas-New Mexico Power, also a distribution electric utility operating in the ERCOT region of Texas, including a 9.65 percent ROE, and a 45.00 percent equity ratio.

recommended in the PFD. The ring-fencing provisions included in the PFD were beyond those already (voluntarily) put in place by CEHE. Although the PUCT indicated it had reached its decision regarding CEHE's ROE, capital structure, and ring-fencing provisions, it directed PUCT Staff to quantify the revenue requirement effect of certain revenue requirement determinations, and allowed parties to the proceeding to file briefs regarding the ring-fencing issue.[498] With that information, the PUCT was expected to issue its final decision at its December 13, 2019 open meeting.[499]

On November 15, 2019, CNP's stock was downgraded by analysts at Bank of America, Merrill Lynch, Credit Suisse, Guggenheim, and SunTrust RH.[500] For the day, CNP lost nearly 5.00 percent of its value, making it the worst performing stock in the S&P 500.[501] On Monday November 18, 2019, analysts at Morgan Stanley reduced their price target for CNP, and financial

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498 As CEHE explained in its November 25, 2019 brief, one of the ring-fencing provisions proposed by PUCT Staff was to limit dividends from CEHE to CNP to CEHE's net income. At the same time, reducing the equity ratio to 40.00 percent would require CEHE to dividend about $800 million to CNP, violating the ring-fencing provision. Together, the capital structure and ring-fencing provisions would put CEHE in the difficult position of choosing between violating the ring-fencing provisions, or maintaining considerably more equity in its actual capital structure than provided in its authorized capital structure. That equity would be "trapped" at the CEHE level, with no ability to earn the authorized return. Source: S&P Global Market Intelligence, *Texas PUC puts off ruling on CenterPoint rate case to allow settlement talks*, December 13, 2019.

499 Source: S&P Global Market Intelligence, *Texas Regulators signal lower ROE, more ring-fencing for CenterPoint Houston*, November 15, 2019.

500 Source: Seeking Alpha, *CenterPoint Energy slammed with downgrades at four Wall Street firms*, November 15, 2019. Each of those four companies also lower their price targets for CNP.

501 *Ibid*.

market reporting services noted an increase in options activity for CNP stock.[502] By closing that day, CNP had lost about 10.50 percent of its value since November 13, only three trading days, representing a loss in market capitalization of about $1.5 billion. By December 3, 2019, CNP's stock price had lost nearly 14.00 percent of its value, reflecting a decline in market capitalization of about $1.85 billion.[503]

On December 12, 2019, CEHE notified the PUCT that several parties to the proceeding were engaged in discussions regarding a possible stipulation, and requested additional time to continue those discussions.[504] At its December 13, 2019 open meeting, the PUCT agreed to give the parties additional time to discuss the potential stipulation, and postponed its final deliberations. On January 23, 2020, CEHE filed a Stipulation and Settlement Agreement among CEHE and intervening parties, including PUCT Staff. The stipulation included an ROE of 9.40 percent, an equity ratio of 42.50 percent, and various ring-fencing measures.[505] During its February 14, 2020 open meeting, the PUCT approved the stipulation.[506]

On February 19, 2020, Fitch downgraded CEHE from A- to BBB+, with a Negative outlook. In summarizing its decision to downgrade CEHE (while

502 Source: Bloomberg Professional.
503 Source: S&P Capital IQ.
504 Source: PUCT Docket No. 49421, Item Number: 777.
505 Source: PUCT Docket No. 49421, Item Number: 785.
506 S&P Global Market Intelligence, *Texas PUC OKs CenterPoint rate case settlement, adds no dividend restrictions*, February 14, 2020.

affirming CNP's existing rating), Fitch explained it "believes that the unfavorable outcome signals a more challenging regulatory environment in Texas for CEHE." Fitch went on to note that "[l]ower authorized returns and equity capitalization, combined with tax-reform related refund will pressure CEHE's and CNP's credit metrics in the next few years", and explained further negative rating action is possible if the Company's credit metrics deteriorate.[507]

To summarize, debt and equity analysts became concerned not only with the financial implication of the PUCT's decision, they became quite concerned with what appeared to be a deterioration in the regulatory environment. As Fitch's downgrade and Guggenheim's comments suggest, those concerns likely reflect higher costs of capital for CEHE.

Q. HAVE YOU ANALYZED THE MARKET REACTIONS TO THE REGULATORY ACTIVITY ASSOCIATED WITH CEHE'S RATE CASE?

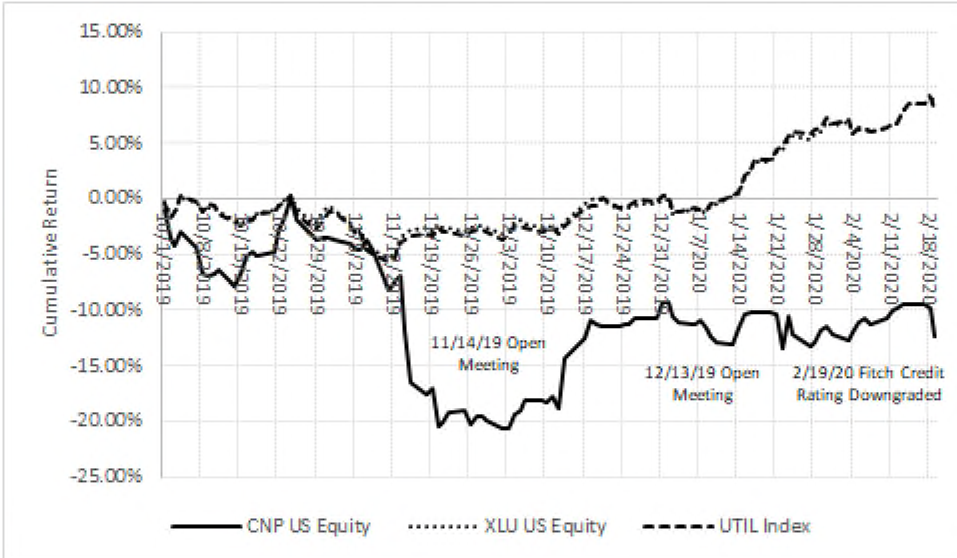
A. Although it is difficult to disentangle the effect of the PUCT's deliberations relating to ROE, capital structure, and ring-fencing, it is clear investors found the combined effect of those factors on CEHE's financial and risk profile to be troubling. One perspective on the extent of that concern is to view CNP's daily returns relative to the daily returns on indices of utility stocks. As noted above, there had been certain events that affected investors' perceptions of CEHE's

[507] FitchRatings, *Fitch Downgrades CenterPoint Energy Houston Electric to 'BBB+'; Affirms CNP; Outlooks Negative*, February 19, 2020.

risk and, therefore, CNP's stock price. To assess the effect of those events, we can view CNP's daily return on a cumulative basis, relative to the cumulative daily returns of utility stock indices.

As Chart A1 (below) suggests, coincident with the PUCT's November 14, 2019 open meeting, CNP began to meaningfully underperform the utility sector. That underperformance continued into December, reaching its lowest point on December 3, 2019. CNP's stock price began to recover around December 13, 2019, when CNP notified the PUCT that settlement discussions were continuing. The price recovered somewhat more through December 20, 2019, shortly after CEHE's update to the PUCT regarding the status of settlement discussions. Subsequent to that, CNP traded in a relatively narrow range.

Chart A1: Cumulative Returns (10/1/2019-2/19/2020)[508]



Q. WHAT CONCLUSIONS DO YOU DRAW FROM THAT INFORMATION?

A. It is apparent that analysts and investors found the PUCT's deliberations troubling. Although we cannot attribute specific portions of CNP's stock price underperformance to the PUCT's deliberations regarding each of the ROE, capital structure, and ring-fencing issues, we can say that in aggregate, the market saw them as value-reducing.

Q. HAVE YOU TESTED WHETHER CNP'S CUMULATIVE UNDERPERFORMANCE IS STATISTICALLY MEANINGFUL?

A. Yes, I have. A method frequently used to determine whether a given event likely had a significant effect on stock returns is an "event study", sometimes referred

508 Source: Bloomberg Professional.

to as a "cumulative abnormal return" analysis. To understand whether a specific event affected stock prices and returns, it is important to look at factors beyond the event under consideration. The portion of the stock's return that is not attributable to those other factors is considered the "abnormal" or "excess" return; the sum of those excess returns is the "cumulative" abnormal return.

To apply that approach, I defined the abnormal return on a given day as:

$$A_t = R_{i,t} - R_{m,t} \quad [A1]$$

where A_t is the abnormal return on day t, $R_{i,t}$ is the actual return for CNP[509] on day t, and $R_{m,t}$ is the expected return for CNP. The expected return is defined in Equation [A2] below.

$$R_{m,t} = \alpha_t + \beta_{m,t} \quad [A2]$$

The expected return, $R_{m,t}$, is based on a regression equation in which CNP's daily returns are the dependent variable, and the utility sector's daily return (measured by XLU) is the explanatory variable. Because it relies on market-adjusted returns, the approach controls for factors that affect companies across the utility sector. I applied the regression (*i.e.*, Equation [A2]) over the period January 1, 2019 to February 19, 2020, using daily returns.[510] The equation and slope coefficient both were statistically significant (*see* Table A1, below).

[509] Calculated as an index. Source: S&P Global Market Intelligence.

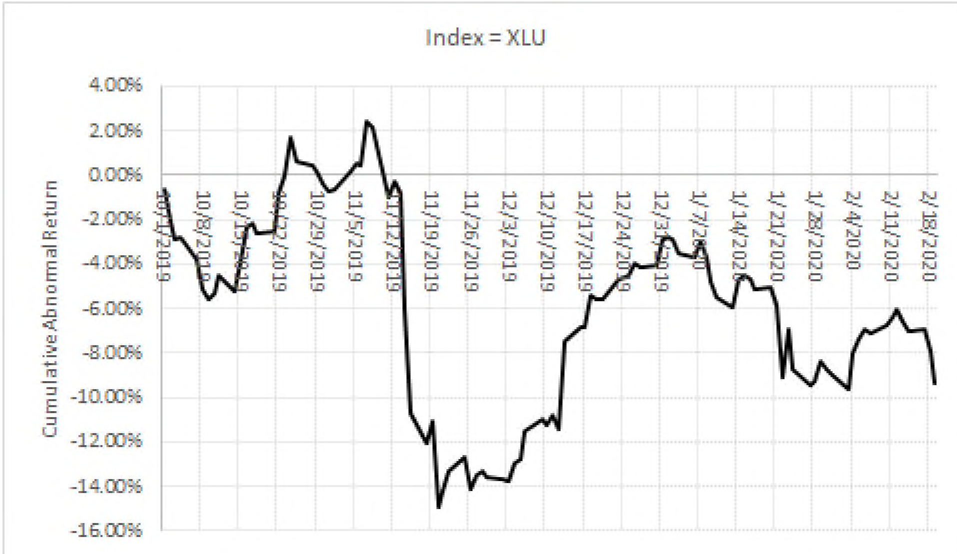
[510] I did not use a longer historical period to avoid any possible effect of CNP's acquisition of Vectren, which closed on February 1, 2019.

Table A1: Regression Statistics (XLU as Index)

	Slope	**Intercept**
Coefficient	0.8323	-0.0010
Std. Err.	0.0847	0.0006
R-Square	0.2472	
F-Statistic	96.5161	
T-Statistic	9.8243	-1.6376

To determine whether the PUCT's deliberations likely affected CNP's stock price and return, I considered the "event date" to be October 1, 2019. Because it pre-dates the deliberations and post-dates the PFD, the event date provides for the possibility that equity investors were aware of the regulatory process, and began to consider how the PUCT's decision might affect CNP's risk profile. I then calculated the cumulative abnormal return for each day from October 1, 2019 to February 19, 2020. Chart A2 (below) provides the cumulative abnormal return during that period. Not surprisingly, the cumulative abnormal return reached its lowest point around December 3, 2019, reversing itself around December 13, 2019 (when PUCT deferred its final decision pending ongoing settlement discussions), then falling coincident with the Stipulation and Settlement, and the Fitch downgrade.

Chart A2: Cumulative Abnormal Return (XLU as Index)



Q. WHAT CONCLUSIONS DO YOU DRAW FROM THAT ANALYSIS?

A. Controlling for sector-wide events, the PUCT's deliberations had a significant effect on CNP's price performance. That is true even if we measure the cumulative abnormal return through February 19, 2020.[511] If that level of underperformance were to continue, CNP would be disadvantaged in its ability to compete for capital, to the detriment of ratepayers and investors.

[511] Based on a t-test. Please note that the same findings hold when the Dow Jones Utility Average is used as the sector index.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1219
DOCKET NO. E-7, SUB 1214

In the Matters of: Application of Duke Energy Progress, LLC For Adjustment of Rates and Charges Applicable to Electric Service in North Carolina and Application of Duke Energy Carolinas, LLC For Adjustment of Rates and Charges Applicable to Electric Service in North Carolina	)))))))))))	**SUPPLEMENTAL REBUTTAL TESTIMONY OF DYLAN W. D'ASCENDIS** **FOR DUKE ENERGY PROGRESS, LLC AND DUKE ENERGY CAROLINAS, LLC**

I. <u>INTRODUCTION AND PURPOSE</u>

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

A. My name is Dylan W. D'Ascendis. I am a Director at ScottMadden, Inc. My business address is 3000 Atrium Way, Suite 241, Mount Laurel, New Jersey 08054.

Q. ON WHOSE BEHALF ARE YOU SUBMITTING THIS TESTIMONY?

A. I am submitting this supplemental rebuttal testimony ("Supplemental Rebuttal Testimony") before the North Carolina Utilities Commission ("Commission") on behalf of Duke Energy Progress, LLC ("DE Progress") and Duke Energy Carolinas, LLC ("DE Carolinas") (collectively, "the Companies").

Q. ARE YOU THE SAME DYLAN W. D'ASCENDIS THAT SUBMITTED DIRECT AND REBUTTAL TESTIMONIES IN THESE PROCEEDINGS?

A. Yes, I am.

Q. WHAT IS THE PURPOSE OF YOUR SUPPLEMENTAL REBUTTAL TESTIMONY?

A. The purpose of my Supplemental Rebuttal Testimony is two-fold. First, I update my cost of common equity ("ROE") models and second, I respond to the Supplemental Direct Testimony of Mr. Richard A. Baudino, witness for the North Carolina Attorney General's Office ("AG").

II. UPDATED ROE ANALYSES

Q. PLEASE SUMMARIZE YOUR UPDATED ROE ANALYSES.

A. My updated analytical results are provided in Table 1. The results are based on market data as of June 30, 2020.

Table 1: Summary of Updated Analytical Results[1]

Discounted Cash Flow	**Mean Low**	**Mean**	**Mean High**
30-Day Constant Growth DCF	8.14%	8.92%	9.67%
90-Day Constant Growth DCF	8.04%	8.82%	9.57%
180-Day Constant Growth DCF	7.76%	8.54%	9.29%
CAPM Results		**Bloomberg Derived MRP**	**Value Line Derived MRP**
Average Bloomberg Beta Coefficient			
Current 30-Year Treasury (1.47%)		13.21%	13.78%
Near-Term Projected 30-Year Treasury (1.72%)		13.45%	14.02%
Long-Term Projected 30-Year Treasury (3.40%)		15.14%	15.70%
Average Value Line Beta Coefficient			
Current 30-Year Treasury (1.47%)		10.19%	10.60%
Near-Term Projected 30-Year Treasury (1.72%)		10.43%	10.85%
Long-Term Projected 30-Year Treasury (3.40%)		12.11%	12.53%
ECAPM Results		**Bloomberg Derived MRP**	**Value Line Derived MRP**
Average Bloomberg Beta Coefficient			
Current 30-Year Treasury (1.47%)		13.21%	13.77%
Near-Term Projected 30-Year Treasury (1.72%)		13.45%	14.02%
Long-Term Projected 30-Year Treasury (3.40%)		15.14%	15.70%
Average Value Line Beta Coefficient			
Current 30-Year Treasury (1.47%)		10.94%	11.40%
Near-Term Projected 30-Year Treasury (1.72%)		11.18%	11.64%
Long-Term Projected 30-Year Treasury (3.40%)		12.87%	13.32%
Bond Yield Risk Premium			
	Current T-Bond	**Near-Term Proj.**	**Long-Term Proj.**
Bond Yield Risk Premium	10.25%	10.08%	9.96%
		Median	**Average**

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[1] Updated model results are contained in Supplemental Rebuttal Exhibits DWD-1 through DWD-6.

Expected Earnings	10.55%	10.18%

Q. WHAT ARE YOUR SPECIFIC OBSERVATIONS REGARDING THE COST OF CAPITAL MODEL RESULTS SINCE YOUR REBUTTAL TESTIMONY IN THE DE PROGRESS PROCEEDING (SPOT DATE AS OF APRIL 17, 2020)?

A. Aside from the updated Beta coefficients provided by Value Line Investment Survey ("Value Line"), which increased from 0.548[2] to 0.743, there has been little movement in the other inputs to my models. This leads me to conclude that market conditions are generally unchanged from my analysis of market conditions in my most recent Rebuttal Testimony;[3] however, the substantial increase in Beta coefficients demonstrates greater risk for utility equities (and therefore a higher ROE) relative to the market. On balance, I maintain my recommended range of ROEs from 10.00 percent to 11.00 percent and a point estimate of 10.50 percent. In my opinion, an authorized ROE of 10.50 percent is a reasonable, but conservative measure of the Companies' required return, especially in view of the highly volatile current market conditions.

Q. HAVE YOU UPDATED YOUR PROXY GROUP IN YOUR ANALYSIS?

A. No, I have not. My Proxy Group is unchanged from my Proxy Group used in

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2 Docket No. E-2, Sub 1219, Rebuttal Exhibit DWD-3.
3 Docket No. E-2, Sub 1219, Rebuttal Testimony of Dylan W. D'Ascendis, at 11-30.

my Rebuttal Testimony.[4]

Q. HAVE YOU APPLIED YOUR COST OF COMMON EQUITY MODELS IN THE SAME MANNER YOU APPLIED THEM IN YOUR DIRECT AND REBUTTAL TESTIMONIES?

A. Yes, I have.

III. RESPONSE TO AG WITNESS MR. BAUDINO

Q. PLEASE BRIEFLY SUMMARIZE MR. BAUDINO'S POSITIONS AND CONCLUSIONS REGARDING THE RECENT CAPITAL MARKET DISLOCATION, AND ITS IMPLICATIONS FOR THE COMPANIES' COST OF COMMON EQUITY.

A. Mr. Baudino's Supplemental Direct Testimony provides an update of the interest rate and market data since the beginning of March 2020, "when concerns about the Covid-19 pandemic began to roil financial markets with extreme volatility".[5]

Mr. Baudino then describes the volatility surrounding 30-year Treasury bond yields, public utility bond yields, the stock market as a whole, and the utility industry for the period between March and June 30, 2020.[6] Additionally, Mr. Baudino summarizes the Federal Reserve Board's (the "Fed") actions to

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4 *Ibid.*, at 30-31. Mr. Baudino uses this same proxy group filed for his updated analyses. Supplemental Direct Testimony of Richard A. Baudino, at 8.
5 Supplemental Direct Testimony of Richard A. Baudino, at 2.
6 *Ibid.*, at 3-4.

attempt to stabilize markets through providing liquidity to individuals and companies throughout that same period.[7]

From these observations, Mr. Baudino draws the following conclusions:

- That the decreases in Treasury and utility bond yields do not support higher ROEs for the Companies;[8]
- That regulated electric utilities like the Companies "continue to be safe, conservative, and relatively stable investments even in present market conditions";[9]
- That the increase in Beta coefficients could be a short-term phenomenon;[10]
- That the increase in Beta coefficients are not consistent with the decrease in bond yields;[11] and
- That the stability of the Companies' credit ratings do not suggest that their required ROE has increased.[12]

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[7] *Ibid.*, at 4-7.
[8] *Ibid.*, at 10.
[9] *Ibid.*, at 7.
[10] *Ibid.*, at 11.
[11] *Ibid.*
[12] *Ibid.*, at 10.

Q. DO YOU HAVE ANY OBSERVATIONS REGARDING MR. BAUDINO'S DISCUSSION ABOUT CAPITAL MARKETS AND THE CONCLUSIONS HE REACHES?

A. I do. While the facts he presents (*i.e.*, the levels of interest rates, market indices, and Fed actions) echo my observations about current market conditions presented in my Rebuttal Testimony,[13] his conclusions from those facts are contradictory. At several points in his Supplemental Direct Testimony, Mr. Baudino discusses the shocks,[14] extreme volatility,[15] unprecedented economic contraction,[16] skyrocketing unemployment,[17] and continuing effect on economic activity[18] brought upon by the COVID-19 pandemic, and yet he continues to support a 9.00 percent ROE, which is below any reasonable measure of the Companies' required return as shown on Chart 1, below:[19]

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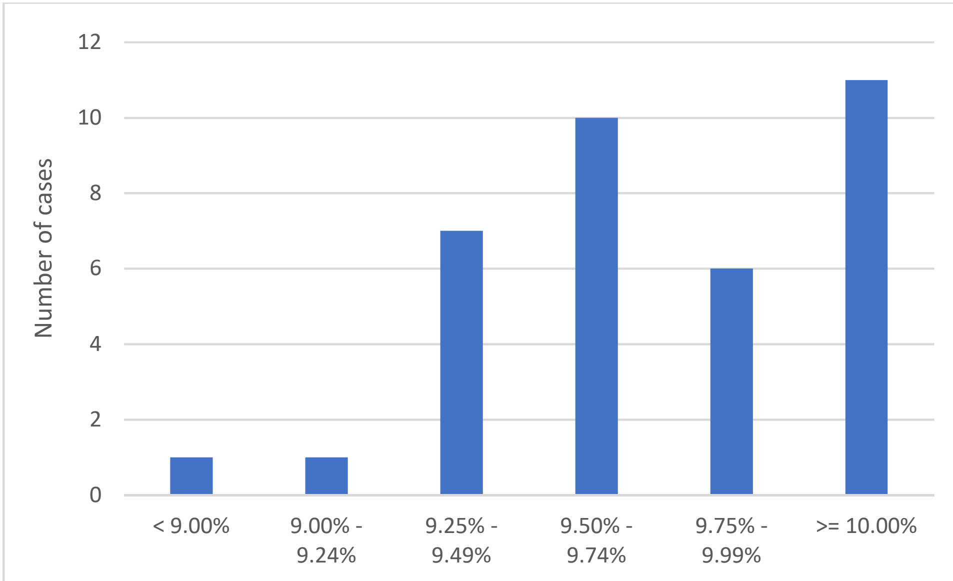
13 Docket No. E-2, Sub 1219, Rebuttal Testimony of Dylan W. D'Ascendis, at 11-30.
14 Supplemental Direct Testimony of Richard A. Baudino, at 2.
15 *Ibid.*, at, 2, 7, 11.
16 *Ibid.*, at 13.
17 *Ibid.*
18 *Ibid.*, at 14.
19 Docket No. E-2, Sub 1219, Rebuttal Testimony of Dylan W. D'Ascendis, at 4.

Chart 1: Frequency of Vertically Integrated Electric Utility Authorized ROEs in 2019-2020[20]



It must be noted that the rate cases in Chart 1 do not reflect current market conditions. As will be discussed in detail below, current market conditions are indicating a higher risk environment than those at the beginning of the year.

Q. WHY DO YOU DISAGREE WITH MR. BAUDINO REGARDING THE RELATIONSHIP BETWEEN CURRENT INTEREST RATES AND THE COST OF CAPITAL?

A. As discussed in my Rebuttal Testimony,[21] despite the Fed's actions, the 30-year Treasury bond yield has become highly volatile, as seen in its Coefficient of

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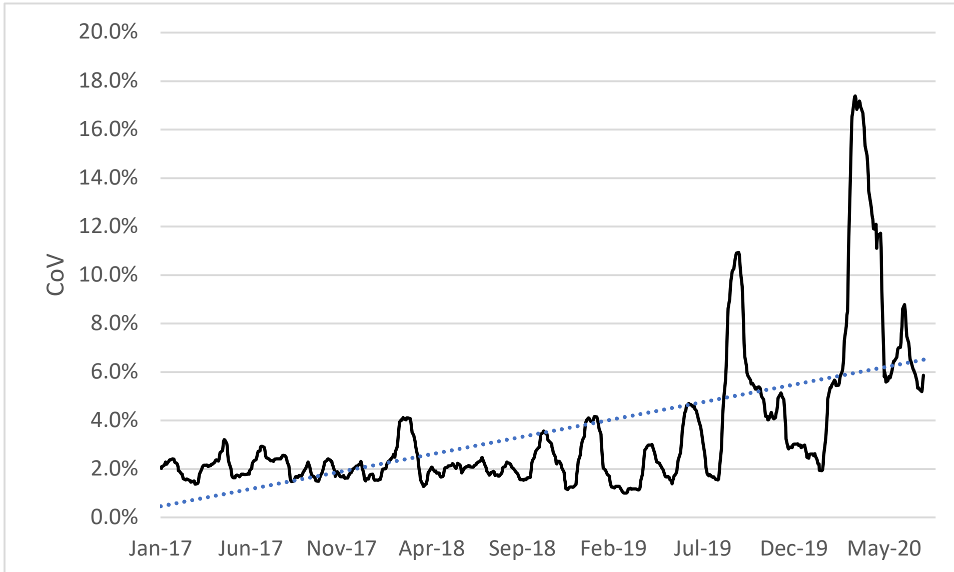
20 Source: Regulatory Research Associates.
21 *Ibid.*, at 17-18.

Variation ("CoV"):[22]

Chart 2: Coefficient of Variation in 30-Year Treasury Yields[23]



In response to Mr. Baudino's observations regarding public utility bonds,[24] I recreated the same analysis for A-rated utility bond yields:

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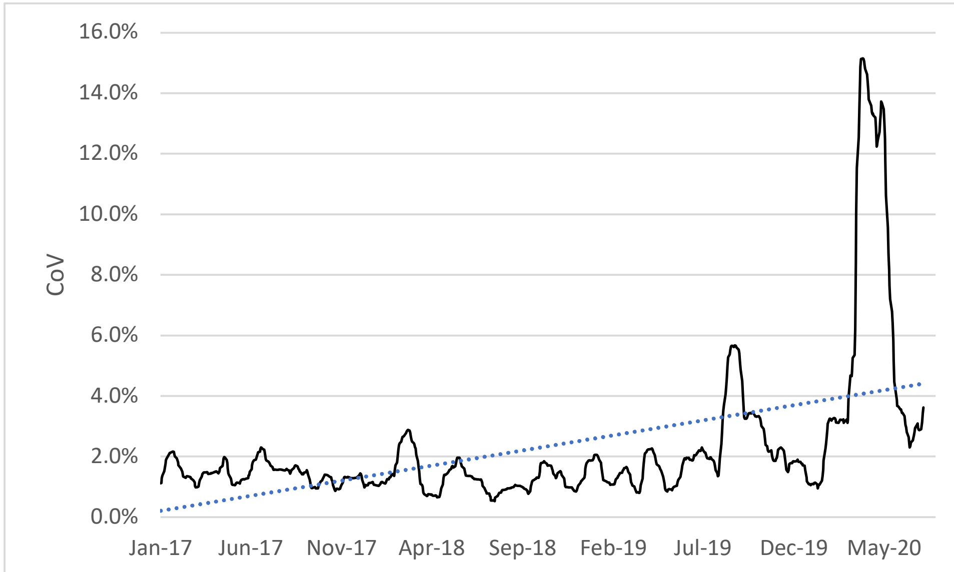
22 The coefficient of variation is used by investors and economists to determine volatility.

23 Source: S&P Global Market Intelligence. Data through July 10, 2020.

24 Supplemental Direct Testimony of Richard A. Baudino, at 3.

Chart 3: Coefficient of Variation in A-Rated Public Utility Bonds[25]



As discussed in my Direct Testimony,[26] significant and abrupt increases in volatility tend to be associated with declines in Treasury yields, as investors seek to preserve their capital in "safe haven" investments. Even though it is Mr. Baudino's opinion that electric utility stocks are "safe haven" investments in this period of extreme market volatility, they are not.

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25 *Ibid.*

26 Docket No. E-2, Sub 1219, Direct Testimony of Dylan W. D'Ascendis, at 67. *see also*, Docket No. E-2, Sub 1219, Rebuttal Testimony of Dylan W. D'Ascendis, at 35.

Q. WHY ARE ELECTRIC UTILITY STOCKS NOT "SAFE HAVEN" INVESTMENTS IN THE CURRENT MARKET?

A. I have studied the relative performance and annualized volatilities[27] of my Proxy Group and the S&P 500 to gauge whether the Proxy Group has weathered the COVID-19 pandemic to date better than the overall market. As shown on Supplemental Rebuttal Exhibit DWD-7, from January 31, 2020[28] to July 10, 2020, returns for the Proxy Group companies ranged from negative 3.21 percent to negative 32.48 percent, averaging negative 20.64 percent while the S&P 500 return over the same period was negative 1.25 percent. The annualized volatility of the Proxy Group companies ranged from 53.44 percent to 80.88 percent, averaging 64.20 percent while the S&P 500's annualized volatility over the same period was 48.84 percent. This study shows that the Proxy Group performed worse than the overall market and has been more volatile (*i.e.*, riskier) than the market as well.

Q. HAVE YOU CONDUCTED ADDITIONAL ANALYSES TO SHOW THAT UTILITY STOCKS SHOULD NOT BE CONSIDERED SAFE OR

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27 The annualized volatility of a stock is measured by taking the standard deviation of the price changes within the sample and multiplying by the square root of 252 (the assumed number of trading days in a year)

28 I chose January 31, 2020 because on June 8, 2020, the National Bureau of Economic Research determined that a peak in monthly economic activity occurred in the U.S. economy in February 2020. The peak marks the end of the expansion that began in June 2009 and the beginning of a recession. https://www.nber.org/cycles/june2020.html

CONSERVATIVE INVESTMENTS IN THE CURRENT ECONOMIC ENVIRONMENT?

A. Yes. In my Rebuttal Testimony in the DE Progress proceeding, I explained that during volatile markets, "correlations go to 1" and utility stocks lose their defensive quality.[29] As such, I calculated the correlation coefficients of the price changes of several groups of utilities relative to the S&P 500 and the Dow Jones Industrial Index ("DJIA") from February 1, 2020 to July 10, 2020. Specifically, I calculated correlation coefficients for the following relationships:

- The price changes of the S&P 500 relative to the price changes of the Proxy Group;
- The price changes of the S&P 500 relative to the price changes of the S&P Utilities Index;
- The price changes of the S&P 500 relative to the price changes of the S&P Electric Index;
- The price changes of the S&P 500 relative to the price changes of the Dow Jones Utility Index ("DJU");
- The price changes of the DJIA relative to the price changes of the Proxy Group;
- The price changes of the DJIA relative to the price changes of the S&P

[29] Docket No. E-2, Sub 1219, Rebuttal Testimony of Dylan W. D'Ascendis, at 20.

Utilities Index;

- The price changes of the DJIA relative to the price changes of the S&P Electric Index; and
- The price changes of the DJIA relative to the price changes of the DJU.

Table 2 provides the results of the calculations:

Table 2: Calculation of Correlation Coefficients for Utility Groups Relative to Market Indices from February 2020 to July 2020[30]

Group	S&P 500	DJIA
Proxy Group	83.62%	82.23%
S&P Utility Index	85.98%	84.67%
S&P Electric Index	85.95%	84.77%
DJU	85.46%	84.49%

As shown on Table 2, utility stocks have been trading in tandem with market indices during the current market dislocation. The behavior of utility stocks to move in tandem with the market during market distress is not limited to the current period. During the Great Recession (December 2007 to June 2009), correlations between these same groups were similar, as shown on Table 3, below:

Table 3: Calculation of Correlation Coefficients for Utility Groups Relative to Market Indices from December 2007 to June 2009[31]

Group	S&P 500	DJIA
Proxy Group	78.71%	80.11%
S&P Utility Index	81.73%	82.27%
S&P Electric Index	79.16%	79.99%
DJU	81.57%	82.13%

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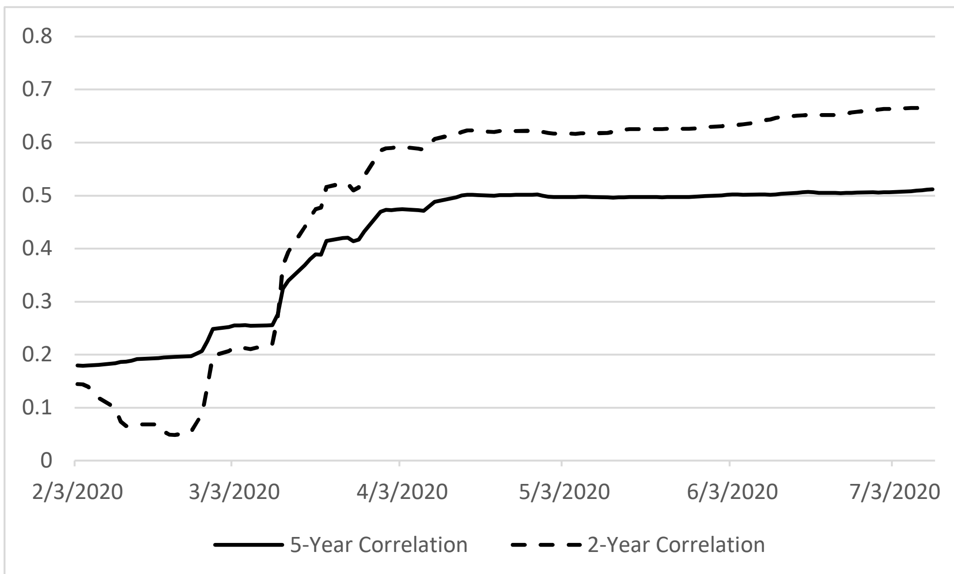
30 Source: Bloomberg Professional Services.
31 *Ibid*.

To further the point, I have calculated two-year[32] and five-year[33] correlation coefficients between the price changes in the S&P 500 and price changes in the Proxy Group from February 2020 to July 2020. As shown on Chart 4, as the COVID-19 pandemic became apparent, the correlation coefficients increased from approximately 0.15 to approximately 0.70 (two-year horizon) and from approximately 0.20 to approximately 0.50 (five-year horizon).

Chart 4: Two-Year and Five-Year Correlation Coefficients for the Proxy Group Relative to the S&P 500[34]



The increase in volatility (*i.e.*, risk), as explained above in combination

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[32] Consistent with the calculation horizon of Bloomberg's Beta coefficients.
[33] Consistent with the calculation horizon of Value Line's Beta coefficients.
[34] Source: S&P Global Market Intelligence.

with the increased correlation between the Proxy Group and market indices ultimately leads to higher Beta coefficients, as evidenced in their increase during the course of these proceedings:

Table 4: Evolution of Beta Coefficients Throughout the Proceedings[35]

Source	Direct (DEC) 6/28/19	Direct (DEP) 8/16/19	Rebuttal (DEC) 1/31/20	Rebuttal (DEP) 4/17/20	Supplemental Rebuttal 6/30/20
Bloomberg	0.498	0.499	0.513	0.995	1.000
Value Line	0.580	0.572	0.561	0.548	0.743

In view of all of the above, it is apparent that electric utilities, as represented by the Proxy Group, are essentially just as risky as the market at this time. Mr. Baudino's conclusion that electric utilities "continue to be safe, conservative, and relatively stable investments even in present market conditions" is not justified by his own analysis. That analysis confirms the highly volatile nature of current market conditions, even as to regulated electric utilities, and these highly volatile conditions are even in his own estimation indicators of increased risk.[36] The upward trend in Beta coefficients depicted in Table 4 shows this, and nothing in Mr. Baudino's Supplemental Direct Testimony refutes it.

[35] Supplemental Rebuttal Exhibit DWD-8.
[36] Supplemental Direct Testimony of Richard A. Baudino, at 10-11.

Q. MR. BAUDINO CLAIMS THAT THE INCREASED BETA COEFFICIENTS ARE A SHORT-TERM PHENOMENON.[37] DO YOU AGREE WITH HIS ASSESSMENT?

A. No. As I discussed previously, Bloomberg and Value Line Beta coefficients are calculated over time horizons of two- and five-years, respectively. That means the effect of the COVID-19 pandemic on markets reflected in the Beta coefficient calculation would last until at least February 2022 (Bloomberg) and February 2025 (Value Line).[38] Additionally, as discussed in my Rebuttal Testimony,[39] the potential range of economic financial outcomes due to COVID-19 is wide, and there is no way anyone, including Mr. Baudino, can know how it will shake out. This is corroborated by the Fed's press release on June 10, 2020, which was cited by Mr. Baudino:

> The ongoing health crisis will weigh heavily on economic activity, employment, and inflation in the near term and poses considerable risks to the economic outlook in the medium term.[40]

Because the public health crisis has not yet abated, its total impact on markets cannot be measured.

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37 Supplemental Direct Testimony of Richard A. Baudino, at 11.

38 *Also see*, Docket No. E-2, Sub 1219, Rebuttal Testimony of Dylan W. D'Ascendis, at 234-235. As noted there, Value Line data is not as current as Bloomberg data regarding Beta coefficients. Further, as Value Line data is updated on a rolling regional basis and updates reflecting COVID-19 effects for the West region have not as yet been provided, at this time Value Line's Beta coefficients lag Bloomberg's.

39 Docket No. E-2, Sub 1219, Rebuttal Testimony of Dylan W. D'Ascendis, at 28.

40 Federal Reserve Board, Press Release, June 10, 2020.

Q. MR. BAUDINO REFERENCES THE DECLINE OF THE CHICAGO BOARD OPTIONS EXCHANGE ("CBOE") VOLATILITY INDEX ("VIX") FROM ITS MARCH 16, 2020 PEAK OF 82.69 TO 30.43 CURRENTLY AS A REASON WHY "IT IS HIGHLY UNLIKELY THAT A 32% INCREASE IN EXPECTED BETAS FOR ELECTRIC UTILITIES SINCE EARLIER IN THE YEAR IS ACCURATE AND RELIABLE."[41] PLEASE RESPOND.

A. While Mr. Baudino is correct that the VIX has declined to approximately 30.00 from its peak of 82.69, a VIX of 30.00 is still 50 percent higher than its historical average level of approximately 20.00.[42] As I discussed in my Direct Testimony,[43] one means of assessing market expectations regarding the future level of volatility is to review CBOE's "Term Structure of Volatility", which is described by CBOE as:

> The implied volatility term structure observed in SPX options markets is analogous to the term structure of interest rates observed in fixed income markets. Similar to the calculation of forward rates of interest, it is possible to observe the option market's expectation of future market volatility through use of the SPX implied volatility term structure.[44]

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41 Supplemental Direct Testimony of Richard A. Baudino, at 12.
42 *See*, Docket No. E-7, Sub 1214, Direct Testimony of Dylan W. D'Ascendis, at 39, Chart 4.
43 Docket No. E-2, Sub 1219, Direct Testimony of Dylan W. D'Ascendis, at 66.
44 Source: www.cboe.com/trading-tools/strategy-planning-tools/term-structure-data.

As shown in Table 5, the implied volatility is expected to remain approximately 50 percent above historical volatility until at least December 2021.

Table 5: CBOE Term Structure of Volatility[45]

Date	Projected VIX
August 2020	28.05
September 2020	29.93
October 2020	31.18
November 2020	32.47
December 2020	33.19
January 2021	31.45
March 2021	30.70
June 2021	29.54
September 2021	28.52
December 2021	29.87

The current and expected increased volatility in the market, in addition to the time horizon used to calculate Beta coefficients, and the uncertainty surrounding the length and total impact of the COVID-19 pandemic would lead to the conclusion that the increase in Beta coefficients will not be short-term in nature.

Q. DO YOU AGREE WITH MR. BAUDINO'S POSITION THAT THE INCREASE IN BETA COEFFICIENTS ARE INCONSISTENT WITH THE ABRUPT FALL IN INTEREST RATES?

A. No, I do not. As discussed in detail previously, event-driven increases in

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45 Source: http://www.cboe.com/trading-tools/strategy-planning-tools/term-structure-data, accessed July 10, 2020.

volatility lowers bond yields as investors seek to preserve capital. As the volatility of the market and utility stocks increase, so did the correlation of their price changes, leading to increasing Beta coefficients.

Q. ONE OF MR. BAUDINO'S REASONS FOR NOT ADJUSTING HIS RECOMMENDED ROE IS BECAUSE THE COMPANIES' CREDIT RATINGS WERE NOT AFFECTED DURING THE PANDEMIC. IS THAT VALID REASONING?

A. No. As discussed in my Rebuttal Testimony,[46] I do not think that credit ratings are a full measure of any company's relative equity risk. That being said, and as I also discussed in my Rebuttal Testimony,[47] S&P downgraded its outlook on the utility sector from "Stable" to "Negative" on April 4, 2020. Regarding liquidity and capital access, S&P observes that "the industry continues to exhibit adequate liquidity and access to the debt markets, despite uneven performance of the commercial paper market for tier 2 issuers", but availability to equity markets "remains extraordinarily challenging."[48] S&P expects the negative discretionary cash flow associated with high capital investment commitments and the "lack of access to the equity markets" to "lead to a weakening of credit measures."[49]

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46 Docket No. E-2, Sub 1219, Rebuttal Testimony of Dylan W. D'Ascendis, at 113-116.
47 *Ibid.*, at 24-25.
48 *Ibid.*
49 *Ibid.*

Moody's Investor Services ("Moody's") similarly observed that "[i]n a prolonged economic downturn, boards of directors are likely to review dividend plans as an option to conserve cash."[50] Moody's expects companies with higher payout ratios as more likely to reduce dividends, and sees the potential for average dividend payout ratios to increase to about 80.00 percent from a median of 63.00 percent in 2019.[51] In Moody's view, the ability to reduce dividends provides utilities "with a significant source of internal cash that could help them offset the impact of a potentially prolonged coronavirus-related economic downturn."[52]

Because utilities require adequate access to capital to provide safe and reliable service,[53] in times of market distress, the ability to access capital is even more critical. Utilities with strong financial profiles will have access to capital at more favorable terms and can pass those lower costs to customers.

Q. HAVE ANY UTILITY COMPANIES RECENTLY CUT THEIR DIVIDEND?

A. Yes. On April 1, 2020, CenterPoint Energy announced that it was reducing its dividend from $0.29 per share to $0.15 per share, in part citing the negative

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50 Moody's Investors Service, *Dividends a major source of cash if coronavirus downturn is prolonged*, April 6, 2020, at 1.

51 *Ibid*., at 2-3.

52 *Ibid*., at 1.

53 Docket No. E-2, Sub 1219, Rebuttal Testimony of Dylan W. D'Ascendis, at 130-131.

effect of the COVID-19 pandemic on the energy market and economy.[54] On July 5, 2020, Dominion Energy, following an asset sale, rebased (*i.e.*, cut) its dividend payment reflecting the sale of the assets and its payout ratio targets.[55] In short, even though the Companies' credit ratings were unchanged (so far) during the current public health crisis, the credit rating agencies recognize the risks presented by COVID-19, and some utilities are already reacting to those risks.

Q. WHAT ARE YOUR CONCLUSIONS REGARDING CURRENT CAPITAL MARKET CONDITIONS?

A. Based on all of the analyses provided previously in this Supplemental Rebuttal Testimony, it has been shown that the volatility of both utility stocks and the market as a whole have increased and that the correlations of the price changes between utility stocks and market indices have likewise increased. Looking toward expected market volatility, it has been shown that the current level of market volatility, which is 50 percent higher than normal levels, is expected to persist until at least the end of 2021. Finally, credit rating agencies and individual utilities have recognized the risk presented by COVID-19 and have begun to act on responding to those risks. On balance, risk is higher now than

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54 Tomi Kilgore, "CenterPoint Energy cuts dividend nearly in half and lowers capex; CFO leaving company," MarketWatch, April 2, 2020.

55 Dominion Energy, Press Release, July 5, 2020.

it was at the beginning of the year and must be reflected in the investor-required return.

Q. PLEASE BRIEFLY SUMMARIZE MR. BAUDINO'S OBSERVATIONS AND CONCLUSIONS REGARDING NORTH CAROLINA-SPECIFIC ECONOMIC CONDITIONS.

A. Mr. Baudino states that the COVID-19 pandemic caused an unprecedented economic contraction and skyrocketing unemployment in North Carolina.[56] He reviews unemployment rates of both North Carolina and the U.S., which have risen from 3.60 percent and 3.50 percent in February 2020 to 12.90 percent and 13.30 percent in May 2020, respectively, and reviews the national Gross Domestic Product ("GDP") growth of negative 5.00 percent for the first quarter 2020.[57] Mr. Baudino then concludes that it is more important than ever for the Commission to consider the impacts of the Companies' requested ROE on their customers.[58]

Q. DO YOU HAVE COMMENTS ON MR. BAUDINO'S OBSERVATIONS AND CONCLUSIONS REGARDING NORTH CAROLINA ECONOMIC CONDITIONS?

A. Yes. While I agree that COVID-19 has affected the North Carolina economy,

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56 Supplemental Direct Testimony of Richard A. Baudino, at 13.
57 *Ibid.*, at 13-14.
58 *Ibid.*, at 14.

it has equally affected the entire U.S. economy. As discussed in my Direct Testimony,[59] in its Order on Remand in Docket No. E-22, Sub 479, the Commission observed that economic conditions in North Carolina were highly correlated with national conditions, such that they were reflected in the analyses used to determine the ROE. Even though the North Carolina and the U.S. economy has contracted, those relationships still hold.

Regarding GDP, the U.S. contracted 5.00 percent (annualized) in the first quarter 2020, while North Carolina's GDP contracted at a similar 5.10 percent in the first quarter 2020. The correlations between U.S. and North Carolina GDP growth for the period 2005 – first quarter 2020, and for the four quarters ended first quarter 2020, are 0.9769 and 0.9993, respectively.

Regarding unemployment rates, as of May 2020 (the most recent data for North Carolina-specific unemployment rates), the unemployment rate[60] for the U.S., North Carolina, the counties served by DE Progress, and the counties served by DE Carolinas were 13.00 percent, 12.70 percent, 11.89 percent, and 12.97 percent, respectively.[61] While all the unemployment rates are extraordinarily high, it could be argued that North Carolina customers, and customers within the Companies' service area have been relatively better off

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59 Docket No. E-2, Sub 1219, Direct Testimony of Dylan W. D'Ascendis, at 57-58.

60 Not seasonally adjusted.

61 Source: U.S. Bureau of Labor Statistics. Unemployment rate for the counties served by DE Progress and DE Carolinas is the average of the respective counties.

than the rest of the country. The correlations between the U.S. unemployment rate with the North Carolina unemployment rate, the counties served by DE Progress unemployment rate, and the counties served by DE Carolinas are shown in Table 6, below:

Table 6: Correlations of Unemployment Rates of U.S., North Carolina, and Territories Served by the Companies February 2020 – May 2020

	U.S. Unemployment Rate
North Carolina Unemployment Rate	99.29%
DE Progress Unemployment Rate	98.84%
DE Carolinas Unemployment Rate	99.41%

On balance, the values and the correlations between national and state-wide measures of economic conditions noted by the Commission in Docket No. E-22, Sub 479 remain in place, and, as such, continue to be reflected in the models and data used to estimate the ROE.

IV. CONCLUSION

Q. DO YOU MAINTAIN YOUR 10.50 PERCENT RECOMMENDED ROE FOR THE COMPANIES GIVEN CURRENT MARKET CONDITIONS?

A. Yes, I do.

Q. WHY IS IT IMPORTANT FOR THE COMMISSION TO AUTHORIZE THE COMPANIES THEIR FULL REQUIRED ROE IN THESE PROCEEDINGS?

A. Utilities, like the Companies, are the engine for economic growth for the communities they serve, and as such need to be able to access capital at reasonable costs to provide safe and reliable service. To allow the Companies an opportunity to earn an ROE below investors' required return not only disadvantages the Companies, but also the businesses and individuals the Companies serve.

Q. DOES THIS CONCLUDE YOUR SUPPLEMENTAL REBUTTAL TESTIMONY?

A. Yes, it does.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-2, SUB 1219

In the Matter of:	)	
	)	
DOCKET NO. E-2, SUB 1219	)	**SECOND SETTLEMENT**
Application of Duke Energy Progress, LLC For	)	**TESTIMONY OF**
Adjustment of Rates and Charges Applicable to	)	**DYLAN W. D'ASCENDIS**
Electric Service in North Carolina	)	**FOR DUKE ENERGY**
	)	**PROGRESS, LLC**
	)	

I. INTRODUCTION

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

A. My name is Dylan W. D'Ascendis. I am a Director at ScottMadden, Inc. My business address is 3000 Atrium Way, Suite 241, Mount Laurel, New Jersey 08054.

Q. ARE YOU THE SAME DYLAN W. D'ASCENDIS WHO SUBMITTED DIRECT, REBUTTAL, AND SUPPLEMENTAL REBUTTAL TESTIMONIES IN THIS PROCEEDING?

A. Yes, I filed direct testimony ("Direct Testimony"), rebuttal testimony ("Rebuttal Testimony"), and supplemental rebuttal testimony ("Supplemental Rebuttal Testimony") on behalf of Duke Energy Progress, LLC ("DE Progress" or the "Company"). In my Direct, Rebuttal, and Supplemental Rebuttal Testimonies I recommended a Return on Equity ("ROE") of 10.50 percent, within a range of 10.00 percent to 11.00 percent.

Q. WHAT IS THE PURPOSE OF YOUR SETTLEMENT SUPPORT TESTIMONY?

A. The purpose of my testimony is to explain my support for the Second Agreement and Stipulation of Partial Settlement dated July 31, 2020 (the "Second Partial Settlement") among the Company and the Public Staff (collectively, the "Settling

Parties"). In particular, my testimony addresses the agreed-upon ROE, capital structure, and overall Rate of Return contained in the Second Partial Settlement.[1]

Q. HAVE YOU PREPARED ANY EXHIBITS IN CONJUNCTION WITH YOUR TESTIMONY?

A. Yes. Settlement Exhibit No. DWD-1 has been prepared by me, or under my direct supervision.

II. STIPULATED ROE, EQUITY RATIO, AND OVERALL RATE OF RETURN

Q. ARE YOU FAMILIAR WITH THE TERMS OF THE SECOND PARTIAL SETTLEMENT AS IT RELATES TO THE COMPANY'S OVERALL RATE OF RETURN?

A. Yes. I understand the Settling Parties have agreed to an ROE of 9.60 percent, and a capital structure including 52.00 percent common equity and 48.00 percent long-term debt for the Company. I further understand the overall Rate of Return contained in the Second Partial Settlement concerning DE Progress is 6.93 percent.[2]

Q. IN GENERAL, DO YOU SUPPORT THE COMPANY'S DECISION TO AGREE TO THE STIPULATED ROE?

A. Yes. I do. Although the Stipulated ROE is somewhat below the lower bound of my recommended range (*i.e.*, 10.00 percent), I recognize the Second Partial Settlement represents negotiations among the Settling Parties regarding several

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[1] *See*, Second Agreement and Stipulation of Partial Settlement, July 31, 2020, at 9. I refer to the 9.60 percent ROE as the "Stipulated ROE", the 52.00 percent equity ratio as the "Stipulated Equity Ratio", and the 6.93 percent overall Rate of Return as the "Stipulated Rate of Return".

[2] *Ibid*.

otherwise-contested issues. I understand the Company has determined that the terms of the Second Partial Settlement, in particular the Stipulated ROE and Equity Ratio, would be viewed by the rating agencies as constructive and equitable. I understand and respect that determination.

Q. PLEASE NOW SUMMARIZE YOUR POSITION REGARDING THE STIPULATED ROE.

A. Although the Stipulated ROE falls below my recommended range (the low end of which is 10.00 percent), it is within the range of the analytical results presented in my Direct, Rebuttal, and Supplemental Rebuttal Testimonies. As discussed throughout my Rebuttal and Supplemental Rebuttal Testimonies, capital market conditions became quite volatile as a result of the COVID-19 pandemic. Consequently, the models used to estimate the Cost of Equity produce a wide range of estimates. Those market conditions, in particular the increasing correlation between the utility sector and the broad market, support investors' increased capital cost requirements. It therefore remains my position that in a fully litigated proceeding, a range of common equity cost rates between 10.00 percent and 11.00 percent is reasonable, if not conservative. Nonetheless, I recognize the benefits associated with the decision to enter into the Second Partial Settlement and as such, it is my view that the 9.60 percent Stipulated ROE is a reasonable resolution of an otherwise contentious issue.

Q. HAVE YOU ALSO CONSIDERED THE STIPULATED ROE IN THE CONTEXT OF AUTHORIZED RETURNS FOR OTHER VERTICALLY INTEGRATED ELECTRIC UTILITIES?

A. Yes. From January 2016 through June 2020, the average authorized ROE for vertically integrated electric utilities was 9.74 percent, 14 basis points above the Stipulated ROE. Of the 107 cases decided during that period, 64 (*i.e.*, nearly 60.00 percent) included authorized returns of 9.60 percent or higher.[3]

Q. ARE THERE OTHER DISTINCTIONS THAT ARE IMPORTANT TO CONSIDER WHEN REVIEWING AUTHORIZED RETURNS?

A. Yes. As noted in my Rebuttal Testimony, the Company's credit rating and outlook depend substantially on the extent to which rating agencies view the regulatory environment as credit supportive, or not.[4] I noted, for example, that Moody's finds the regulatory environment to be so important that 50.00 percent of the factors that weigh in its ratings determination are determined by the nature of regulation.[5]

Given the Company's need to access external capital and the weight rating agencies place on the nature of the regulatory environment, I believe it is important to consider the extent to which the jurisdictions that recently have authorized ROEs for electric utilities are viewed as having constructive regulatory environments.

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[3] *See* Settlement Exhibit DWD-1.
[4] Rebuttal Testimony of Dylan W. D'Ascendis, at 182.
[5] *Ibid.*

Q. IS NORTH CAROLINA GENERALLY CONSIDERED TO HAVE A CONSTRUCTIVE REGULATORY ENVIRONMENT?

A. Yes, it is. As discussed in my Rebuttal Testimony, Regulatory Research Associates ("RRA"), which is a widely referenced source of rate case data, provides an assessment of the extent to which regulatory jurisdictions are constructive from investors' perspectives, or not.[6] As RRA explains, less constructive environments are associated with higher levels of risk:

> RRA maintains three principal rating categories, Above Average, Average, and Below Average, with Above Average indicating a relatively more constructive, lower-risk regulatory environment from an investor viewpoint, and Below Average indicating a less constructive, higher-risk regulatory climate from an investor viewpoint, Within the three principal rating categories, the numbers 1, 2, and 3 indicate relative position. The designation 1 indicates a stronger (more constructive) rating; 2, a mid range rating; and, 3, a weaker (less constructive) rating. We endeavor to maintain an approximately equal number of ratings above the average and below the average.[7]

Within RRA's ranking system, North Carolina is rated "Average/1", which falls in the top one-third of the 53 regulatory commissions ranked by RRA.[8]

Q. DID YOU CONSIDER THOSE DISTINCTIONS IN YOUR REVIEW OF AUTHORIZED RETURNS RELATIVE TO THE STIPULATED ROE?

A. Yes. Across the 107 cases noted above, there was a 40-basis point difference between the median return for the Top Third and Bottom Third of jurisdictions (the higher-ranked jurisdictions providing the higher authorized returns, see Table 1,

[6] Rebuttal Testimony of Dylan W. D'Ascendis, 183.

[7] Source: Regulatory Research Associates, accessed July 28, 2020. *See*, also, Rebuttal Testimony of Dylan W. D'Ascendis, at 183.

[8] Source: Regulatory Research Associates, accessed July 28, 2020.

below). As Table 1 indicates, authorized ROEs for vertically integrated electric utilities in jurisdictions that, like North Carolina, are rated at least Average/1 range from 9.25 percent to 10.55 percent, with a median of 9.90 percent.

Table 1: Average Authorized ROE by RRA Ranking[9]

	Authorized ROE Vertically Integrated Electric Utilities		
RRA Ranking	Top Third	Middle Third	Bottom Third
Average	9.91%	9.53%	9.62%
Median	9.90%	9.50%	9.50%
Maximum	10.55%	10.30%	11.95%
Minimum	9.25%	8.75%	9.06%

Q. WHAT CONCLUSIONS DO YOU DRAW FROM THAT DATA?

A. The Stipulated ROE falls 30 to 31 basis points below the median and mean authorized ROE, respectively, for jurisdictions that are comparable to North Carolina's constructive regulatory environment, and 10 basis points above the median return authorized in less supportive jurisdictions. Taken from that perspective, the Stipulation ROE is a reasonable, if not somewhat conservative measure of the Company's Cost of Equity.

[9] Source: Regulatory Research Associates. "Top Third" includes Above Average/1,2,3 and Average/1; "Average" includes Average/2 and Average/3; "Bottom Third" includes Below Average/1,2,3. The "Top Third" group includes 18 of 53 jurisdictions, or about one-third of the total. *See* Settlement Exhibit DWD-1

Q. DO YOU BELIEVE THE STIPULATED CAPITAL STRUCTURE ALSO IS REASONABLE?

A. Yes, I do. As demonstrated in Table 2 (below) the Stipulated Equity Ratio is equal to the median authorized equity ratio in supportive regulatory jurisdictions (*i.e.*, 52.00 percent), and is well within the range of equity ratios authorized in those jurisdictions (40.25 percent to 57.16 percent).

Table 2: Average Authorized Equity Ratio by RRA Ranking[10]

	Authorized Equity Ratio Vertically Integrated Electric Utilities		
RRA Ranking	Top Third	Middle Third	Bottom Third
Average	51.29%	51.58%	50.69%
Median	52.00%	51.48%	49.46%
Maximum	57.16%	57.10%	58.18%
Minimum	40.25%	44.00%	48.35%

As discussed in my Rebuttal Testimony, because no two companies are identical, we should not view the average (or median) equity ratio (whether authorized or observed) as a strict measure of industry practice.[11] Nonetheless, the Stipulated Equity Ratio falls well within the range of authorized equity ratios, and is equal to the median for constructive regulatory jurisdictions. In my view, that finding provides additional support for its acceptance.

[10] Source: Regulatory Research Associates. Excludes capital structure decisions from Arkansas, Florida, Indiana, and Michigan, all of which include some form of non-investor supplied capital in the ratemaking capital structure.

[11] Rebuttal Testimony of Dylan W. D'Ascendis, at 30.

Q. HOW DOES THE 6.93 PERCENT OVERALL RATE OF RETURN CONTAINED IN THE SECOND PARTIAL SETTLEMENT COMPARE TO RECENTLY AUTHORIZED RETURNS?

A. It is quite low. Since January 2016, there have been 105 cases reported by RRA (for vertically integrated electric utilities) in which an overall Rate of Return was specified. Over those 105 cases, the median Rate of Return was 7.20 percent, 27 basis points above the 6.93 percent Rate of Return for the Company as contained in the Second Partial Settlement. From a slightly different perspective, 70 of the 105 cases had overall Rates of Return greater than 6.93 percent. In fact, the Second Partial Settlement's overall Rate of Return falls in the bottom 33rd percentile of the 105 cases decided since 2016.

The low overall Rate of Return contained in the Second Partial Settlement are brought about by the Company's rather low cost of debt. That low cost of debt is supported by reasonable regulatory outcomes, including constructive decisions regarding the Return on Equity, and capital structure. In my view, the Second Partial Settlement continues that support, and produces the low overall Rate of Return on which customer rates would be set. From that important perspective, the Stipulated ROE and capital structure strike the necessary balance between customer and investor interests.

Q. HAS YOUR TESTIMONY CONSIDERED ECONOMIC CONDITIONS IN NORTH CAROLINA?

A. Yes, it has. I understand and appreciate the Commission's need to balance the interests of investors and ratepayers, and to consider economic conditions in the State, as it sets rates. As explained in my Supplemental Rebuttal Testimony, I recognize that economic conditions have deteriorated in North Carolina in the first half of 2020, as have the economic conditions in across the U.S.[12] Because North Carolina's economic conditions remain highly correlated to the overall conditions in the U.S., my review of North Carolina's economic conditions do not alter my conclusion that the Stipulated ROE, Equity Ratio, and Rate of Return are reasonable resolutions to otherwise contentious issues.

Q. DOES THIS CONCLUDE YOUR SETTLEMENT TESTIMONY?

A. Yes.

[12] Supplemental Rebuttal Testimony of Dylan W. D'Ascendis, at 21-23.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1219

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

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND POSITION WITH DUKE ENERGY CORPORATION.

A. My name is Karl W. Newlin. My business address is 400 South Tryon Street, Charlotte, North Carolina, 28202. I am employed by Duke Energy Business Services, LLC ("DEBS") as Senior Vice President, Corporate Development and Treasurer. DEBS provides various administrative and other services to Duke Energy Progress, LLC, ("DE Progress," "DEP," or the "Company") and other affiliated companies of Duke Energy Corporation ("Duke Energy").

Q. PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL QUALIFICATIONS.

A. I graduated from Southern Methodist University with a Bachelor of Business Administration degree in 1991. I subsequently received a Master in Business Administration degree from UCLA's Anderson School of Management in 1998. I am also a Chartered Financial Analyst.

Q. PLEASE SUMMARIZE YOUR PROFESSIONAL EXPERIENCE.

A. In November 2018, I assumed the role of Senior Vice President, Corporate Development and Treasurer for Duke Energy. Previously, I served as Senior Vice President and Chief Commercial Officer for Duke Energy's natural gas business. In this role, I was responsible for gas commercial operations, which included supply, wholesale marketing, transportation and pipeline services, field customer service, sales and delivery, and business development. I was named to this position following Duke Energy's acquisition of Piedmont Natural Gas ("Piedmont") in October 2016.

I joined Piedmont in 2010 to manage Piedmont's strategic planning functions, new business development activities and joint venture investments. In November 2011, I was appointed to the position of Chief Financial Officer, assuming responsibility for Piedmont's accounting, controller, finance, treasurer, investor relations, insurance, credit policy, risk management and state regulatory affairs areas. Prior to joining Piedmont, I served as Managing Director of Investment Banking for Merrill Lynch & Co. in its New York and Los Angeles offices.

Q. PLEASE DESCRIBE YOUR DUTIES AS SENIOR VICE PRESIDENT, CORPORATE DEVELOPMENT AND TREASURER.

A. In my role as Treasurer, I am responsible for treasury-related services to Duke Energy and its subsidiaries, including DE Progress. I monitor trends in the investment markets and maintain key relationships with debt investors, analysts, and financial institutions. Under my supervision, the Treasury Department arranges and executes all capital raising and liquidity transactions, including credit facilities and commercial paper, debt securities, preferred and hybrid securities, and common stock, as well as daily cash management for Duke Energy and its subsidiaries. My responsibilities include managing Duke Energy and its subsidiaries' credit ratings and interactions with the major credit rating agencies, commercial banks, and the capital markets. I am also responsible for liability management and long-term investments. As head of corporate development, I am responsible for the Company's corporate development activities, as well as mergers and acquisitions.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION OR OTHER STATE PUBLIC UTILITY COMMISSIONS?

A. Yes. I have testified before the North Carolina Utilities Commission and have filed testimony on behalf of Piedmont Natural Gas in my prior role as Piedmont's Chief Financial Officer.

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

A. My testimony will address DE Progress' financial objectives, capital structure, and cost of capital. I will also discuss the current credit ratings and forecasted capital needs of DE Progress. Throughout my testimony, I will emphasize the importance of DE Progress' continued ability to meet its financial objectives.

Q. PLEASE PROVIDE AN OVERVIEW OF YOUR TESTIMONY.

A. As detailed in my testimony, DE Progress faces substantial capital needs over the next several years. The Company competes for capital in the open market, and must appeal to debt and Duke Energy's equity investors to attract the capital it needs. As Roger Morin, a leading expert on utility finance, indicates, "[t]he … prices of debt capital and equity capital are set by supply and demand, and both are influenced by the relationship between the risk and return expected for those securities and the risks expected from the overall menu of available securities." Morin, Roger A., *Utilities' Cost of Capital* (Public Utilities Reports, Inc. 1984), at 20. Investors have a variety of investment opportunities available to them, and require a return commensurate with the risk they incur. They will invest elsewhere if they feel the expected return provided by a company is inadequate, and lower credit quality weakens a company's attractiveness as an investment opportunity relative to companies with higher credit quality and similar return profiles. For this reason, it is critically important that the Company maintain strong, investment-grade credit quality to assure its financial strength and flexibility and ensure access to capital on reasonable terms.

The Company is making significant capital investments to provide cost-effective, safe, and reliable electric service to its customers well into the future. The Company's proposed rate increase will allow it to recover prudently incurred costs, compete in the capital markets for needed capital, and preserve its financial standing with both equity and debt investors as well as the credit rating agencies, to the long-term benefit of customers.

Q. WHAT ARE DE PROGRESS' FINANCIAL OBJECTIVES?

A. Financial strength and access to capital are necessary for DE Progress to provide cost-effective, safe, and reliable service to its customers. The Company, at all times, seeks to maintain its financial strength and flexibility, including its strong investment-grade credit ratings, ensuring reliable access to capital on reasonable terms. Specific objectives that support financial strength and flexibility include: (a) maintaining at least 53 percent common equity for DE Progress on a financial capitalization basis; (b) ensuring timely recovery of prudently incurred costs; (c) maintaining sufficient cash flows to meet obligations; and (d) maintaining a sufficient return on equity to fairly compensate shareholders for their invested capital. The ability to attract capital (both debt and equity) on reasonable terms is vitally important to the Company and its customers, and each of these specific objectives helps the Company both to maintain its investment-grade credit ratings and to meet its overall financial objectives.

Q. DO DE PROGRESS' CUSTOMERS BENEFIT FROM THE COMPANY'S STRONG CREDIT RATINGS?

A. Yes. To ensure reliable and cost-effective service, and to fulfill its obligations to serve customers, the Company must continuously plan and execute major capital projects. This is the nature of regulated, capital-intensive industries like electric and gas utilities. The Company must be able to operate and maintain its business without interruption and refinance maturing debt on time, regardless of financial market conditions. The financial markets can experience periods of volatility, and DE Progress must be able to finance its needs throughout such periods. Strong investment-grade credit ratings provide DE Progress with greater access to the capital markets on reasonable terms during such periods of volatility.

Q. WHAT RATEMAKING TREATMENT IS BEING REQUESTED IN THIS PROCEEDING AND HOW WILL THE COMPANY'S FINANCIAL OBJECTIVES BE IMPACTED?

A. As explained in the Company's Application and by Witness Kim Smith, DE Progress is requesting an overall rate increase of approximately 15.6 percent, equating to an increase in pre-tax revenue requirement of approximately $586 million. The proposed capitalization in this request is comprised of 47 percent debt and 53 percent equity.

In addition, the requested increase reflects, in part, an increase in the Company's cost of equity capital from the level approved by the Commission in the Company's last general rate case. The testimony of the Company's Return on Equity ("ROE") Witness, Robert Hevert, indicates that the Company's cost of equity capital is in the range of 10.0 percent to 11.0 percent. Based on his quantitative and qualitative analyses including the risk profile of the Company, Witness Hevert's view is that 10.5 percent is a reasonable and appropriate estimate of the Company's cost of equity capital.

The Company fully supports Witness Hevert's testimony and analysis. However, as a rate mitigation measure, and in recognition of the Company's ongoing efforts to keep rates affordable for customers, we have proposed rates to be set with an ROE of 10.3 percent. This requested ROE is within Witness Hevert's range, but 20 basis points below Witness Hevert's point estimate.

Approval of the Company's request in this case will support its financial objectives by allowing timely recovery of its investments in plant and equipment, providing sufficient cash flows to fund necessary capital expenditures and service debt, and providing a fair and reasonable return to equity investors.

Q. PLEASE EXPLAIN CREDIT QUALITY AND CREDIT RATINGS, AND HOW THEY ARE DETERMINED.

A. Credit quality (or creditworthiness) is a term used to describe a company's overall financial health and its willingness and ability to repay all financial obligations in full and on time. An assessment of DE Progress' creditworthiness is performed by two major credit rating agencies, Standard & Poor's ("S&P") and Moody's Investors Service ("Moody's"), and results in DE Progress' credit rating.

Many qualitative and quantitative factors go into this assessment. Qualitative aspects may include DE Progress' regulatory climate, its track record for delivering on its commitments, the strength of its management team, its operating performance, and the economic vitality and customer profile of its service area. Quantitative measures are primarily based on operating cash flow and focus on the level at which DE Progress maintains debt leverage in relation to its generation of cash and its ability to meet its fixed obligations (interest expense in particular) based on internally-generated cash. The percentage of debt to total capital is another example of a quantitative measure. Creditors and credit rating agencies view both qualitative and quantitative factors in the aggregate when assessing the credit quality of a company.

Q. WHAT IS THE ROLE OF REGULATION IN THE DETERMINATION OF THE FINANCIAL STRENGTH OF A UTILITY COMPANY?

A. Investors, investment analysts and credit rating agencies regard constructive regulation as one of the most important factors in assessing a utility company's financial strength. These stakeholders want to be confident that the Company operates in a stable regulatory environment that will allow the Company to recover prudently incurred costs and earn a reasonable return on investments necessary to meet the demand, reliability, service, and environmental requirements of its customers and service area. Important considerations include the allowed rate of return, the cash quality of earnings, the timely recovery of capital investments, the stability of earnings, and the strength of its capital structure. Positive consideration is also given for utilities operating in states where the regulatory process is streamlined, the time lag in capital investment recovery is minimized through cost recovery mechanisms such as riders and trackers, and outcomes are equitably balanced between customers and investors.

Q. HOW ARE DE PROGRESS' OUTSTANDING SECURITIES CURRENTLY RATED BY THE CREDIT RATING AGENCIES?

A. As of the date of this testimony, DE Progress' outstanding debt is rated as follows:

Rating Agency	**S&P**	**Moody's**
Issuer / Corporate Credit Rating	A-	A2
Senior Secured	A	Aa3
Outlook	Negative	Stable

Obligations carrying a credit rating in the "A" category are considered strong, investment-grade securities subject to low credit risk for the investor. "A" rated debt is presumed to be somewhat susceptible to changes in circumstances and economic conditions; however, the debt issuer's capacity to meet its financial commitments is considered strong. By contrast, ratings in the "BBB" category are considered adequate and have less assurance of access to the capital markets in challenging market conditions. (AA and Aa category ratings for S&P and Moody's, respectively, are stronger than A ratings.)

S&P may also modify its ratings with the use of a plus or minus sign to further indicate the relative standing within a major rating category. An "A+" credit rating is at the higher end of the "A" credit rating category and an "A-" is at the lower end of the category. Moody's credit rating assignments use the numbers "1", "2" and "3", with the numbers "1" and "3" analogous to a "+" and "-", respectively. For example, Moody's credit ratings of "A2" and "A3" would be analogous to "A" and "A-" credit ratings at S&P, respectively.

The ratings outlook assesses the potential direction of a long-term credit rating over an intermediate term (typically six months to two years). DE Progress' "Stable" outlook at Moody's means that those credit ratings are not likely to change at this time; however, a change in outlook or rating could occur if the Company experiences a change in its qualitative or quantitative credit quality. S&P utilizes a family rating methodology, whereby the credit rating and outlook of the parent company, Duke Energy Corporation, is applied to each of the parent's subsidiaries. S&P revised its outlook to "Negative" on May 20, 2019 citing concerns of weaker financial measures due to 2018 storms, uncertainty over growing coal ash remediation costs and recovery in the Carolinas, regulatory lag during a period of robust capital spending and delays related to the Atlantic Coast Pipeline. S&P stated in its May 2019 Duke Energy

Corporation report[1] that the outlook could be restored to stable if Duke Energy Corporation and its subsidiaries improve financial measures in the next 12-24 months without any deterioration in the Company's business risk profile.

Q. WHAT STRENGTHS AND WEAKNESSES HAVE THE CREDIT RATING AGENCIES IDENTIFIED WITH RESPECT TO DE PROGRESS?

A. The rating agencies believe DE Progress operates in a generally constructive regulatory environment that supports long-term credit quality, and view the Company's position within the Duke Energy corporate family as credit supportive. However, the rating agencies have identified several challenges the Company faces in maintaining its credit ratings. In March 2019, Moody's identified several factors that could adversely impact the Company's financial metrics (specifically, cash flow coverage ratios), which, in turn, could affect its ratings.[2]

- Regulatory Lag: Moody's is particularly focused on downward pressure on financial metrics due to regulatory lag, including in the recovery of coal ash basin closure costs and storm expense.
- Tax Reform: Moody's also points to federal tax reform putting pressure on the Company's credit metrics due to reduced cash flows.

[1] *See* S&P Global Ratings, Research Update "Duke Energy Corp. And Subs. Outlook Revised To Negative On Coal Ash Risks, Regulatory-Lag, And Project Delays," May 20, 2019 ("May 2019 Duke Energy Corporation Report").

[2] *See* Moody's Investors Service, Credit Opinion, "Duke Energy Progress, LLC – Update to Credit Analysis," March 28, 2019 ("March 2019 DE Progress Report").

- Capital Expenditures: Moody's notes elevated capital expenditures, due to new generation, transmission and distribution upgrades and environmental compliance, including coal ash basin closure and remediation.

S&P identifies similar risks to Duke Energy Corporation and DE Progress in its September 2018 research update.[3] As indicated previously in my testimony, as of May 20, 2019, S&P revised its outlook for Duke Energy Corporation, as well as its subsidiaries including DE Progress, from "Stable" to "Negative." S&P highlighted "…several headwinds, including coal ash risks, project delays, regulatory lag, and high capital spending that we expect could pressure and weaken its financial measures over the next 12-24 months."[4] Furthermore, S&P includes recent regulatory directives in South Carolina within its Rating Action Rationale, "…which effectively lowers Duke Energy's authorized returns, and disallows recovery of certain coal ash costs, elevates both coal ash and regulatory risks for the company, signaling a potential change in the consistency and predictability of that state's regulatory construct." [4]

Q. HOW DO THE RATING AGENCIES VIEW THE IMPACT OF TAX REFORM ON UTILITY CREDIT QUALITY?

A. In January 2018, Moody's published a report outlining its initial assessment of the impact of tax reform on the regulated utility sector.[5] In its report, Moody's noted "the legislation was broadly credit positive for corporate cash flows but

[3] *See* S&P Global Ratings, "Summary: Duke Energy Progress LLC," September 13, 2018 ("September 2018 DE Progress Report").

[4] *See* May 2019 Duke Energy Corporation Report.

[5] *See* Moody's Investors Service, Sector Comment, "Tax Reform is Credit Negative for Sector, but Impact Varies by Company," January 24, 2018 ("January 2018 Report").

for regulated investor-owned utilities, which include electric, gas, and water utilities, the effect was the opposite."[6] In addition to outlining the negative impact of tax reform on utilities and the regulatory uncertainties related thereto, Moody's changed the rating outlook of 24 utilities (including Duke Energy Corporation) from "Stable" to "Negative."

In June 2018, Moody's updated its 2019 outlook for the regulated utility sector to "Negative" from "Stable."[7] A key factor in this outlook change was a decline in cash flows. Moody's stated that "the combination of a lower tax rate and the loss of bonus depreciation as a result of the federal Tax Cuts & Job Act ("TCJA") in December 2017 means that utilities and their holding companies will lose some of the cash flow contribution from deferred taxes on an ongoing basis."[8] Moody's estimated that since 2010, the cash due to deferred taxes averaged 14% of Funds from Operations ("FFO"), which is a measure of cash flow generated by a company's operations, on a consolidated basis.

Of the 24 utilities Moody's placed on "Negative" outlook in January 2018, Duke Energy was the first to have its outlook resolved. In August 2018, Moody's issued a credit opinion restoring Duke Energy's outlook to "Stable."[9] Moody's attributed this to an expectation that Duke Energy will maintain supportive regulatory relationships and highlighted credit supportive rate case outcomes across several regulatory jurisdictions. Moody's also described how

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[6] January 2018 Report, p. 1.
[7] *See* Moody's Investors Service, Outlook, "2019 Outlook Shifts to Negative Due to Weaker Cash Flows, Continued High Leverage," June 18, 2018 ("June 2018 Report").
[8] June 2018 Report, p. 2.
[9] *See* Moody's Investors Service, Credit Opinion, "Duke Energy Corporation – Update Following Change of Outlook to Stable," August 14, 2018 ("August 2018 Duke Energy Corporation Report").

Duke Energy's 2018 equity issuance and reduced capital program in response to tax reform helped reduce parent-level debt financing.

Q. MOODY'S HAS NOT CHANGED DE PROGRESS' RATINGS OUTLOOK. DOES THIS MEAN TAX REFORM DOES NOT MATERIALLY IMPACT DE PROGRESS?

A. No. While the Moody's January 2018 Report identifies certain utility issuers whose credit metrics are weaker relative to their current ratings, it does not mean that Moody's will not take action on other utility issuers in the future. If unmitigated, the reduction in cash flows will erode DE Progress' credit metrics. In its June 2018 Report, Moody's included a financial forecast using a peer group of 102 utility operating companies. Moody's forecasted that the reduction in cash flow will cause operating company FFO/Debt metrics to drop "to 20% from 24% over the next 12-18 months."[10] This is an industry-wide analysis where some issuers will be affected more than others.

Additionally, Moody's issued an updated credit opinion for Duke Energy Corporation on October 13, 2019,[11] highlighting the fact that "…revenues and cash flow are being negatively impacted by the 2017 Tax Cuts and Jobs Act (TCJA), continued lag in recovery of coal ash remediation costs, severe storm activity, and lag in recovery of grid modernization investments." Moody's also emphasized certain factors that could lead to a downgrade including "A deterioration in the credit supportiveness or emergence of a more

[10] June 2018 Report, p. 2.
[11] *See* Moody's Investors Service, Credit Opinion, "Duke Energy Corporation – Update to credit analysis," October 13, 2019 ("October 2019 Duke Energy Corporation Report").

contentious regulatory relationship which negatively impacts cash flows or the timeliness of cost recovery, particularly with regards to coal ash remediation recovery in North Carolina." Moody's identifies "Credit supportive regulatory relationships" as a credit strength and elaborates that "The stable outlook reflects our expectation that [Duke Energy Corporation] will maintain supportive regulatory relationships in all of its jurisdictions."

Q. HOW COULD TAX REFORM CREATE CONCERNS FOR CUSTOMERS AND FOR UTILITIES?

A. As I explain further below, deferred taxes are not large pools of money that the Company is holding in an account somewhere. Instead, they are collections that occur over time based on the life of the underlying assets, which the Company has used to invest in its business during the deferral period to better serve customers. As a result, customers have benefitted because the Company has used these "zero interest" loans to finance its business rather than incurring financing costs that are passed on to customers. When the tax rate changes, either up or down, leveraging the over and under-collection of these funds in a proper and principled manner benefits both the Company and customers. If, however, adjusting rates to account for tax changes is done in a haphazard manner, it can cause rate volatility and harm to customers as well as the financial health of the utility as explained further below.

For example, if the Commission sets a precedent in this case that decreases in tax rates should be provided to customers as quickly as possible, then it logically follows that DE Progress would need to access capital markets to raise cash to provide for the shortfall in funds collected. The unplanned and possibly large capital raise could put stress on DE Progress' credit quality and rating. It also logically follows that any future tax increases should be collected from customers as quickly as possible in similar fashion. With a tax increase, customers would then experience an immediate, and perhaps dramatic, increase in rates, which is something the Commission attempts to avoid by deploying the concept of gradualism. That same concept of gradualism applies equally to tax decreases and must be considered just as it would with a tax increase.

Q. PLEASE EXPLAIN HOW DEFERRED TAXES ARE CREATED.

A. As noted by Witness Panizza in his testimony, the Company has Accumulated Deferred Income Taxes ("ADIT"), where it has collected a book level of tax expense for tax liabilities from customers. Because the IRS rules provide certain financial incentives, such as accelerated depreciation and credits, actual tax expense can be lower for tax purposes than book, and create timing differences between when the costs are recovered from customers versus when the costs are payable to the government. Often, IRS income is lower in the early years because the IRS offers credits, accelerated depreciation, and other incentives so that the Company is collecting from customers at a level higher than what is actually being paid in cash taxes, which is common across the industry. As a result, a liability to pay those taxes in the future is recorded to the Company's balance sheet because it is not a permanent reduction in taxes; rather a delay in payment of cash taxes.

A deferred tax liability is a customer benefit. These ADIT are essentially a free loan the Company uses to finance its investments. Thus, instead of having to access third-party capital from either debt or equity investors (which, as a cost of service, customers pay for in rates), the Company can use these funds to invest in its business, amounting in essence to an interest-free loan from the government. That liability also benefits customers because it serves as a reduction to rate base and, as the Company does not earn on rate base to the extent that we have deferred tax liability on the balance sheet, customers effectively save the weighted average cost of capital on the deferred tax balance. As such, the deferred tax balance is an additional source of capital to the Company, and a source of capital for which customers do not pay.

Over time, the deferred taxes become due and what was once a lower cash tax today versus what the Company collected on that same asset reverses, and the Company ends up paying more cash taxes than it has collected, depleting the ADIT balance for an asset (of course this process occurs on hundreds of thousands of assets in the Company over various windows of time).

Q. WHAT IS THE IMPACT OF THE TAX REFORM ON THE COMPANY'S DEFERRED TAXES AND HOW DOES THAT IMPACT CUSTOMERS?

A. Because of the change in the corporate tax rate from 35% to 21%, the Company now has Excess Deferred Income Taxes ("EDIT"), which is excess ADIT that must be returned to customers where the Company previously collected from customers at the higher 35% tax rate and will now have a lower payment obligation at the new 21% tax rate. However, those ADIT were used to invest in the business so the question becomes how to return those excess deferred taxes back to customers. Because the ADIT are currently being used to finance Company investments, in turn benefitting customers, as the Company pays the EDIT back to customers, it must find other sources of financing for these investments.

Q. WHAT POTENTIAL NEGATIVE IMPACT COULD THE TAX REFORM HAVE ON THE COMPANY AND HOW MIGHT THAT IMPACT CUSTOMER RATES?

A. For the EDIT not subject to a statutory flow-back period, the question becomes what is the appropriate flow-back period to customers that balances both the best interest of customers and the financial strength of the Company and the cash flows of the Company. EDIT flow-back has several effects, which move in sometimes contradictory directions – it reduces the Company's cash flow, but also results in an increase in rate base. Reduction in the Company's cash flow obviously negatively affects the Company, but it also negatively affects customers. Customers benefit from a financially strong utility, which can then access capital markets as needed on favorable terms. Increase in rate base ultimately leads to higher rates for customers – a negative for customers, although a positive for the Company. Thus, the EDIT issue is complex.

By using the deferred taxes to invest in the business, the Company avoided having to go to the capital markets to raise this portion of the funds that it invested, and customers saved the capital cost of its being able to use the interest-free loan from the government instead of investor-supplied capital. But having invested in the business, there is not a readily available reserve pool from which the cash needed to return the EDIT can be drawn. As previously explained, there is a property-related life cycle to deferred taxes and based on our analysis, the average flow-back had those deferred taxes not become excess deferred taxes, is 22 years. Accordingly, the Company is proposing to flow these property-related excess deferred taxes back to customers over a 20-year period. An EDIT flow-back period that more closely matches the underlying asset lives smooths out the cash flow hit the Company must take as it returns EDIT to customers, and lessens the need for the Company to raise those funds from investors and third-parties.

In contrast, had the tax rate increased, the Company would not request to recover the increased amount instantly or over a short-time frame for the same reason - because the higher taxes would be paid over the life of the asset.

Addressing the impact on customer rates over a longer period also helps avoid rate volatility. For example, if the Company were to return the EDIT instantly or over a two-year period, customers would experience a dramatic reduction in rates followed by a dramatic increase due to the expiration of the flow-back and higher rate base. In contrast, had the tax rate increased and the Company requested that payment from customers in two years, the converse would be true and if the Company requested that customers pay the increased taxes over a short period of time, customers would experience a dramatic increase in rates, followed by a dramatic decrease. Thus, addressing the customer rate impact of tax rate changes over a longer period serves to smooth out rate volatility and we propose it be applied to the unprotected excess deferred taxes in this case. In either situation, whether the tax rate decreases or increases, when considering the collection or return of funds through customer rates, it is appropriate to consider the life of the underlying asset, to achieve gradualism rather than rate volatility, consider impacts in cash flows to the Company, and to fairly balance the interest of customers and the Company.

Q. HAVE OTHER UTILITY COMMISSIONS TAKEN STEPS TO MITIGATE THE NEGATIVE IMPACTS OF TAX REFORM?

A. Yes. Examples include:

- In South Carolina, the Public Service Commission granted DE Carolinas and DE Progress the ability to use an EDIT rider to reflect the reduction in tax rates enacted in the TCJA, authorizing a 20-year amortization period of approximately $269 million of unprotected Federal EDIT related to property, plant, and equipment for DE Carolinas and approximately $58 million for DE Progress.
- In Florida, the Public Service Commission ordered Duke Energy Florida to accelerate depreciation of coal assets by $50 million per year. It also granted DE Florida the ability to use the remainder of the customer benefits of a lower tax rate to avoid a rate increase for power restoration costs associated with Hurricane Irma. In August 2018, Moody's stated

that it views "these tax reform related developments as supportive of credit quality."[12]

- The Indiana Utility Regulatory Commission also issued a credit-supportive order to mitigate the near-term impacts of tax reform. DE Indiana was authorized a 10-year amortization period of approximately $167 million unprotected EDIT. However, the refund to customers is limited to $7 million per year in the first five years, increasing to $35 million per year until the entire deferral amount has been returned to customers. This back-end shaping of the deferral is credit-supportive as it limits the near-term negative impact from lower cash flows and allows the utility more time to prepare for and absorb the higher payback obligation.
- In Georgia, a settlement between Georgia Power and the Commission staff puts off EDIT issues for two years, and increases the equity portion of the utility's equity-to-debt ratio while flowing back to customers the effects of the tax rate decrease. Adjustments to the utility's ROE or equity layer are on the Moody's list of mitigation measures.[13]
- In Alabama, the Public Service Commission approved a plan to increase Alabama Power's equity ratio to 55 percent by 2025. It also authorized Alabama Power to offset $30 million of under-recovered fuel costs with its EDIT.

[12] *See* Moody's Investors Service, Credit Opinion, "Progress Energy, Inc. – Update Following Upgrade to Baa1," August 13, 2018, p. 3 ("August 2018 Progress Energy Report").
[13] January 2018 Report, p. 4.

Q. WHAT IS DE PROGRESS' PROPOSED CAPITAL STRUCTURE?

A. As mentioned earlier in this testimony, DE Progress' proposed capital structure is 47 percent long-term debt and 53 percent equity. The Company believes this proposed capital structure is optimal for DE Progress, as it introduces an appropriate amount of risk due to leverage while minimizing the weighted average cost of capital to customers. Approval of the proposed capital structure will help DE Progress maintain its credit quality. This level is also consistent with the Company's target credit ratings for DE Progress.

Q. DOES THE ACTUAL FINANCIAL CAPITAL STRUCTURE VARY OVER TIME?

A. Yes, it does. The specific debt/equity ratio will vary over time, depending on a variety of factors, including, among other things, the timing and size of capital investments and payments of large invoices, debt issuances, seasonality of earnings, and dividend payments to the parent company. Achieving an approved regulatory capital structure of 47/53 is consistent with the Company's financial objectives and overall plan to maintain its ability to finance operations at rates favorable for customers and DE Progress will manage its capital structure within reasonable range of this base. As of December 31, 2018, DE Progress' capital structure was 46.3 percent long-term debt and 53.7 percent equity.

Q. WHAT IS DE PROGRESS' COST OF EQUITY?

A. Witness Robert Hevert, who has separately filed testimony, indicates that the Company's cost of equity is 10.5 percent, and the Company supports Mr.

Hevert's analysis. However, as indicated previously in my testimony, for rate mitigation purposes, the Company has proposed rates including an ROE of 10.3 percent.

Q. WHAT ROLE DO EQUITY INVESTORS PLAY IN THE FINANCING OF DE PROGRESS, AND HOW WILL THE OUTCOME OF THIS CASE IMPACT THESE INVESTORS?

A. Equity investors provide the foundation of a company's capitalization by providing significant amounts of capital, for which an appropriate economic return is required. DE Progress compensates equity investors for the risk of their investment in Duke Energy by targeting fair and adequate returns, a stable dividend, and earnings growth – these are all necessary to preserve access to equity capital. Returns to equity investors are realized only after all operating expenses and fixed payment obligations (including debt principal and interest) of the business have been paid. Because equity investors are the last to receive surplus earnings and cash flows, their investment involves significantly more risk. For this reason, equity investors require a higher return for their investment. Equity investors expect utilities like DE Progress to recover their prudently incurred costs and earn a fair and reasonable return for their investors. The Company's proposal in this proceeding supports this investor requirement.

Q. WHAT EFFECT DOES CAPITAL STRUCTURE AND RETURN ON EQUITY HAVE ON CREDIT QUALITY?

A. Capital structure and return on equity are important components of credit quality. As mentioned in the previous answer, the greater the equity component of capitalization, the safer the returns are to debt investors, which translates into higher credit quality and lower borrowing costs. In addition, the allowed return on equity is a key component in the generation of earnings and cash flows. An adequate return on equity helps ensure equity investors receive fair compensation for their investment while also helping to protect the interests of debt investors.

A strong capital structure and an adequate return on equity provide balance sheet protection and cash flow generation to support high credit quality. High credit quality creates financial flexibility by providing more readily available access to the capital markets on reasonable terms, and ultimately lower debt financing costs. Conversely, a weak capital structure and an inadequate allowed return on equity produces lower earnings and cash flows, lowers credit quality, and may limit financial flexibility. As mentioned in my testimony above, regulatory directives in South Carolina, including lower authorized returns, were highlighted in S&P's Rating Action Rationale supporting their revised "Negative" outlook for Duke Energy Corporation and its subsidiaries in May 2019.

Q. DO YOU BELIEVE THAT DE PROGRESS' CAPITAL STRUCTURE HAS AN ADEQUATE EQUITY COMPONENT TO ENABLE DE PROGRESS TO ACHIEVE THE COMPANY'S FINANCIAL STRENGTH AND CREDIT QUALITY OBJECTIVES?

A. Yes. DE Progress' equity component, as requested in this case, enables it to maintain current credit ratings and financial strength and flexibility. This level of equity enables the Company to tolerate different business cycles while also providing more confidence to the Company's lenders and bondholders. Like many utilities, DE Progress is in a period of significant capital investment necessary to provide cost-effective, safe, and reliable service to its customers in a time of rising costs, lower load growth and rapidly evolving state and federal requirements. The magnitude of its capital requirements dictates the need for a strong equity component of the Company's capital structure to ensure access to capital funding at reasonable terms.

Q. WHAT IS DE PROGRESS' AVERAGE COST OF LONG-TERM DEBT?

A. DE Progress' weighted average cost of long-term debt as of December 31, 2018 is 4.15 percent. Over the last several years, DE Progress has been taking advantage of low interest rates, steadily decreasing the weighted average cost of long-term debt as older bonds are replaced with new, lower cost, issuances.

Q. WHAT ARE DE PROGRESS' CAPITAL REQUIREMENTS OVER THE NEXT THREE YEARS?

A. DE Progress faces substantial capital needs over the next several years to comply with environmental requirements, refurbish, replace and upgrade aging infrastructure; construct or acquire needed generation resources; strengthen and modernize our energy grid; and satisfy its debt maturities. The Company's capital requirements for the next three years (2020-2022) are projected to be approximately $8.1 billion. This amount consists of approximately $6 billion in projected capital expenditures and approximately $2.1 billion in debt retirements.

Q. HOW WILL DE PROGRESS' CAPITAL REQUIREMENTS BE FUNDED?

A. DE Progress' capital requirements are expected to be funded from internal cash generation, the issuance of debt, and equity funding from Duke Energy.

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

A. Yes.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1219

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

I. INTRODUCTION AND PURPOSE

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

A. My name is Karl W. Newlin, and my business address is 550 South Tryon Street, Charlotte, North Carolina, 28202. I am employed by Duke Energy Business Services, LLC as Senior Vice President, Corporate Development and Treasurer.

Q. DID YOU FILE DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes. I filed direct testimony supporting Duke Energy Progress, LLC's ("DE Progress" or the "Company") financial objectives, capital structure, and cost of capital.

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

A. The purpose of my rebuttal testimony is to respond to portions of the testimony submitted by the following:

- Dr. J. Randall Woolridge and Mr. John R. Hinton, witnesses on behalf of the Public Staff of the North Carolina Utilities Commission ("Public Staff");
- Mr. Richard A. Baudino, witness on behalf of the North Carolina Attorney General's Office ("AGO");
- Mr. Kevin W. O'Donnell, witness on behalf of Carolina Utility Customers Association, Inc. ("CUCA"); and
- Mr. Nicholas Phillips on behalf of Carolina Industrial Group for Fair Utility Rates ("CIGFUR II").

In my testimony, I will address their respective recommendations on the following:

- Capital structure and Return on Equity ("ROE") and the financial impacts to the Company from the overall revenue requirement;
- Reducing the amortization period of the unprotected excess deferred income taxes ("EDIT") related to the Company's investments in property, plant, and equipment ("PP&E") assets; and
- Recovery and treatment of costs incurred to comply with regulations relating to coal combustion residuals ("CCR") and the impacts on the credit quality of the Company.

Apart from flaws in their positions, I urge the Commission to consider the negative consequences the arguments put forth by the witnesses above will have on the Company and its customers if adopted. In sum, a reduction in return on equity from the proposed 10.30% to 8.75% (O'Donnell) or even 9.00% (Woolridge and Baudino); a reduction in the equity component of the capital structure from 53% to 51.5% (Baudino) or 50% (Woolridge and O'Donnell); EDIT refunding over five years rather than 20 years (Hinton); extraordinary coal ash basin closure cost disallowances (multiple witnesses); an unprecedented CCR cost sharing program between customers and shareholders, contrary to pre-existing precedent established in the Commission's order in the Company's last rate case, Docket No. E-2, Sub 1142 (the "2017 Rate Case"); and the disallowance of a debt and equity return on billions of dollars of investments all will harm the quantitative and qualitative aspects of DE Progress' credit quality. Individually and in the aggregate, I believe these actions will lead to reduced cash flows, increased leverage and risk, stressed credit metrics, higher borrowing costs, lowered financial flexibility, and, ultimately, higher cost of capital (both debt and equity), to the detriment of our customers. My position is further supported by the testimony of Company witnesses Steven K. Young, Robert B. Hevert, and Steven M. Fetter.

II. FINANCIAL IMPACTS OF THE PUBLIC STAFF RECOMMENDATION

Q. DO YOU HAVE ANY CONCERNS WITH THE OVERALL PUBLIC STAFF AND OTHER INTERVENORS' RECOMMENDATIONS?

A. As an initial matter, each of the Public Staff and other intervenors' positions discussed throughout my testimony do not exist in isolation and should not be viewed as such. Rather, they must be viewed as part of an overall recommendation by the Public Staff to decrease the Company's base revenue requirement by approximately $405 million, as summarized in Dorgan Supplemental Exhibit 1, Schedule 1.

To fully understand the adverse impact to the Company's credit quality, the entire recommendation must be considered. Among other things, Dorgan Exhibit 1, Schedule 1 outlines a reduction of the current allowed ROE by 120 basis points to 9.0%, an increase in leverage of 300 basis points resulting from a revised capital structure of 50% debt-to-equity, accelerated EDIT flowback over an arbitrary 5-year period, no return on CCR environmental compliance costs during a 27 year amortization period – with not even a debt return – and extending the period of recovery for other costs. Adopting the Public Staff position would exacerbate the magnitude of regulatory lag cited by the rating agencies and weaken the Company's credit metrics. On a quantitative basis, the Company's leverage would increase and cash flows to fund its operations and service debt would decrease. In recent credit reports, both Moody's and S&P view the Company's current regulatory framework as generally constructive, supporting long-term credit quality. Adopting the Public Staff position with a significantly lower ROE, more leveraged capital structure, accelerated EDIT flowback, and insufficient recovery of and on CCR environmental compliance costs, will likely lead the rating agencies to question their view regarding the constructiveness of North Carolina's regulatory environment. As I note below, this in turn will lead to even more pressure on the Company's credit profile.

As I will describe throughout my testimony, when considering a company's credit rating, the rating agencies contemplate both qualitative and quantitative components of a borrower's credit quality. Moving one component changes how a rating agency will view other components. For example, if the agencies' qualitative assessment of a company is lowered, they may then require stronger quantitative metrics to offset the change to avoid a credit downgrade. Again, if the Public Staff's recommendations are adopted, it would have an adverse impact on both the qualitative (less constructive regulatory environment) and quantitative (weaker credit metrics) aspects in evaluating the Company's credit quality, which would compromise its ability to undertake investments aimed at allowing it to continue to provide reliable, increasingly clean, and reasonably priced electric service.

DE Progress has maintained A2 (Moody's) / A- (S&P) credit ratings since 2016 and 2015 respectively. Additionally, the Company has worked constructively since the early 2000s to improve its credit profile while continuing to make investments to better serve customers. As other witnesses state, this has allowed the Company to provide customers excellent service at low rates. Given the Company is facing unprecedented capital requirements, including billions of dollars in required CCR compliance costs, I believe now is the time to continue to preserve credit strength and flexibility so the Company may meet its capital obligations on behalf of customers. The aggregate impact of a lower ROE, more leveraged capital structure, accelerated EDIT flowback, and delayed or inadequate coal ash recovery without a full debt and equity return would stress the quantitative and qualitative credit aspects of DE Progress and would be expected to lead to increased risk and higher costs for customers. The more punitive the impacts of reduced cash flows or incremental leverage, including those driven from a lower ROE or a more leveraged capital structure, the higher the risk and greater the impact on credit quality and future borrowing costs.

Q. GIVEN YOUR CONCERNS WITH HOW THE OVERALL PUBLIC STAFF AND OTHER INTERVENOR RECOMMENDATIONS WILL ADVERSELY IMPACT CREDIT QUALITY, HOW DO YOU BELIEVE FIXED INCOME INVESTORS WILL REACT IF THESE RECOMMENDATIONS WERE TO BE ADOPTED?

A. When evaluating investment alternatives, fixed income investors use a set of criteria similar to that of the rating agencies. As previously stated, if the Public Staff and/or other intervenor recommendations were to be adopted, the Company's leverage would increase, and cash flows would decrease. For a fixed income investor, the risk of investing in DE Progress' debt securities would increase. To compensate for the increased risk, investors would require a higher interest rate for loaning money to the Company. Additionally, based on a data request during discovery, I provided an estimate that moving from an Aa3 to an A1 senior secured first mortgage bond borrowing at DE Progress would be expected to add 10 basis points to the cost of debt in a normal or a typical period in the bond market. While that may be the case in a typical period, during periods of dramatic market volatility, such as the 2009 financial crisis and what is being experienced with COVID-19, credit spreads will, and have historically, widened out dramatically with lower rated entities having more limited access (if they have any access at all) and experiencing increased borrowing costs. Strong investment grade credit provides protection, flexibility, and access to issuers with higher credit ratings during these periods.

III. CAPITAL STRUCTURE

Q. PLEASE SUMMARIZE THE KEY POINTS MADE BY INTERVENOR WITNESSES REGARDING YOUR RECOMMENDATION THAT THE COMPANY'S CAPITAL STRUCTURE BE 53% EQUITY AND 47% DEBT.

A. The key points are as follows:

- Mr. O'Donnell and Dr. Woolridge recommend a 50/50 capital structure based upon the "average" capital structure calculated for the companies that they utilize as "proxy" companies for purposes of their calculation of DE Progress' rate of return on equity (ROE), or cost of equity capital. Mr. Baudino makes a similar comparison when recommending his 51.5 percent equity ratio, referencing the "average" capital structure of certain "proxy" companies as summarized in Table 3 of his testimony. That is, these witnesses compare the capital structure of DE Progress, a regulated utility operating company, with the capital structures of a multitude of publicly traded holding companies, with utility operating company subsidiaries. This is an inappropriate, apples-to-oranges comparison, as I demonstrate in my testimony, and as the Commission has already held.
- Mr. O'Donnell also utilizes data from S&P Global Market Intelligence which purports to show capital structures approved by various utility regulatory commissions. This data is also inappropriate to utilize in this

fashion, because it does not differentiate between various types of utility companies, which present radically different risk profiles.

- Mr. Baudino recommends that the Commission use a capital structure of 51.5% equity and 48.5% debt, consistent with his recommendation in the ongoing Duke Energy Carolinas ("DE Carolinas") 2019 rate case which Mr. Baudino based on DE Carolinas actual capital structure as of December 31, 2018 (the end of the test year), in setting rates in that proceeding. As noted in my direct testimony, the specific debt/equity ratio of a utility will vary over time, depending on a variety of factors including the timing and size of debt issuances, seasonality of earnings, and dividend payments to the parent company. The assertion that a 51.5% equity ratio based on the actual capital structure of a sister utility of DE Progress at a specific point in time ignores the practical reality that a capital structure will vary due to specific situations for that particular utility as well as timing. Furthermore, as provided in Public Staff Data Request 24-6, DE Progress' actual capital structure as of December 31, 2018 and 2019 was 51.8% and 52% respectively. Were witness Baudino being consistent with his DE Carolinas methodology, he would have used the Company's actual capital structure as he did in the DE Carolinas case, and his failure to do so evidences his result-oriented analysis. Like witnesses Woolridge and O'Donnell, Mr.

Baudino also supports his capital structure recommendation by comparison to a proxy group including holding companies.

- Dr. Woolridge addresses the concept of double leverage and uses Duke Energy's holding company capital structure as support for his recommended 50/50 capital structure for DE Progress. This is an inappropriate comparison as DE Progress is a regulated utility operating company, not a parent-level holding company. DE Progress is a separately rated entity that issues its own debt and maintains a capital structure that is separate and distinct from its parent, Duke Energy Corporation.

Q. DR. WOOLRIDGE, MR. O'DONNELL, AND MR. BAUDINO'S ANALYSES ARE BASED UPON A COMPARISON OF DE PROGRESS' PROPOSED CAPITAL STRUCTURE TO THE CAPITAL STRUCTURES OF PARENT-LEVEL HOLDING COMPANIES. DO YOU HAVE ANY CONCERNS WITH THIS APPROACH?

A. Yes. All three witnesses utilize parent-level holding companies in their analysis, as shown by Woolridge Exhibit JRW-2, O'Donnell Table 10, and Baudino Table 3. It is inappropriate to compare the Company's capital structure to these groups, as DE Progress is a regulated utility operating company, not a parent-level holding company. The assets obtained by DE Progress to serve customers were financed in a manner consistent with the Company's capital structure as a regulated utility, not that of a parent-level holding company.

Holding company capital structures differ from regulated utility operating company capital structures for a variety of reasons, and the risk profile for a consolidated entity can be very different than the risk profile of a single subsidiary. Arbitrarily imposing a holding company capital structure upon DE Progress would increase its leverage (and, therefore, risk), reduce its cash flows, and erode credit quality – all to the detriment of the Company's customers.

Q. COMPANY WITNESS HEVERT USES HOLDING COMPANIES FOR HIS ROE ANALYSIS. WHY DOES THAT MAKE SENSE FOR ROE BUT NOT FOR CAPITAL STRUCTURE?

A. Cost of Equity models require observable stock price data, which only occur at the parent level, and, therefore, those models must utilize parent company data. The appropriate capital financing structure for a given utility operating company is not dependent upon that kind of information, and there is no reason to conflate capital structure and ROE in this way.

Q. WHAT DO YOU THINK REPRESENTS AN APPROPRIATE COMPARISON GROUP FOR PURPOSES OF ANALYZING DE PROGRESS' CAPITAL STRUCTURE?

A. If the objective is to compare DE Progress' capital structure against those of other companies, I believe a more appropriate group of companies against which to compare is a set of regulated utility operating companies. However, a meaningful comparison may still be complicated by the unique facts and circumstances surrounding each utility business model. Capital structure should not be viewed in isolation; it is part of an overall structure which considers asset mix, business model, allowed ROE, and the various mechanisms used to recover costs.

Q. DID THE COMPANY PERFORM AN ANALYSIS OF THE CAPITAL STRUCTURES OF HOLDING COMPANIES VERSUS REGULATED UTILITY OPERATING COMPANIES?

A. Yes. Witness Hevert performed this analysis on behalf of the Company, and his findings are presented generally in his rebuttal testimony, as well as in Rebuttal Exhibits RBH-7 (for witness Hevert's updated proxy group), RBH-17 (for Dr. Woolridge's proxy group), and RBH-24 (for Mr. O'Donnell's proxy group). His analysis demonstrates that it is inappropriate to compare the capital structures of holding companies to operating companies. His analysis further demonstrates that the Company's proposed 53/47 capital structure is very consistent with the capital structures of other operating utilities.

Q. HAS THIS COMMISSION PREVIOUSLY ISSUED A DECISION FAVORING AN APPROACH THAT USES UTILITY OPERATING COMPANY CAPITAL STRUCTURES INSTEAD OF THE WOOLRIDGE/O'DONNELL/BAUDINO APPROACH, WHICH USES PARENT-LEVEL CAPITAL STRUCTURES?

A. Yes. In DE Carolinas' 2009 Rate Case (Docket No. E-7, Sub 909), DE Carolinas sought approval of a 53% equity/47% debt capital structure, and a settlement agreement reached with the Public Staff recommended a 52.5%

equity/47.5% debt capital structure. The Attorney General, through witness David Parcell, argued for a 50% equity/50% debt structure, which, he testified was more in line with the average equity ratio of most electric utilities. Witness Parcell's analysis in that case was also based upon review of parent-level capital structures. Company witness Stephen DeMay's rebuttal testimony in that case analyzed certain operating utility level capital structures instead, just as Mr. Hevert did here. The Commission, in its *Order Granting General Rate Increase and Approving Amended Stipulation*, issued on December 7, 2009 in that docket ("2009 DE Carolinas Order"), approved the stipulated 52.5% equity/47.5% debt capital structure, indicating that "[b]ased on the evidence in this proceeding, the Commission simply finds the testimony of Duke Energy Carolinas witness De May more persuasive than the testimony of Attorney General witness Parcell with regard to the comparisons of capitalization ratios …." *See* 2009 DE Carolinas Order at 27-28.

Q. HOW DO YOU RESPOND TO WITNESS O'DONNELL'S CONCERNS THAT THE REQUESTED EQUITY RATIO OF 53% IS TOO HIGH?

A. Witness O'Donnell indicates the requested 53% "is a reflection of the amount of equity financing that DEP's owner, Duke Energy Corp, wishes to infuse into the utility relative to the amount of debt DEP issues" and that as a result "does not reflect market forces but, instead, represents a decision by its parent holding company as to the capital structure on which it wishes rates to be determined." The requested capital ratio proposed by the Company is not arbitrary and has much to do with the Company's credit metrics and the ultimate rate debt investors will demand – the very market Mr. O'Donnell references.

In its March 30, 2020 Credit Opinion, Moody's Investor's Services ("Moody's") cites that DE Progress' credit challenges include "Uncertainty regarding [the] ability to fully recover coal ash remediation spending with a return in all jurisdictions" and "Storm prone service territory…". This was particularly evident in 2018 where severe storm activity contributed to softening Funds from Operations ("FFO")[1] to Debt of 19.6%, below Moody's published downgrade threshold of 20%. Moody's also includes the "…uncertain impacts of coronavirus"[2] in its credit challenges. While the immediate credit-related impacts of the coronavirus ("COVID-19") and related economic shutdown are not yet fully known, depressed demand and reduced cash flows are expected, particularly as it relates to the industrial and commercial sectors in the Company's service territory. While COVID-19 can be expected to negatively impact the Company's cash flows and the corresponding FFO numerator, lowering the Company's allowed equity ratio to 50 percent will amplify this negative impact, both reducing cash flows (numerator) and increasing leverage (denominator) in the critical FFO / debt metric. While the Company's credit metrics showed some improvement in 2019, with the downgrade threshold of 20% on FFO to Debt having already

[1] Moody's does not use the term FFO, but instead the term "CFO pre W/C" meaning Cash Flow from Operations, Pre Working Capital. Functionally that is the same as FFO, so I will refer in my testimony to this concept as FFO.
[2] See Moody's DE Progress Credit Opinion, March 30, 2020

been breached in 2018, the Company's request is designed to seek an adequate capital structure and equity return to "hold" its A-level rating. Weakening credit metrics and a potentially lower rating will lead to higher debt funding costs in the marketplace which will ultimately be borne by customers. An increase in debt capitalization (lower equity) as witness O'Donnell recommends to 50% / 50% would weaken the critical FFO / Debt metric which Moody's cites above.

Witness O'Donnell also states that the Commission should "examine similarly-situated utility holding companies and equity ratios set by utility regulators across the country to ascertain a more market-driven capital structure that is best used in setting rates." For the same reasons highlighted above with respect to the use of holding company ratios, I reject this analysis along with the assertion that utility regulators across the country set utility holding company ratios. Utility holding company equity ratios, including Duke Energy Corporation, are not governed by a specific state commission and have the benefit of providing additional liquidity for their utilities during periods of elevated capital investment as has been the case with DE Progress in recent years. Additionally, holding companies can provide access to additional sources of liquidity during periods of extreme market volatility, as was the case with DE Corporation's actions in March 2020 in response to a lack of liquidity in the commercial paper market. Actions included drawing $500 million on an existing corporate revolver and executing a new $1.5 billion term loan. DE Progress has not received any equity infusions from DE Corporation in the last four years and has been retaining more earnings and withholding more dividends to facilitate its capital plans. This included DE Progress not making any dividends to DE Corporation in 2019.

Witness O'Donnell also mentions the average common equity ratio granted by regulators in 2019 to electric utilities was 49.94%, citing S&P Global Market Intelligence. RRA, a group within S&P Global Market Intelligence, notes this same 49.94% for 2019 but also highlights that the average Common Equity Ratio authorized for Electric utilities nationwide, excluding capital structures that include cost-free items or tax credit balances, "was 51.55%, in 2019, 50.53% in cases decided during 2018 and 50.02% in 2017." I discuss this further later in my testimony, but the data reflects an upward trend in the equity portion of capital structures.

Q. PLEASE BRIEFLY SUMMARIZE DR. WOOLRIDGE'S POSITION REGARDING DOUBLE LEVERAGE WITH RESPECT TO DE PROGRESS.

A. The concept of double leverage is that of a holding company borrowing money (i.e., incurring debt) and injecting the proceeds into the subsidiary operating company. This downstream flow of money is then treated as equity by the subsidiary. The implication of the double leverage concept is that this subsidiary equity is in some part truly debt and therefore makes the subsidiary enterprise more levered than it would appear. Dr. Woolridge compares Duke Energy Corporation's capital structure to DE Progress, and notes that Duke

Energy's capital structure includes more debt than DE Progress. In his capital structure recommendation, Dr. Woolridge notes a 50% equity ratio is more in line with DE Progress' parent, Duke Energy Corporation.

Q. SHOULD DOUBLE LEVERAGE BE CONSIDERED WHEN ESTABLISHING DE PROGRESS' CAPITAL STRUCTURE?

A. No. As I stated earlier in my testimony, DE Progress is a regulated utility operating company, not a parent-level holding company. The Company is capitalized in a manner that is consistent with similar, regulated utility operating companies, and its actual capital structure is managed around its current approved equity ratio of 52.0%. For the same reasons that it is inappropriate to use a proxy group of holding companies, it is inappropriate to apply a holding company capital structure to DE Progress. Furthermore, arbitrarily imposing a holding company capital structure on DE Progress would have detrimental effects on the Company's credit profile and ultimately customer rates. The more debt that is put into the capital structure, the more it will dilute cash flows and weaken credit coverage ratios – the consequence of which would weaken the Company's credit profile and have a negative impact on DE Progress' credit ratings. Duke Energy has not infused any equity into DE Progress for the last four years. Instead, DE Progress has reduced dividends to the parent and generally relied on retained earnings and access to the credit markets to meet its capital needs.

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
DR 22-7 ($ Millions)

Year	Dividend Payments	Equity Infusions
2015	-	625
2016	300	-
2017	125	-
2018	175	-
2019	-	-

Note: The 2015 equity infusion was related to DE Progress's approved acquisition of the additional ownership interest in generating assets from the North Carolinas Eastern Municipal Power Agency (NCEMPA).

Q. IN HIS TESTIMONY, MR. BAUDINO STATES THAT DE PROGRESS' AUTHORIZED CAPITAL STRUCTURE SHOULD BE CONSISTENT WITH HIS RECOMMENDATION IN THE 2019 DE CAROLINAS' RATE CASE, WHICH WAS BASED ON DE CAROLINAS' ACTUAL TEST PERIOD CAPITAL STRUCTURE OF 51.5% EQUITY. DO YOU AGREE THAT IS THE APPROPRIATE EQUITY RATIO FOR PURPOSES OF EVALUATING DE PROGRESS' REGULATORY CAPITAL STRUCTURE?

A. No. Mr. Baudino references two data points as his basis for proposing 51.5%: (1) DE Carolinas reported regulated equity ratio of 51.5% as of December 31, 2018 and (2) a calculated average equity ratio based on 2018 GAAP equity of holding companies derived from witness Hevert's peer group. DE Carolinas' and DE Progress' current allowed regulated equity ratio is 52% and, as such, both have been managed to approximate the authorized level. As noted in my direct testimony, the specific debt/equity ratio will vary over time, depending on a variety of factors. The assertion that a 51.5% equity ratio based on the actual capital structure of a sister company of DE Progress, 50 basis points below the Company's currently allowed equity ratio, will continue to be supportive of the Company's current credit ratings ignores the qualitative and quantitative impacts expected from reduced cash flows and incremental leverage required with such a structure. It also ignores the practical reality that a capital structure will vary due to timing. In regard to (2), I also reject Mr. Baudino's calculated equity ratio based on GAAP equity at holding companies. As described above, such an analysis is not representative of a regulated utility's stand-alone capital structure.

Q. DO YOU CONTINUE TO BELIEVE THAT 53% IS THE APPROPRIATE EQUITY COMPONENT FOR DE PROGRESS' CAPITAL STRUCTURE?

A. Yes. As noted in my direct testimony, the specific debt/equity ratio will vary over time, depending on a variety of factors, including, among other things, the timing and size of capital investments and payments of large invoices, debt issuances, seasonality of earnings, and dividend payments to the parent company. However, a regulatory capital structure comprised of 53% equity is consistent with the Company's financial objectives and overall plan to maintain its ability to finance operations at rates favorable for customers. A healthy capital structure and an adequate return on equity provide balance sheet protection and cash flow generation to support high credit quality. High credit quality creates financial flexibility by providing more readily available access to the capital markets on reasonable terms, and ultimately lower debt financing costs for the benefit of customers.

Regulatory Research Associates ("RRA") Regulatory Focus, *Major Rate Case Decisions January – December 2019* highlights the fact many utilities have sought higher common equity ratios to offset the negative cash flow impact of federal tax reform and the average authorized equity ratios adopted by utility commissions in 2019 were higher than the levels observed in 2018. RRA states "the average authorized equity ratio for electric utility cases nationwide was 49.94% in 2019, 49.02% in 2018 and 48.90% in 2017." Mr. O'Donnell references a similar 2019 allowed equity ratio of 49.94% from S&P Global Market Intelligence (RRA is a group within S&P Global Market Intelligence) as does Mr. Nick Phillips who cites 49.94% directly from RRA. The aforementioned averages, including the 49.94% referenced by Mr. O'Donnell and Mr. Phillips, however, include allowed equity ratios adopted by utility commissions in jurisdictions that typically authorize capital structures that include cost-free items or tax credit balances. Excluding those occurrences, RRA states "the average authorized equity ratio for electric utilities nationwide was 51.55% in 2019, 50.53% in cases decided during 2018 and 50.02% in 2017," an almost 150 basis point increase since 2017. This metric is more relevant to the Company as deferred taxes are excluded from both rate base and the Company's allowed capital structure. The proposed 53 percent equity ratio would result in a 100 basis point increase since the 2017 Rate Case, only two-thirds of the increase regulatory commissions across all electric utilities cited in RRA have allowed on average since 2017. As I mention in greater detail below and reference throughout my testimony, the impact of a lower allowed equity ratio will be amplified by accelerated flowback of EDIT, reduced allowed ROE, and other credit negative proposals by many of these same intervenors.

In addition to DE Carolinas' and Duke Energy Progress, LLC's ("DE Progress") allowed equity component of 53.0% in May of 2019 by the South Carolina Commission, several peers within the RRA data have been awarded equity ratios in excess of 53.0% including Wisconsin Electric Power Company (54.46% in October 2019) and Georgia Power (56.0% in December 2019). Georgia Power, in particular, should be relevant as it is a vertically integrated utility located in the Southeast with extensive capital needs and a similar risk profile of the Company and is often a relevant peer for comparison.

Q. HOW WOULD LOWERING THE EQUITY COMPONENT OF DE PROGRESS TO 50%, AS SEVERAL INTERVENOR WITNESSES SUGGEST, IMPACT THE COMPANY?

A. A 50.0% equity ratio would weaken the Company's credit quality, making access to capital on historically competitive terms more difficult. A 50.0% equity ratio represents a 200 basis point reduction to the Company's previously approved ratio of 52.0% and a 300 basis point reduction to the ratio of 53.0% that has been proposed in this case. Lowering the equity ratio by this magnitude would result in higher leverage, greater interest expense, and lower FFO. The combination of lower FFO and a higher amount of debt would further weaken the Company's FFO to Debt ratio.

Moody's has been keeping a close watch on the Company's credit metrics and the impact of recent regulatory outcomes, noting that the current rating outlook for the Company of Stable reflects "historically credit supportive regulatory frameworks, and our expectation that the company will be able to sustain CFO pre-WC to debt ratios [in] the low 20% range" and factors that could lead to a downgrade include "a decline in the credit supportiveness of the regulatory relationships in North or South Carolina" and a "ratio of [FFO] to debt remaining below 20% on a sustained basis." [3]

The three most recent FFO to Debt metrics in Moody's March 30, 2020 credit opinion are 23.7% (December 2017), 19.6% (December 2018), and 22.4% (December 2019), demonstrating a slightly downward trend and including one annual period below the 20% downgrade threshold. As mentioned above, while the specific impacts of COVID-19 are not yet known, reductions in industrial and commercial demand are expected as a result of the mandatory economic shutdown. The Company has also committed to ease processes to enforce the disconnection of service in the event of non-payment

[3] See Moody's DE Progress Credit Opinion, March 30, 2020

during this period of unprecedented economic hardship. Additionally, there are ongoing legal challenges proposing reductions or elimination of established demand charges for industrial clients which would further reduce reliable cash flow. As such, it appears reasonable to expect reduced cash flows in the coming periods and, correspondingly, increasing pressure on credit metrics.

Additionally, 50% of Moody's Rating Methodology is driven by the Regulatory Framework (25%), including the consistency and predictability of regulation, and the Ability to Recover Costs and Earn Returns (25%). As such, a lower-directed equity ratio will have more than just an impact on quantitative metrics and could be expected to also impact the qualitative aspects of Moody's credit rating methodology, particularly if taken in conjunction with other potentially credit negative determinations including a lower allowed ROE, accelerated EDIT flowback, and / or an altered view on the previously allowed full debt and equity return on coal ash. In short, a material reduction in the equity component of the Company's regulatory capital structure would weaken the quantitative credit metrics and the qualitative aspects that the Company's credit rating agencies and investors consider when evaluating credit quality, including the credit supportiveness of previously established regulatory treatment. This, in turn, is expected to result in higher costs of capital for DE Progress and its customers. In my experience, once a utility has been downgraded, the ratings agencies do not immediately implement upgrades even if the utility's financial profile improves. Rather, they wait – typically for years

– for sustained improvement in the credit metrics and in the interim cite examples or scenarios that could lead to an upgrade within the Company's credit opinions.

Q. ARE THERE RECENT EXAMPLES OF HIGHER CREDIT QUALITY UTILITY ISSUERS HAVING ACCESS TO THE DEBT MARKETS DURING MARKET VOLATILITY WHILE OTHER POTENTIAL ISSUERS OF LOWER CREDIT QUALITY DID NOT?

A. Yes. As I highlight above, high credit quality creates financial flexibility by providing more readily available access to the capital markets on reasonable terms, and ultimately lower debt financing costs for the benefit of customers. Such financial flexibility is particularly important during periods of extreme market volatility, such as the recent volatility associated with COVID-19. During late February and March 2020 and as a result of high volatility and economic uncertainty, there were twelve days where no investment grade issuers had access to the markets. Furthermore, entities that "re-opened" the market on acceptable days were those with the highest credit ratings, primarily AA and A rated issuers. Highly rated electric utilities were among the most prevalent issuers, executing 29 transactions during this volatile period. Such issuances included Duke Energy Indiana's $550 million 30-year first mortgage bonds (Aa3/A) executed on March 10, 2020 at 2.75 percent. While certain issuers were effectively "locked out" of this volatile market, Duke Energy Indiana was able to find an acceptable window and access the market at competitive rates, tying the then all-time low 30-year coupon by an investment grade issuer. During this volatile period and as of the date of this testimony, DE Indiana' outstanding debt was rated the same as DE Progress:

Rating Agency	**S&P**	**Moody's**
Issuer / Corporate Credit Rating	A-	A2
Senior Secured	A	Aa3
Outlook	Stable	Stable

However, it should be stressed that utilities with lower credit ratings experienced wider spreads and, in some cases, had no access at all or had to cancel deals the day of announcement. For example, on March 17th, Entergy Corporation (Baa2/BBB) had to cancel a planned benchmark SEC registered 2-part senior note offering (5-year and 10-year) while on the same day Consumers Energy Co (Aa3 / A / A+) was able to execute $575 million of 30-year first mortgage bonds at 3.50%. Additionally, on March 20th Appalachian Power Company (Baa1/A-) had to cancel a planned offering while Berkshire Hathaway Energy Co (A3 / A-) placed $1.25 billion of unsecured 5-yr notes at 4.05%.

All of these examples emphatically demonstrate that utility issuers with higher ratings had continued access to capital at more favorable rates and indeed on certain days were the only companies that had access, providing much needed financial flexibility and economic benefits for their customers during this highly volatile period. This further demonstrates the criticality of credit quality during periods of uncertainty and extreme market volatility and illustrates the importance of the Company being able to maintain high credit ratings.

IV. EDIT FLOWBACK

Q. DO YOU AGREE WITH WITNESS HINTON'S RECOMMENDATION FOR RETURNING PP&E-RELATED UNPROTECTED EDIT OVER A 5-YEAR PERIOD?

A. No. On top of the other proposed credit weakening proposals made by several intervenors, with respect to the return of PP&E-related unprotected EDIT, Witness Hinton advocates for an arbitrary five-year flowback period in the Company's revenue requirement to benefit customers following the Tax Cuts & Jobs Act (the "Tax Act") versus the Company's recommendation of a 20-year flowback period for property, plant, and equipment related balances.[4] Witness Hinton does not consider the longer-term benefits to customers of a longer flowback period, as EDIT balances offset rate base as a regulatory liability on the Company's balance sheet at a zero-percent cost of capital. Additionally, a faster flowback will result in rate base increasing at a faster rate and the potential for future rate volatility. Furthermore, should tax rates be revised upward under a new administration or otherwise, there will be a precedent for accelerated recovery going forward under an arbitrary five-year period.

[4] In his testimony, Company witness Panizza states that the 20-year flowback the Company has proposed for unprotected property-related EDIT is tied directly to the underlying assets that created the deferred tax balances which became EDIT when the federal corporate tax rate dropped to 21%. The 5-year flowback period advocated by witness Hinton is simply an arbitrary number not connected to the actual assets at issue.

Through its proposed EDIT Rider, the Company advocates a 20-year amortization of the regulatory liability as supported by Company Witness John Panizza's direct testimony. Mr. Panizza further describes the rationale for the 20-year amortization as it more closely matches the remaining life of the underlying PP&E assets, lessens the cash flow impacts to the Company, and reduces the volatility in customer rates.

While it is clear that customers should, and ultimately will, benefit from the overall reduction in the revenue requirement, the Commission should also take into account other impacts of the Tax Act, particularly as it relates to cash flow. In March 2020, Moody's in its Credit Opinion of DE Progress identified tax reform as one of several factors that could adversely impact the Company's financial metrics (specifically, cash flow coverage ratios). As indicated in my direct testimony, DE Progress faces substantial capital needs over the next several years necessary to meet the demand, reliability, service, and environmental requirements of its customers and service area. As highlighted in my direct testimony, the Company's capital requirements for the next three years (2020-2022) were projected to be approximately $8.1 billion. This amount consisted of approximately $6 billion in projected capital expenditures and approximately $2.1 billion in debt retirements. As of February 2020, and as highlighted within the Company's Fourth Quarter 2019 Earnings Review and Business Update, DE Progress now projects $6.65 billion in projected capital expenditures over the same period, increasing my original estimate of total capital requirements for the next three years from $8.1 billion to $8.75 billion. Reducing the Company's cash flow through a more accelerated flowback of unprotected EDIT at the same time DE Progress is investing in large capital projects to benefit customers and faced with large refinancing obligations will negatively impact its credit metrics, which must be taken into account.

Q. IS IT REASONABLE THAT CUSTOMERS SHOULD BENEFIT FROM THE CHANGES IN THE COMPANY'S COST TO SERVE AS A RESULT OF THE TAX ACT?

A. Yes. Customers should benefit, and they will. As this Commission is well aware, electric utilities are one of the most capital-intensive industries in the country and DE Progress is no exception. The Company invests in infrastructure not because of federal tax policy, but because it is critical, necessary and often legally-required to serve customers. Our statutory obligation to serve requires the financial strength to support our commitments to our customers on a reliable and cost-effective basis. Credit quality drives access to affordable capital and it is for this reason it is in the best interest of customers to prevent a weakening of the Company's cash flow and credit quality from pre-Tax Act levels. Such preventative measures are particularly important during periods of extreme market volatility as recently observed as a result of COVID-19.

Without the Commission's thoughtful consideration regarding all aspects of the Tax Act, the Company could be adversely affected by the legislation, particularly through a reduction in cash flow, which is vital to the Company's credit quality. The Tax Act represents a unique opportunity to deliver savings to customers, but, as with all ratemaking actions, the interests of customers and the Company must be balanced. Adjusting utility rates solely to account for the impact of the reduction in the federal corporate tax rate and an accelerated flowback of excess deferred taxes without giving consideration to the impact of all other ratemaking considerations is not appropriate.

Q. COULD THE COMPANY'S FINANCIAL CONDITION BE HARMED AS A RESULT OF A 5-YEAR FLOWBACK OF PP&E RELATED UNPROTECTED EDIT?

A. Yes. An accelerated return of EDIT over an arbitrary five-year period would adversely impact the Company's cash flow to fund ongoing operations and new infrastructure investments. An unmitigated cash flow shortfall could force the Company to rely excessively on third-party capital to fund itself, to the ultimate detriment of its financial condition.

In Hinton Exhibits 1 and 2, Witness Hinton uses 7 years of FFO to Debt metrics (2017 to 2019 based on historical data and 2020-2023 based on projected data as provided by the Company) and focuses on a 3-year moving average to determine a 40 basis point degradation in FFO to Debt based on a 5-year flowback as compared to the flowback as proposed by the company in this rate case (a 20-year period for PP&E-related EDIT and a 5-year flowback for non-PP&E). While Moody's presents a 3-year trend in its credit opinions, credit metrics are a snapshot of an issuer's potential default risk at a point in time and there is an inherent emphasis on forward looking metrics when providing credit opinions, as the overall rating represents the risk of default on a prospective basis. As summarized in Hinton Exhibits 1 and 2, individual periods are impacted by as much as 50 basis points over the five-year period. Furthermore, this analysis focuses on EDIT flowback in isolation and does not consider the cumulative impact of other potentially credit negative proposals by the Public Staff including reduced ROE, a more leveraged capital structure, disallowance of a full debt and equity return on coal ash, and other measures that would reduce cash flows and increase debt. These actions, both individually and collectively, would be expected to harm the Company's quantitative credit metrics and impact the qualitative aspects that rating agencies and investors consider when evaluating credit quality, including the perceived credit supportiveness of the Company's jurisdictions.

Conversely, the 20-year flow back of unprotected PP&E-related EDIT is proposed to balance the interests of customers with the financial strength and cash flows of the Company. The Federal tax law changes provide the Commission an opportunity to help reduce and levelize customer rates over the short- and longer-term, while maintaining the utility's ability to provide safe, reliable and affordable rates.

Witness Hinton also suggests the Company should moderate upstream equity dividends to Duke Energy Corporation to alleviate potential credit pressures as a result of accelerated EDIT flowback. Duke Energy Corporation has a long-term targeted dividend payout ratio of 65-75% and subsidiaries can be expected to contribute at a similar level over the long-term. DE Progress' average payout ratio over the last three years has been approximately 15%, well below this threshold, to facilitate its ongoing capital plans, large expenditures related to coal ash remediation, and investments to better serve our customers. For example, during 2019, DE Progress did not provide any dividends to the parent, its lowest contribution in the last four years.

Witness Hinton also suggests Duke Energy Corporation can use funds from its $2.5 billion November common equity issuance to allow DE Progress to further decrease equity infusions to the parent. The equity issuance was intended to protect DE Corporation's credit in light of a range of scenarios related to the delay and regulatory uncertainty around the Atlantic Coast Pipeline, a key infrastructure project intended to provide low cost natural gas to our service territory and better serve our customers. Ultimately, preserving the credit quality of DE Corporation is likewise important to DE Progress and its sister companies because S&P uses a family rating methodology whereby weakness in the parent or some of the subsidiaries could lead to a lower credit opinion for the entire family of rated entities under the same parent.

Q. WHAT ARE THE IMPACTS, BOTH SHORT AND LONG TERM, OF A POTENTIAL CREDIT DOWNGRADE FOR DE PROGRESS?

A. Witness Hinton mentions that a downgrade from A2 to A3 is expected to cost the company 10 basis points in a normal market based on an estimate I provided. Financial markets, like any market, are a function of supply and demand. In light of continued easing by central banks and negative yields in certain global markets, investors as of recent have been in search of yield. The Company, and our customers, have benefited as capital has been available and borrowing costs have been economical.

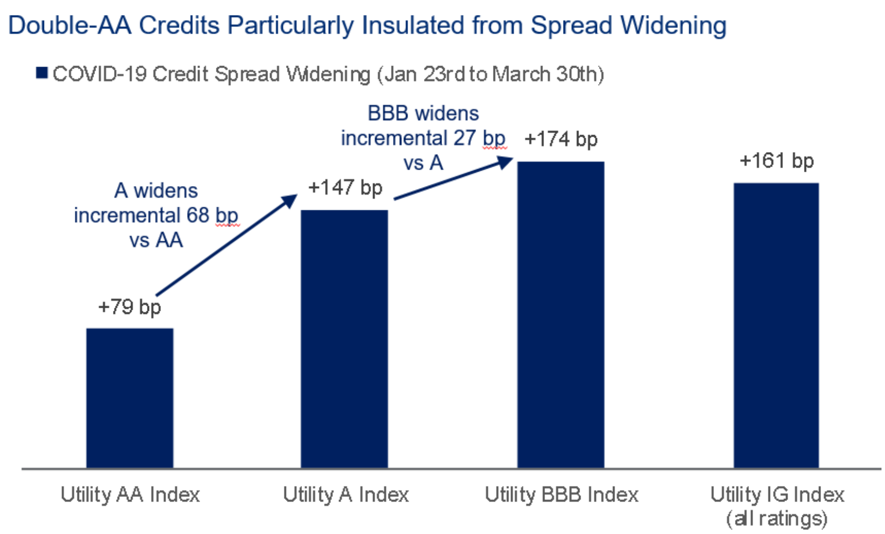
As demonstrated by recent market conditions related to the COVID-19 crisis, however, we would caution that credit spreads can widen significantly during periods of uncertainty and market volatility. The better an issuer's credit quality, the more flexibility and optionality it has with financing during these periods and the more likely it can access the market at reasonable rates. As observed in March of 2020, issuers with lower credit ratings and more stressed financial metrics will experience greater borrowing costs and heightened pricing pressures during such periods. Additionally, witness Hinton's presumption is that any near-term action as a result of this rate case outcome involves only a one-notch downgrade. Standard and Poor's, in its April 2, 2020 sector comment for the North American regulated utility industry, revised its outlook for the industry to negative from stable as a result of COVID-19. S&P notes "We view COVID-19 as a source of incremental pressure and expect that the recession will lead to an increasing number of downgrades and negative outlooks.[5]" While this sector comment does not directly impact the Company at this time in terms of directly changing its rating our outlook, it can be interpreted to provide an opening for S&P to take future rating actions including potential downgrades as a result of the economic and cash flow impacts of COVID-19. While moving from A2 to A3 may only cost 10 basis points in a "normal" environment, an additional downgrade as a result of a holistically credit negative rate case outcome could push DE Progress further down the spectrum two notches and into the 'Baa' (Moody's) or 'BBB' (S&P) category ("BBB" issuers).

As demonstrated by my previous examples from March 2020, 'BBB' issuers can be expected to have greater difficulty in accessing the market and will certainly face wider credit spreads and larger incremental borrowing costs in periods of market volatility, all to the detriment of their customers. For example, as illustrated in Table 1 below, when examining the Citi Fixed Income Indices (the "index") from late January through March 2020, lower rated credit utilities experienced higher borrowing costs and greater spread widening, or more simply, their cost of borrowing relative to the underlying U.S. Treasuries became more expensive as compared to their higher rated peers. Also, of significance during this period when reviewing the index for different ratings levels, the spread between 'AA' and 'A' rated utilities widened 68 basis-points

[5] See S&P Global Ratings, "COVID-19: The Outlook For North American Regulated Utilities Turns Negative", April 2, 2020.

while the spread between 'A' and 'BBB' utilities increased only 27 basis points. In short, not only did higher rated, 'AA' utilities on average experience pricing approximately 100 basis points lower than their 'BBB' peers, they were also better insulated to market volatility than their 'A' rated counterparts and experienced less pricing pressure during this period.

Table 1[6]



Furthermore, with the extreme volatility, ongoing uncertainty of capital market conditions, and the extensive capital needs the Company is currently facing as highlighted above, I believe it would be both judicious and practical to avoid aggressive actions that, in the aggregate, could harm the credit quality of DE Progress, whether it results in a downgrade of one notch, two notches, or more.

Moody's mentions a downgrade "would occur if [FFO[7] to Debt] is below 20% on a sustained basis." However, it is important to note that should

[6] Citi Fixed Income Indices (Citi Velocity, Citigroup Global Markets)
[7] *See supra* n. 1.

DE Progress be downgraded, an upgrade would be expected to require significantly higher metrics. For example, as an order of magnitude, an upgrade to A1 would require a 25% FFO to Debt level on a sustained basis as calculated by Moody's. As calculated in Moody's March 30, 2020 credit opinion and holding debt constant at $9,604 million, FFO would need to increase from $2,153 to $2,401 million to move from 22.4% to 25% FFO to Debt, or approximately $250 million in incremental cash flows annually on a sustained basis with no incremental leverage. Incremental cash flows of such a scale would likely require significant rate increases to customers over prolonged periods.

Q. HOW IS SECURITIZATION VIEWED BY THE RATING AGENCIES?

A. Generally, S&P ignores the impacts of securitization in quantitative metrics. Moody's typically views securitization debt of utilities as on-credit debt, in part because the rates associated with it reduce the utility's headroom to adjust rates for other purposes while keeping all-in rates affordable to customers. Thus, where accounting treatment is off balance sheet, Moody's adjusts the company's financial ratios by including the securitization debt and related revenues in their analysis. While overall securitization is viewed positively by Moody's in terms of certainty of cash recoveries, certain quantitative metrics can be negatively impacted by its inclusion in FFO to Debt. Because securitization is structured with amortizing debt and based on the relatively constant cash flows from recovery, FFO to Debt can generally be expected to be degraded in the early years (due to the immediate incremental leverage relative to supporting cash flows) with improvements in later years. This may challenge credit metrics in the early years at DE Progress and could be amplified by any other credit negative decisions including lower revenues from a reduced ROE, a lower equity ratio, or disallowance of a full debt and equity return on coal ash.

V. RECOVERY AND TREATMENT OF CCR COMPLIANCE COSTS

Q. WHAT IS THE CREDIT IMPACT OF LOSING THE FULL DEBT AND EQUITY RETURN ON COAL ASH RECOVERY?

A. DE Progress' issuer credit ratings of A2 and A- from Moody's and S&P, respectively, would likely be downgraded if the utility were to lose the full debt and equity return on coal ash remediation costs. Following the 2017 Rate Case, which provided recovery of deferred coal ash costs over a 5-year amortization period with a full debt and equity return at DE Progress' weighted average cost of capital (WACC), both credit rating agencies modified their methodology when calculating a key credit metric (FFO to Debt). This metric is the primary financial measure used by the rating agencies to determine the credit quality of utility companies, including DE Progress.

GAAP requires expenditures related to the settlement of current liabilities, including the current portion of asset retirement obligations, be included as a reduction in cash flows from operating activities in a company's statement of cash flows. When the Commission issued its order in the 2017

Rate Case, granting DE Progress a full debt and equity return on coal ash expenditures during the recovery period, both rating agencies began treating these expenditures as ordinary, regulated investments. By treating the spend associated with the settlement of coal ash AROs as an investing activity, rather than an operating activity, the rating agencies were essentially removing a sizeable operating cash outflow from the utility's computation of FFO, which results in a stronger FFO to Debt ratio.

Moody's explains in its March 30, 2020 credit opinion of DE Progress that "…as a result of the rate base like treatment of the majority of Duke Energy Progress' spending for coal ash remediation, we view these costs as being akin to a capital expenditure." As calculated by Moody's, the corresponding adjustment to FFO treating related coal ash spend as an investing activity in the Company's FFO/Debt metric as of December 31, 2019 provided approximately 400 basis points of support to DE Progress' FFO to Debt metric, making that metric 22.4% as of December 31, 2019. Without the full debt and equity return, the Company's FFO to Debt ratio would fall approximately 400 basis points, which is well below Moody's downgrade threshold of 20%.

Q. IS THERE A THREAT THAT THE RATING AGENCIES COULD MODIFY THE DOWNGRADE THRESHOLD IF THE PREVAILING TREATMENT FOR COAL ASH RECOVERY WERE TO CHANGE?

A. Yes. The credit rating agencies consider both qualitative and quantitative factors when assessing overall credit quality of a regulated utility. Positive consideration is given for regulatory environments that provide consistency and predictability of regulation. As I highlight above, Moody's rating methodology for electric and gas utilities incorporates the regulatory framework and the ability to recover costs and earn sufficient returns as 50% of their overall credit scoring. In Moody's March 30, 2020 credit opinion on DE Progress, the agency includes "credit supportive regulatory environments" as a credit strength, a key qualitative benefit that supports DE Progress' ability to maintain strong credit ratings. With 25% of Moody's credit scoring derived from consistency and predictability of regulation with respect to recovery and earnings potential, it is logical to expect a change in regulation that weakens a utility's credit quality would cause the rating agencies to seek stronger credit metrics to maintain the same credit rating now that the regulatory environment in which that utility operates has introduced a higher degree of credit risk.

Furthermore, Moody's[8] has been closely monitoring the uncertainty around coal ash recovery, noting the following:

- Credit challenges include "Uncertainty regarding ability to fully recover coal ash remediation spending with a return in all jurisdictions"
- "The stable outlook also reflects our expectation that the company will continue to be able to recover the majority of its coal ash closure and remediation costs with a full return…"

[8] See Moody's DE Progress Credit Opinion, March 30, 2020, pages 1, 2, and 3.

- "We view the ability to reach a settlement agreement on traditional ratemaking parameters, and the approval for the recovery of coal ash and storm costs with a return, as credit positive. We note however that the decision has been appealed by the state Attorney General and the Public Staff, and that the NCUC has recently taken a different position in the case of another smaller utility operating in the state. In the case of Virginia Electric and Power Company (A2 stable) [Dominion], the NCUC authorized recovery of coal ash spending, but over a ten-year period rather than five, with no return during the amortization period."
- "We are also closely watching the regulatory treatment of coal ash remediation spending."

As highlighted in the above commentary, were the Commission to accept the Public Staff's position in this case, or were the Commission to decide the coal ash cost recovery issues in this case in a manner substantially similar to its Dominion Order, the rating agencies would likely view the result as contrary to the 2017 DE Progress rate case decision. The agencies would also see that result as a marked change in the predictability and consistency of regulation. All of these references reinforce the critical nature of coal ash cost recovery to credit quality and DE Progress' current credit ratings, including the expectation of continued recovery over a reasonable time period with a full return, consistent with previously directed in the 2017 rate case.

Q. WHAT IS THE IMPACT OF A CREDIT DOWNGRADE AT DE PROGRESS?

A. If a credit rating downgrade occurred at DE Progress, the utility's overall cost of capital would increase. If the downgrade were caused by a change in the method of recovery of coal ash remediation costs, both debt and equity investors would perceive the change in consistency and predictability of the utility commission's rate making as a heightened risk to the utility. In the debt capital markets, utilities with lower ratings are charged higher credit spreads to compensate investors for the additional risk assumed, which leads to higher overall pricing of new debt issuances. Likewise, equity investors would require a higher economic return on invested capital to be properly compensated for assuming additional risk. Any incremental financing costs incurred by the utility would be passed on to customers through higher rates.

Q. WILL A DOWNGRADE TO DE PROGRESS IMPACT THE CREDIT QUALITY OF DUKE ENERGY CORPORATION?

A. Yes. Duke Energy Corporation is a holding company that relies on stable and predictable cash flows from each of the subsidiary utilities to pay fixed payment obligations and dividends to equity investors. Given the relative size and position of DE Progress within the overall portfolio of utilities, a negative rating action at DE Progress would negatively impact the credit quality of Duke Energy Corporation. In Moody's credit opinion of Duke Energy Corporation, October 13, 2019, the agency states that a factor that could lead to a downgrade is a deterioration in the credit supportiveness or emergence of a more contentious regulatory relationship. This would negatively impact cash flows or the timeliness of cost recovery, particularly with respect to coal ash remediation recovery in North Carolina.

Q. IF DUKE ENERGY CORPORATION IS DOWNGRADED, WHAT IMPLICATIONS ARE THERE TO THE SUBSIDIARY UTILITIES?

A. Each of the utility subsidiaries directly benefit from a healthy and stable holding company. During periods of elevated capital expenditures, including large amounts of coal ash impoundment closure investments, the utilities are able to retain more of their earnings as equity capital to maintain the regulated capital structure. During these periods of lower dividend payouts from the utilities to the holding company, the holding company can access capital markets on favorable terms to supplement the cash shortfall in the near term. A rating downgrade at the holding company would increase the cost to access certain investor classes, which in turn would increase its cost of capital. In turn, the utilities would likely need to reduce investments that were intended to provide customer benefits.

VI. CONCLUSION

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS.

A. To summarize, the aggregate impact of a lower ROE, more leveraged capital structure, accelerated EDIT flowback, and delayed or inadequate coal ash recovery without a full debt and equity return will harm the quantitative and qualitative aspects of DE Progress' credit quality. Individually and in the aggregate, I believe these actions will lead to reduced cash flows, increased leverage and risk, further stressed credit metrics, higher borrowing costs, lowered financial flexibility, and, ultimately, higher cost of capital (both debt and equity) to the detriment of our customers, who must bear that cost, now and for years to come.

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

A. Yes.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-2, SUB 1219

In the Matter of: **DOCKET NO. E-2, SUB 1219** Application of Duke Energy Progress, LLC For Adjustment of Rates and Charges Applicable to Electric Service in North Carolina	**SETTLEMENT TESTIMONY OF KARL W. NEWLIN FOR DUKE ENERGY PROGRESS, LLC**

I. WITNESS IDENTIFICATION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Karl W. Newlin. My business address is 550 South Tryon Street, Charlotte, North Carolina, 28202.

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

A. I am employed by Duke Energy Business Services, LLC ("DEBS") as Senior Vice President, Corporate Development and Treasurer. DEBS provides various administrative and other services to Duke Energy Progress, LLC ("DE Progress" or the "Company") and other affiliated companies of Duke Energy Corporation ("Duke Energy").

Q. DID YOU OFFER DIRECT AND REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. Yes.

II. PURPOSE AND OVERVIEW OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony supports the capital structure proposed in the Second Agreement and Stipulation of Partial Settlement by and between DE Progress and the Public Staff (the "Second Partial Settlement") when that provision is viewed as part of the overall terms of the Second Partial Settlement. My Direct and Rebuttal Testimony remain effective as applicable to the testimony of any non-settling Party, and as to the point that cash flows, including from the unresolved issue of coal ash, have an adverse impact on DE Progress's financial health.

Q. PLEASE PROVIDE AN OVERVIEW OF YOUR TESTIMONY.

A. The 52 percent to 48 percent equity-to-debt capital structure is reasonable and appropriate when viewed in the context of the overall Second Partial Settlement. All other things equal, credit rating agencies view the constructiveness of the regulatory environment and the Company's ability to timely recover prudently incurred costs as important ratings criteria in their assessment of the Company's credit quality. The Second Partial Settlement, on a stand-alone basis, demonstrates an ability to do this and I believe its approval would be viewed by the rating agencies as constructive and equitable.

The Second Partial Settlement, however, leaves some issues unresolved, including particularly the issue of the Company's recovery of coal ash basin closure costs, as well as a return on those costs. The potential impact of coal ash cost recovery upon the Company's cash flows is consequential, as I indicate in my Rebuttal Testimony, and the potential impact upon cash flows has a corresponding impact upon the Company's credit metrics, liquidity, and credit ratings. This is a different matter than earnings. Even if a Company's earnings are reasonable, if it lacks the cash to fund operations and provide an adequate return to investors, then the Company's ability to raise capital – both debt and equity – on reasonable terms is weakened. Ultimately, adverse cash flow impacts also have an adverse impact upon customer rates – DE Progress's customers benefit through lower electricity rates when the Company has lower financing costs, ready access to capital, and more timely cash recovery of its investments.

III. SECOND PARTIAL SETTLEMENT

Q. PLEASE DESCRIBE YOUR INTERACTION WITH CREDIT RATING AGENCIES.

A. One of my primary responsibilities is to manage the relationship with each of the major credit rating agencies for Duke Energy and all of its utility subsidiaries, including DE Progress. I and my team maintain frequent and regular contact with the agencies, providing them with information and updates on Duke Energy and DE Progress.

Q. HOW DO YOU BELIEVE THE AGENCIES WOULD LIKELY REACT IF THE COMMISSION WERE TO APPROVE THE COMPANY'S SECOND PARTIAL SETTLEMENT AGREEMENT WITH PUBLIC STAFF?

A. DE Progress's credit rating agencies view the constructiveness of the regulatory environment and the Company's ability to recover prudently incurred costs as important ratings criteria in their assessment of the credit quality of DE Progress. The Second Partial Settlement demonstrates this ability, and I believe its approval would be viewed by the rating agencies as constructive and equitable. Approval of the Second Partial Settlement will support the Company's ability to achieve its financial objectives, all other things being equal and depending on the outcome of the unresolved issues in the case.

Q. WHAT ARE DE PROGRESS'S FINANCIAL OBJECTIVES?

A. As I discussed in my Direct and Rebuttal Testimony, the Company at all times seeks to maintain its financial strength and flexibility, including its strong investment-grade credit ratings, ensuring reliable access to capital on reasonable terms. Financial strength and access to capital are necessary for DE Progress to provide cost-effective, safe, environmentally-compliant, and reliable service to its customers. Specific objectives that support financial strength and flexibility include: (a) maintaining a reasonable common equity component for DE Progress on a regulatory capitalization basis; (b) maintaining current credit ratings; (c) ensuring timely recovery of prudently incurred costs; (d) maintaining sufficient cash flows to meet obligations; and (e) maintaining a sufficient return on equity to fairly compensate shareholders for their invested capital. The ability to attract capital (both debt and equity) on reasonable terms is vitally important to the DE Progress and its customers, and each of these help the Company meet its overall financial objectives.

Q. HOW DO CUSTOMERS BENEFIT FROM THE COMPANY'S STRONG CREDIT RATINGS?

A. To assure reliable and cost-effective service, fund infrastructure projects, and refinance maturing debt, DE Progress must be able to finance without interruption, regardless of capital market conditions. The lack of access to capital can force interruption of capital projects to the long-term detriment of customers, and both the financial crisis of 2008-09 and the COVID-related market volatility during 2020 illustrate the importance of maintaining financial strength and flexibility. Although market conditions have improved somewhat from the extreme volatility of late March, they remain uncertain, and increased volatility can return at any time. Strong credit ratings result in lower debt costs for our customers and greater assurance of access to capital, even in challenging market conditions.

Q. WHAT ISSUES COULD AFFECT THE COMPANY'S CREDIT RATINGS IN THIS CASE NOTWITHSTANDING THE APPROVAL OF THE PROPOSED SECOND PARTIAL SETTLEMENT?

A. The Commission's ultimate resolution of the unresolved issues in the case – including timely recovery of and on coal ash basin closure costs – could affect DE Progress's credit ratings and the overall financial health of DE Progress notwithstanding approval of the Second Partial Settlement.

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

A. Yes.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1219

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

I. WITNESS IDENTIFICATION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Steven K. Young and my business address is 550 South Tryon Street, Charlotte, North Carolina 28202.

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

A. I am the Executive Vice President and Chief Financial Officer for Duke Energy Corporation ("Duke Energy"), the parent holding company for Duke Energy Progress, LLC. ("DE Progress" or the "Company").

Q. CAN YOU PROVIDE A BRIEF SUMMARY OF YOUR EDUCATIONAL AND PROFESSIONAL EXPERIENCE?

A. Yes. I have a Bachelor of Arts degree in Business Administration from UNC-Chapel Hill and have also attended the Advanced Management Program at the Wharton Business School and the Reactor Technology Course for Utility Executives at the Massachusetts Institute of Technology. I joined Duke Energy in 1980 as a financial assistant and have held various positions of increasing responsibility at the Company, primarily in the areas of finance and utility regulation since that time. I was appointed to my current position in 2013.

II. PURPOSE AND OVERVIEW OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony describes the fundamental financial profile of Duke Energy and DE Progress, the financial needs of our investors, how utility regulation impacts our profile and investors, and how having a financially healthy utility benefits customers and our State. Finally, I explain the Company's concerns with some of the proposals offered by Intervenors in this proceeding (and with the Commission's recent Dominion Energy North Carolina Order issued in Dockets E-22, Sub 562 and E-22, Sub 566), and why they should not be adopted by the Commission in this case.

Q. DO YOU HAVE ANY EXHIBITS TO YOUR REBUTTAL TESTIMONY?

A. Yes, the following exhibits are attached to this testimony:

1. Moody's Sector In-Depth Report (March 2, 2020)
2. Duke Energy P/E Ratio, Growth Rate, and Rate Base Growth
3. Moody's Credit Opinion (October 13, 2019)
4. Moody's Credit Opinion (March 30, 2020)
5. BOA Securities Duke Energy Ratings Report (January 13, 2020)
6. Wolfe Research Duke Energy Report (February 13, 2020)
7. Fleishman Daily Duke Energy Report (February 25, 2020)
8. Barclay's Report (March 28, 2020)

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

A. Yes.

Q. COULD YOU EXPLAIN THE FUNDAMENTAL FINANCIAL OPERATIONS AND PRESSURES FACING DE PROGRESS IN ITS PROVISION OF ELECTRIC SERVICE TO NORTH CAROLINA CUSTOMERS?

A. Yes. We are a regulated provider of energy utility service in North Carolina, South Carolina, and several other jurisdictions. DE Progress operations, including pricing and ultimately earnings, are regulated by state and federal utility commissions. Price and earnings regulation exist across the United States primarily due to the capital intensive nature of the energy utility business.

As a consequence of this paradigm, virtually all of our services and the rates we are permitted to charge for those services are determined by public service commissions like the North Carolina Utilities Commission ("NCUC"). To fund the significant capital investments required to provide electric service, we must be able to attract debt capital and Duke Energy must be able to attract equity capital in the same financial markets utilized by our peers and by other non-regulated businesses to provide effective service to the public. If access to the capital markets is unduly impaired, our ability to provide customers with safe and reliable electric service at a reasonable cost can be jeopardized.

Q. CAN YOU DESCRIBE AT A HIGH LEVEL HOW DUKE ENERGY'S REGULATED UTILITY FINANCIAL OPERATIONS WORK?

A. Yes. Duke Energy generates roughly $8 billion a year in cash flow from its utility operations. This consists of net income (revenues remaining after the payment of all the costs of operating its utilities, including approximately $2 billion a year in interest expense on debt used to fund infrastructure investment) and the return of a portion of prior capital investment through depreciation. Of this amount, we allocate approximately $3 billion a year to our shareholders in the form of dividends. The dividend is necessary to attract equity capital investors who expect a quarterly cash dividend in addition to any hoped-for stock price appreciation. This leaves approximately $5 billion a year for reinvestment in our system.

Our current level of annual capital investment in our regulated utilities is approximately $10 billion a year – roughly twice the amount we have available after payment of dividends. This level of investment is needed to maintain, improve, and expand our system to meet customer demand and to meet our obligations to provide safe and reliable utility service to the public in the jurisdictions in which we operate. It is also required to meet our obligations associated with, among other investments, the ongoing closure of our North and South Carolina coal ash impoundments and for storm recovery activities.

Neither Duke Energy nor DE Progress have access to any established "reserves" to pay the carrying costs of their unavoidable need to incur debt (and equity) to support utility operations. Having to simply absorb those carrying costs could have significant negative implications to the financial stability of the enterprise as a whole.

Q. HOW DOES DUKE ENERGY PROVIDE FOR THE DIFFERENCE BETWEEN THE $5 BILLION AVAILABLE FOR REINVESTMENT FROM CURRENT EARNINGS AND THE $10 BILLION NEEDED ANNUALLY FOR NEW INVESTMENT?

A. We have to obtain the difference from the debt and equity markets, which we access on a regular and ongoing basis, and in which we compete against other utilities and non-utilities for such capital.

Q. PLEASE DESCRIBE DEBT AND EQUITY SOURCES OF FUNDS AND WHY THEY ARE IMPORTANT.

A. Virtually all utilities fund operations and capital investment with both long-term debt and equity. Debt typically carries a fixed yield or interest rate to the bond holder and has priority over equity investors in a bankruptcy or liquidation scenario. For these reasons, debt financing is less risky and, therefore, cheaper than equity financing. Equity investors typically seek growth in the underlying stock value and/or a cash dividend. For utility stocks, the vast majority of the value sought by shareholders is in the security of a quarterly cash dividend.

Q. PLEASE DESCRIBE DUKE ENERGY'S DIVIDEND HISTORY AND POLICY.

A. Duke Energy has paid a cash dividend to its shareholders for 94 consecutive years. We target to pay between 65% and 75% of our net income to our shareholders in the form of a cash dividend.

Q. PLEASE DESCRIBE THE COMPOSITION OF DUKE ENERGY'S SHAREHOLDERS.

A. Duke Energy's shareholder base is about 60% institutional investors and about 40% retail or individual investors. Approximately 10% of our shareholders live in North and South Carolina.

Q. YOU MENTIONED EARLIER THAT DUKE ENERGY IS CASH-FLOW NEGATIVE. HOW DOES THIS WORK IF THE COMPANY IS INVESTING MORE THAN IT IS EARNING EACH YEAR?

A. As I stated earlier, energy utility operations are often cash flow negative due to the need to serve a growing customer base, repair and maintain existing infrastructure, and immediately respond to all service interruptions, such as those caused by major storms. Duke Energy's ability to fund these investments is based upon investor confidence that customer rates will be set at levels that allow all prudent utility operating and financing costs to be recovered.

Q. WHAT HAPPENS IF ALL PRUDENT COSTS OF PROVIDING SERVICE, SUCH AS THE CARRYING COSTS ASSOCIATED WITH DEBT AND RETURNS TO SHAREHOLDERS ARE NOT RECOVERABLE IN RATES?

A. Fundamentally, as is discussed in the Rebuttal Testimony of DE Progress witness Newlin, if cash from operations declines then fewer funds are available for infrastructure investments and shareholder dividends. This means several things might happen:

1. The Company's liquidity ratios decline due to lower cash revenues;
2. Credit Rating Agencies may lower the Company's credit ratings; and/or
3. The dividend level may be constrained.

Items 1 and 2 above will result in higher financing costs on future infrastructure investment, which translates into higher rates for customers. Item 3 will result in challenges in obtaining competitive equity financing, also leading to higher costs to customers. Additionally, item 3 is a return many of our individual shareholders, including those in the Carolinas, rely upon to meet their ongoing cost of living.

Q. WHAT CAN A UTILITY DO TO MINIMIZE ITS FINANCING NEEDS?

A. First, it can operate as safely and efficiently as possible to reduce its costs and maximize its cash from operations, something we are committed to doing. DE Progress utility operations are outstanding in this regard. DE Progress, for example, has rates that are below national averages. As rates are based on costs, this means that DE Progress' costs are below national averages. Duke Energy's nuclear fleet was the lowest cost fleet in the country in 2019 (while having an outstanding capacity factor and safety record) and our overall transmission and distribution costs per customer are in the top quartile of electric utilities nationally.

Q. CAN YOU MINIMIZE THESE CARRYING COSTS BY RELYING ON LESS EXPENSIVE DEBT TO FUND THE INVESTMENTS?

A. Not as a practical matter. The risk appetite for regulated utility investors anticipates utility capital structures that are relatively balanced between debt and equity. An over reliance on debt would increase our debt ratio (and decrease our equity ratio), which would cause Duke Energy to be riskier in the eyes of lenders and investors, who would then demand a higher return before providing debt and equity capital to us, leading to increased customer rates.

Q. GIVEN THESE FINANCIAL CONSTRAINTS AND THE ONGOING OBLIGATION TO PROVIDE SAFE AND RELIABLE SERVICE TO DE PROGRESS' CUSTOMERS, WHAT CHALLENGES DO YOU SEE WITH SOME OF THE INTERVENORS' POSITIONS IN THIS CASE?

A. Let me discuss a few of the major issues I see. First, let's look at coal ash or CCR impoundment closure cost recovery. These costs for DE Progress and DEC, which are derived from our legal obligation to close our coal ash impoundments at various coal-fired generating plants (some of which are still in operation), are estimated to be in the range of approximately $8.5 billion over the next 15-20 years. These plants have provided for decades, and continue to provide in many cases, low cost power to our customers in North and South Carolina. Additionally, state environmental regulators have deemed our methodologies to permanently close the basins in North Carolina as reasonable, prudent and in the public interest. Nonetheless, some intervenors have stated that substantial portions of these costs should be shared by customers and shareholders or disallowed.

For example, the Public Staff has perpetuated its "equitable sharing" proposal for coal ash basin closure costs in this case that, if granted, would cause the Company to absorb hundreds of millions of dollars in this case (and billions of dollars over time) with no ready source for those funds.

In the recent Dominion Energy North Carolina rate case order, the Commission itself disallowed recovery of a significant portion of the financing costs associated with coal ash basin closure. Disallowances of the recovery of these costs in DE Progress' case would decrease the Company's cash-flow from operations and increase funding requirements from debt and equity investors as these costs are unavoidable and will continue to be incurred. As I described earlier, this would impair the credit quality of DE Progress and ultimately drive up financing costs and customer rates. As of the end of 2019, DE Progress is carrying over $538 million (NC retail allocation) of deferred CCR costs incurred as a regulatory asset on its balance sheet awaiting future recovery. These amounts, which represent actual past expenditures by DE Progress, have clearly depended heavily on debt and equity financing.

The Commission's recent order in the Dominion Energy North Carolina rate case, if applied fully to DE Progress, would have significant negative impacts on the economic health of the Company because it would force DE Progress to incur carrying costs on billions of dollars of required coal ash basin closure costs over an extended period with no ability to recover those carrying costs.

Q. SOME INTERVENORS TESTIFIED THAT CCR COSTS ARE NOT CAPITAL COSTS AND, THEREFORE, SHOULD NOT EARN A RETURN. DO YOU AGREE?

A. No. If a utility prudently incurs costs, whether they are capital or operational in nature, and does not receive revenues sufficient to cover those costs until some future date, the costs will have to be financed in the interim. In this scenario, customers will benefit by delaying the time when they will be asked to begin paying such costs but the interim financing expenses that accrue in the meantime are real and should ultimately be paid for by customers as they constitute the actual costs of the utility's business.

Q. HAS THIS PRINCIPLE BEEN PREVIOUSLY RECOGNIZED?

A. Yes. Both storm costs and post in-service plant costs are categories of operating expenses that, when deferred, the Commission historically has allowed a return on the unamortized balance through inclusion in rate base. Another example is the levelization of purchased power expense that the Commission ordered in DE Carolinas' 1985 rate case. At the time, DE Carolinas was purchasing capacity from the Catawba joint owners and the purchased power expense declined over time per the contract. Instead of setting revenue requirements in that case at the then current level of expense, the Commission required that rates be set based on a levelized level of expense over the remainder of the contract. The Commission included a return in the levelization calculation, so the regulatory asset created accrued a return. The Commission recognized that while this arrangement provided less timely cost recovery for the company, the inclusion of a return on the regulatory asset made the company whole. More directly to the point, in DE Progress' last rate case, this Commission allowed DE Progress to recover its carrying charges on deferred coal ash basin closure investments as part of the amortization of the recovery of those investments from customers. In addition, the Commission denied the Company's request for a more real time recovery of its ongoing ash basin closure expenditures, and instead ordered the Company to defer those costs into a regulatory asset with a return. In terms of recovery of those costs, the Commission stated:

> "The Commission will address the appropriate amortization period in DEP's next general rate case, and, unless future imprudence is established, *will permit earning a full return on the unamortized balance*. While this ratemaking treatment will, in limited fashion, diminish the quality of DEP's earnings, over time, assuming reasonable and prudent CCR management practices, it permits appropriate recovery." (emphasis added).

Again, the Commission recognized that while the Company would receive less timely recovery of its costs, the inclusion of a return on the regulatory asset would make the Company whole. Without a return on the unamortized balance, the Company will be denied recovery of its costs.

Q. ALSO, IN REGARD TO CCR COSTS, SOME INTERVENORS HAVE STATED THAT DUKE ENERGY KNEW OF THE NEED TO BEGIN COAL ASH REMEDIATION AS EARLY AS THE 1980S OR 1990S. GIVEN YOUR LONG HISTORY WITH THE COMPANY, CAN YOU PROVIDE ANY INSIGHTS ON THESE ASSERTIONS?

A. Yes. I am glad to provide some insights. I have been involved in regulatory matters and particularly accounting related regulatory matters for virtually my entire career at Duke Energy. Until very recently, I do not recall any industry-wide requirement (or generally accepted practice) involving the inclusion of coal ash basin closure costs in either our operating expense budgets or depreciation expense calculations. In particular, I do not have any recollection of coal ash basin closure costs being the subject of any precedential legal, regulatory or accounting practices adopted by or applicable to the industry for the vast majority of my career.

Q. WHAT OTHER INTERVENOR POSITIONS CONCERN YOU REGARDING THE FUTURE FINANCIAL VIABILITY OF DUKE ENERGY AND DE PROGRESS?

A. Some intervenors have proposed denial of a cost deferral (or denial of cost recovery) for grid modernization investments set out in our Grid Improvement Plan, as described in the testimony of DE Progress witness Oliver. This is problematic given the increased storm activity we are seeing in the Carolinas, the need to prepare to accommodate smaller-sized, multiple location renewable resources on our system, and the desire to advance our customer communications capabilities, along with the other Megatrends identified in the testimony of Witness Oliver, the need for and benefit of grid modernization is greater than ever. Grid investments are placed into service in smaller, more frequent increments than generation plants. Upon completion, they begin to accrue depreciation, interest and tax expenses without any offsetting increase in rates until the Company's next rate case. In the absence of a rate case or deferral as requested by DE Progress, these expenses erode the Company's economic performance and, ultimately, shareholder returns. Given the extensive need to modernize our grid, transmission and distribution investments are now the largest area of new capital investment for the Company. As such, the regulatory lag associated with these investments creates a significant financial gap for DE Progress.

Q. WHY ARE NEW REGULATORY MECHANISMS NEEDED NOW FOR GRID INVESTMENTS?

A. In the past, the major capital investment area for DE Progress was large generating facilities such as nuclear, gas, and coal generation plants. The accounting mechanisms in place for these types of facilities allowed all of the costs of the facility to be deferred up to and even beyond the commencement of service dates for these facilities. The utility could book the earnings immediately and only recover the cash it had spent in a future rate case following the in-service date of the generating facility. The use of a deferral mechanism for Grid Improvement Plan costs would effectively allow these new major capital investments to have the same earnings profile as DE Progress' prior capital investments.

Q. WHAT IMPACT WOULD A GRID DEFERRAL MECHANISM HAVE ON DE PROGRESS' FINANCIAL HEALTH?

A. The ratings agencies have clearly identified regulatory lag associated with new grid investments as a problem for the industry. The agencies look for recovery mechanisms such as riders, multi-year rate plans, and deferrals with full returns as critical to sustaining solid credit ratings. The March 2, 2020 Moody's Sector In-Depth report attached hereto as Young Rebuttal Exhibit 1 supports this focus on grid investment and cost recovery.

Q. ARE THERE ANY OTHER CRITICAL ISSUES IN THIS RATE CASE YOU WOULD LIKE TO DISCUSS?

A. Yes. Several intervenors, including the Public Staff, are proposing allowed rates of return on common equity ("ROE") that are at or below 9.0%. This level of ROE, if adopted by the Commission, would be well below any electric utility ROE allowed by the Commission during at least the last decade and would also be inconsistent with DE Progress' operating performance and risk profile and would make it much more difficult for the Company to compete in the capital markets. The Commission should also be mindful of the fact that DE Progress has a substantial fleet of nuclear generation assets that provide electricity at low cost but carry a higher relative risk profile than more common non-nuclear generation assets.

Q. HAVE THE ECONOMIC CHALLENGES YOU HAVE DESCRIBED ABOVE IMPACTED THE QUALITY OF SERVICE PROVIDED BY DE PROGRESS?

A. No. We have continued to provide excellent service to our customers at very reasonable rates notwithstanding the financial challenges I have described. In addition to DE Progress' low-cost profile, our response to the three major storms we experienced in 2018, as described in the testimony of DE Progress witness Jackson, was superlative. We have also recently been recognized by EEI for our overall safety record and have demonstrated excellence in the operation of our nuclear generation facilities. From a customer service perspective, as described further by Company witness Hatcher in his direct testimony, we are proud of our record of providing high quality service at reasonable rates.

Q. HOW ARE DUKE ENERGY AND DE PROGRESS CURRENTLY FARING FROM A FINANCIAL PERSPECTIVE?

A. From a debt investor perspective, Duke Energy and DE Progress enjoy strong credit ratings with stable outlooks from the agencies; however, on April 2, 2020, S&P put the entire North American Regulated Utilities sector on negative outlook due to concerns the COVID-19 pandemic will weaken many regulated utilities credit metrics as the broad economy is expected to weaken.

Our credit metrics are low for our ratings and, as evidenced by the various ratings agency and analyst reports attached as exhibits to this testimony, the agencies have directly expressed concern about CCR/Coal ash cost recovery in North Carolina, specifically citing the Commission's recent Dominion Energy North Carolina rate case order. If similar treatment is given to DE Progress (which has a dramatically larger spend on coal ash basin closures), it may become very difficult to maintain our current credit ratings.

Q. INTEREST RATES ARE CURRENTLY LOW. DOES A LOWER CREDIT RATING REALLY MATTER?

A. Witness Newlin discusses this issue in more detail in his testimony but even though interest rates have been at historically low rates, a lower credit rating would still result in higher financing costs for DE Progress. And although the increment in cost is currently relatively small, that has not always been the case. The difference could be more significant in periods of higher rates or increased market volatility. In fact, although U.S. Treasury rates have declined during the recent economic uncertainty caused by the COVID-19 pandemic, credit spreads widened significantly, and many utilities incurred higher debt costs overall as a result.

Q. WHAT IS THE EQUITY INVESTOR VIEWPOINT?

A. Price to earnings (P/E) ratio, which is a company's stock price divided by its estimated earnings per share, is the most relevant measure in our industry of how attractive a stock is to investors compared to peers. As is reflected on

Young Rebuttal Exhibit 2 attached hereto, as of April 24, 2020, Duke Energy's P/E on 2021 estimated earnings was 15.7x, compared to our regulated peer companies P/E ratio average of 19.7x. Therefore, Duke Energy is trading at an approximate 20% discount to peer companies, representing over $10 billion in equity market capitalization. While a portion of this discount can be attributed to Duke Energy's approximate $2 billion investment in Atlantic Coast Pipeline, I believe the majority of the discount is attributable to perceived regulatory risks in the Carolinas. It is informative to note that this discount was 15% as of February 21, 2020 but has worsened during this time of COVID-19 related market uncertainty. The discount to the Duke Energy stock valuation has grown, I believe, due to the rate case uncertainty that Duke Energy faces in the Carolinas, as well as the lack of modernized regulatory constructs such as load decoupling and bad debt expense trackers, that many of our peers enjoy. I believe the higher discount in Duke Energy's stock compared to peers implies that the cost of equity for the company has increased in 2020. Furthermore, as is also reflected on Young Rebuttal Exhibit 2, Duke Energy's earnings growth rate is near the bottom of our peer group. This makes us a less attractive investment for potential equity investors than other similar companies with higher earnings growth rates and P/E ratios.

When a utility company's stock underperforms, it is an indicator that equity investors view it as riskier than its peers, thus making equity investors more likely to invest in neighboring states with peers that trade at higher multiples. Higher discount rates to a company's stock also ultimately means more shares have to be issued to obtain the same level of equity capital, increasing cash outlays for dividends, thereby resulting in a higher cost of equity.

As described further by Company witness De May, we are entering a critical period in the development of the State of North Carolina's energy and regulatory policy, which will require a strong utility in order to attract investors to fund the significant investments needed for our customers.

Q. DO YOU HAVE ANY DIRECT EVIDENCE THAT DUKE ENERGY'S REGULATORY ENVIRONMENT IS CAUSING CONCERN IN THE INVESTMENT COMMUNITY?

A. Yes. I deal directly with stock analysts and institutional investors frequently and concerns over our ability to fully and efficiently recover our utility investments from customers, including investments in grid modernization, storm cost recovery, and coal ash basin closures, are a frequent topic of discussion. Some of these concerns spill over into worries about the ability of the Company to receive favorable regulatory treatment with respect to recovery of these costs and those concerns are starting to be reflected regularly in equity and credit analyst reports.

Q. CAN YOU PROVIDE SOME SPECIFIC EXAMPLES OF THIS PHENOMENON?

A. Yes. Moody's, in its October 13, 2019 opinion on Duke Energy, attached hereto as Young Rebuttal Exhibit 3, commented on the circumstances that could lead to a ratings downgrade to include:

"A deterioration in the credit supportiveness or emergence of a more contentious regulatory relationship which negatively impacts cash flows or the timeliness of cost recovery, particularly with regards to coal ash remediation recovery in North Carolina." Moody's, in its March 30, 2020 opinion on DE Progress, attached hereto as Young Rebuttal Exhibit 4, highlights credit challenges as including " uncertainty regarding ability to fully recover coal ash remediation spending with a return in all jurisdictions" and factors that could lead to a downgrade include "A decline in the credit supportiveness of the regulatory environments in North or South Carolina." This same report goes on to state that "Duke Energy Progress' coal ash basin closure and remediation spending is not recovered via trackers or other automatic cost recovery provisions . . . . As a result, there will likely continue to be regulatory lag in the recovery of these costs, and there is an increased risk that recovery of, or a return on, the spending may be denied." Similar concerns have been voiced by other agencies/analysts such as Bank of America Securities, which in a January 13, 2020 equity analyst report, attached hereto as Young Rebuttal Exhibit 5, noted Duke Energy's trading discount from its peers and expressed concerns over coal ash recovery and uncertainty over potentially punitive recovery treatment for those costs. These same concerns have also been reflected in recent equity analyst reports such as those of Wolfe Research and Fleishman Daily attached hereto as Young Rebuttal Exhibits 6 and 7.

Q. DOES DUKE ENERGY VIEW THE REGULATORY TREATMENT IT HAS HISTORICALLY RECEIVED FROM THE NORTH CAROLINA UTILITIES COMMISSION NEGATIVELY?

A. No. The prevailing opinion in the financial markets for regulated utilities for some time has been that the NCUC has historically been a supportive and stable public service commission and we agree with that assessment. Under that regulatory regimen, we have been confident of our ability to operate successfully and fulfill our mission to provide safe and reliable utility service at reasonable rates. My testimony in this case does not challenge that conclusion but it does alert the Commission to some storm clouds on the horizon involving perceptions of material risk related to DE Progress' ability to recover significant and ongoing investments, including financing costs, in coal ash basin closure and grid modernization that are worrying investors and lenders.

Q. ARE YOU SAYING THAT INVESTORS VIEW THE REGULATORY TREATMENT DE PROGRESS HAS RECEIVED FROM THE NCUC NEGATIVELY?

A. No. I am saying that investors are concerned with the Company's significant amount of investment at risk for recovery in this and other NCUC dockets. This concern, and the attendant uncertainty over when and how DE Progress will be permitted to earn on these investments is creating financial risk for the Company, which could result in diminished credit ratings for the Company and higher debt and equity costs for both the Company and its customers. This concern is significant enough that it is being openly discussed in analyst reports and, accordingly, I thought it important enough to bring it to the Commission's attention (i) so the Commission would be aware of this phenomenon as it considers the appropriate resolution of this case, and (ii) because we are faced with intervenor proposals (and recent Commission precedent) in this case that, if adopted, would significantly exacerbate the financial concerns I have described above and potentially harm both DE Progress and its customers.

Q. COULD YOU DESCRIBE WHAT DE PROGRESS' GOALS ARE COMING OUT OF THIS RATE CASE?

A. Yes. Duke Energy is extremely proud of our long-time record of providing exemplary safe and reliable electric service to customers. In order to fund the significant capital investments required to maintain this level of electric service, we must be able to attract debt and equity capital in the same financial markets utilized by peers and by other non-regulated businesses. If our access to the capital markets is unduly impaired, then our ability to provide customers with safe and reliable electric service at reasonable rates is jeopardized. Intervenor's proposals, if adopted, would do just this to the detriment of customers over the long-term. We request that the Commission approve a reasonable capital structure reflecting the actual capitalization of the Company and an ROE that allows us to compete with our peers for capital and is reflective of the value and quality of the service we provide to our customers. We would also hope to mitigate the impacts of lag associated with needed investments in modernizing our grid for the benefit of customers. Finally, we would hope to receive treatment with regard to the recovery of coal ash basin closure costs consistent with the Commission's decision in the prior DE Progress rate case, which was positively received by the ratings agencies and which recognizes the very real carrying costs associated with closing those utility assets.

As witness De May states, we are at a cross roads in North Carolina regarding how we will dramatically reduce our carbon emissions, strengthen our grid, accommodate significantly more renewable and distributed energy resources on to our system, continue to meet the growth in our state, and keep rates affordable. A financially healthy and strong electric utility is critical to the success of our state in achieving these goals.

Q. MR. YOUNG, THE FOREGOING TESTIMONY IS VERY SIMILAR TO WHAT YOU FILED IN REBUTTAL IN THE PENDING DE CAROLINAS RATE CASE IS DOCKET NO. E-7, SUB 1214. CAN YOU EXPLAIN WHY THAT IS THE CASE?

A. Yes. The similarity is due to two factors. The first is that to the extent that my rebuttal testimony is addressing matters at the holding company level, then quite naturally the same conditions applicable to DE Carolina are applicable to DE Progress. The second is that DE Progress is very similarly situated to DE Carolinas both with respect to geography, the business and operational challenges it faces and with regard to its pending rate case proposals. We operate these two utilities in the Carolinas in a similar manner, and in fact, our customers enjoy joint dispatch capabilities between these two adjacent utilities.

Q. HAS ANYTHING CHANGED SINCE THE TIME YOU FILED YOUR REBUTTAL TESTIMONY IN THE DE CAROLINAS RATE CASE THAT IS MATERIAL TO YOUR TESTIMONY?

A. Yes. As I alluded to above, the impacts of the spreading COVID-19 pandemic on the debt and equity markets have been dramatic and have introduced substantial volatility into both debt and equity markets. Within the last several weeks we have seen situations where long-term debt rates and projected equity investment returns have jumped by hundreds of basis points. For example, on March 10, 2020, Duke Energy Indiana successfully priced a placement of $550 million in 30-year first mortgage bonds at an interest rate of 2.75%. Seven days later, and as a consequence of the extreme volatility introduced into the markets by COVID-19 pandemic, Consumers Energy Co., with the same credit rating as Duke Energy Indiana, issued $575 million of 31-year debt at 3.50%. Ten days later on March 20, 2020, Berkshire Hathaway Energy, also with the same credit rating as Duke Energy Indiana, priced $1,250 million in 5-year bond at an interest rate of 4.05%. Similarly, in a March 28, 2020 Barclays report on indicators of required ROE's to attract equity capital in light of the new pandemic market conditions, they projected required increases in returns on equity in the short-terms of hundreds of basis points. A copy of this report is attached hereto as Exhibit 8.

As described in witness Newlin's testimony we have even seen days in the last month where the credit markets were effectively closed or closed to all but those companies with the highest credit ratings.

Q. ARE YOU PROPOSING THAT THE COMMISSION INCREASE DE PROGRESS' DEBT EXPENSE AND ALLOWED ROE BY HUNDREDS OF BASIS POINTS IN THIS PROCEEDING BECAUSE OF THESE CHANGES IN THE OVERALL MARKET?

A. No. Our proposed cost of debt and allowed rate of return on common equity are set forth in the testimony of Company witnesses Hevert and Newlin and I am not proposing to change those recommendations in this testimony. What I am suggesting though is that the Commission should evaluate extrinsic evidence of the state of the capital markets in reaching decisions about how to treat DE Progress in this case and should not pursue changes to DE Progress' current debt and equity costs that would threaten DE Progress' credit ratings in what is already a very unsettled and volatile capital market. Additionally, this provides further support to the reasonableness of our proposed cost of debt and allowed rate of return on common equity.

Q. CAN YOU ELABORATE ON THIS POINT?

A. Yes. As I have explained earlier in my testimony, DE Progress operates on a negative cash-flow basis, which makes access to debt and equity on reasonable terms absolutely critical to its ability to provide safe and reliable service to its customers. As I have also explained previously, and as Company witnesses Fetter and Newlin explain in their testimony, the Company's credit metrics are low for its overall credit rating and its stock is trading at a discount compared to other similar utility holding companies. Further, the ratings agencies have indicated they are watching the Company closely, particularly regarding the results of pending rate cases and matters involving coal ash remediation cost recovery and proposed progressive regulatory mechanisms to reduce regulatory lag on capital investments.

As Company witness Newlin discusses at length in his testimony, depending on the impacts of the current pandemic on Company operations and depending on the Commission's resolution of critical issues in this case, and the pending DE Carolinas case, it is entirely possible that the Company's credit rating could be downgraded by one or more notches. This would make access to debt and equity more difficult and more expensive, ultimately increasing costs to the Company's customers.

Even without a downgrade, given the volatility injected into the capital markets by the COVID-19 pandemic, it is highly likely that spreads between the various credit ratings will be higher than in more normal circumstances and could result in materially higher costs to fund the Company's day-to-day operations. The pandemic has further exacerbated the Company's vulnerability to increasing credit spreads and potential downgrades by impairing demand for its services and disrupting the normal operations of its customers. The full impact of this aspect of the COVID-19 virus has yet to be realized but is certain to be credit and revenue negative.

Q. WHAT IS YOUR CONCLUSION ABOUT THE IMPACTS OF THE COVID-19 PANDEMIC ON YOUR CONCERNS REGARDING THE CREDIT STABILITY OF DE PROGRESS?

A. In my testimony in the DE Carolinas case and in the testimonies of DE Carolinas witnesses Newlin and De May, we discussed the threat that certain intervenor proposals posed to our credit stability and access to the debt and equity markets. These included punitive capital structures, proposed rates of return on common equity well below those allowed to our peers or to us previously, accelerated return of excess deferred income taxes which would increase borrowing pressure on the Company, disallowance of recovery of coal ash remediation costs, and disallowance of accelerated recovery of costs associated with improvements to our grid. These same threats exist in this case and witnesses Newlin and De May similarly address them in their rebuttal testimony in this case.

The risks posed to the Company from these threats have now been further exacerbated by the dramatic negative impacts of a global pandemic. The continuation of a supportive and forward-looking regulatory environment where DE Progress can maintain its credit rating and recover its prudent costs of operations and costs of financing in a reasonable time period in the face of this additional external disruptive force is more important than ever, and we ask the Commission to consider these facts as it reaches its conclusions about an appropriate resolution of the various issues pending in this proceeding.

Q. IN THE FACE OF THE VOLATILITY IN THE EQUITY AND DEBT MARKETS CREATED BY THE COVID-19 PANDEMIC, HAS THE COMPANY TAKEN ANY STEPS TO MITIGATE THE IMPACTS OF THE PANDEMIC ON ITS CUSTOMERS?

A. Yes. As is discussed more fully in the Rebuttal Testimony of Company witness De May, we have taken several steps to assist our most vulnerable customers in the face of the pandemic and the State of Emergency declared by Governor Cooper in Executive Order No. 116. These include a voluntary moratorium on disconnections of service for non-payment for the duration of the State of Emergency and a waiver of reconnection and other fees granted by the Commission at the Company's request. These actions will negatively impact the Company's revenues in the short-term but are the right thing to do in terms of assisting our most economically vulnerable customers during a very challenging time. The Company has also implemented safety procedures to minimize contact between its employees and customers to minimize the risk of spreading the virus and has made multiple donations (totaling more than a million dollars) to a number of relief organizations designed to assist in the ongoing public health and economic crisis we are all currently facing.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1219

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

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND POSITION WITH DUKE ENERGY CORPORATION.

A. My name is John Panizza, and my business address is 550 South Tryon Street, Charlotte, North Carolina. I am employed by Duke Energy Business Services LLC ("DEBS") as Director, Tax Operations. DEBS provides various administrative and other services to Duke Energy Progress, LLC ("DE Progress" or the "Company") and other affiliated companies of Duke Energy Corporation ("Duke Energy").

Q. PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL QUALIFICATIONS.

A. I have a Bachelor of Science degree in Accounting from Montclair State University and a Master's in Taxation from Seton Hall University. I am a Certified Public Accountant in the state of New Jersey. My professional work experience began in 1989 as an auditor with KPMG. From 1993 to 2002, I held several financial positions primarily at two companies, in telecommunications and automotive (AT&T Corp., and Collins & Aikman Inc.). In 2002, I joined Duke Energy and have held several financial positions of increasing responsibilities, including various accounting and tax related positions. In March 2018, after a three year rotation primarily in Corporate Accounting, I moved back into the role of Director, Tax Operations, a position that I had previously held.

Q. PLEASE DESCRIBE YOUR DUTIES AS DIRECTOR, TAX OPERATIONS.

A. As Director, Tax Operations, I have overall responsibility for corporate tax compliance and accounting for Duke Energy. The Duke Energy Tax Operations Department is responsible for all federal, state, and local income tax returns for Duke Energy including various joint ventures if Duke Energy is the designated tax matters partner. The Tax Department is responsible for maintaining and reconciling Duke Energy's tax accounts and for the reporting and disclosure of tax-related matters, to the extent required.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION OR OTHER STATE PUBLIC UTILITY COMMISSIONS?

A. I have not testified before this Commission, but I have filed testimony on behalf of Duke Energy in proceedings before the South Carolina, Indiana, and Kentucky utility commissions.

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

A. I address federal tax reform legislation, namely, the Tax Cuts and Jobs Act (the "Tax Act"), which became law on December 22, 2017.

Q. PLEASE PROVIDE AN OVERVIEW OF YOUR TESTIMONY.

A. While the headline change brought by the Tax Act is a reduction of the statutory corporate tax rate from 35 to 21 percent, this reduction in rate is accompanied by many other provisions. The varying impacts of the Tax Act on the revenue requirement all must be considered, as the Company has done in its proposal for how best to address the Tax Act for the benefit of customers in North Carolina. Customers should – and will through the Company's proposal in this case – benefit from the overall reduction in the revenue requirement, but it is appropriate to also consider other, non-tax impacts of the legislation, particularly as it relates to cash flow. This need was highlighted by Moody's Investors Service ("Moody's") in an article it published on January 24, 2018[1] (approximately a month after the Tax Act became law), which highlights the Tax Act effect of putting pressure on cash flow and the possibility of an overall negative credit impact on utilities. This was, of course, an industry-wide analysis where some issuers will be affected by a greater amount, some by a lesser amount. However, I wish to highlight in my testimony that the implementation of the Tax Act has the potential to adversely affect the Company's cash flows and credit metrics. These negative impacts must be considered, and make having a strong equity to debt capital structure even more important post-Tax Act reform.

Further detail concerning the credit quality impact of the Tax Act is provided in the pre-filed direct testimony of Witness Karl Newlin, and additional details on the effect of the Tax Act on revenue requirements are included in the testimony of Witness Kim Smith. My testimony reviews the Company's plan. I conclude in my testimony that the Company's plan to

[1] Moody's Investors Service, Sector Comment, "Tax Reform is Credit Negative for Sector, but Impact Varies by Company," January 24, 2018. This article notes (at p. 2) that "[f]or the investor-owned utilities sector, the 2017 tax reform legislation will have an overall negative credit impact on operating companies and their holding companies." Moody's estimates that the Tax Act "will dilute a utility's ratio of cash flow before changes in working capital to debt [FFO/Debt] by approximately 150-250 basis points on average, depending to some degree on the size of the company's capital program."

incorporate the benefits of the Tax Act for the benefit of customers is balanced, appropriate, and consistent with the Commission's direction to defer tax benefits for consideration in DE Progress's next rate case.

II. <u>TAX REFORM</u>

Q. WHAT ARE THE KEY PROVISIONS OF THE TAX ACT AS IT RELATES TO DE PROGRESS?

A. Most changes to the corporate tax code apply to all U.S. corporations equally, while a limited set of others affect regulated utilities uniquely. For utilities in general, and DE Progress in particular, the key provisions of the Tax Act that will affect customer rates are as follows: (1) reduction of the corporate tax rate from 35 percent to 21 percent; (2) retention of net interest expense deductibility; (3) elimination of bonus depreciation; (4) elimination of the manufacturing deduction; and (5) normalization of excess accumulated deferred income taxes resulting from the Tax Act.

Q. PLEASE SUMMARIZE HOW THESE KEY PROVISIONS COULD IMPACT DE PROGRESS AND CUSTOMER RATES.

A. <u>REDUCTION IN CORPORATE TAX RATE</u>: The new statutory income tax rate of 21 percent represents a 40 percent reduction from the previous rate of 35 percent. This will lower a key component of cost of service, i.e., income taxes. In contrast to this lower cost of service impact, however, rate base will be higher in future rate proceedings due to the elimination of bonus depreciation (see below) and the reduced value of accelerated depreciation due to the lower federal income tax rate.

INTEREST EXPENSE DEDUCTIBILITY: The Tax Act generally provides that net interest expense is deductible only to the extent it does not exceed a stated percentage of an adjusted taxable income calculation, a calculation that becomes even more restrictive four years hence. However, regulated utilities are exempt from this limitation provision and may deduct their interest expense without limitation. Duke Energy and EEI (the regulated electric utility trade association) fought hard to achieve this important exemption, and our customers will retain the significant benefits that flow from it.

DEPRECIATION AND EXPENSING OF CAPITAL: The Tax Act generally provides that corporations may immediately expense capital as it is placed in service, akin to 100 percent bonus depreciation. However, the Tax Act specifically prohibits the immediate expensing of capital by regulated utilities. Instead, utilities are directed to use MACRS (modified accelerated cost recovery system) depreciation for capital investment placed in service. Though no longer accompanied by “bonus” depreciation, MACRS still represents a significantly accelerated rate of depreciation compared to book depreciation. As a result, deferred taxes will continue to accrue under MACRS, but will do so at a slower rate compared to bonus depreciation and at a much slower rate under the lower 21 percent corporate tax rate (see above)—this will cause a more rapid increase to rate base relative to pre-Tax Act.

MANUFACTURING DEDUCTION: Prior to the Tax Act, domestic manufacturers were granted a tax deduction based on a certain percentage of qualifying manufacturing income, and the production of electricity qualified for this tax benefit. To avail itself of this deduction, a corporation had to be in a taxable income position—this was often not the case recently for most regulated utilities because of the impact of bonus depreciation. Unfortunately, the elimination of bonus depreciation for utilities in the Tax Act coincided with the elimination of this tax deduction for all manufacturers, which is directionally detrimental to customer rates.

EXCESS DEFERRED INCOME TAXES: At the end of 2017, DE Progress has a significant net deferred tax liability, booked at a 35 percent corporate tax rate and driven overwhelmingly by accelerated and bonus depreciation of fixed assets for tax purposes. Because a deferred tax liability represents taxes collected from customers but not yet paid to taxing authorities, and because the ultimate payment of these taxes will now occur at a 21 percent corporate tax rate (down from 35 percent), the balance of deferred tax liability must be remeasured. The resulting "excess" deferred tax balance becomes a regulatory liability. The Tax Act requires that excess deferred taxes generally associated with property, and specifically connected to the accelerated depreciation of property, must be normalized into customers rates in a highly-prescribed manner that mimics the remaining life of the underlying assets. These are known as "protected" excess deferred taxes. All other excess deferred taxes may be treated by the Commission like any other regulatory liability in the rate-setting process.

Q. PLEASE DISCUSS THE CONCEPT OF BONUS DEPRECIATION.

A. Bonus depreciation is an enhanced form of accelerated depreciation for tax purposes. Congress has used bonus depreciation for well over a decade to encourage capital investment, at varying times renewing the provision just as it is set to expire and modifying the degree to which depreciation in the first year (the "bonus") could be claimed. Prior to the Tax Act, existing bonus depreciation laws were scheduled to sunset in 2020, but could very well have been extended as in years past. In 2017, prior to the Tax Act, bonus depreciation was 50 percent—this means that corporate taxpayers could depreciate 50 percent of capital placed in service in the first year *in addition to* a normal level of tax depreciation (MACRS) on the remaining 50 percent.

Bonus depreciation has the effect, generally, of reducing taxable income, and therefore deferring associated cash taxes. However, utilities, being very capital-intensive businesses, were often put into tax loss positions (net operating losses, or NOLs) from an abundance of bonus depreciation and therefore were limited in their ability to incrementally delay cash taxes. To the extent that a utility could defer cash taxes due to bonus depreciation, however, a net deferred tax liability was established. The cash collected from customers but deferred from the taxing authorities was used to fund the operations and investments of the utility and avoided a commensurate level of third-party financings that would otherwise have been necessary but for the additional deferred income taxes.

Q. PLEASE DISCUSS THE CONCEPT OF ACCUMULATED DEFERRED INCOME TAXES.

A. Many timing differences exist between when income taxes are collected from customers in rates and when the Company pays those taxes in cash to the IRS. Sometimes the taxes are paid sooner than when they are collected from customers (which creates a deferred tax asset on the Company's books), and sometimes they are paid later (creating a deferred tax liability). Deferred taxes balances, therefore, result from book/tax timing differences between the recognition of income and expenses. All deferred tax balances, whether they are assets or liabilities, reverse over time and converge to zero over the life of the underlying item giving rise to the deferred tax balance.

To illustrate, see the table below. In this example, I assume the Company invests $1,000 in an asset with a useful life of ten years. Because the useful life is ten years, the initial cost of the asset will be spread out evenly over the ten-year period such that the depreciation expense for book purposes is $100 per year. Another assumption in this example is that the Company can accelerate the depreciation of the investment over a much shorter life for tax purposes—five years in my example (the IRS provides tables that are used to calculate the annual tax depreciation expense).

In this example, DE Progress can depreciate $200 of its investment for calculating its current year tax liability, but only $100 for calculating its book tax expense. Because of that difference, the Company's income taxes paid is $35 less (at the 35 percent tax rate) than it would have been using the useful life as the basis for calculating taxes. In the example below, it shows that by end of year six the Company will have fully depreciated its investment for tax purposes but is still recording depreciation expense for book purposes. The benefit to the Company and customers is apparent in the "accumulated" column. The figures in this column represent cash available to the Company from what amounts to a zero-cost loan from the government. This balance benefits customers by providing an offset to rate base.

Table 1

	Depreciation Expense			Deferred Tax	
Year	**Per Books**	**Per Tax**	**Difference**	**Current Year**	**Accumulated**
1	$100	$200	$100	$35	$35
2	100	320	220	77	112
3	100	192	92	33	145
4	100	115	15	5	150
5	100	115	15	5	155
6	100	58	(42)	(15)	140
7	**100**	**-**	**(100)**	**(35)**	**105**
8	100	-	(100)	(35)	70
9	100	-	(100)	(35)	35
10	100	-	(100)	(35)	0
	$1,000	$1,000	$0	$0	$0

III. <u>THE COMPANY'S PROPOSAL</u>

Q. HOW DOES THE COMPANY'S APPLICATION IN THIS RATE CASE REFLECT THE IMPACTS OF THE TAX ACT?

A. Witness Smith describes how the Company has incorporated into the base rate revenue requirements in this case the reduction in the corporate income tax rate from 35 to 21 percent. For the remaining benefits of the Tax Act, the Company is proposing to create an Excess Deferred Income Tax ("EDIT")

Rider (the "EDIT Rider").[2] It is my understanding that the EDIT Rider contains the following five categories of benefits for customers:

1. Federal EDIT – Protected
2. Federal EDIT – Unprotected, PP&E related
3. Federal EDIT – Unprotected, non PP&E related
4. Deferred Revenue
5. NC EDIT

While Witness Smith describes the structure and mechanics of the EDIT Rider, my testimony addresses the categories of federal EDIT that are included in the rider.

Q. PLEASE DESCRIBE THE THREE BUCKETS OF FEDERAL EDIT.

A. To understand the Company's proposal, it is necessary to understand the different types of assets from which EDIT is derived, and their differing treatment by the Tax Act. The $1,177 million of EDIT, as of the end of 2018, is in three different buckets. In one is approximately $823 million as of the end of 2018 of what is called "protected EDIT" – that is, EDIT related to the Company's investment in property, plant and equipment, whose flow back treatment is expressly made subject to IRS normalization rules by the Tax Act. The normalization rules – specifically, Section 13001(d)(3)(B) of the Tax Act – require protected EDIT to be flowed back over the remaining lives of the property giving rise to the deferred tax balance.

The remaining EDIT, totaling approximately $354 million, as of the end of 2018, is "unprotected" under IRS rules, and, therefore, subject to flow

[2] Also referred to as "EDIT-2" in Witness Michael Pirro's rate design exhibits.

back in a timeframe open to discretionary action by the Commission. But the lion's share of unprotected EDIT, totaling approximately $327 million still relates to the Company's investment in property, plant, and equipment, and is the second bucket of EDIT. This portion of unprotected EDIT is not required to be normalized under the Tax Act. Although both buckets are property-related, the Internal Revenue Code protects one but not the other. However, the rationale for normalization applies to this portion of EDIT as much as it applies to protected EDIT, and so normalization at some level is appropriate. The assets represented in this bucket have an average life of approximately 22 years for DE Progress, although, as discussed below, the Company's proposal uses a shorter 20-year period over which to accomplish this flow-back.

The third and final bucket, totaling approximately $27 million, as of the end of 2018, is unprotected EDIT. This primarily relates to the EDIT that transitioned from Protected to Unprotected during 2018.

Again, these balances are as of the end of 2018. The Company has made and may make additional adjustments to these amounts in 2019, as protected amounts ultimately become unprotected over time.

Q. WHAT IS THE FLOW BACK PERIOD FOR PROTECTED EDIT?

A. These amounts are generally related to Property, Plant & Equipment ("PP&E") and there are specific IRS requirements that require that this amount be returned to customers no more quickly than the prescribed method. For protected EDIT, the Company applies the Tax Act-prescribed IRS normalization rules. The amortization period the Company is using here is called the Average Rate Assumption Method ("ARAM"). ARAM is the method under which the excess in the reserve for deferred taxes is reduced over the remaining lives of the property as used in its regulated books of account which gave rise to the reserve for deferred taxes. Under such method, during the time period in which the timing differences for the property reverse, the amount of the adjustment to the reserve for the deferred taxes is calculated by multiplying—(i) the ratio of the aggregate deferred taxes for the property to the aggregate timing differences for the property as of the beginning of the period in question, by (ii) the amount of the timing differences which reverse during such period.

Q. WHY IS THE COMPANY PROPOSING TO FLOW BACK THE CLASS OF UNPROTECTED PROPERTY-RELATED EDIT OVER 20 YEARS?

A. The 20-year period is appropriate because it is tied directly to the underlying assets that created the deferred tax balances that became EDIT when the Tax Act dropped the corporate tax rate to 21 percent. Protected and unprotected property related deferred taxes are no different except for the fact that they come from two places in the Internal Revenue Code and the statute protects one and it does not the other. The flow-back of excess deferred taxes over the life of the underlying assets makes sense, as does normalization concept underlying the 20-year flow-back proposal. Normalization, or the gradual return of EDIT over the life of the capital asset being depreciated, balances the customer and the Company's interests; it protects the Company's cash flow and also protects the customer against rate volatility, because the deferred balance acts as an offset to rate base, and, therefore, a reduction in rates.

Matching the flow-back period to the timeframe over which the flow-back would have occurred absent the Tax Act is important in other ways. Deferred taxes represent an interest-free loan from the government. The Company then used these funds, at no cost to customers, to invest in its business. By doing so, the Company avoided having to go to the capital markets to raise this portion of the funds that it invested, and customers saved the capital cost of its being able to use the interest-free loan from the government instead of investor-supplied capital. But having invested in the business, there is not a readily available reserve pool from which the cash needed to return EDIT can be drawn. Flow-back over the 20-year period that more closely matches the asset lives, smooths out the cash flow hit that the Company must take as it returns EDIT to customers and lessens the need for the Company to raise those funds from investors and third parties.

Q. PLEASE SUMMARIZE HOW CUSTOMERS BENEFIT FROM THE CHANGES IN THE COMPANY'S COST TO SERVE AS A RESULT OF THE TAX ACT?

A. As this Commission is well aware, electric utilities are one of the most capital intensive industries in the country. The Company invests in infrastructure not because of federal tax policy, but because it is critical, necessary, and often legally required that it do so. The Company's privilege and obligation to serve customers requires the financial wherewithal to support operational commitments on a reliable and cost-effective basis. Credit quality drives access to affordable capital, and for this reason it is in the best interest of customers to prevent a weakening of the Company's cash flow and credit quality from pre-Tax Act levels.

The Company's proposal included in this case both provides immediate benefit from the Tax Act and continues benefitting customers through the return of deferred taxes over time, as explained by Witness Smith. The Company's proposal further complies with accounting requirements while preserving the Company's credit rating by not creating undue pressure on cash flows.

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

A. Yes.

MR. ROBINSON: If it's appropriate at this time, we would call Mr. De May and Mr. Hatcher to testify as a panel.

COMMISSIONER CLODFELTER: We will have Mr. De May and Mr. Hatcher - and make sure I have you both on my screen - there you are, Mr. De May. Mr. Hatcher, where are you? I see you there.

STEPHEN G. DE MAY and LARRY E. HATCHER;
having been duly affirmed,
testified as follows:

COMMISSIONER CLODFELTER: Mr. Robinson, you may proceed.

MR. ROBINSON: Thank you. I will start with Mr. De May first.

DIRECT EXAMINATION BY MR. ROBINSON

Q Mr. De May, would you please state your name and business address for the record, please?
A (Mr. De May) My name is Stephen De May. My business address is 410 South Wilmington Street, Raleigh, North Carolina.
Q By whom are you employed and in what capacity?
A I'm the North Carolina President for Duke Energy Progress.
Q On October 30th, 2019, did you cause to be

prefiled in Docket E-2, Sub 1219 direct testimony consisting of 14 pages?
A Yes, I did.
Q And did you on May 4th, 2020, cause to be prefiled in that docket rebuttal testimony consisting of 17 pages?
A Yes, I did.
Q Do you have any changes or corrections to your prefiled direct or rebuttal testimony?
A No, I do not.
Q And, as corrected, if I asked you the same questions here today, would you answers be the same?
A Yes, they would.
Q And did you on June 2nd, 2020, cause to be prefiled in Docket E-2, Sub 1219 settlement supporting testimony consisting of seven pages?
A I did, yes.
Q And on July 31st, 2020, in that same docket, did you cause to be prefiled second settlement supporting testimony consisting of nine pages?
A Yes.
Q Do you have any changes or corrections -- Stephen, if wouldn't mind putting yourself on

mute when I'm speaking. Thanks.

Do you have any changes or corrections to your prefiled settlement supporting testimony?

A I do not.

Q If I asked you the same questions here today would your answers be the same?

A Yes.

Q And, Mr. De May, did you on September 3rd, 2020, provide oral testimony at the hearing held in Docket Number E-7, Sub 1214?

A Yes, I did.

Q If I asked you the same questions here today would your answers be the same?

A Yes, they would.

Q Mr. De May, did you prepare a witness summary for purposes of this hearing?

A Yes.

MR. ROBINSON: Commissioner Clodfelter, at this time I would move that Mr. De May's prefiled testimony as previously described and Mr. De May's testimony summary be entered into the record as if given orally from the stand.

(Pause)

Commissioner Clodfelter, I don't know if you heard me.

COMMISSIONER CLODFELTER: I'm learning with a new mute and unmute buttons that are on Webex now. If there is no objection to Mr. Robinson's motion, it is so ordered.

(WHEREUPON, the prefiled direct, rebuttal, settlement supporting, second settlement supporting testimony, and summary of Stephen G. De May is copied into the record as if given orally from the stand.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1219

In the Matter of:	)	
	)	**DIRECT TESTIMONY OF**
Application of Duke Energy Progress, LLC	)	**STEPHEN G. DE MAY**
for Adjustment of Rates and Charges	)	**FOR DUKE ENERGY**
Applicable to Electric Service in North	)	**PROGRESS, LLC**
Carolina	)	

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND POSITION WITH DUKE ENERGY CORPORATION.

A. My name is Stephen G. De May, and my business address is 410 South Wilmington Street, Raleigh, North Carolina, 27601. I am the North Carolina President for Duke Energy Progress ("DE Progress" or the "Company"), which is a wholly owned subsidiary of Duke Energy Corporation ("Duke Energy"), as well as Duke Energy Carolinas ("DE Carolinas") and Progress Energy, Inc., also wholly owned subsidiaries of Duke Energy.

Q. PLEASE BRIEFLY SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL QUALIFICATIONS.

A. I have a Bachelor of Arts degree in Political Science from the University of North Carolina at Chapel Hill and a Master of Business Administration degree from the McColl School of Business at Queens University in Charlotte, North Carolina. In 2010, I completed the Advanced Management Program at the Wharton School of the University of Pennsylvania. I am a Certified Public Accountant ("CPA") in the state of North Carolina and I am a member of the American Institute of Certified Public Accountants and the North Carolina Association of Certified Public Accountants.

Q. PLEASE DESCRIBE YOUR BUSINESS BACKGROUND AND EXPERIENCE.

A. My professional work experience began in 1986 with the public accounting firm of Price Waterhouse (now PricewaterhouseCoopers) and, subsequently, Deloitte, Haskins and Sells (now Deloitte & Touche), where my work focused on tax accounting and consulting for a variety of clients. In 1990, I joined Crescent Resources, Inc., a then wholly-owned real estate development subsidiary of Duke Power Company (a predecessor company to today's Duke Energy) where I was responsible for real estate accounting and finance. In 1994, I moved to the Treasury and Corporate Finance Department where I held, except for a two-year period, various finance-related positions of increasing responsibility. The two-year exception was for the majority of 2004 and 2005, during which time I had the lead responsibility for developing and managing Duke Energy's energy and regulatory policies. I was named Treasurer in 2007, a position I held until my current role. While Treasurer, I also served, at separate times, as Chief Risk Officer, head of Investor Relations and head of Tax. I assumed my current position as North Carolina President in November 2018.

Q. WHAT ARE YOUR RESPONSIBILITIES IN YOUR CURRENT POSITION?

A. I lead Duke Energy's regulated electric utility businesses in North Carolina, which include serving approximately 1.4 million DE Progress electric customers. I am responsible for the financial performance of the Company's electric utility in North Carolina and managing state and local regulatory and governmental relations, and community affairs. I also have responsibility for advancing the Company's legislative and regulatory initiatives related to its electric operations.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE COMMISSION?

A. Yes. I testified before this Commission in the Company's 2013 and 2017 rate cases (Docket Nos. E-2, Sub 1023 and E-2, Sub 1142, respectively). I also testified before this Commission in DE Carolinas' 2009, 2011 and 2017 rate cases (Docket Nos. E-7, Sub 909; E-7, Sub 989, and E-7, Sub 1146, respectively). I have also filed testimony for Duke Energy in various proceedings before the South Carolina, Ohio, Indiana, and Kentucky commissions.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to provide a brief overview of the Company's Application in this case. In my testimony, I note the key drivers and describe the three major elements of the Company's Application, which are: (1) how we are making investments in a manner that improves service to our customers and improves the customer experience; (2) the steps we are taking to transition from our reliance on coal, including the responsible management and closure of coal ash basins; and (3) how we are exploring additional ways to better assist our customers most in need. I also explain how the requested rate increase will allow the Company to remain a financially strong utility that is well positioned in financial markets to the benefit of our customers.

II. OVERVIEW AND CONTEXT OF THE COMPANY'S APPLICATION

Q. WHY DOES THE COMPANY BELIEVE THAT NOW IS THE TIME TO FILE THIS APPLICATION?

A. The conditions under which we operate have continued to evolve since 2017, the year of DE Progress' last base rate proceeding, challenging our ability to continue to provide the type of electric service our customers expect. The Company is seeing and experiencing significant changes throughout many aspects of the electric industry, and the investments we have made and must continue to make are designed to keep pace with evolving customer needs and expectations. These investments are capital-intensive and the Company has incurred costs that are not otherwise reflected in current rates. Through testimony in this case, we clearly explain why a rate change is needed to support these drivers. We also describe how the Company has performed, and will continue to perform, through thoughtful planning and prudent investment to continue to provide safe, reliable and efficient electric service.

Q. PLEASE DESCRIBE THE MAJOR DRIVERS BEHIND THE COMPANY'S APPLICATION.

A. The energy sector is in a period of transformation and profound change driven by technological advancements, environmental mandates, storm activity and response, energy security and resiliency efforts, as well as changing customer expectations. We are taking steps to anticipate and keep pace with the changes occurring in our state, and this rate application reflects three general themes that demonstrate our attention to the needs of our North Carolina customers.

IMPROVING THE CUSTOMER EXPERIENCE AND RELIABILITY

Technology is transforming North Carolina, and changing the way customers use electricity and interact with their electric provider. Reliability remains essential as an increasingly connected population continues to expand, especially in urban areas of the state. Today, the need for consistent, reliable service isn't just the expectation of industry and manufacturing, but extends into every home and business—even at a time when that reliability is challenged by the increasing frequency of severe weather events and the threat of physical and cyber-attack. Customers today want a new and better experience, driven by information about how they consume energy and by tools that help them manage their consumption. From investments in cleaner, highly-efficient generation resources to plans to invest in our distribution grid, smart meters, and the tools we use to communicate with our customers, you will read and hear testimony from several witnesses in this case describing the steps the Company has taken to continuously improve the service our customers receive from, and the interactions they have with, DE Progress.

In this category, Witness Jay Oliver discusses the Company's Grid Improvement Plan and how that Plan works now and into the future to improve the customer experience and reliability, and Witness Donald Schneider discusses how our deployment of smart meters has worked and will continue to work well with our investments to modernize our grid. Witness Rufus Jackson details the challenges we faced with storms and severe weather in 2018 and 2019 and how the Company was successfully able to restore power to over a million customers, quickly and efficiently. Witness James Henning describes the high-quality customer service provided by DE Progress and the efforts that the Company has taken to improve the customer experience when they interact with us, and Witness Michael Pirro discusses various proposed changes to the Company's service regulations to better reflect current cost studies and ultimately meet the expectations and needs of our customers.

MOVING PAST COAL

The Company is actively working towards achieving a lower carbon future by taking steps to close the final chapters on coal ash and reduce our reliance on coal-fired generation. We understand the need to protect the natural beauty and environment of North Carolina in a responsible manner while keeping prices as low as reasonably possible. Through testimony in this case, we describe steps we have taken to comply with environmental regulations for the disposal of coal combustion residuals, including the investments necessary to support ash basin closure activities, and investments we have made in generation resources like natural gas and solar. As part of our strategy to reduce our reliance on coal, we have taken a fresh look at the viability of several of our coal-fired plants and have concluded that making shifts in the expected remaining depreciable lives of some of our coal-fired assets is a reasonable action to take now, while we continue to monitor the changing industry landscape and impacts of market forces.

In this area, Witness Jessica Bednarcik discusses investments necessary to support ash basin closure under federal and state regulatory requirements, and

Witness Julie Turner discusses our fossil/hydro fleet and how that fleet is becoming cleaner and more efficient as we make this transition, including the Company's addition of a new, combined-cycle natural gas facility at Asheville. Witness John Spanos addresses the shortened depreciable lives for our coal-fired plants, and Witness Kelvin Henderson explains how the Company's high-performing nuclear fleet has and will continue to provide North Carolina carbon free generation now and into the future.

LOW-INCOME CUSTOMER SUPPORT

DE Progress is committed to helping customers who struggle to pay for basic needs with programs and options to assist them during times of financial hardship. The assistance programs that we offer, such as the Helping Home Fund, the Energy Neighbor Fund, and our portfolio of demand-side management ("DSM") and energy efficiency ("EE") programs, including the Neighborhood Energy Saver Program, have helped many of our customers reduce energy costs, pay home energy bills, manage fluctuations in their monthly bill, and manage through the difficulty of paying their entire bill by the due date. We want to do even more for these customers, particularly those most in need, and are considering ways for the Company and our customer base to continue to be good stewards.

In this area, Witness Karl Newlin discusses how the Company has proposed a return on equity of 10.3% as a rate impact mitigation measure instead of the 10.5% that Witness Robert Hevert has offered. Witness Pirro discusses how the Company has not requested an increase in the Basic

Customer Charge for customers in this application, even though an increase is warranted, so that the Company and interested stakeholders can have the time and the opportunity to collaborate on ways to help low-income customers in our rate design. Witness Kim Smith discusses proactive decreases that we have made in our filing (such as reductions to executive compensation) to give customers the benefit of reductions that the Company has agreed to in previous rate cases, and Witness Henning discusses our proposal to eliminate direct credit card fees for all our residential customers who pay their electric bills in that manner. Finally, as I will more fully discuss below, I propose other ways that we may be able to help our low-income customers.

Q. WHAT OTHER WAYS ARE YOU PROPOSING THAT THE COMPANY CAN HELP MITIGATE PRICE IMPACTS ON CUSTOMERS WHO ARE MOST IN NEED?

A. DE Progress is convinced 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. For example:

- Low-Income Bill Credit on the Basic Customer Charge: A fixed monthly bill credit off the Basic Customer Charge that would apply to qualifying customers' bills.
- Bill Round-Up Program: A voluntary program allowing customers to round-up bill payments to the next dollar and the difference would then

be forwarded to an energy assistance foundation to help provide financial assistance with electric bills.

- Implementation of a Supplemental Security Income (SSI) Price Discount: A discount program where customers receiving SSI are eligible to receive a discounted rate on their usage per month. While DE Carolinas currently has such a program, DE Progress does not. For DE Carolinas, Duke Energy is considering expanding the eligibility for and increase the amount of the discount for eligible customers. The DE Progress program would then mirror the expanded DE Carolinas program.

Before seeking to implement these programs, the Company believes that stakeholder engagement is necessary to adequately consider these and other programs to develop an appropriate suite of effective options for the Commission to consider for approval. Accordingly, the Company requests that as part of its order in this case, the Commission direct the Company to host, and the Public Staff to participate in, a collaborative workshop with interested stakeholders to address the establishment of new low-income programs at DE Progress and require that the Company and/or the Public Staff file a final report with the Commission outlining the feedback and recommendations obtained in that workshop. The Company proposes to use the feedback and recommendations it receives from participants in such a workshop to form formal requests to the Commission for new, low-income programs.

Q. HAS THE COMPANY CONSIDERED ANY OTHER WAYS TO REDUCE THE IMPACT OF THIS REQUESTED RATE INCREASE TO ITS CUSTOMERS?

A. Yes. In this case, the Company is requesting a determination from the Commission that the storm costs submitted for recovery and supported in the testimony of Witness Jackson are reasonable and prudent. If the Commission issues a determination that the storm costs submitted are approved as reasonable and prudent for recovery in this case, the Company proposes to begin recovering those costs in current rates in the manner described by Witness Smith in her testimony. 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.

Q. HAS THE IMPACT OF THE 2017 TAX CUTS AND JOBS ACT BEEN INCORPORATED INTO THE COMPANY'S REQUEST?

A. Yes. As explained by Witnesses John Panizza and Smith, the proposed rates include a reduction from the corporate income tax rate from 35 percent to 21 percent. The Company also includes a proposal to return to customers, through a rider, excess federal and state deferred income taxes ("EDIT") and deferred revenue resulting from federal tax reform legislation (i.e., the 2017 Tax Cuts and Jobs Act) and reductions in the North Carolina corporate income tax rate.

III. IMPORTANCE OF A STRONG FINANCIAL POSITION

Q. WHY IS IT IMPORTANT TO MAINTAIN A STRONG FINANCIAL POSITION FROM THE STANDPOINT OF DE PROGRESS' CUSTOMERS?

A. DE Progress is making and will continue to make important investments in our infrastructure to make it stronger, smarter, cleaner and more efficient. It is our responsibility to plan ahead and make these investments efficiently and prudently. To deliver on these promises, it is critical that we maintain a strong financial position and thereby ensure that the Company has the financial strength and flexibility to not only fund long term capital requirements, but to ensure the ability to meet short term funding needs as well. The single-most determinative factor of a healthy balance sheet and strong financial position is timely recovery of costs and the ability to generate cash flows sufficient to meet obligations as they become due, in all market conditions.

Q. PLEASE DISCUSS THE BENEFITS TO CUSTOMERS OF DE PROGRESS MAINTAINING A STRONG FINANCIAL POSITION.

A. Witness Newlin describes these in greater detail, but I think it is important to emphasize the benefits that result from our overall request in this proceeding, particularly our request on return on equity, capital structure and timely recovery of costs. Historically, because of its financial position, the Company has had the financial strength and flexibility necessary to fund its long-term capital requirements, as well as to meet short-term liquidity needs, at an economical cost to customers. As such, DE Progress has been able to obtain cost-effective capital, something that has benefited customers and will continue to benefit customers as we continue to make the large investments required to provide a more robust, more efficient, smarter and cleaner electric delivery system. As important as low cost is, ready access to capital is critical to serving our customers. Access to capital is most assured for companies who have strong financial positions, strong investment-grade credit ratings and adequate cash flow generation to meet obligations as they become due. The financial flexibility that comes from the ability to access cost-effective capital in all market conditions, in such a capital-intensive industry, serves the best interests of our customers.

Q. PLEASE SUMMARIZE WHY DE PROGRESS' REQUEST IN THIS PROCEEDING IS SO IMPORTANT FROM THE STANDPOINT OF THE INVESTMENT COMMUNITY.

A. Witness Newlin addresses this in detail, but I would like to make some general observations on this critical subject. DE Progress has enjoyed strong and cost-effective access to capital markets for years. This is a result of maintaining a strong balance sheet and constructive regulation that has recognized the need for an appropriate rate of return to Duke Energy's equity investors. Given our ongoing need for tremendous amounts of investor-supplied capital now and in the coming years, the Commission's decisions in this proceeding regarding the Company's return on equity, capital struture and the timely cash recovery of its costs will be critical.

IV. CONCLUSION

Q. WHAT IS THE KEY OBJECTIVE OF THE COMPANY'S REQUESTED GENERAL RATE ADJUSTMENT?

A. As I mentioned at the beginning of my testimony, the power business has entered a period of transformation and profound change driven by technological, environmental and operational forces, as well as changing customer expectations. Within this sea change, the Company recognizes that its most important objectives are to continue providing safe, reliable, affordable, and increasingly clean electricity to our customers with high quality customer service, both today and in the future. To achieve this, the Company must continue to invest in improving our grid; the transition from our reliance on coal, including our responsible management and closure of coal ash basins; investing in ways to make the energy we produce cleaner, more diverse, more reliable, and even more efficient for the benefit of our customers; and investing in new technologies to enhance the customer experience. Our Application is therefore made to support investments that benefit North Carolina and our customers while preserving the Company's financial position all while keeping prices as low as reasonably possible.

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

A. Yes.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1219

In the Matter of:	)	
	)	**REBUTTAL TESTIMONY OF**
Application of Duke Energy Progress, LLC	)	**STEPHEN G. DE MAY**
for Adjustment of Rates and Charges	)	**FOR DUKE ENERGY**
Applicable to Electric Service in North	)	**PROGRESS, LLC**
Carolina	)	

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND POSITION WITH DUKE ENERGY CORPORATION.

A. My name is Stephen G. De May, and my business address is 410 South Wilmington Street, Raleigh, North Carolina, 27601. I am the North Carolina President for Duke Energy Progress, LLC ("DE Progress" or the "Company"), which is a wholly owned subsidiary of Duke Energy Corporation ("Duke Energy"), as well as Duke Energy Carolinas, LLC ("DE Carolinas") and Progress Energy, Inc., also wholly owned subsidiaries of Duke Energy.

Q. DID YOU OFFER ANY DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes. I filed direct testimony in this docket.

II. PURPOSE AND OVERVIEW OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I discuss the unprecedented impact of the current pandemic on the Company's customers and its ability to serve, introduce the Company's rebuttal case and witnesses, and address certain aspects of intervenors' proposals that, if accepted, would have a negative impact on the Company and, by extension, its customers.[1]

[1] The absence of specific rebuttal on the part of DE Progress to any policy concern, accounting adjustment or ratemaking issue proposed by an intervenor does not constitute acceptance of the recommendation made by the intervenor, nor does it reflect agreement with any calculations made by intervenors.

Q. ARE OTHER COMPANY WITNESSES PROVIDING REBUTTAL TESTIMONY?

A. Yes. All of our direct witnesses in this case are providing rebuttal testimony today with the exception of witnesses Kimberly McGee, Rufus Jackson, John Panizza, and Donald Schneider. The Company is also filing rebuttal testimony from DE Progress' witnesses Conitsha Barnes, David L. Doss Jr., Lon Huber, Renee Metzler, James Wells and Steven K. Young, and external expert witnesses Rudolph Bonaparte, Steven Fetter, Erik Lioy, Sean Riley, and Marcia Williams.

Q. IS THE COMPANY SUBMITTING TESTIMONY IN RESPONSE TO THE COMMISSION'S ORDER ISSUED ON JANUARY 22, 2020, DIRECTING THE PUBLIC STAFF TO FILE TESTIMONY ON FOUR TOPICS?

A. Yes. Witness Hager addresses the Public Staff's testimony concerning cost of service methodologies in her pre-filed rebuttal testimony and Witness Conitsha Barnes addresses the Public Staff's testimony on the proposed stakeholder process to review affordability of electricity within the Company's service territory in her pre-filed rebuttal testimony. The depreciation and decommissioning of the Company's coal plants is addressed in the rebuttal testimony of Witness Spanos. Finally, Witness Bednarcik responds to the testimony of the Public Staff on coal combustion residual compliance costs in her rebuttal testimony.

III. IMPACT OF CORONAVIRUS PANDEMIC

Q. HOW IS THE NOVEL CORONAVIRUS ("COVID-19") PANDEMIC IMPACTING CUSTOMERS' ABILITY TO PAY THEIR ELECTRIC BILLS?

A. On March 10, 2020, in response to the significant health threat posed by COVID-19, Governor Roy Cooper issued Executive Order No. 116, declaring a State of Emergency in North Carolina. To minimize the risk of virus transmission to North Carolinians, many businesses temporarily closed or significantly scaled back operations and some businesses were forced to respond to the financial impact of the pandemic by laying off employees or decreasing their pay. We understand that during this pandemic our customers are dealing not only with significant risks to their health and well-being, but in many cases, severe financial hardships as a result of the pandemic and its impact on the economy.

Q. WHAT STEPS HAS THE COMPANY TAKEN FOR ITS CUSTOMERS TO HELP MITIGATE THE IMPACT OF COVID-19 ON THEIR ELECTRIC SERVICE?

A. Duke Energy, DE Progress and its affiliates remain committed to serving their customers with safe and reliable electric and natural gas utility service, while protecting the health and well-being of our customers, employees, and the communities they serve. To help prevent the spread of the COVID-19 virus, for example, DE Progress and DE Carolinas worked to limit direct customer interaction with our employees or vendors by suspending work that could have required an in-home visit. Moreover, DE Progress, DE Carolinas, and Piedmont

Natural Gas Company, Inc. have already acted to mitigate the financial impact of the COVID-19 pandemic on their customers, by voluntarily suspending all customer disconnections for nonpayment of bills and obtaining Commission approval to waive late charges and other fees throughout the state of emergency.[2] The Duke Energy Foundation donated $150,000 to DE Progress' Energy Neighbor Fund and DE Carolinas' Share the Warmth program to assist about 600 low-income North Carolina families with heating or cooling costs. The Duke Energy Foundation has also provided $900,000 to support hunger relief and help local health and human services non-profits in North Carolina.

There is a never a good time for a rate increase, and in the face of a pandemic, the Company understands the additional financial pressure its request may impose on some customers. In addition, the Company is sensitive to the risks posed by convening evidentiary hearings during a time when social distancing is required. As a result, on April 3, 2020, the Company filed a *Motion for an Order Addressing Procedural Issues*. In its Motion, the Company recognized the appropriateness of the Commission's decision to postpone the evidentiary hearing and the Company proposed modifications to the testimony schedule, filing requirements, and discovery guidelines to help alleviate and address some of the administrative challenges created by the pandemic. The Company also voluntarily waived through December 31, 2020, its statutory right to seek to implement its original proposed rates in this proceeding[3] in the event that the

[2] *See Order Granting Additional Temporary Waivers of Specific Provisions of Commission Rules,* Docket Nos. E-7, Sub 1236, E-2, Sub 1228 and G-9, Sub 767 (March 20, 2020).
[3] *See* N.C. Gen. Stat. § 62-134(b).

postponement of the evidentiary hearing rendered issuance of a Commission determination on just and reasonable rates in this proceeding prior to the end of the suspension period infeasible.

Q. HAS THE COVID-19 PANDEMIC IMPACTED THE COMPANY'S ABILITY TO PROVIDE SAFE AND RELIABLE SERVICE?

A. I am extremely proud of how our employees have maintained their focus on safety while continuing to put our customers first during these unprecedented times. In March, Duke Energy transitioned all office staff and non-field personnel to work from home. Our customer service teammates, who are typically the first, and in many cases, only personal point of contact with our customers, seamlessly transitioned to working from home to take calls from customers and continue to provide the type of customer service that our customers expect and deserve. Our customer delivery team had to quickly adjust their work practices to maintain social distancing and adhere to CDC guidelines while maintaining our energy grid and restoring customer outages. Our recent storm response is a key example: Over Easter weekend, DE Progress' (and Duke Energy Carolinas') logistics team in the Carolinas had to devise a plan to station crews in a way that would keep them safe from the coronavirus while restoring power to 600,000 customers as quickly and safely as possible. Despite the challenges of a pandemic, crews restored power to more than 95 percent of our customers in less than 48 hours. Lineworkers, tree crews and damage assessors followed social distancing guidelines and wore face masks as they worked around the clock to restore power to our customers and repair and rebuild the energy grid. Behind the scenes, hundreds of additional employees planned and supported these efforts. Our generation teammates have continued to maintain and operate the DE Progress fleet, again while maintaining appropriate protections against the spread of the coronavirus, so that our diverse generation fleet has been able to reliably meet our customers' needs during this critical time. I am very grateful for our employees' continued dedication and excellent service to our customers while responding to all of the unprecedented circumstances associated with this pandemic.

As a testament to the past decades of constructive regulation in North Carolina, DE Progress entered the pandemic on sound financial footing enabling it to continue to provide the same level of safe, reliable and cost-effective electric service to its customers. However, as with any major impact to the economy during times of financial uncertainty, the Company's ability to maintain its strong financial standing necessary to provide the same standard of electric service our customers benefit from today, is becoming increasingly challenging as the pandemic continues to impact our communities. The Company is not insulated from the financial and economic impacts of the pandemic. Certainly reduction in load and associated revenues is a matter of concern, as is the extreme volatility recently experienced in the debt and equity markets. These issues are presenting, or soon will be presenting, challenges for the Company. The potential impact of the pandemic on DE Progress' cash flows, uncollectibles, and lost revenues if the COVID-19 state of emergency in North Carolina continues for several months are significant – particularly in the context of the overall challenges the Company is experiencing.

We understand that electricity is a necessity and that we have an obligation to serve and continue to provide our customers with this necessary utility. It is more important than ever that we also continue to provide reliable electric service to medical facilities and those essential services and workers on the frontlines fighting this pandemic. Even in the case of financial constraints, DE Progress does not have the option to scale back its operations or cease providing essential electric service to its customers, nor would it be appropriate for the Company to do so. We will continue to seek ways to mitigate the financial impact of the pandemic on our customer's access to electric service, while preserving the Company's ability to meet its obligations.

As noted, the Company waived its right under N.C. Gen. Stat. § 62-134(b) to implement its proposed rates in the event the Commission is unable to render a decision in this matter prior to the end of the 270-day suspension period. To ensure the Company is able to maintain its financial health to the benefit of its customers, the Company reserved its right subject to N.C. Gen. Stat. § 62-135 to implement temporary rates and to seek appropriate accounting treatment relief if it becomes necessary. This would not be an action the Company would enter into lightly but would be a necessary action taken to enable the Company to receive the financial resources it requires to continue to meet its obligation to serve under the regulatory compact.

IV. KEY POINTS OF REBUTTAL CASE

Q. PLEASE PROVIDE AN OVERVIEW OF THE COMPANY'S VIEW OF THE PUBLIC STAFF AND INTERVENOR TESTIMONY FILED RECENTLY IN THIS CASE.

A. The State of North Carolina is at a crossroads in terms of its energy and regulatory policy. On one hand, the Governor has outlined aggressive goals to significantly reduce greenhouse gases, including an aggressive 70% reduction target by 2030. These goals will require the Company to accelerate the move beyond coal and coal ash; safely and reliably facilitate thousands more megawatts ("MWs") of renewables and other distributed energy resources such as solar, wind and energy storage, including the investment in transmission and distribution systems necessary to accommodate the influx; continue to improve the efficiency of its current generation fleet; continue (and seek to further extend) the operation of and investment in the Company's carbon-free nuclear fleet; and expand energy efficiency and demand-side management measures, all while consistently delivering electric service that is safe and reliable at low cost.

On the other hand, if accepted by this Commission, many of the recommendations set forth by the Public Staff and other intervenors would negatively affect the Company's financial ability to make these investments and help the State achieve its desired energy future. Regulatory outcomes that are contrary to well-established principles and that fail to strike the right balance between the Company and its customers would be detrimental to the State, just at a time when the State's policymakers are positioning North Carolina as a leader on climate policy and as one of the premier states in which to do business.

To transform our business and to meet the needs and desires of our customers and the State, DE Progress needs the consistent and timely recovery of its prudently incurred costs and investments, as well as the continued ability to access capital at reasonable rates on favorable terms. The recommendations the intervenors make in this case materially challenge these core principles. DE Progress requests to recover or defer costs for the *exact* types of investments that will help transition the State to a lower carbon future and allow the Company to partner with the State to achieve its goals. These investments include: 1) the closure of the Company's coal ash basins in compliance with Federal and State laws and regulations, 2) accelerating the depreciable lives of some of the Company's coal-fired plants to foster more rapid plant closures, and 3) investment in the Grid Improvement Plan.

As I noted before, while there is a never a good time for a rate increase, the requests put forth by the Company in this case are needed to reflect in rates the prudent investments it made for the benefit of its customers. If the Commission were to accept the recommendations of the Public Staff and intervenors, it would reverse years of constructive regulation that has enabled DE Progress to perform at high levels while maintaining rates below the national average. A significant change in the balance and constructiveness of the State's regulatory environment would reduce the Company's financial strength and flexibility, which would be to the detriment of customers now and in the long-term.

Q. HOW WOULD YOU RATE THE COMPANY'S QUALITY OF SERVICE?

A. The Company's performance by any measure has been outstanding for decades. The Company's rates for all classes of customers are well below the national average and have been for decades. The Company has been repeatedly recognized as a leader in the industry in storm restoration and over the last several years has been able to restore service to 95% of its customers within a few days over the course of several storms. The Company's nuclear fleet is recognized as being one of the best in the industry in terms of safety, reliability/availability and production costs. The Company's Fossil and Hydro operations have similar superior safety, reliability and production cost performance, while reducing carbon emissions by 39% from 2005 levels. The Company's transmission and distribution reliability has performed well, and we have continued to provide safe and reliable electric service; we have deployed new smart meters across our jurisdiction and are in the process of replacing the Company's outdated customer information system with a new, modern customer service platform that will transform how the Company serves customers by providing them with the easy, personalized experiences they expect from other service providers.. The Company's Economic Development organization – named one of the nation's leaders for the last 15 years – has brought more than two hundred businesses to the state, totaling $13 billion of capital invested in the State, 26,000 jobs and generated billions in tax revenues. Many more examples are described by Company witness Hatcher in his direct testimony.

Notwithstanding the Company's responses to 7,630 data requests, providing 17,211 files consisting of 406,097 pages of documentation, not a single intervenor contests any of the aforementioned quality of service facts. As witness Hatcher states in his direct testimony, we are a well-run company and we believe that customers see and experience the benefits of our efforts every day. Nevertheless, in response to the Company's filing, intervenors propose that the Commission respond to the Company's performance with the following:

- Award the Company the lowest ROE in the nation for vertically integrated utilities and, at best, the national average – notwithstanding the performance and risk profile of the Company in the current regulatory environment;
- Reduce the Company's equity structure, which would further impair its financial health, earnings growth and balance sheet strength, and weaken its ability to earn a reasonable return;
- Disallow billions of dollars of costs associated with coal ash impoundment closure;
- Disallow any return – including even a debt return – on prudently incurred coal ash management costs over decades to come; essentially requiring the Company to borrow billions of dollars over the next 30 years without being able to recover the interest expense it incurs, receive the time value of the money borrowed, or receive an equity return;
- Limit the Company's ability to defer expenses necessary to modernize the electric grid and enable greater distributed energy resources; and
- Simultaneously require the Company to flow back hundreds of millions of dollars in excess deferred income taxes to customers immediately or in the very short term – and, in stark contrast to intervenors' position on recovery of coal ash costs, if over time

then with interest at the Company's weighted average cost of capital.

Many of the intervenors' positions are contrary to established regulatory rules and precedent, including precedent as recently as established as the Company's 2017 rate case in Docket No. E-2, Sub 1142. If adopted by this Commission, those measures would send a strong and clear signal to investors that the stable regulatory environment that has benefitted customers for the last 50 years with some of the lowest electric rates in the country has fundamentally shifted. The intervenors' positions, if adopted, would also send a clear message to rating agencies, which likely would result in an immediate downgrade of the Company's credit quality causing a further deterioration of the Company's balance sheet, increasing its cost of capital, and adversely affecting the terms on which the Company can borrow the billions of dollars of funds it needs to maintain a growing and changing system. Company witnesses Fetter, Hevert, Newlin, and Young will explain these potential ramifications in greater detail.

Q. PLEASE DESCRIBE THE ENERGY POLICY SIGNALS COMING FROM THE STATE OF NORTH CAROLINA AS THEY RELATE TO THE COSTS THE COMPANY SEEKS TO RECOVER IN THIS CASE.

A. Around the same time the Company filed its Application in this Docket, the Department of Environmental Quality ("DEQ") presented to the Governor its Clean Energy Plan ("CEP") to meet North Carolina's goals to 1) "reduce electric power sector greenhouse gas emissions by 70% below 2005 levels by 2030 and obtain carbon neutrality by 2050, 2) foster long-term energy affordability and price stability for North Carolina's residents and businesses by modernizing regulatory and planning processes, and 3) accelerate clean energy innovation, development, and deployment to create economic opportunities for both rural and urban areas of the state."[4] As DEQ notes, "[t]o successfully transition to a clean energy future, North Carolina must establish a 21st-century regulatory model that ***incentivizes business decisions that benefit both the utilities and the public in creating an energy system that is clean, affordable, reliable, and equitable***."[5] As part of the CEP, DEQ makes the following key recommendations it deems "critical to the transition":

> • Develop carbon reduction policy designs for accelerated retirement of uneconomic coal assets and other market-based and clean energy policy options.
>
> • Develop and implement policies and tools such as performance-based mechanisms, multiyear rate planning, and revenue decoupling, that better align utility incentives with public interest, grid needs, and state policy.
>
> • Modernize the grid to support clean energy resource adoption, resilience, and other public interest outcomes.[6]

The Company's Application seeks to recover or defer costs for the very investments the CEP promotes: 1) the closure of our coal ash basins in compliance with Federal and State laws and regulations, 2) accelerating the depreciable lives of some of our coal-fired plants to foster more rapid plant closures, 3) investment in the Grid Improvement Plan, and 4) dual fuel optionality conversions. A fair capital structure and return on equity that will allow the Company to continue to

[4] https://deq.nc.gov/energy-climate/climate-change/nc-climate-change-interagency-council/climate-change-clean-energy-16 (last visited April 21, 2020).
[5] *Id* (emphasis added).
[6] *Id.*

access the capital markets on favorable terms necessary to fund these investments is warranted.

In terms of the Company's proposal to accelerate the depreciable lives of some of its coal-fired units, the Company understands the Public Staff's position is to stick with the status quo and not accelerate the retirement dates in the Company's Depreciation Study. However, in line with the desires of the State, the Company anticipates ongoing pressure to meet aggressive carbon reduction and emissions goals and to adapt further climate change-related policymaking. The Company already faces calls for early retirement of its coal-fired generating units,[7] so it is seeking to take proactive steps in this case to position itself to meet these expectations. The Company believes the time to act on this highly foreseeable policy shift is now.

Q. HAVE THERE BEEN ANY OTHER NEW DEVELOPMENTS THAT SUPPORT THE COMPANY'S APPLICATION SINCE THE TIME OF THE FILING?

A. Yes. Another new development since the Company filed its Application in this Docket, is the passage of Senate Bill 559, an Act to Permit Financing for Certain Storm Recovery Costs ("SB 559"), by the North Carolina General Assembly which provides utilities an alternative to finance storm costs through securitization. The Company is pleased SB 559 passed and believes it will lead to savings for its customers. The Company looks forward to pursuing

[7] In fact, while the Company submits that a rate case proceeding is not the proper proceeding in which to address the economics of continued operation of its coal-fired units, the Sierra Club submitted testimony in this proceeding opposing recovery of the costs related to the continued operation of certain coal-fired units.

securitization at the appropriate time; however, these costs should remain a part of the Company's request in this proceeding until the Commission reaches the same determination of the Company and the Public Staff[8] that the costs were prudently incurred, and the Commission subsequently approves a financing petition. As I stated in my direct testimony:

> . . . . [T]he 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.*[9]

Witness Smith describes the removal of the Public Staff's proposed adjustment to remove the storm costs from the Company's requested revenue requirement.

Q. IN TERMS OF LOW-INCOME CUSTOMER SUPPORT, DO THE PUBLIC STAFF AND INTERVENORS GENERALLY SUPPORT THE COMPANY'S PROPOSED COLLABORATIVE STAKEHOLDER PROCESS?

A. Yes. We are pleased with the portions of the testimony of Public Staff Witness Floyd and North Carolina Justice Center, et. al. Witness Howat; supporting dialogue on ways the Company can mitigate electricity costs for its low-income customers. The Company looks forward to the opportunity to engage with its interested stakeholders in a collaborative workshop to address this important issue for our customers.

[8] *See* Testimony of Shawn L. Dorgan Public Staff – North Carolina Utilities Commission, Docket No. E-2 Sub 1219 at 32 (April 13, 2020).
[9] De May Direct Testimony at 11 (*emphasis added*).

V. CONCLUSION

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

A. Yes.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-2, SUB 1219
DOCKET NO. E-2, SUB 1193

In the Matter of: **DOCKET NO. E-2, SUB 1219** Application of Duke Energy Progress, LLC For Adjustment of Rates and Charges Applicable to Electric Service in North Carolina **DOCKET NO. E-2, SUB 1193** Petition of Duke Energy Progress, LLC for an Accounting Order to Defer Incremental Storm Damage Expenses Incurred as a Result of Hurricanes Florence and Michael and Winter Storm Diego	**SETTLEMENT TESTIMONY OF STEPHEN G. DE MAY FOR DUKE ENERGY PROGRESS, LLC**

I. WITNESS IDENTIFICATION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Stephen G. De May, and my business address is 410 South Wilmington Street, Raleigh, North Carolina, 27601.

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

A. I am the North Carolina President for Duke Energy Progress ("DE Progress" or the "Company"), which is a wholly owned subsidiary of Duke Energy Corporation, as well as Progress Energy Inc. and Duke Energy Carolinas, LLC, also wholly owned subsidiaries of Duke Energy.

Q. DID YOU OFFER ANY DIRECT AND REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. Yes. I filed direct testimony in this docket on October 30, 2019 and rebuttal testimony on May 4, 2020.

II. PURPOSE AND OVERVIEW OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I support the Agreement and Stipulation of Partial Settlement the Company reached with the North Carolina Utilities Commission Public Staff ("Public Staff"), filed with the Commission on June 2, 2020 in this docket (the "Partial Settlement"). The Company was able to reach a Partial Settlement with the Public Staff (together, the "Stipulating Parties") subsequent to the Company's filing of its pre-filed direct, rebuttal and supplemental testimony and exhibits and after extensive discovery conducted by the Public Staff and other intervenors. The Partial Settlement represents a balanced settlement for the parties on these issues, is in the public interest, and should be approved by the Commission. My direct and rebuttal testimony remain effective as applicable to the testimony of any non-settling Party, including the unresolved matters between the Company and Public Staff listed in the Partial Settlement.

III. THE PARTIAL SETTLEMENT

Q. PLEASE PROVIDE AN OVERVIEW OF THE MAJOR COMPONENTS OF THE PARTIAL SETTLEMENT.

A. The Partial Settlement resolves several of the revenue requirement issues between the Company and the Public Staff. Most notably, the Stipulating Parties came to a decision to remove the Company's deferred storm expenses, incurred to restore service to the approximately 4.7 million customers that were impacted by Hurricanes Florence and Michael and Winter Storm Diego in late 2018 and Hurricane Dorian in 2019 (collectively, the "Storms"), from its requested increase in this rate case and permit the Company to proceed with filing a petition to securitize these storm costs as permitted by N.C.G.S. §§ 62-69, 72. Over the last few years, North Carolina has been hit by several severe storms that left hundreds of thousands of people and businesses without power. These Storms caused extraordinary damage and widespread outages across the DE Progress distribution system and required a robust response from the Company. This response involved the activation and deployment of storm response teams internal to the Company, utilization of thousands of outside contractors, and the need to seek mutual aid from other electric utilities and allies in the industry. Despite the extraordinary damage to the Company's transmission and distribution systems because of these Storms, I am very proud of the Company's commitment to timely restoration efforts and a positive customer experience, which resulted in more than 90 percent of customers impacted by Hurricane Michael being restored within 72 hours, restoration within 48 hours for more than 79 percent of customers impacted by Hurricane Florence, more than 90 percent of the customers impacted by Winter Storm Diego restored within 48 hours, and more than 95 percent of customers impacted by Hurricane Dorian restored within 48 hours.

In 2019, North Carolina lawmakers put legislation in place to alternatively pay for major storm recovery, in a way that reduces costs for customers and allows the Company to recoup its storm-related expenditures to restore the system, harden it, and be better prepared for future storm activity. It is hard to imagine a better time to implement the cost-effective financing provided by the securitization statute than the catastrophic Storms.

Specifically, once the Public Staff conducted its audit of the Company's storm expenses and concluded that such costs were prudently incurred[1], the Stipulating Parties agreed that the Company would remove from Commission consideration in this case its request for recovery of the deferred storm expenses and instead proceed with filing a financing petition within 120 days from the

[1] Dorgan Direct Testimony at 32; Dorgan Supplemental Direct Testimony at 9.

date of the Commission order addressing the prudency of the Company's storm costs in this proceeding. For purposes of settlement, the Stipulating Parties also agreed on the assumptions that will be used in the subsequent securitization docket to evaluate whether securitization provides quantifiable customer benefits when compared to traditional storm cost recovery. The Stipulating Parties further agreed that a storm cost recovery rider, initially set at $0, should be established in this rate case to provide the Company a mechanism to request recovery of its storm costs if the Company is unable to securitize its storm costs.

Further, as discussed in greater detail by Company witness Kim H. Smith in her testimony, the Stipulating Parties agreed to revenue requirement adjustments addressing Aviation; Executive Compensation; Board of Directors; Lobbying; Sponsorships and Donations; Rate Case Expenses; Outside Services; Severance; Incentive Compensation; the Asheville Combined Cycle project; Credit Card Fees; End of Life Nuclear Reserve; Protected Federal EDIT; and treatment of the CertainTeed payment obligation in this rate case.

Q. DOES THE COMPANY AGREE WITH THE AGREED-UPON ADJUSTMENTS AS DESCRIBED IN THE SETTLEMENT AGREEMENT?

A. Yes.

Q. PLEASE ELABORATE ON HOW THE PARTIAL SETTLEMENT BALANCES THE COMPANY'S NEED FOR RATE RELIEF WITH THE IMPACT OF SUCH RATE RELIEF ON CUSTOMERS.

A. I attended public hearings held by the Commission in this matter and personally heard from dozens of our customers who are concerned about the impacts of any rate increase on their families and businesses. We are very mindful of these concerns. Although we are pleased that our rates are competitive and below the national average, and will remain so with this Partial Settlement, we know that providing safe, reliable, increasingly clean electricity at competitive rates is key to powering the State's economy and the lives of our customers. For these reasons, we especially look forward to using the storm securitization mechanism to help secure storm restoration cost savings for North Carolina energy customers. We also believe the concessions the Company has made in this Partial Settlement fairly balance the needs of our customers with the Company's need to recover investments made to continue to comply with regulatory requirements and safely provide high quality electric service to our customers.

Q. IN THE PARTIAL SETTLEMENT, DID THE COMPANY AND PUBLIC STAFF REACH AGREEMENT ON ALL ISSUES IN THIS DOCKET?

A. No. There are a number of issues that remain disputed between the Company and the Public Staff. Those issues are outlined in the Partial Settlement.

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

A. Yes.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-2, SUB 1219

In the Matter of:	)	
	)	**SECOND SETTLEMENT**
DOCKET NO. E-2, SUB 1219	)	**TESTIMONY OF**
Application of Duke Energy Progress, LLC For	)	**STEPHEN G. DE MAY**
Adjustment of Rates and Charges Applicable to	)	**FOR DUKE ENERGY**
Electric Service in North Carolina	)	**PROGRESS, LLC**
	)	

I. WITNESS IDENTIFICATION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Stephen G. De May, and my business address is 410 South Wilmington Street, Raleigh, North Carolina, 27601.

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

A. I am the North Carolina President for Duke Energy Progress ("DE Progress" or the "Company"), which is a wholly owned subsidiary of Duke Energy Corporation, as well as Progress Energy Inc. and Duke Energy Carolinas, LLC, also wholly owned subsidiaries of Duke Energy.

Q. DID YOU OFFER ANY DIRECT AND REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. Yes. I filed direct testimony in this docket on October 30, 2019; rebuttal testimony on May 4, 2020; and partial settlement supporting testimony on June 2, 2020.

II. PURPOSE AND OVERVIEW OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I support the Second Agreement and Stipulation of Partial Settlement the Company reached with the North Carolinas Utilities Commission Public Staff ("Public Staff") (together, the "Stipulating Parties"), filed with the Commission on July 31, 2020 in this docket (the "Second Partial Settlement"), and introduce several other witnesses that support the reasonableness of the Second Partial Settlement. The Company was able to reach a Second Partial

Settlement with the Public Staff subsequent to the Company's filing of its pre-filed direct, rebuttal and supplemental testimony and exhibits; extensive discovery conducted by the Public Staff and other intervenors; and prior settlements reached with the Public Staff, the Commercial Group, CIGFUR, Harris Teeter, Vote Solar, NCSEA, NCJC, NCHC, NRDC, and SACE in this proceeding. The Second Partial Settlement represents a balanced settlement for the Stipulating Parties on these issues, is in the public interest, and should be approved by the Commission. My direct and rebuttal testimony remain effective as applicable to the testimony of any non-settling party, including the unresolved matters between the Company and Public Staff listed in the Second Partial Settlement. Additionally, my settlement supporting testimony remains effective as applicable to the first partial settlement the Company entered into with the Public Staff.

III. THE PARTIAL SETTLEMENT

Q. PLEASE PROVIDE AN OVERVIEW OF THE MAJOR COMPONENTS OF THE PARTIAL SETTLEMENT.

A. Overall, the Second Partial Settlement resolves most, but not all, of the remaining revenue requirement issues between the Company and the Public Staff. I describe the Unresolved Issues later in my testimony.

As discussed by other Company witness testimony being filed today by Kim H. Smith, Dylan D'Ascendis, and Karl Newlin, the agreement reached between the Stipulating Parties in the Second Partial Settlement can be summarized as follows:

Shareholder Contribution – The Company has agreed to make an annual $2.5 million shareholder contribution to the Energy Neighbor Fund in 2021 and 2022, for a total contribution of $5 million.

Cost of Capital – The Stipulating Parties have agreed to a return on equity of 9.6 percent, based upon a capital structure containing 52 percent equity and 48 percent debt as described by Witnesses D'Ascendis and Newlin. The Company's debt cost rate shall be set at 4.04 percent. The resulting weighted average rate of return is 6.93 percent.

EDIT – The Stipulating Parties have agreed to several terms in the Second Partial Settlement addressing the return of state and federal excess deferred income taxes ("EDIT") to customers. For example, the Company has agreed to return to customers the total unprotected federal EDIT amount over a five-year period and North Carolina EDIT over a two-year period. Additionally, if state or federal income tax rates happen to change again during the respective flowback periods, the Company may, under certain conditions, propose to reflect the effect of any future tax rate change on the remaining EDIT balance.

Grid Improvement Plan – The Public Staff has agreed to the Company's requested deferral accounting treatment for the following programs, as described in Witness Oliver's Exhibit 10, limited to the estimated three-year capital budget period of 2020-2022: Self-Optimizing Grid ("SOG") (all subprograms including

Capacity and Connectivity, Segmentation and Automation, ADMS), Integrated System and Operations Planning ("ISOP"), Transmission System Intelligence, Distribution Automation, Power Electronics, DER Dispatch Tool, and Cyber Security. For all other Grid Investment Plan ("GIP") investments proposed by the Company in this docket, the Company agrees that it will withdraw its request for deferral accounting. Further, the Company, in conjunction with the concurrent commitment of DE Carolinas, and the Public Staff will work together to develop biannual reporting requirements to track GIP expenditures that receive accounting deferral treatment.

Cost of Service – The Public Staff has accepted, for this case only and subject to agreement on certain conditions outlined in the Second Partial Settlement, the Company's proposal to calculate and allocate the Company's cost of service based on a 1CP Summer methodology.

May Updates - The Stipulating Parties have agreed to include the Company's updates to certain pro forma adjustments through May 31, 2020 ("May Updates"), pending and subject to the Public Staff's audit of the updates. In addition, the Stipulating Parties have agreed to limit the update to revenues to 75% of the difference between the May Updates and the Company's February update to recognize the uncertainty regarding the effects of COVID-19. The Stipulating Parties further agreed that the May Updates shall also include updates for benefits and executive compensation through May 2020.

Nuclear Decommissioning Trust Fund – The Company has agreed to reduce the annual funding for the Company's Nuclear Decommissioning Trust Fund by $8.7 million, and further agree to support this funding amount in DE Progress's current cost and funding decommissioning Docket No. M-100, Sub 56.

Non-ARO Environmental Costs – The Stipulating Parties have agreed to amortize deferred non-asset retirement obligation ("non-ARO") environmental costs over an eight-year period.

Other Areas of Agreement – The Stipulating Parties have also agreed to terms governing the start date of the evidentiary hearings to allow time for the Public Staff to audit the May Updates; ongoing assessments of the cost effectiveness of GIP-related projects; clarification of GIP costs that are eligible for deferral; commitments to future cost of service studies; rate design issues; commitments to conduct audits and reporting obligations regarding plant, materials & supplies inventory, vegetation management, and service reliability index reporting.

Q. DOES THE COMPANY AGREE WITH THE CHARACTERIZATION OF THE AGREED-UPON ADJUSTMENTS AS DESCRIBED IN THE SETTLEMENT AGREEMENT?

A. Yes.

Q. PLEASE ELABORATE HOW THE PARTIAL SETTLEMENT BALANCES THE COMPANY'S NEED FOR RATE RELIEF WITH THE IMPACT OF SUCH RATE RELIEF ON CUSTOMERS.

A. I attended public hearings held by the Commission in this matter and personally heard from many of our customers who are concerned about the impacts of any rate increase on their families and businesses. I also followed the consumer statement positions filed in this Docket. We are very mindful of these concerns. Although we are pleased that our electric rates are competitive and below the national average, and will remain so with this Second Partial Settlement, we know that providing safe, reliable, increasingly clean electricity at competitive rates is key to powering the State's economy and the lives of our customers. Particularly in light of the current economic conditions of many of our customers due to the COVID-19 pandemic, we believe that the concessions the Company has made in this Partial Settlement fairly balance the needs of our customers with the Company's need to recover substantial investments made in order to continue to comply with regulatory requirements and safely provide high quality electric service to our customers. Our electric rates need to be adjusted to reflect these investments. Moreover, given the size of the necessary capital and compliance expenditures we are facing, it is essential that DE Progress maintain its financial strength and credit quality so that we will be in a position to finance these needs on reasonable terms for the benefit of our customers. In my opinion, we have been able to strike that balance with this Partial Settlement on the agreed upon items. However, we remain concerned about cost recovery for the Unresolved Items, as that is critical to the financial health of the Company.

Just a few of the ways we have struck this reasonable balance include: (1) the Company's willingness to settle for rates designed on the basis of a 9.6 percent return on equity and a 52 percent equity component of its capital structure, both of which will mitigate the impact of the rate increase on customers; (2) the Company's willingness to accept an overall lower revenue requirement will also mitigate the impact on customers; and (3) the Company's agreement to contribute $5 million to help many of our most vulnerable customers pay their electric bills.

Q. IN THE PARTIAL SETTLEMENT, DID THE COMPANY AND PUBLIC STAFF REACH AGREEMENT ON ALL ISSUES IN THIS DOCKET?

A. No. As I noted previously, a number of issues remain disputed between the Public Staff and the Company: (1) the Company's request to recover its deferred coal ash costs and its ongoing environmental compliance costs necessary to safely close the Company's coal ash basins; (2) the depreciation rates appropriate for use in this case, including whether the Company's proposal to shorten the lives of certain coal-fired generating facilities should be approved; and (3) any other revenue requirement or non-revenue requirement issues other than those issues specifically addressed in the Stipulation or agreed upon in the testimony of the Stipulating Parties.

Q. IS THE COMPANY PRESENTING TESTIMONY OF OTHER WITNESSES IN SUPPORT OF THE AMENDED STIPULATION?

A. Yes. DE Progress's Witness Smith supports the adjustments, rate making and accounting aspects of the Stipulation, while Witness Newlin supports the capital structure provided in the Stipulation. Finally, Witness D'Ascendis supports the overall return and capital structure provided in the Partial Settlement.

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

A. Yes.

My name is Stephen De May and I am the North Carolina President of Duke Energy Progress. Chair Mitchell and members of the Commission, I am pleased to appear before you today to put our rate application in perspective and provide insight into the Company's future priorities. Normally I would offer these remarks at the start of the hearing, but the restructured proceeding caused a change in our witness line up.

Rate cases are complex undertakings and they serve a vital role in the service to our electric customers in North Carolina. I would like to thank this Commission, the Public Staff, the intervenors in this proceeding, and the citizens who came to public hearings across our great state. We are aligned with all parties that this proceeding should strike a balanced outcome that benefits customers and ensures the Company's ongoing ability to serve them at the highest level. I would also like to thank my colleagues from Duke Energy. Those involved in putting this rate application together worked hard to put a serious, thoughtful and balanced case in front of this Commission. Their focus on our customers, and their efforts to build for this hearing a record of prudent utility management is matched *only* by the dedication of the thousands of others in our Company who come together every day to reliably power the lives and businesses of North Carolina.

Even before COVID-19, I would have said that we live in interesting times. But events since the pandemic began, including the tragic loss of life, the loss of jobs and businesses from the economic downturn, the upheaval to our way of life, and the rising focus on social and racial injustice, demonstrate that our country and our state are sailing through very rough seas right now, fraught with uncertainty. Duke Energy's role in all of this is clear: We must continue providing the essential service of electric power—deliver it reliably, affordably, with an eye on the conditions our customers are currently experiencing and with an eye on the future. The pandemic notwithstanding, our customers want cleaner energy, they want more convenience and control over their usage, and they want relief for those among us who are least able to afford their power bills. We want those same things too, and we plan, we invest, and we innovate to deliver them.

Three general themes define our request to adjust rates. They are: Improving the Customer Experience, Moving Past Coal, and Low-Income Support. I will take a moment to touch on each.

We continue to improve the experience our customers have in their relationship with Duke Energy, and to provide additional tools that increase convenience and control related to their usage. My fellow panelist Larry Hatcher provides great perspective on our customers' experience in his testimony. We are also seeking Commission approval to defer, for accounting purposes, investments in our grid improvement plan over a 3-year period. This plan, already described in great detail by Witness Jay Oliver, is foundational to our ability to continue bringing such benefits to our customers in a timely, cost-effective way, to supporting reliability and to transition to cleaner energy.

As the Company works diligently towards its goal of a low-carbon future, it is writing the final chapters on coal ash and coal-fired generation. We are responsibly managing the disposition of coal combustion residuals, simultaneously complying with federal CCR rules, state-level CAMA requirements, and a comprehensive settlement with North Carolina's Department of Environmental Quality, the Southern Environmental Law Center, and others. These actions are good for the state and our customers, and they position North Carolina as a leader in the resolution of an operational challenge facing utilities across the United States. The Company is seeking fair and equitable recovery of its coal ash mitigation costs, including a reasonable rate of return on investor capital needed to bring closure to the byproduct of burning coal.

Another important chapter closing on coal relates to our currently-operating coal generation facilities. Today, these facilities are critical to serving load and, in some cases, to system integrity and support. But the end of their useful lives is approaching, more quickly than anyone would have thought even just a couple of years ago. Expected retirement dates are accelerating, and we believe it is prudent to prepare for this by likewise accelerating the depreciation of our coal fleet. Few things are as foreseeable now as the end of coal-fired generation in North Carolina and we are asking the Commission to approve our proposal to continue to address it. No one will want to deal with the issue of unrecovered book values down the road while simultaneously constructing replacement generation, so let's deal with it now while there is still time.

Low-income support is prominent in this rate application, but it is also, importantly, a pillar of our future plans. Our original filing in this docket provides for no-change to the Basic Facilities Charge, a reduction to ROE, the elimination of direct fees assessed on credit or debit card payments, and a request of this Commission to direct the Company and the Public Staff to conduct a collaborative process, with other parties, to evaluate and develop new tools and measures to assist low-income customers with their electric bills. Our commitment to customer assistance then expanded through the many settlements we reached with intervening parties, including significant contributions of shareholder funds to low-income energy assistance programs—a total of $16 million over the next two years between Duke Energy Progress and Duke Energy Carolinas – as well as an agreement to explore an on-tariff financing pilot program.

I would be remiss if I didn't mention other steps we took to benefit our customers, including our plan to pull significant 2018 storm costs from this rate proceeding and proposing instead to securitize such costs under the provisions of recently enacted SB-559. This complex financing tool will deliver valuable savings for customers. Our customers will also benefit from an agreement to further reduce ROE and to flow back excess deferred income taxes on an accelerated timeline. These benefits are especially helpful to mitigating the challenging conditions brought on by the current pandemic.

As I close my remarks, let me end on a concept I opened with: Balance. Under the laws of this state, we have the obligation and privilege to serve our franchised customers, and to do so reliably and affordably. In return, as a regulated, investor-owned utility, we are allowed to recover our prudently-incurred costs, as well as a fair and reasonable return on investor capital. That compact sits at the intersection of customer interests and those of the Company and its investors. For the reasons articulated by Steve Young in his testimony, we urge the Commission to consider the harm that certain intervenor positions would do to this compact and to this balance—for example, the Public Staff and the Attorney General's positions on coal ash are unprecedented, harmful to the financial integrity of the Company, and inconsistent with the law and the precedent this Commission set just two years ago.

The State of North Carolina is positioned to become a leader in energy and climate policy and is one of the premier states in which to live and do business. It is home to Duke Energy. We stand ready to deliver the energy future our customers expect and deserve, to respond to destructive storms quickly and safely, to help our customers in need, and to always act in our customers' best interests. The Company respectfully asks that balance and fairness guide the Commission's decisions.

This concludes my testimony summary.

MR. ROBINSON: And, Commissioner Clodfelter, I would also move that the portions of Mr. De May's oral testimony elicited at the expert hearing in Docket Number E-7, Sub 1214, the specific portions of which were stipulated to with the Office of the Attorney General, NC Justice Center, et al, the Sierra Club, and CUCA be moved into the record in this case. And I'm happy to provide the transcript citation if needed.

COMMISSIONER CLODFELTER: Mr. Robinson, please do, read the transcript in for the benefit of the court reporter. Read the citations, I'm sorry.

MR. ROBINSON: Sure. So that citation is transcript volume 11, pages 932, line 9 through 949, line 9; pages 979, line 11 through 1012, line 17; pages 1019, line 13 through 1048, line 6. And in transcript volume 12 pages 15, line 6 through page 32, line 23; pages 33, line 14 through 34, line 22; and pages 35, line 6 through 45, line 20.

COMMISSIONER CLODFELTER: You've heard the motion. Are there any objections? Hearing none it will be so ordered, Mr. Robinson.

MR. ROBINSON: Thank you.

(WHEREUPON, the stipulated

testimony of Stephen G. De May
from Docket Number E-7, Sub 1214
is copied into the record as if
given orally from the stand.)

Steven G. De May
Stipulated Testimony from DEC Evidentiary Hearing

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219

STEPHEN G. DE MAY AND LARRY E. HATCHER,
having previously been duly affirmed, were examined
and continued testifying as follows:

CONTINUED EXAMINATION BY COMMISSIONER McKISSICK:

Q. Of course, Mr. Hatcher, if at any point you want to chime in, certainly feel free to do so.

I know, Mr. De May, when Commissioner Duffley was discussing the idea of rate fatigue, one of the things you brought up was, you know, multiyear ratemaking authority. I did not know if, at this point in time, it was the intention of either Duke Carolinas -- or the Duke entities, I should really say, because they should both think about it as a potential -- to pull together stakeholders to work through the issues and challenges that multiyear ratemaking presents. That might clarify and provide answers to some of the concerns that were raised last year when this was considered.

COMMISSIONER GRAY: Mr. De May, would

you unmute, please.

THE WITNESS: (Stephen G. De May) Sorry about that. I mentioned multiyear rate planning as an illustration of a way to address rate case fatigue. There are many ways to do so. You asked are we considering ways of addressing or exploring the opportunity with stakeholders; and I am pleased to say that the Clean Energy Plan process that is underway right now has two very important tracks associated with it. One is a climate policy track, and the other is a regulatory mechanisms track where the group -- and it's a large group of stakeholders, but all the important stakeholders are at the table. We are evaluating decoupling -- things like decoupling, multiyear rate plans, performance-based ratemaking, and the like.

So I'm very happy to say that a lot of work is going on in that space right now. So while I mention this as an example, and I also mention it as an example of the importance of the right inclusion and the way to role things out and so on, we are in a much different place and in a much better process right now. You're on mute.

Q. What is the timeline for that to -- for that group to try to reach some sort of consensus as opposed to this being relatively open-ended?

A. Well, it's definitely -- while it may technically be open-ended, the regulatory mechanisms part, I can't imagine it's going to go on much beyond, say, the early part of next year for two reasons. One is the first track, the climate policy track posed the governor a report by the end of the year. We expect that that report will not just address climate policy issues, it will include regulatory -- a discussion of regulatory mechanisms that will help the state achieve its climate objectives.

But I think importantly, this group of stakeholders is not one to sit on this discussion for long. There's going to be no dillydallying, I can promise you. And I expect that the report to the governor at the end of the year will include some recommendations to explore further those mechanisms.

Q. And one other issue that has emerged, you know, in the last year or so. I mean, there was authority given for securitization for storm-related costs and expenses. Has there been a thought given to expanding securitization for other areas that might be appropriate outside of just storm-related costs?

A. Yes. Yes. I would say of securitization, as the former treasurer of the Company, and I actually led the transaction -- securitization transaction for our Crystal River 3 nuclear river plant in Florida. It is an extremely complex tool, but it is an extremely effective one. But it has limited utility, I should say.

The Company cannot -- first of all, it has to get new legislation; secondly, a company can only avail itself of so much securitization, because securitization is a binding imposition of a cost on customers. Nothing can change it. No Commission can change it. Really, the legislature can't even change it. So once it's set, it's a binding commitment. And if you just start piling up these binding commitments, it takes flexibility away from the Commission, for instance, to do things in a more creative sense, expanding amortization periods and the like.

And so securitization has that limitation. Securitization also has the limitation, though, of eliminating the return that investors were getting on their capital. It is true that a securitization returns that capital instantly, the unamortized capital back to the investor or back the Company, but the ability to redeploy those kinds of proceeds is not always an easy thing to do.

So securitization comes with some complexities. It is a tool that has been used for storms, it has been used for stranded assets, but not a great deal more than that. And I see the opportunity to use that tool again in our future. But I wouldn't say -- oh, and I would add, sorry, that securitization is also a topic of discussion at the Clean Energy Plan table.

Q. Another area of concern. I know that we have before us a plan for grid improvements, they're looking at, like, $2.3 billion or so over the next three years, which is pretty strong, pretty aggressive program. I know, when witness Oliver testified, I asked questions with him about, you know, if the engineering would be done in house or using outside services. He mentioned there would likely be both. I asked him about the way work would be performed, internal crews or whether you're bidding out some of this work.

We did not get into whether it would be public bidding or private bidding. And when I say public, you know, advertising it for people to submit bids, or whether it will be private where you went back to people you have utilized in the past, and just got competitive offers from different companies or providers of services.

But the thing that I did not hear anybody speak of is the extent to which, with such a substantial amount of money being spent in that area potentially, the utilization of what I would call firms that have been historically unutilized. Disadvantaged businesses as they might have once been known. And are breaking into segments, so that small businesses, regardless of their make-up, have a greater opportunity to get a portion of that work, particularly in a day and time where our economy is being burdened, small businesses in particular.

Can you share with me your thoughts on what plans Duke has, at this time, to really try to reach out and provide contracting opportunities to competent and qualified small businesses and historically unutilized businesses, providing this moves forward as it is proposed at this time?

A. Yes, absolutely. I can speak in a general -- in a general sense about our supply chain objectives. I can't speak specifically to the grid improvement plan. But I think what I'm about to say to you encompasses the grid improvement plan.

Back in June, the Company announced that it was launching Hire NC, which is a Commission kind of directed program, and that is something that we are very enthusiastic about, very excited about. It will push more of our supply chain spending to local companies, North Carolina companies, and diverse companies: women-owned companies, veteran-owned companies, minority-owned companies, and so on.

And we are -- kind of the nature of the program is that for investments greater than, I think it's $700 million, we are -- you know, it's kind of -- it's -- one of the protocols of the program is to include those kinds of firms in that work.

So we're really excited about that. But I also wanted to mention to you that it's not -- we didn't just start using those firms under the Hire NC program. For the past five years we have averaged $1 billion spend with the kind of firms you were describing. And, in fact, in 2019, it was kind of a high watermark; $1.6 billion was spent with those firms.

So I am pleased to say that I actually think we're ahead of the curve on this. And I would expect that segments of our grid improvement plan will be part of the Hire NC initiative.

Q. Thank you for that explanation and putting things in context. I know I have read and heard about what some other utilities are doing that are comparable to Duke. I had not read or heard as much about what Duke has done. But I think, to the extent to which significant efforts and substantial efforts could be made to continue to promote and enhance those opportunities, I think it would be for the greater good of the economy and for helping to build opportunities for those who have not had a chance to participate traditionally in that American economic mainstream.

Now, I guess the other questions I have, I guess, really perhaps are more appropriate for Mr. Hatcher. So, Mr. Hatcher, I guess in reviewing your direct testimony and in reviewing your rebuttal testimony, you spoke about a CX monitoring program and how it was developing data and analytics to improve delivery of service to customers.

So I'm wanting to know, what information have you actively obtained? And how has that data, that information obtained, been utilized to improve services? And is there any measurable index that you are using to measure success as a result of those programs or initiatives you've undertaken?

A. (Larry E. Hatcher) Yes, sir. So the CX monitor tool is a propriety survey that we developed in house back in 2018. And the reason we did that, we were looking at J.D. Powers as an indicator, but it's really an indicator of how we perform against southern utilities. And you don't get a lot of internal written feedback on why people score you the way they score you.

So the CX monitor survey was created to really see how customers received Duke Energy, and would they recommend Duke Energy to their friends and family, or would they not, and kind of what is the reason why. And there is an index to that, it's MPS 4 that we track internally. And we're kind of tracking that to see if we're improving on the areas that are raised as concern or if we're lacking.

In addition to that, we created a fast track 2.0 propriety survey, which is more of a transactional-based survey. So if we have one of our technicians go to a customer's home and perform a service, we can get immediate feedback off of that transaction. And it also gives us verbatims so we can understand how the customer -- why they rated us the way they rated us.

Another component of that is called a reflect survey, and we're doing the same types of feedback from our digital services and our call center services. So we could take all of that data, along with our customer complaint data, and we can really see the things that are frustrating customers as they move along their journey with us.

Some of the things that we've done with that, if you really look at the top three things, it's around billing and payment. So folks wanted their bill simplified so they can understand it better. They wanted more information and more control. So if you look at what we're doing with AMI and the information that's being provided to the customer, you know, we're meeting that need from that respect. If you look at the other options the AMI is giving the customer around pick your own due date, start/stop service, making things easier for the customer, we're seeing positive feedback there. The -- they want more flexible payment arrangements. So if you look at that -- what we've done with our COVID response, a lot of the feedback that we received from customers, we applied in our

COVID response.

The other area that we heard loud and clear from our customers is they want us to communicate better with them, especially around outages. How long are we going to be without power? When is my power going to be back on, not necessarily my neighbors? So AMIs help us in that space. The tool, itself, has helped because we can communicate more directly with the individual customer. We can send them pictures of the damage, we can show them where it's located, we can send them another picture when the crews arrive. It keeps them updated along the way so they're not wondering what's going on.

And the last piece of that is really around the outage experience. And what our customers are telling us is that they recognize they're going to have outages due to the major storms, but they want us to recognize that and figure out ways to minimize those impacts and really get faster on the response and restoration. So, hence, what you're hearing in the testimony of Mr. Oliver is addressing a lot of that.

Q. Okay. Now, it sounds as if, as you said, it was a propriety system, you've used it in house, and it's helped a great deal.

Do you ever use outside firms or consulting firms that might help in doing similar type of analysis and comparative analysis comparing what your performance is at Duke compared to other comparable utilities to try to get some sense as to where you are in terms of a national performance if -- you know, if you can speak to that?

A. Sure. So J.D. Powers is our major source of data, in terms of how we're performing against our industry peers across the country. We also do consortiums with like my peers, where we talk about what's working for them and what's working for us, and we share ideas back and forth. And periodically we'll do benchmarking with another utility that we hear is doing something really well. We'll go visit them to learn about what they're doing and vice versa. So yes, sir.

Q. Okay. And can you point to any things that you've learned from that or any enhancements or changes that you made?

A. So one of them is the fee-free credit and debit card program that is, you know, part of this rate case.

Q. Right.

A. We've gotten a lot of feedback from our customers that they want this, they're very frustrated that they have to pay a fee. And we've also gotten the same feedback when we did benchmarking with some of the other utilities. So, hence, we're bringing that one forward, you know, to eliminate the customer concern. That would be one example.

Q. In your testimony, you also refer to something known as a Ping It program and what that constituted, as well as discussing additional efforts you were utilizing to communicate with customers using social media. So can you address those two issues?

A. Sure. So Ping It is a part of the AMI technology that we can actually send a signal from our control center to that meter to determine if that meter is active, and it's powered up, and there's power at the home or not. So it's a quick way for us to be able to determine the status of a customer's electricity, so to speak. So it's really a new improved technology versus our old meters that used to be in the homes where you have to roll a truck just to determine, you know, if the meter was operational or not operational.

In terms of some of what we're doing in social media and other ways to communicate with customers, we have drastically improved our website. We've done kind of a web refresh starting back, I believe, it was in 2015. We've had quite a few updates to that over the years. We're being able to give customers a lot more self-serve options so they don't necessarily have to call the call center to start or stop service. They don't have to call the call center to make a payment, so they can do all that online. There's other services that they can go out there and self-serve, versus having to wait on the phone to be able to talk to an agent.

We are using social media a lot with our customers who we have email accounts for or phone numbers to be able to send information. If we need to send them a notice about a proactive outage that we're taking for some reason, we can do that in advance so they're aware of that. If we need to send them information related to a potential bill change, we do that in advance so it's not a surprise. Those types of things, where we're able to communicate with our customer in, kind of, a more individual and more directly than we have been in the past.

Q. And I guess my last question deals with sustainability, and in terms of -- I guess what -- I know in your testimony you talk about what I call a corporate sustainability goal, or sustainability that are being pursued, that are being implemented, and initiatives that are being undertaken to obtain them.

Can you speak to those in a more discrete way?

A. I'll give a shot at it. Before I do that, you asked for some tangible results or scores.

Q. Yeah.

A. I'll give you a little bit of that out of our fast track surveys. If you just look at DEC alone for start/stop service, 86 percent of our customers are satisfied with their experience with us for start/stop service. If you look at outage restoration, 81 percent of our customers have been satisfied with how we responded to outages. And then streetlight repairs is another key area that we've gotten a lot of feedback on. 73 percent of our customers are satisfied with their experience for streetlight repair. So maybe that would give you a little bit of tangible data, have some context for that service.

In terms of sustainability, the Company -- I'm really proud of what the Company is doing in terms of our sustainability goals and how those goals are in alignment with what you see out of climate change. And if you look at really goal 7 and goal 13 of the climate looking forward, we're really in alignment with those goals. So it's around affordable and clean energy as well as protecting the planet and climate action.

So if you think about just what we've done over the last several years since 2005, a 39 percent reduction in carbon emissions by the way we manage our fleet; think about our solar development, we're the second largest solar capacity in the country behind California; you look at what we're doing in terms of battery storage and the plans for battery storage going forward over the next 15 years, 375 megawatts of battery storage; and then with our plan to be at 50 percent carbon reduction by 2030, I think it just speaks to a lot of what Steven has talked about and what was in our IRP and what we've been doing to really improve, you know, our sustainability going forward.

Q. Thank you for those responses, and I hope, as we move forward with the IRP, that we will really work in a very concrete way to move forward the sustainability goals.

And I guess the last thing -- and perhaps neither of you are the best witness to speak to it, but how would, say, accelerated depreciation of the coal-fired generating plants help us get closer to that? And if we did not have it, what would the impact be?

A. (Stephen G. De May) So I'll take a stab at that. So we believe that nothing is more -- well, this is an exaggeration, perhaps, but we think the accelerated or the end of coal-fired generation in North Carolina is extremely foreseeable. And we think that we should be dealing with something so foreseeable at this point in time. An accelerated depreciation of this fleet would allow us to match the expected life of the asset to the expected depreciation rate, and it would also help us avoid a stranded asset situation, which is really not good for any stakeholder, at the end of their useful lives.

So we believe that the accelerated depreciation of this, of the coal fleet, carries those virtues, and we support it very strongly.

COMMISSIONER McKISSICK: Thank you, Madam Chair. I don't have any further questions.

CHAIR MITCHELL: I believe, Commissioner Clodfelter, you had an additional question?

COMMISSIONER CLODFELTER: Sure. Thank you, Madam Chair. I'm going to pile onto the request that Commissioner Duffley made, and if it sounds like a conspiracy, well, it sounds like whatever it is.

In addition -- for the Company and for Ms. Downey, in addition to the analysis of the -- on the revenue requirement effective off -- using some of the EDIT to offset some of the coal ash costs requested in this case, I'd like to see a second scenario; and what happens to the revenue requirement if some portion of the EDIT were used to offset in what I call the Crystal River matter, to offset the accelerated retirement of the coal plants as proposed by the Company in the case.

So how would the revenue requirement change, if at all, if some of the EDIT were used to offset the additional depreciation expense to retire those coal plants in the schedule the Company is now proposing? That would be scenario number two.

CHAIR MITCHELL: All right. Thank you, Commissioner Clodfelter.

EXAMINATION BY MR. PAGE:

Q. Again, this is for Mr. De May. I think I understood you to say, in response to some of Commissioner Clodfelter's earlier questions that in the process to come, between this rate case and the next Duke rate case, there's going to be a fairly deep dive into the areas of cost of service studies and rate design; and that in that process, Duke welcomes the input of all stakeholders. Did I correctly understand that?

A. (Stephen G. De May) If you're referring to the low-income collaborative -- we have a couple of things going on. I'm not sure which one you were referencing. But at one point in time, I was talking about the low-income collaborative, where we would be looking at all kinds of measures that will achieve structural change in support of low-income customers. That could include rate design and cost of service-type enhancements or changes.

I didn't mention, but I have an opportunity to now, that we are conducting a rate design study as a company, and we will be doing that over the next year or so. There'll be more said about that by witness Lon Huber on the rate design panel.

Q. I guess to get directly to the point, I represent a pretty good-size stakeholder, and we would like very much to be a part of whatever conversations Duke is willing to entertain in those areas of cost of service and rate design between now and the next case. Is Duke willing to do that?

A. Of course we are. It's supposed to be a stakeholder-led process.

Q. Thank you very much. That's all I have.

EXAMINATION BY MR. NEAL:

Q. Good afternoon, Mr. De May. I'm David Neal representing the North Carolina Justice Center, et al.

How are you doing this afternoon?

A. I'm well. Thank you, Mr. Neal.

Q. Good. The first follow-up on some questions raised by Commissioner McKissick regarding the sustainability goals.

You would agree, would you not, that improving the grid's ability to integrate clean renewable energy resources is an important part of achieving the Company's and the state's carbon reduction goals?

A. I would agree with that.

Q. Would you agree that the elements of the grid improvement plan reflected in the second settlement with the Public Staff and in the settlement with my clients and the North Carolina Sustainability Energy Association include elements of the grid improvement plan that will facilitate integration of clean renewable energy?

A. In fact, the amount of the grid improvement plan that was settled upon is almost exclusively the integration distributed energy resources. There's some cyber investment there as well, but yes.

Q. And now turning to some follow-up questions from Commissioner Clodfelter's questions around affordability.

Did you have the chance to observe -- Mr. De May, did you have the chance to observe John Howat's live testimony in the consolidated hearing dockets earlier this week?

A. Most of it, yes.

Q. And have you had a chance to -- have you had a chance to review his prefiled testimony?

A. I did skim it, I would say.

Q. Would you agree that Mr. Howat has a depth of experience on utility affordability at low-income rate design issues?

A. Certainly I would acknowledge he has experience and certainly a passion.

Q. And do you recall that Mr. Howat supported your call to use a collaborative stakeholder process to be overseen by the Commission before initiating any new low-income programs, including new low-income rate designs?

A. I do.

Q. Mr. De May, are you familiar with the Helping Home Fund?

A. I am.

Q. And would you agree that the Company's contributions to the Helping Home Fund have provided material improvements to the homes of participating low-income customers?

A. I would agree with that; and the Company is pleased to be a participant in those gifts.

Q. And did you hear Mr. Howat's support for the Company's settlement with my clients and the Sustainable Energy Association, including the Company's commitment to contribute an additional $6 million towards the Helping Home Fund and to develop new low-income energy efficiency programs as steps that would be important to improve affordability in the short term?

A. Yes.

Q. And I take it you would agree with his statements?

A. With his statements?

Q. Yes.

A. I didn't agree with all of his statements.

Q. I'm sorry, to be clear, agree with his statements in support of the settlement.

A. I agree with those statements.

MR. NEAL: Thank you, Chair Mitchell. No further questions.

EXAMINATION BY MR. ROBINSON:

Q. Mr. De May, do you recall a discussion you had with Commissioner Duffley when the topic of run rates was brought up?

A. (Stephen G. De May) Yes.

Q. Mr. De May, did the Company recently file a late-filed exhibit that dealt with run rate issues?

A. Yes.

Q. Did you have a chance to review that exhibit?

A. Yes, I did.

Q. Can you describe the exhibit and the major conclusions you draw from it?

A. Yes, I'd be happy to. Thank you. So the exhibit was borne from a request of Commissioner Duffley who asked if we would do a pro forma analysis of what our FFO metric in 2019 would have been had we been awarded a run rate in the rate -- the 2018 rate order. And schedule A in that exhibit describes that calculation, that analysis. And I want to just point out a few things to think about as you consider schedule A.

One is the run rate was requested for and is always contemplated to be a recovery of costs on a prospective basis. So we were not seeking to recover historic spend with a run rate. And so, in 2018, had the order approved a run rate and we were looking to adjust the 2019 FFO metric, we simply changed the treatment of 2019's coal ash costs from a capital-like treatment and called it more of a period expense. And in so doing, we adjusted the metric.

And the way that occurs is coal ash, when it's being capitalized and deferred, is not part of our FFO numerator. It is not an operating cash flow item because it has been treated like capital. And so we have to then add that back in because a run rate implies that it's no longer being treated like capital. So we added that cost to FFO and reduced it.

But then the way a run rate would work, we would increase the revenues to FFO to reflect the allowed run rate.

And so you can see on schedule A -- we'll just look at DEC -- that once the Commission -- once the Commission would make the move from capital treatment to O&M, or an operating cost, then the rating agency would treat all coal ash expenditures as an operating expense. And therefore, we took out $278 million. We put in 201, because that was the 2017 run rate. And you can see that, while we are able to recover through the run rate revenues, a good bit of the total coal ash spend, we didn't recover all of it. And therefore, you can see its relatively modest reduction in the FFO-to-debt calculation.

So there are three lessons, I would say, that you can take away from that one exhibit. One is the test year does not necessarily equal future spend. I know that's intuitive, but you have to set a run rate that approximates the coal ash spend that you expect to incur if you want that metric to be supported. The other thing I would say is that the coal ash -- when the rating agencies change their view of this as a result of moving to a run rate, they're going to take systemwide coal ash costs and put them back as a deduction to FFO. Systemwide. But, of course, this Commission would only be able to grant a run rate on the North Carolina retail portion. So there will be South Carolina components, there will be wholesale components.

We -- so those -- again, not necessarily the purview of this Commission but just for context. It will be hard for a run rate to completely offset the change in treatment by the rating agencies, but you can get close.

The third is that, you know, that mismatch that I'm describing to you, the mismatch you see here in this pro forma calculation, creates a bit of lag in and of itself. And you would have to establish some kind of deferral mechanism to where undercollections are dealt with or overcollections are dealt with.

So we -- this was a -- in response to Commissioner Duffley's request, but if I could take you to schedule B for a moment, the Company went a step further. Because it's important to understand the trade-offs of the different recovery mechanisms.

And I want to start with the predicate that coal ash is a recoverable expense. You have to start there to embrace this table and the calculations that we're making here. If coal ash is accepted as a recoverable cost, then it is either in current expense being paid for by current revenues, or it is a current expense being deferred as a deferred expense and then recovered over time by a Commission decision in a future rate hearing, or is treated as a capitalized regulatory asset that will actually function very similar to the deferred cost.

And so one of two things has to happen in order for the Company to recover its costs -- its prudent costs. Let's just make that assumption as well. That it is either receiving recovery in the period of expense, or if it's being deferred or capitalized, then it has to receive a return as well to compensate for these -- of shareholder funds.

And so I want to just quickly just say what this table does. And with the first column -- we might should have reordered these columns, but the first column and the fourth column, they're numbered, are taking the existing treatment of coal ash from the 2018 order to DEC and to DEP. In the first column is exactly the same treatment with the five-year flow -- return and recovery. The fourth column is an extension of that recovery period from 5 years to 10 years. And that is merely taking the request of, you know, effectively what's in this rate case today and applying the current treatment with a different amortization period. And you can see that what's intuitive is the longer amortization period has a mitigating impact on customer rates. It's just like taking a 15-year mortgage and refinancing it to a 30-year mortgage. You're getting that benefit of a longer period of time.

But what happens in columns 2 and 3 is the run rate concept. And the run rate works for prospective costs, but you still have to deal with the historic costs. And what this table shows is, not only are we recovering the current ask through the column 1 mechanism, five years, but we're also adding a run rate for future costs.

Column 2's run rate is a 2018 test year;

column 3's run rate is an average of a future five years. That's the difference between those. But there is almost no difference between the 28-test-year spend and the 21 to 25 average spend.

And so the story really isn't a comparison between column 2 and 3, they just happen to be very close in scale. The story here is that a run rate will be -- is an effective way to recover coal ash costs and -- but it will have a dramatically stronger impact to customer rates than the ability to defer or capitalize these costs and set them for recovery at a future date. And even with the return, which we believe these deserve, that will be less impactful to customer rates than the run rate.

But importantly, either is a reasonable mechanism for achieving timely recovery. Column 1 is more timely than column 4, and -- excuse me, column 2 and 3 are more timely than column 1 and 4; column 1 is more timely than column 4. You get the point I'm trying to make here.

But there is a series of trade-offs here, and we just wanted the Commission to appreciate and understand that, if you start with that predicate I suggested, that coal ash is recoverable, and if it is using shareholder funds, in other words, not being recovered in the period it was incurred, then the -- you know, the current mechanism is probably the most effective.

In the last -- in the 2018 order, the Commission said that we were to continue to defer our costs, that they would be evaluated at the next rate case, and barring any imprudent costs -- again, I just want to say, for the sake of argument, assume all imprudent costs -- then we would be allowed to recover these with the return during the amortization period, and the Commission will set the amortization period. And we wanted you to see that a 5-year return and a 10-year return are both credit support to the Company.

So hopefully you were able to follow some of those lessons I think we were trying to convey from this analysis.

Q. Thank you.

MR. ROBINSON: I have no further questions.

MR. ROBINSON: Commissioner Clodfelter, separately per that same stipulation, the cross examination exhibit, which was the March 2017 complaint filed by Duke Energy against insurance companies which is prefiled as AGO Cross Number 13, which was introduced as De May AGO Cross Examination Exhibit 1 in the DEC case, I would move that it be identified as such and moved into the record.

COMMISSIONER CLODFELTER: This is the first incidence we've had of -- with respect to an exhibit from the prior case, and Mr. Robinson is moving that that exhibit as he described it be designated in the same manner in this case and that it be admitted into the record in this case. Is there any objection?

(Pause)

Mr. Robinson, it will be so ordered.

MR. ROBINSON: Thank you, Commissioner Clodfelter.

(WHEREUPON, De May AGO Cross Examination Exhibit 1 was marked for identification as prefiled and received into evidence.)

MR. ROBINSON: I will move to Mr. Hatcher next.

Q Mr. Hatcher, would you please state your name and business address for the record?
A (Mr. Hatcher) I'm Larry Hatcher. I work out of 400 South Tryon Street, Charlotte, North Carolina.
Q And by whom are you employed and in what capacity?
A I'm employed by Duke Energy and I'm the Senior Vice President of Customer Services.
Q Mr. Hatcher, on December 20th, 2019, did you cause to be prefiled in Docket E-2, Sub 1219 direct testimony consisting of 32 pages?
A Yes, sir.
Q Do you have any changes or corrections to your prefiled direct testimony?
A No, sir.
Q If I asked you the same questions here today, would your answers be the same?
A Yes, sir.
Q Mr. Hatcher, did you on September 3rd, 2020, provide oral testimony at the hearing held in Docket Number E-7, Sub 1214?
A Yes, sir.
Q Mr. Hatcher, if I asked you the same questions

here today would your answers be the same?
A They would.
Q Mr. Hatcher, did you prepare a witness summary for purposes of this hearing?
A Yes, sir.

MR. ROBINSON: Commissioner Clodfelter, I would move at this time that Mr. Hatcher's prefiled testimony as previously described and Mr. Hatcher's testimony summary be entered into the record as if given orally from the stand.

COMMISSIONER CLODFELTER: You've heard the motion. Is there any objection?

(Pause)

Hearing none, it will be so ordered.

(WHEREUPON, the prefiled direct testimony and summary of Larry E. Hatcher is copied into the record as if given orally from the stand.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1219

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

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND POSITION WITH DUKE ENERGY PROGRESS, LLC.

A. My name is Larry E. Hatcher, and my business address is 400 South Tryon Street, Charlotte, North Carolina 28202. I am the Senior Vice President of Customer Service for Duke Energy Corporation, including Duke Energy Progress ("DE Progress" or the "Company") and Duke Energy Carolinas ("DE Carolinas").

Q. BRIEFLY SUMMARIZE YOUR EDUCATIONAL BACKGROUND.

A. I have a Bachelor of Science degree in Electrical Engineering from the University of South Alabama. Additionally, I have attended numerous industry and company-sponsored programs and courses.

Q. PLEASE DESCRIBE YOUR BUSINESS BACKGROUND AND EXPERIENCE.

A. I have worked in the energy and chemical industries for 26 years. Before joining Duke Energy, I worked for Monsanto Company for nine years in a variety of engineering and leadership roles. Prior to working for Monsanto, I worked for the U.S. Navy as an electronics engineer for 5 years. In 2002, I joined Duke Energy at the Asheville station as an Operations Superintendent. I have held various leadership roles within the Fossil Hydro Organization ("FHO"), the Environmental, Safety and Health organization ("EH&S"), the Piedmont Natural Gas organization ("PNG") and the Customer Delivery organization ("CD"). Before assuming my current role, I served as Duke

Energy's Senior Vice President of Central Governance, Programs and Support in the customer delivery organization. My responsibilities included overseeing the safe and efficient operation of Duke Energy's distribution central services organization, including the control centers, emergency response, lighting, vegetation management, vehicle fleet and continuous improvement. I assumed my current position as Senior Vice President of Customer Services for Duke Energy in November 2019.

Q. WHAT ARE YOUR RESPONSIBILITIES IN YOUR CURRENT POSITION?

A. In my role as Senior Vice President of Customer Services, I am responsible for customer contact operations, which includes Duke Energy's customer care centers and online customer interactions, revenue billing and receivables, and metering services for all our customers. My responsibilities also include managing the strategies to engage, interact and serve the Company's small and medium business customers.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE COMMISSION?

A. No.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to highlight DE Progress' excellent service to our customers and how that translates to customer satisfaction. I also describe some of the steps the Company is taking to further improve the experience and satisfaction of our customers when they engage with us. Finally, I support

(1) the Company's proposal to establish a transaction fee-free payment program for credit, debit and electronic check/automated clearing house ("ACH") (hereinafter, "credit cards") methods for our residential customers; and (2) the Company's proposal to change when bills are considered past due and delinquent for our nonresidential customers.

Q. ARE YOU PROVIDING ANY EXHIBITS WITH YOUR TESTIMONY?

A. Yes. Hatcher Exhibit 1 is an audio file comparing the Company's current integrated voice response ("IVR") system to our new IVR, which contains enhanced functionality designed to improve our customers' experiences when they contact us. I provide details about our new IVR later in my testimony.

Q. WAS HATCHER EXHIBIT 1 PREPARED OR PROVIDED HEREIN BY YOU, UNDER YOUR DIRECTION AND SUPERVISION?

A. Yes it was.

Q. HOW DOES THE COMPANY FOCUS ON DELIVERING EXCELLENT CUSTOMER SERVICE?

A. At Duke Energy, the customer is at the center of our purpose. Evolving customer expectations, emerging technologies and changing public policies all converge to create a dynamic environment for Duke Energy and the industry. As I describe in my testimony, Duke Energy works to build genuine connections with all customers by listening, anticipating their needs and offering solutions. The Company is using Customer Experience Monitor ("CX Monitor"), a proprietary survey, to measure Net Promoter Score ("NPS") by asking customers to rate 'How likely it is that they will recommend Duke Energy to a friend or colleague' on a '0-10' scale. NPS is the top metric used by companies across industries to measure customer advocacy. The NPS metric tracks customer loyalty and helps the Company get better insight into improving customer satisfaction. Using data and analytics, the Company is executing a long-term, customer-focused strategy designed to deliver greater value to our customers.

II. CUSTOMER SERVICE OVERVIEW

Q. PLEASE PROVIDE AN OVERVIEW OF THE COMPANY'S CUSTOMER SERVICE FUNCTIONS.

A. DE Progress' Customer Service Functions are comprised of multiple organizational departments responsible for developing and executing policies, processes and procedures to successfully interact with our customers via multiple communication channels. The primary channels our customers use to interact with DE Progress are phone; email; social media, inclusive of Facebook, Instagram, LinkedIn and Twitter; Duke Energy's website; and face-to-face interactions. Our organization includes customer care centers; customer service field operations, which is responsible for metering field services; and other activities, including complaint resolution, billing and payment processes and credit and collections activities.

A. Customer Care Centers

Q. PLEASE DESCRIBE THE OPERATION OF THE CUSTOMER CARE CENTERS.

A. Our customer care centers are designed (and continuously enhanced) using state-of-the-art technology with the objective to ensure that all customer inquiries are answered promptly and accurately. There are several locations and numerous remote agents that handle inbound and outbound calls, as well as emails, web inquiries, mailed letters, faxes and social media inquiries. There are over 500 Duke Energy representatives processing and supporting work in response to customer inquiries. Customer calls are either processed in the IVR, allowing customers to self-serve, or by a call center specialist. While we receive an ever-increasing number of inquiries via digital channels per year, we have not experienced a decrease in the number of phone calls that we receive from our customers. In fact, in 2018, DE Progress' customer care centers received an average of 880,000 phone calls per month to the IVR system, of which 96 percent of the calls were handled by the IVR or an agent.

Q. DOES THE COMPANY RECOGNIZE THE DIVERSE NEEDS OF ITS CUSTOMER BASE WHEN PROVIDING CUSTOMER SERVICE?

A. Yes. In addition to its primary responsibility to provide safe and reliable electric service, the Company understands that its customer base has diverse service needs and we do our best to recognize them and accommodate where appropriate. For example, DE Progress assigns account managers to our large, complex customer accounts to answer questions, resolve issues and manage the customer relationship to enhance customer satisfaction. Another recent example is individuals from DE Progress' small and medium business organization met with builders in North Carolina to hear directly from them about ways we can improve their customer experience. Because of those discussions, the Company developed and launched a new Builder Portal App designed to improve the experience of builders and developers when submitting work orders, requesting status updates or seeking online support.

The Company also conducts ongoing evaluations of operational improvements and continuously looks for ways to improve the customer experience. For example, we offer a variety of billing and payment choices, including Paperless Billing, Pick Your Due Date and Equal Payment Plans to make paying bills simple, secure and convenient. We share important information with our customers through monthly bill inserts, text or email and offer programs and tips to help protect our customers from high energy bills from extreme temperatures. DE Progress also offers a variety of energy efficiency programs and, for our low-income customers, energy assistance and bill management programs such as the Energy Neighbor Fund, the Helping Home Fund and the Neighborhood Energy Saver Program. Additionally, we continue to enhance our customer service practices to address language, cultural and disability barriers. Among other accommodations, the Company's customer care center offers customer service and correspondence in Spanish, handles calls from TTY devices (text telephones), offers bills in Braille, and accepts pledges to pay from social service agencies. Moreover, our customer care centers provide 24/7 service for emergency and outage related requests.

B. <u>Customer Service Field Operations</u>

Q. PLEASE DESCRIBE HOW DE PROGRESS PROVIDES SERVICE THROUGH ITS CUSTOMER SERVICE FIELD OPERATIONS GROUP.

A. DE Progress' field service employees complete service requests inclusive of new meter installations, service repair orders and start/stop service. Additionally, metering services is responsible for meter reading of non-smart meters, meter inventory management, acceptance testing and provisioning of meters for new installations, testing and refurbishment of meters removed from the field, installation and maintenance of transformer-rated meters, tamper and theft detection and investigation, and meter engineering and standards.

In addition to the work performed in normal operating conditions, these men and women support service restoration efforts due to extreme weather conditions. For example, in 2018 and 2019, Hurricanes Michael, Florence, Dorian and Winter Storm Diego severely impacted Duke Energy Progress' service territory. Members of the Company's field operations group led restoration efforts for impacted customers. As Company witness Rufus Jackson explains in his testimony, the Company's commitment to timely restoration efforts and a positive customer experience resulted in more than 90 percent of customers impacted by Hurricane Michael being restored within 72 hours, restoration within 48 hours for more than 79 percent of customers impacted by Hurricane Florence, restoration within 48 hours for more than 95 percent of customers impacted by Hurricane Dorian, and more than 90 percent of the customers impacted by Winter Storm Diego.

Q. HAS THE COMPANY RECEIVED RECENT RECOGNITION FOR EFFORTS BY THE FIELD SERVICE OPERATIONS GROUP?

A. Yes. Edison Electric Institute ("EEI") recently recognized Duke Energy with the "Emergency Recovery Award".[1] The awards were in response to the Company's outstanding power restoration efforts after Hurricane Florence hit North Carolina and South Carolina in September 2018 and Winter Storm Diego that hit the Carolinas in December 2018. The Emergency Recovery Award is given to select EEI member companies to recognize their extraordinary efforts to restore power to customers after service disruptions caused by severe weather conditions or other natural events.

C. Digital Experience

Q. PLEASE DESCRIBE HOW DE PROGRESS ENHANCES THE CUSTOMER EXPERIENCE THROUGH THE DIGITAL CHANNEL.

A. As I mentioned previously, the Company continues to experience an increased number of inquiries and service related requests received via the Company's website and social media sites. With the rapid transformation of technology, devices and new channels, customer expectations are increasing at an

[1] https://www.prnewswire.com/news-releases/duke-energy-earns-eeis-emergency-recovery-award-for-power-restoration-efforts-in-carolinas-after-hurricane-florence-300776958.html;

accelerated rate, and we work to provide an easy-to-use, straightforward digital experience to meet their expectations.

The Company's digital transformation strategy began in 2015 to help deliver exceptional customer benefits, streamline previously manual processes and deliver long-term efficiencies. The development of a customer mobile app, a major refresh of duke-energy.com and a suite of new and enhanced customer solutions, some in part enabled by the installation of smart meters as discussed by Company witness Schneider, are summarized in the table below:

Program/Product	**Description**	**Channels**
Proactive Outage Communications	A messaging program that alerts customers when there is an outage in their area	• Email • Text • Voice
Pick Your Due Date[2]	Enrolled customers select the billing due date that best aligns with their financial situation	• Online Web Form • Call Center Enrollment
Track My Service – Start and Stop Service	Eligible customers automatically receive order confirmations and reminders when they start, stop, and transfer service	• Email • Text • Voice
Usage Alerts[2]	Eligible customers automatically receive an email at the midpoint of their billing cycle with their current electricity cost broken down by appliance and projected cost and can opt to receive budget alerts	• Email • Text
Payment Confirmations	Eligible customers automatically receive an email or text message when their payment is received by Duke Energy	• Email • Text

Customers can now use duke-energy.com/home or the Customer Mobile App to complete most of the transactions available through the IVR, such as updating account information; making billing inquiries; reporting

[2] Smart meter enabled program or service.

power outages; checking the status of an outage; viewing bills; paying bills; and connecting, disconnecting or transferring service. Customers are also reporting a higher usage of digital methods to report outages and request service orders, with reported digital utilization up from 20 percent to 25 percent in 2018. Further, our customers reported satisfaction with our web offerings (with results for April 2019 reaching a record high), and reported higher levels of satisfaction with first contact resolution and ease of completing tasks.

Other examples of digital transformation efficiencies include a program called Ping It, which allows employees of the Company to remotely connect or check the status of a smart meter in lieu of sending a technician to the premise, saving time and travel costs. The Ping It program is especially useful during major storm events where the Company can use Ping It to determine which customers are out of power without the need for them to call and report an outage. The Company also proactively communicates outage updates to customers, via text and email, and provide updates on outage maps without the customer having to call.

Q. PLEASE DESCRIBE HOW DE PROGRESS' SOCIAL MEDIA PROGRAM HAS EVOLVED TO KEEP PACE WITH CUSTOMERS' CHANGING EXPECTATIONS.

A. With the rise in the use of social media in recent years, DE Progress has seen an increased number of its customers contacting the Company for account-related service through social media. Duke Energy has more than 550,000 followers on its Facebook, Twitter, Instagram and LinkedIn pages. The Company uses these channels to inform customers about reliability updates in their area and changes that could impact their bill. Further, in the event of an emergency or major storm, DE Progress uses social media to proactively distribute (or "post") information so it reaches as many customers and stakeholders as possible, engage with customers who have questions, and analyze social media conversations to monitor how messages are being received. In advance of a major forecasted storm, the Company posts warning and safety preparedness messages. During a major storm, when large areas of customers are without power, Company employees respond to storm-related or outage- related customer service inquiries received via social media sites. Moreover, the Company may post updates from our meteorology team, videos detailing storm restoration progress, and photos of significant damage to infrastructure to show customers the scale of repairs underway.

III. <u>CUSTOMER SATISFACTION MEASURES</u>

Q. HOW DOES THE COMPANY MEASURE CUSTOMER SATISFACTION?

A. DE Progress recognizes that customer expectations continuously change and evolve and, to successfully enhance their experience, it is critical that the Company hears and understands the "voice of the customer" through several avenues, including direct customer feedback and industry benchmarking, to improve customer satisfaction ("CSAT"). The Company operates a robust CSAT program, which includes both national benchmarking studies and transaction and relationship CSAT studies. We then analyze results from these studies in vigorous monthly data review sessions, with findings driving improvements to processes, technology and behaviors – all to continuously improve the customer experience.

DE Progress also measures overall customer satisfaction and loyalty perceptions about the Company in an ecosystem of measurement tools intentionally designed to allow us to strategically identify opportunities to improve the customer experience. In 2018, the Company launched the CX Monitor survey, a randomized, census-based survey that measures customer loyalty and the ongoing perceptions of the customer experience via an email invitation with an embedded online survey link. The CX Monitor survey is sent to residential, small and medium business ("SMB") customers and large business customers for whom the Company has a valid email address. Customers are asked to rate 'How likely it is that they will recommend Duke Energy to a friend or colleague' on a '0-10' scale. In addition to measuring customer advocacy, the CX Monitor survey measures customer satisfaction using key experiences customers have had with us over the past 12 months. Examples of these experiences may be an outage experience or a payment experience. Customers rate their experience on a '0-10' scale and provide open-end verbatim comments detailing the primary reason(s) for their score. While the Company still utilizes J.D. Power as a relative benchmark against peer utilities, the value of the CX Monitor over other surveys is that it asks our own customers about their perception of an experience, which can then be compared against their actual experience.

Since the CX Monitor survey launched in 2018, Duke Energy has collected responses from more than 410,000 residential electric customer surveys and over 25,000 SMB customer surveys enterprise-wide.[3] Since the survey launch in 2018, the Company has seen a significant increase in its NPS score. Further, some of DE Progress' top month over month NPS scores came at one of the most challenging periods for our Company, between the months of September and December of 2018 when the Company's service territory was severely impacted by storms. Customers responding to the CX Monitor survey during that period returned some of our highest NPS scores to date, all at a time when they, the Company and our neighbors were impacted by Hurricanes Florence, Michael, or both. During last year's hurricane season, the Company demonstrated exemplary performance in field operations and customer service. In a first for the Company, every employee who did not already have a primary storm role was assigned one.

In addition to our CX Monitor survey, Duke Energy uses "Fastrack 2.0", a proprietary, post-transaction measurement program. Fastrack 2.0 measures the quality of interactions customers have with the Company. Fastrack 2.0 was intentionally designed to complement the CX Monitor survey and provide greater insight into experiences that matter to our customers and near real time feedback to our front line, customer-facing

[3] The CX Monitor was launched to our large business customers in January 2019 and the Company is currently developing the baseline.

employees. The survey questions cover the customer's experience about completed field work such as requests to begin and end electric service, outdoor lighting repairs and new construction service requests. Analysis of these ratings helps to identify specific service strengths and opportunities that drive overall satisfaction and to provide guidance for the implementation of process and performance improvement efforts. Through 2018, roughly 85 percent of DE Progress residential customers expressed high levels of satisfaction with these key service interactions (Start/Transfer Service (90 percent), Outage/Restoration (85 percent), and Street Light Repair (79 percent). The Company has also implemented 'Reflect', a post-contact survey that will gather customers' immediate feedback after contacting Duke Energy by web, text, call to automated system or live agent. As data is collected, this tool will provide critical feedback to improve all channels customers use to interact with Duke Energy.

Q. WHAT DO YOU ATTRIBUTE TO THE POSITIVE CSAT SCORES YOU JUST DESCRIBED?

A. At Duke Energy, our mission is to provide safe and reliable service, transform the customers' experience, modernize the energy grid, generate cleaner energy and be a good corporate citizen - all while keeping costs low. We are a well-run company and we believe that customers see and experience the benefits of our efforts every day. Here are just a few of the many recognitions Duke Energy has received in the past two years across the enterprise:

- For the 13th consecutive year, Duke Energy was named to the Dow Jones Sustainability Index for North America.

- Duke Energy was named to Fortune magazine's 2019 "World's Most Admired Companies" list for the second year in a row.

- Forbes magazine named Duke Energy as one of "America's Best Employers" – making the 2018 and 2019 list for U.S. electric utilities.

- The NAACP named Duke Energy an inaugural member of its Equity Inclusion and Empowerment Index, identifying Duke Energy as a corporate leader in fostering an equitable, just and inclusive workplace.

- For the 14th consecutive year, Duke Energy has been named to Site Selection magazine's annual list of "Top Utilities in Economic Development."

Further, I believe the robust team of customer care center representatives and customer field service personnel, our IVR options, and processes and procedures heavily influence our CSAT scores. I also believe the multiple options our customers have to communicate with and receive information from us, including through digital channels and social media, improves the customers' overall communication experience. The Company's ability to keep our customers' lights on reliably, efficiently and affordably all while being a good corporate citizen also contributes to positive CSAT scores. I provide just a few examples below:

Power Efficiency, Diversity and Reliability

Each day, we work to make our power system more efficient, more diverse and more reliable. In fact, over the years, DE Progress has become a leader in efficiency: for example, as witness Henderson describes, the reliability and performance of our nuclear plants remains strong. In fact, in 2018 our nuclear fleet provided approximately 45% of DE Progress' generation needs and achieved an 88.58 percent capacity factor despite significant challenges attributable to the landfall of Hurricane Florence. Further, H. B. Robinson Nuclear ("Robinson") employees were recognized by the Nuclear Energy Institute with a Top Innovation Practice award for inventing the control room glass top simulator. The screens, invented by the Robinson team, were first of their kind in the industry, and provided the training environment at a fraction of the costs that would have otherwise been required.

The Company's fossil-fueled power plants continue to operate reliably and efficiently as well. As witness Turner explains, over the past five years, the percentage of time our fossil-fueled power plants are available to generate power, as measured by the Equivalent Availability Factor ("EAF"), is at or above the NERC average for comparable units. We are also working to make our system cleaner and more diverse. For example, we are planning to retire two coal-fired units at the existing Asheville Plant and have invested in a new combined-cycle natural gas plant at Asheville ("Asheville CC"). Further, Duke Energy added 500 megawatts of solar in North Carolina during the year, which helped the state remain second in the nation for solar capacity. Duke Energy also outlined plans to deploy 300 megawatts of battery storage projects in the Carolinas over the next 15 years. Further, as witness Oliver details in his testimony, the reliability of our power delivery system has performed well, and we have continued to provide safe, reliable and affordable electric service. However, over the past ten years, we are seeing trends affecting our grid that indicate more must be done to improve the energy infrastructure to meet the needs of our customers. Our grid improvement plan, as explained by witness Oliver, was developed to deliver on customer expectations and address these trends. Overall, we are investing in making our infrastructure stronger, smarter, cleaner, more efficient and less reliant on any single fuel source, which leads to more reliable energy and a better experience for our customers.

Corporate Sustainability Goals

Duke Energy's approach to sustainability focuses on the issues that are most important to us and our stakeholders. We have mapped our priority issues to the United Nations Sustainable Development Goals ("SDGs"), which aim to "end poverty, protect the planet and ensure prosperity for all."[4] While we have alignment between our priorities and several of the SDGs, goals "Seven: Affordable and Clean Energy" and "Thirteen: Climate Action" are especially applicable to us. Our goals fall under four categories: Customers, Growth, Operations and Employees.

- Customers: Improve the lives of our customers and vitality of our communities (e.g., providing affordable energy, promoting energy efficiency – consumption and peak demand, charitable giving, community leadership and volunteerism, etc.)

[4] The United Nations, *A/RES/70/1 - Transforming our World: The 2030 Agenda for Sustainable Development* (September 2015), *available at* https://sustainabledevelopment.un.org/content/documents/21252030%20Agenda%20for%20Sustainable%20Development%20web.pdf

- Growth: Grow and adapt the business, and achieve our financial objectives (e.g., stimulating economic development, promoting renewables, corporate governance, etc.).
- Operations: Excel in safety, operational performance and environmental stewardship (e.g., enhanced safety, reliable energy, reduced carbon emissions, etc.).
- Employees: Develop and engage employees, and strengthen leadership (e.g., employee engagement, diversity and inclusion, etc.).

Generating Cleaner Energy

Duke Energy continues to advance its efforts to generate cleaner energy. Overall, we have lowered our carbon emissions by over 30 percent since 2005, consistent with Duke Energy's goal to reduce carbon emissions by at least 50 percent by 2030 and to net-zero by 2050. Additionally, we have plans to increase our reliance on renewable sources and invest in natural gas-fired power plants and battery storage projects.

Corporate Citizenship and Neighboring with Our Communities

Duke Energy has proudly served our communities through charitable giving and employee volunteerism for decades. During 2018, the Duke Energy Foundation contributed $31.6 million to our communities, and our employees and retirees volunteered 16,000 hours of community service across our jurisdictions. For DE Progress, we commit to helping our customers and communities with programs such as the Neighborhood Energy Saver Program to help our low-income customers become more energy efficient and our Energy Neighbor and Helping Home Fund, assistance programs for our customers in need. And, as discussed by witness De May in his testimony, we look forward to doing more to help our low-income customers through the low-income energy assistance program collaborative we are requesting the Commission establish with participation from the North Carolina Public Staff and other key stakeholders.

Supplier Diversity

At Duke Energy, our supplier partners share our commitment to the local economies and communities we serve. As such, many of our suppliers are locally based and/or diverse. With the inclusion of local and diverse suppliers as one of the Company's priorities, Duke Energy was recently honored for having a Top Veteran-Friendly Supplier Diversity Program by the U.S. Veterans magazine. Our efforts to identify and recruit diverse suppliers are important to the Company's overall supply chain sourcing strategy. The relationships we have with state and community economic development organizations enables Duke to positively impact our communities while creating enhanced value for the Company.

Price

While one might assume that such performance would result in significantly higher costs to customers, our achievements have been accomplished while maintaining rates that compare well nationally even with the full projected increase. The latest survey from the EEI reflects national average cents per kWh price for typical residential, commercial and industrial customers. The 2018 national average for residential customers is 13.16¢ per kWh, for commercial customers is $10.77¢ per kWh, and for industrial customers is 7.01¢ per kWh. DE Progress' North Carolina projected price of currently 13.83¢ per kWh for residential customers, 9.90¢ per kWh for commercial customers, and 7.18¢ per kWh for industrial customers are comparable to the national average.

IV. <u>CUSTOMER SATISFACTION MEASURES</u>

Q. IS THE COMPANY WORKING TO FURTHER IMPROVE THE LEVEL OF CUSTOMER SERVICE?

A. Yes. Duke Energy is working hard across the business to further improve the customer experience. In my organization, we are doing our part to transform the customer experience by making strategic, value-based investments for the benefit of our customers.

Q. PLEASE PROVIDE EXAMPLES OF WAYS YOUR ORGANIZATION IS HELPING TO TRANSFORM THE CUSTOMER EXPERIENCE.

A. Two key examples are enhancements to our integrated voice response ("IVR") system and the deployment of Customer Connect.

Integrated Voice Response

In 2016, the Company launched an effort to replace the existing IVR system with advanced technology focused on transforming the caller's experience. The new IVR design reflects learnings from customer feedback and industry best practices that led to several key areas of focus, which included: 1) proactively identifying the customers and why they are calling the Company, 2) a tailored customer experience like what they receive from other consumer product companies and 3) less menu options to complete their request in the IVR. Options available after the deployment of the new IVR include call prediction, easy self-serve options, customer call back and a post-call survey. The call prediction functionality predicts the reason the customer is calling the Company. For example, “I see you have a pending service order scheduled for tomorrow. Is this why you are calling?” The Company recognizes customers want the ability to self-serve while navigating seamlessly through the IVR. Existing self-service functionality such as requesting a payment arrangement and reporting a power outage will be improved via voice activated prompts which will help provide a more positive customer experience. New self-serve options include texting a link to local payment locations, allowing customers the ability to update their phone number in the IVR and requesting their account number through the IVR. An audio comparison of the existing IVR and new IVR is provided as Hatcher Exhibit 1.

An increased number of calls during a specified timeframe may result in longer than usual hold times to speak with a specialist. The new IVR will also allow customers the option to continue holding until a specialist is available, or have their place in line reserved for them allowing for us to return their call at the number of their choice. The Company’s ongoing focus to understand “the voice of the customer” has been expanded to the new IVR with the implementation of the post-call survey. The post-call survey offers customers the option to provide immediate feedback on their experience. The Company plans to launch the new IVR in 2019.

Customer Connect

In 2017, the Company began the conversion of its old customer information system ("CIS") into a modern customer service platform, known as Customer Connect. Through this conversion, the Company will be able to deliver a customer experience that will simplify, strengthen and advance our ability to serve our customers. The platform will be leveraged to provide real-time insights to enhance the customer experience. One example of this is how the Company can leverage these insights to enhance operations during significant storm events. With this new platform, data can be visualized in new ways to uncover insights into experiences customers are having across the Company's phone, web and social media channels. The Company can also leverage the automated, targeted marketing capabilities to increase effectiveness of communication campaigns during major storm events and for other operational needs.

In June 2018, the Company successfully deployed the first of several deliverables under the Customer Connect Program, which provides the capabilities to start gathering, storing and analyzing customer insights to better understand our customers so we can better serve them to their personal level of satisfaction, and this deliverable is the first step in doing that. Specifically, the Company began gathering relevant touchpoints that customers are having with Duke Energy in real time such as web visits, phone calls, power outages, outbound communications, and product and service participation. The Company also delivered enhanced communication capabilities which provide more personalized service with automated and targeted campaigns. These capabilities automate processes, increase effectiveness and provide metrics to gauge success.

The integrated analytics platform will be used to provide real-time learnings to enhance the customer experience. One example of this is how the Company can use this newly available information to enhance operations during significant storm events. With this new platform, data can be visualized in new ways to uncover insights into experiences customers are having across the Company's phone, web and social media channels. The Company can also use the automated, targeted marketing campaigns to increase effectiveness of communication campaigns during major storm events and for other operational needs.

In February 2019, leveraging insights from the holistic customer profile, the Company began using the new platform to predict the intent of customers when they call. Additionally, the Company has been making this information more readily available to our customer care agents, who are now using it for insight into why a customer may be calling, which is allowing for more informed and productive conversations with our customers. In May 2019, the Customer Connect Program implemented a new capability to better communicate with customers during major storms. The Company is now able to create targeted customer communication lists by leveraging attributes that are particularly relevant during major storms, such as the substation or operations center a customer is served by, or whether the customer or nearby customers are experience an outage. These lists will be used to send more specific communications about the specific storm-related circumstances near the customer's home or business. Additionally, later this year, these capabilities will be expanded to include the ability to automate these email campaigns from Customer Connect and allow them to be configured in advance and quickly executed in desired circumstances.

V. ENHANCEMENTS TO CUSTOMER OFFERINGS

Q. HAS THE COMPANY IDENTIFIED ADDITIONAL PROGRAMS THAT IT MAY OFFER TO IMPROVE CUSTOMER SATISFACTION?

A. Yes. The Company is seeking approval in its Application to eliminate convenience fees for credit and debit card payments made by our residential customers. The requirement to pay a convenience fee when making a payment is one of the largest frustrations our residential customers experience. Customers have grown accustomed to paying for other products and services with a credit card or debit card without a separate, additional fee. Eliminating these fees for our residential customers would provide additional, convenient options for residential customers to pay their bills, which would ultimately increase customer satisfaction. Additionally, the Company is seeking approval to change the bill payment due date for non-residential customers from fifteen days to twenty-five days after the bill date. The Company's proposal is in response to feedback received from its non-residential customers.

Q. PLEASE EXPLAIN THE COMPANY'S PROPOSAL FOR A FEE-FREE CREDIT/DEBIT CARD PROGRAM.

Currently, customer payments made by mailing a check, paying with cash or check at a free pay station, using bank draft or paperless billing, are free of charge. The costs for the Company to offer these methods are paid for by all customers and not recovered exclusively by those specific customers that use that method of payment. However, residential customers using a credit or debit card through any payment channel are subject to a $1.50 convenience fee per transaction. The convenience fee is collected from the customer by the Company's third-party vendor, Speedpay. The Company receives no portion of this fee.

Q. WHY IS THE COMPANY PROPOSING THIS PROGRAM NOW?

A. As customer expectations change and more payments are processed electronically, utility companies are beginning to offer fee-free payment programs for their residential customers for all methods of payment.[5] Customers are increasingly making more payments today by credit or debit card. The number of payments made by credit and debit cards continues to grow as a preferred method of payment by many consumers.[6] In fact, Duke

[5] According to J.D. Power and Associates, as of 2016, about 28 percent of surveyed electric utilities provide a fee-free card payment option. *See* J.D. Power Catalog. J.D. Power and Associates, 2016 Electric Utility Residential Customer Satisfaction Study.

[6] According to the Federal Reserve Payments Study: 2018 Annual Supplement. The number of payments made by credit, non-prepaid debit, and prepaid debit cards grew more rapidly than the number of payments made by any other payment type in the 2012 to 2015 and 2016 to 2017 periods.

Energy Corporation has seen 14 percent average year-over-year growth in credit/debit card transactions over the past several years, and with this change we expect the growth rate to double – so 28 percent more transactions in 2019 than in 2018.

A recent study by Fiserv (a leader in financial services) also discusses the trends by customers moving toward card transactions and away from checks: "Checks are on a continual downward trajectory in the United States as consumers shift away from checks and toward card payments, a market dynamic that billers should not overlook". The Company believes it is reasonable to offer a fee-free payment program for these payment methods to its residential customers, and recover the costs associated with that program from all customers through cost of service. Eliminating these fees for the Company's residential customers would provide additional options for residential customers to pay their bills. Consumer advocate groups have also suggested that convenience fees for paying utility bills can be burdensome to customers.[7]

We also know that our customers want this option. The Company's Customer Service department routinely receives inquiries about no-cost electronic payment methods. In the Company's Monthly Residential Transaction Surveys, residential customers noted some of the following when asked what they liked least about Duke Energy:

[7] Nat'l Ass'n of State Util. Consumer Advocates, *Urging Utilities to Eliminate "Convenience" Fees for Paying Utility Bills with Debit and Credit Cards and Urging Appropriate State Regulatory Oversight* (Nov. 13, 2012), *available at* https://nasuca.org/2012-07-urging-utilities-to-eliminate-convenience-fees-forpaying-utility-bills-withdebit-and-credit-cards-and-urging-appropriate-state-regulatory-oversight/.

> *"I refuse to pay a convenience fee. No one else charges this for their products…"*

> *"I like everything except the processing fee of $1.50 by doing it over the phone. I pay all my bills this way with zero fees."*

> *"Shouldn't charge me a fee to pay you."*

> *"It's ridiculous to pay an extra fee to pay off my monthly statement."*

> *Í think it is stupid that there is a $1.50 charge to pay online or over the phone. Duke is the only company that I deal with that does that."*

We think our customers will appreciate being able to use credit cards with the Company the same way they can with other companies.

Q. HOW EXACTLY WOULD COST FREE ALTERNATIVE PAYMENT METHODS BENEFIT THE COMPANY'S CUSTOMERS?

A. Eliminating these fees for the Company's residential customers would provide additional fee-free options for residential customers to pay their bills. In addition, the option of a fee-free payment when using a credit card, debit card or electronic check would lead to greater satisfaction for all customers who primarily pay for goods and services with these payment methods. There are many reasons why customers prefer to use their credit or debit card, which may include: (1) customers feel safer using a debit or credit card that includes security protections from their bank, (2) using a prepaid card, (3) receiving loyalty rewards for credit cards, (4) using a fast payment method to prevent a pending disconnection for non-pay, or (5) having a lack of a checking account (some customers have salaries or social security funds provided on prepaid debit cards and do not have a bank account). Regardless of the reason a customer may have, they would be more satisfied with the ability to pay by the method of their choice without incurring additional fees.

Q. HOW DOES THE COMPANY PROPOSE TO PAY FOR THE FEES THE PROGRAM WOULD ELIMINATE?

A. The Company proposes to recover the costs associated with the fee-free payment program—the elimination of the convenience fees—from all customers through an adjustment to the cost of service as explained by witness Smith. This would eliminate the $1.50 convenience fee currently directly charged by Speedpay to these residential customers paying by credit, debit or electronic check.

Q. WILL DE PROGRESS STILL OWE SPEEDPAY THE CREDIT CARD TRANSACTION FEES?

A. Yes. We have worked with Speedpay throughout the Duke Energy enterprise to obtain a low cost for card and electronic check payments of $1.50 per transaction for residential customers. DE Progress will pay the per transaction fees to Speedpay.

Q. WHY IT IS REASONABLE FOR THE COMPANY TO INCLUDE THE COST OF FEE FREE PAYMENT IN ITS COST OF SERVICE THAT IS PAID BY ALL RESIDENTIAL CUSTOMERS?

A. The more convenient the Company can make the bill paying process for customers to pay bills, the more all customers will benefit. Customers who self-serve, pay on time, and are satisfied with the options available to them are the least expensive to serve, which is a benefit to all customers. Customers who do not pay on time and enter the credit collections cycle drive increased costs, which are ultimately borne by all customers. Lastly, customers who are not satisfied tend to call Customer Care Centers more often. Every call into the call center results in increased costs for all customers. This means that every call that can be avoided leads to savings for all customers. Giving customers options to pay by the method of their choice without incurring additional fees will lead to more satisfied customers and, ultimately, savings.

Q. CAN YOU SUMMARIZE THE ADOPTION RATE THAT THE COMPANY ANTICIPATES IF THIS PROGRAM WERE IMPLEMENTED?

A. Yes. Based on market research, analytics and industry trends, the Company anticipates that the average percentage increase in adoption once the fee-free program is implemented is a 100%-200% increase in transaction volume within the first 12 months. This expectation is aligned with what vendors have experienced with other utilities that make the switch from a convenience fee model to a fee-free payment model.

Q. IS THE COMPANY PROPOSING A FEE-FREE PROGRAM FOR ITS COMMERCIAL AND INDUSTRIAL CUSTOMERS AT THIS TIME?

A. Not now. Cost-effective payment methods are generally available to commercial and industrial customers because the average payment amounts for these customers are significantly higher than residential (which leads to higher processing costs). As such, the Company is not proposing a fee-free program for commercial and industrial customers at this time.

Q. HAS THE COMPANY ADOPTED THIS PROGRAM IN ANY OF ITS OTHER JURISDICTIONS?

A. Yes. The Company requested and received approval to implement the transaction fee-free program in its most recent rate case proceeding in South Carolina in Docket No. 2018-318-E. The program went into effect in South Carolina on July 1, 2019.

Q. PLEASE DESCRIBE THE PROPOSED CHANGE TO THE NON-RESIDENTIAL RATE SCHEDULES RELATED TO BILL PAYMENT DUE DATE.

A. In response to requests from nonresidential customers for additional time to process electric invoices, the Company is proposing to change when bills are past due and delinquent from fifteen days to twenty-five days to match the current requirement for residential customers.

Q. WHY IS THE COMPANY PROPOSING THIS NOW?

A. The Company has received feedback from its non-residential customers of their desire for additional time to make their payments to the Company. Not only will this extension align our remittance period with the number of days the Company offers residential customers, but it will better align with the payment terms of net thirty days non-residential customers have with other vendors. Further, by the time a bill is rendered and delivered by the United States Posta Service, our non-residential customers are often left with only a few days to process and remit their payments. Changing the remittance period will help extend the number of days for them to process and remit their payments in a timely manner. Accordingly, the Company believes this change will be positively received by the Company's non-residential customers and may help mitigate the challenges our current remittance period places on them.

VI. CONCLUSION

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

A. Yes.

I am the Senior Vice President of Customer Service for Duke Energy Progress, LLC. In my direct testimony, I highlight our customer service efforts and how that translates to customer satisfaction. I also describe several steps the Company has taken to further improve the experience and satisfaction of our customers when they engage with us, including enhancements to our integrated voice response system and proposals in this rate case to implement a fee-free payment program for residential customers using credit and debit cards, and to change when bills are considered past due and delinquent for our nonresidential customers.

As a leader in our customer service organization at Duke Energy, I am proud of our continued mission to provide safe and reliable service, transform the customers' experience, modernize the energy grid, generate cleaner energy and be a good corporate citizen - all while keeping costs low. As examples, the Company's nuclear fleet is recognized as being one of the best in the industry in terms of safety, reliability, availability and production costs. The Company's Fossil and Hydro operations have similar superior safety, reliability and production cost performance, while reducing carbon emissions by 39% from 2005 levels. The Company's transmission and distribution systems have also performed well notwithstanding the need for modernization as described by witness Oliver. We continue to deploy new smart meters across our jurisdiction and are in the process of replacing the Company's outdated customer information system with a new, modern customer service platform that will transform how the Company serves customers by providing them with the easy, personalized experiences they expect from other service providers.

At Duke Energy, the customer is at the center of our purpose. Evolving customer expectations, emerging technologies and changing public policies all converge to create a dynamic environment for Duke Energy and the industry. As I describe in my testimony, Duke Energy works to build genuine connections with all customers by listening, anticipating their needs, and offering solutions. Our response to the ongoing COVID-19 Pandemic is evidence of this, as Mr. De May just highlighted. Another example is our consistent storm response. The Company has been repeatedly recognized as a leader in the industry in storm restoration and over the last several years have been able to restore service to 95% of its customers within just a few days over the course of hurricanes and winter storms. We have been repeatedly recognized for our efforts by organizations including the Dow Jones, Forbes, Edison Electric Institute, the U.S. Department of Labor, the NAACP, and the Ethisphere Institute to name a few.

This concludes the summary of my direct testimony.

COMMISSIONER CLODFELTER: You may proceed.

MR. ROBINSON: Thank you, Commissioner Clodfelter. And I would move that the portions of Mr. Hatcher's oral testimony elicited at the expert hearing in Docket Number E-7, Sub 1214, the specific portions of which were stipulated to with the Office of the Attorney General in its Stipulation filed on September 24th, 2020, be moved into the record in this case with the specific citation being as follows: Transcripts volume 11, pages 949, line 12 through 978, line 23; pages 1016, line 7 through 1019, line 13; and in transcript volume 12, pages 22, line 14 through page 30, line 22.

COMMISSIONER CLODFELTER: You've heard Mr. Robinson's motion. This is for admission of portions of the testimony given by Mr. Hatcher in the Duke Energy Carolinas proceedings be moved into the record in this case. Is there any objection?

(Pause)

Hearing none, the motion is allowed.

MR. ROBINSON: Thank you, Commissioner Clodfelter.

(WHEREUPON, the stipulated testimony of Stephen G. De May

from Docket Number E-7, Sub 1214
is copied into the record as if
given orally from the stand.)

Larry E. Hatcher
Stipulated Testimony from DEC Evidentiary Hearing

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219

CROSS EXAMINATION BY MS. FORCE:

Q. Good morning, Mr. Hatcher.

A. (Larry E. Hatcher) Good morning.

Q. Are you okay?

A. Yes, ma'am.

Q. Let me know if I need to turn my monitor off, I'm hearing a little feedback.

CHAIR MITCHELL: I'm hearing it too, Ms. Force, so I would ask that you-all keep your lines on mute until the moment you need to speak, please. Thank you.

MS. FORCE: Okay.

Q. Mr. Hatcher, my name is Margaret Force. I'm with the Attorney General's Office. And in looking at your testimony, I see that your responsibilities include customer care, online customer interactions, billing and metering services, and you also address some of the new features of the Customer Connect system; is that right?

A. Yes, ma'am.

Q. I think I only heard part of your answer, but it was a "yes, ma'am," right?

A. Correct.

Q. I have some questions about the technology that Duke is using with Customer Connect to help customers take advantage of emerging programs or apps that make use of the detailed data that Duke is collecting from customers' smart meters, the advanced meter infrastructure, to monitor and conserve energy. And it looks like the questions are appropriate for you and for Mr. Schneider both, so I plan to start with you. But if you think that I need to ask another witness, just let me know who to ask, please. Okay?

A. Okay.

Q. Okay. I see, on page 4 of your direct testimony, starting on line 16, that you stated that the customer is at the center of Duke's purpose and that evolving customer expectations, emerging technologies, and change in public policies all converge to create a dynamic environment for Duke. And you also say that Duke works to build genuine connections with customers by listening, anticipating their needs, and offering solutions.

Is that a fair restatement of your testimony at that point?

A. Yes, ma'am.

Q. In the -- excuse me -- in the last Duke Carolinas rate case, there were some parties who questioned Duke's investment in Customer Connect and in AMI meters, and their position was that customers should be able to access their own very detailed data that Duke is collecting from AMI meters. I'm sorry, did that last part not come through?

CHAIR MITCHELL: Ms. Force, just for purposes of the record, restate the whole question, please, ma'am.

MS. FORCE: Okay.

Q. In the last Duke Carolinas rate case, there were some parties who questioned Duke's investment in Customer Connect and AMI, and posited that customers should be able to access their own very detailed data that Duke is collecting from AMI meters.

Are you familiar with that testimony and position that was made in the last case, Mr. Hatcher?

A. Are you referring to the Retha Hunsicker testimony?

Q. One of the testimonies from Duke was from Ms. Hunsicker -- I'm sorry about the pronunciation of the name -- and there was also testimony from Mr. Schneider, but also there were other witnesses -- other parties who addressed that issue in their briefs, namely the EDF, the Environmental Defense Fund; and North Carolina Stainable Energy Association; and others.

Does that -- are you familiar with that?

A. So I'm familiar with Mrs. Hunsicker's testimony. Some of the others that you mentioned, I understand that they did provide testimony in that hearing, but I personally have not reviewed it.

Q. Okay. One of the things that was posited in that case was that customers should be able to use their own already available -- their own customer data through already available and used national standard protocol that's called the Green Button Collect My Data standard; are you familiar with that?

A.   Yes, ma'am.
Q.   So would you disagree that Green Button Collect was identified as an important feature for customers to benefit from the implementation of Customer Connect and the rollout of AMI meters?
A.   I would agree that that was the testimony; yes, ma'am.
MS. FORCE: I'd like to ask the Commission to take judicial notice of its order in the Sub 1146 rate case, which was the last Duke rate case, and I refer that that is available through AGO Exhibit 44. I don't believe it's been taken -- it could be that it's already in the record, but I'm not sure.
CHAIR MITCHELL: Just for purposes of the record, Ms. Force, can you -- will you please indicate the date of the Commission's order that you were referencing? And we'll take judicial notice, hearing no objection to your request. I just want to make sure you specify the date of the order.
MS. FORCE: The date of the Commission's order, as I have it, appears on page 334 of that order, and it was issued on June 22nd of 2018.

CHAIR MITCHELL: In docket number?

MS. FORCE: And the main docket number in that case was Docket Number E-7, Sub 1146. And also, in addition to the 334 pages in the majority order, there were also dissenting opinions that appear after that.

CHAIR MITCHELL: All right. Hearing no objection, Ms. Force, to your motion, we will take -- the Commission will take judicial notice of its order. Thank you.

MS. FORCE: Thank you. I appreciate that. And I do not propose to put that into an exhibit, and I'm not going to rehash what appears in the order in this hearing. We can take that up in our brief. But as I understand it, the Commission has indicated that it intends to take judicial notice of at least some of the issues from the other case, so I want to make sure this is available to our -- for our use. Okay.

Q. Mr. Hatcher, the Commission has a pending rulemaking about access to the detailed customer data that Duke is collecting using the new AMI meters and related customer privacy issues, and that's in Docket Number E-100, Sub 161.

Are you familiar with that docket?

A. Is that referred to as the data access docket?

Q. That's right.

A. I am familiar with that docket as taken. I don't personally have any details as to what's being discussed in that.

CHAIR MITCHELL: Ms. Force, you're on mute, so you'll need to start your question over.

MS. FORCE: I'm sorry.

Q. And can you tell me, is there another witness that you'd suggest that would have more familiarity with that docket?

A. I would refer you to Don Schneider. What I'm aware of, Ms. Force, in terms of Green Button, is I know we're currently not part of that alliance. I do know that we do make and allow energy consumption data available to our customers if they request it. They are free to use that data however they see fit. So if there's an app out there that they feel like they could use that data to plug into and get better information on how to manage their energy usage or whether they think they should pursue solar installations at their home, they're certainly welcome to that data, and we can and do provide that to our customers.

The data access docket I know has taken up some of these issues, and, you know, we do look forward to the outcome of that docket. But beyond that, really the technical issues associated with Green Button I will refer to Mr. Schneider.

Q. And for clarification, it's my understanding that some of those issues -- well, let me put it this way. That the Customer Connect works in tandem with the AMI meters. So I want to be clear that I will be able to ask my questions and get them answered if it overlaps in the Customer Connect and how that's being rolled out; is that correct, then?

A. It does overlap, so it's kind of one of the key components to the overall customer information system that we put in with Customer Connect. So the information coming off the meters goes into the billing system is where I pick up on it in my organization, and then we also did maintenance of those meters after they were installed. So, in terms of the information that would be coming in, it would be coming in through billing databases, and then, you know, we could run queries or be able to provide that information back to the customer if they request it.

Also, you know, we have a smart meter app that the customers can use to be able to extract that energy usage data pretty much on a realtime basis if they want to, you know, enroll with that app and be able to get that information.

Q. I do have some more --

CHAIR MITCHELL: I'm sorry, Ms. Force, I'm going to interrupt you. Mr. Hatcher, you are trailing off. We're having a hard time hearing you, particularly when you get to the end of your sentences. So if you could just be cognizant of that. We can hear you when you start your sentences, but then you trail off. So just try to moderate your vol- -- the volume of your voice to make sure that we hear, and that everybody can hear your responses to the questions.

All right. Ms. Force, I interrupted you, so you may proceed. Ms. Force, you're on mute.

MS. FORCE: I apologize.

Q. Mr. Hatcher, it looks like you're familiar with some of the issues that go to customer access to the data. And so I'd ask you to turn to AGO Exhibit 46, please.

A. Okay. Just a moment, please.
Q. Sure.
(Pause.)
Q. Let me know when you're there.
(Pause.)
THE WITNESS: Give me just a moment. We're pulling that up.
(Pause.)
Q. Mr. Hatcher, while you're bringing that up, I'm going to have some questions about some of the other exhibits that appear nearby there that the AGO has put -- provided ahead of time. If you have that folder, that would be helpful.
A. Okay. We'll work to get that information.
(Pause.)
CHAIR MITCHELL: Ms. Force, are you -- where are you in your cross examination of the witness?
MS. FORCE: I have another 15 minutes or so.
CHAIR MITCHELL: Okay. So, Mr. Robinson, at this point, are we waiting to get documents in front of the witness?
THE WITNESS: Yes, ma'am.

CHAIR MITCHELL: Okay.

MR. ROBINSON: Chair Mitchell, if we could just have five minutes to ensure that Mr. Hatcher has what he needs.

CHAIR MITCHELL: All right. Mr. Robinson, I'll give you your five minutes. And let's also check the volume with Mr. Hatcher's system. We're having a hard time hearing him. He's trailing off, and then there is sort of a hum that also occurs when he speaks. So if you could have someone look into the system just to ensure that you-all have it functioning optimally, that would be appreciated. All right. Let's go off the record. We'll go back on at 10:10.

(At this time, a recess was taken from 10:04 a.m. to 10:10 a.m.)

CHAIR MITCHELL: All right. Let's go back on the record, please.

MS. FORCE: Shall I begin?

CHAIR MITCHELL: All right. Mr. Hatcher, would you please confirm that you have the documents in front of you?

THE WITNESS: Yes, ma'am, I do.

CHAIR MITCHELL: All right. And I would

remind you to just be cognizant of the volume level of your voice so that we can hear your complete sentences. All right. Ms. Force, you may proceed.

MS. FORCE: Thank you.

Q. Mr. Hatcher, you have what was AGO Exhibit 46 before you. That was what was prefiled before.

Do you recognize -- would you agree with me that that is on Duke letterhead, and it's a February 10, 2020, filing in that docket we were talking about, the rulemaking concerning customer data that was made by Duke?

A. Yes, ma'am, I do.

MS. FORCE: I would ask to mark this as AGO Hatcher Cross Exhibit 1, please.

(Pause.)

MS. FORCE: I'm sorry, can you hear me? I'd ask to mark this as AGO Hatcher Cross Exhibit 1, please, for the record.

CHAIR MITCHELL: All right. Ms. Force, the document shall be marked as AGO Hatcher Cross Exhibit Number 1.

(AGO Hatcher Cross Exhibit Number 1 was marked for identification.)

MS. FORCE: Thank you.

Q. Would you please turn to page 4, Mr. Hatcher. And I'm looking just partway down the page, there's a date shown there, and these are -- this is Duke copying in what has been proposed in a Public Staff proposed rule change that would be effective January 1, 2022.

And can you agree with me that Duke opposes this requirement that would say that customer data must be maintained and made available to customers and customer-authorized third parties in electronic machine readable format that conforms to the NAESB standard described there or another Commission-approved electronic machine readable format that conforms to national recognized standards and best practices?

MR. ROBINSON: Chair Mitchell, if I may, the Company objects. This has to do with a completely different docket. There has been no Green Button testimony that has been filed or prefiled in this case. I'm not sure as to why Ms. Force is asking Mr. Hatcher these questions.

CHAIR MITCHELL: All right. Ms. Force, how do you respond?

MS. FORCE: I would explain that, in the last rate case, there was quite a bit of discussion, not only about Customer Connect, but about the cost recovery for AMI meters and whether the benefits to customers are sufficient to justify cost recovery. And, in this case, that question comes up again where the Company has gone forward and implemented its program without embracing some of the very important pieces of it that were put in the record last time and were to be taken up subsequently.

CHAIR MITCHELL: All right. Ms. Force and Mr. Robinson, I'm going to overrule the objection. The Commission historically and typically allows open cross, but, Ms. Force, I would ask that you just move through this as quickly as you can in the interest of making the most efficient use of our hearing time. Thank you.

MS. FORCE: Okay.

Q. Now, I don't remember that you answered the question, Mr. Hatcher.

Would you agree that Duke opposes the proposal that has been put forward in that rule and gives some reasons for that? That's what I wanted to talk to you about. And just to elaborate, this is a Green Button Connect-type standard in my understanding. Is that your understanding too?

A. Yes, Ms. Force. So I agree that what you've read is in this document that I'm looking at. You know, we didn't --

(Reporter interruption due to sound failure.)

CHAIR MITCHELL: All right. We are having significant issues with the audio in the -- on Mr. Hatcher's setup. So here's what we're going to do. We are going to take a 15-minute recess. Duke, I'm going to ask that you provide a different setup for Mr. Hatcher and for anyone that was to testify using the audio/visual setup you have in that room. So let's go off the record. We will go back on at 10:30.

MR. ROBINSON: Yes, Chair Mitchell.

(At this time, a recess was taken from 10:15 a.m. to 10:30 a.m.)

CHAIR MITCHELL: All right. Mr. Hatcher, have we remedied the situation with your audio?

THE WITNESS: I think so, yes, ma'am.

CHAIR MITCHELL: Okay. All right. Let's go back on the record, please.

Ms. Force, you may proceed.

Q. Mr. Hatcher, okay, I didn't see you back on the screen. You've moved in my windows, I'm sorry.

We were talking about the --

CHAIR MITCHELL: Ms. Force, I'm sorry, let me interrupt you just one moment.

Mr. Hatcher is now sitting behind Alison Williams' system, just so persons participating on the video conference are clear who's testifying. Mr. Hatcher is behind Alison Williams.

MR. ROBINSON: Yes. And, Chair Mitchell, if I may, I just want to apologize. There was an issue with Mr. Hatcher's actual computer, so we're using Ms. Williams' computer for him to be able to testify, I hope the audio is much better on this one.

CHAIR MITCHELL: Thank you, Mr. Robinson.

All right, Ms. Force, you may proceed.

Q. Mr. Hatcher, looking at that exhibit that we were discussing before the break, there is a rule that's set out there, and Duke has indicated about the proposal to incorporate a Green Button Connect-like standard. And I gather that one of the reasons is that, even though the requirement would not kick in until January of 2022, Duke says that, if the standard is required, then Duke will have difficulty implementing its Customer Connect program fully by April 2021 as is now planned. Do you agree?

A. Yes, ma'am, I do.

Q. And you mentioned earlier that, instead of using the Green Button Connect, that Duke offers its customers what's called My Duke Data Download, correct?

A. Yes, ma'am; that's correct.

Q. I'm having a little trouble hearing you, but I'll try to listen up.

A. Yes, ma'am, that is correct.

Q. That was much better. Okay.

My Duke Data Download is not a national standard, is it? Isn't that something that's Duke's own version that's based on the older technology called Green Button Download My Data?

A. You probably know more about that than I do, from a technical perspective. If I may, the reason that we were having concerns about the January date, the Customer Connect platform is really not just designed to deal with the Green Button issue. It's really designed -- it's a whole new customer information system for our entire enterprise.

So it's designed to give kind of a state-of-the-art interaction for customers to interact with us, just like they would other large retail-type customers. It's designed to be able to take advantage of the advanced meter infrastructure that's been installed in the field so the customers do have a lot more of that information available to them and have more control. But it's also designed to give us a more personal experience with the customer versus kind of a more global experience with the customer.

So all of that is really built into this tool. So it's a lot bigger than just what you're talking about with the Green Button.

The reason we said that the date was going to be a challenge, the deployment of Customer Connect goes into DEC in April of next year, and then you're looking at a three- to four-month, you know, checkout period, a deployment period to make sure everything is good and that we're solid. And then we're going to do DEP in November of next year. So to be able to get through that, get the project implemented across the Carolinas, that January date was of concern.

And to do something with our legacy systems when we're trying to implement this new customer information system just didn't feel prudent from that perspective.

Q.   Okay. I'd ask you to please turn to AGO Exhibit 45 now.

A.   Okay. Just a moment, please.

Q.   Sure.

(Pause.)

THE WITNESS: Okay.

CHAIR MITCHELL: Ms. Force, you're on mute.

MS. FORCE: I'm sorry. I got that backwards.

Q.   Mr. Hatcher, I'd submit that this is a response to a data request by Duke to the Public Staff; do you see that? Are we on the same page?

A.   Yes, ma'am.

Q.   All right.

MS. FORCE: And I'd ask to mark this AGO Hatcher Cross Exhibit 2, please.

CHAIR MITCHELL: The document will be so marked.

(AGO Hatcher Cross Exhibit 2 was marked for identification.)

CHAIR MITCHELL: Ms. Force, you are on mute again.

MS. FORCE: I apologize.

Q. Mr. Hatcher, I submit to you that these -- this is a description by Duke on the difference between the My Duke Data Download program and the Green Button Connect program. And it looks to me like there's a difference in functionality that, in the one case, the information would also be available automatically for approved third parties under the Green Button Connect program, but not under Duke's. At least that's one of the differences; do you agree?

A. Let me read this, and I will let you know. Just a moment.

(Witness peruses document.)

Yes, ma'am, I agree.

Q. So if you go back to the comments that Duke filed that we were looking at in that Cross Exhibit 1, on pages 4 through 5, would you agree with me, then, that Duke gives a couple of reasons for not adopting the Green Button Connect approach? One of those being that Duke has surveyed its customers and found that customer demand for that technology was not out -- did not outweigh the project costs implemented; do you see

that comment?
A. Yes, ma'am.
Q. Do you agree?
A. Yes, ma'am.
Q. And Duke would require Commission to vet potential third-party involvement, right?
A. Yes, ma'am.
Q. Okay. Taking that first reason, that Duke has not found customers are interested, I'd ask you to please turn to AGO Exhibit 48.
A. Exhibit 48. Okay. Just a moment, please.
Q. Sure.
A. 48.
(Pause.)
Q. Do you have that?
A. I'm getting it, yes, ma'am.
Q. Okay.
A. Okay. It's in front of me. Okay. I have it, Ms. Force.
Q. And at the top of that, does it say on your copy, "Duke Energy Green Button position and cost-benefits analysis dated 4/12/2019"?
A. Yes, ma'am.
Q. Is this something that you recognize,

Mr. Hatcher? I almost called you Mr. Williams. Mr. Hatcher.

A. I have not reviewed this.

Q. Okay.

MS. FORCE: Well, first, I'd ask that this be marked as AGO Hatcher Cross Exhibit 3, please.

CHAIR MITCHELL: The document will be so marked.

(AGO Hatcher Cross Exhibit 3 was marked for identification.)

Q. And I submit to you, Mr. Hatcher, that this was a document that was part of a discovery response to another party in the rulemaking proceeding. And it describes Duke's survey of its customers and cost-benefit analysis. Can you just look at it briefly and see if that appears to be the case to you? If you can look on page 2 in particular, I'm going to have a question there.

A. Okay. Yes, ma'am.

Q. So on page 2 there are some projected costs of using the Green Button Connect standard. The analysis here shows total cost for five years including integration, setup, O&M, et cetera, about $1.7 million, right?

A. Yes, ma'am.

Q. And then there's an analysis of how many customers might make use of their data using the Green Button Connect standard; do you see that?

A. I do.

Q. And Duke indicates, as I understand it, that they've looked at how many users have shown an interest by looking at how many sessions have occurred where customers have gone on to the Duke portal to look at their data and taken a percentage of that. Do you agree with me there?

A. I believe that's correct; yes, ma'am.

MR. ROBINSON: Chair Mitchell -- Chair Mitchel, I'm sorry, this is Camal. If I may, renewing my objection, Chair Mitchell. It's -- obviously, it's one thing to evaluate the benefits of AMI and Customer Connect, but these cost analyses that Ms. Force is going into, I question whether this witness should be the one receiving these questions.

CHAIR MITCHELL: All right. Ms. Force, how do you respond?

MS. FORCE: This document is a Duke

document, and it speaks for itself. I'd like to just get it into evidence, and we can move along. I don't have too many more questions for the witness.

CHAIR MITCHELL: All right. I'll overrule the objection and ask Ms. Force that you please move along.

Q. I do want to ask you, this indicates a cost of $1.7 million, but putting that into perspective, it's my understanding from the last rate case that Duke has invested $73.9 million in AMI meters in 2016.

Is that better asked to a different witness, then?

A. Mr. Schneider; yes, ma'am.

Q. Okay. I'll save that. My understanding of the investment in Customer Connect as of the last rate case was, if I have this right, $123.1 million is the North Carolina retail share. Does that sound right to you?

A. Give me a moment, and I'll let you know.

Q. Okay. Thanks.

(Pause.)

THE WITNESS: Can you repeat that amount, please?

Q. In the last rate case, I saw that the North Carolina retail share of actual and estimated costs of the implementation was then $123.1 million.

A. I believe that is correct.

Q. Okay. Thank you. And I think we talked about this a little bit, but you don't disagree with me that, in the last rate case, there were advocates for consumers, including the Public Staff -- and in the customer data access proceeding -- including the Public Staff and the AGO, North Carolina Sustainable Energy Association, and EDF, all recommending that Duke be required to offer access using the Green Button Connect standard or some similar standard that would make it more flexible for customers to be able to use third-party applications and programs, not just Duke's. Would you disagree with that?

A. I would agree the way you stated it; yes, ma'am.

Q. Okay. I am going to ask -- and I'm not going to ask questions on that. I can do the text. But would you please look at AGO Exhibit 47? I'll try to make it quick.

A. Okay. Just a moment.

(Pause.)

THE WITNESS: Okay.

Q. Would you agree with me that these appear to be reply comments from Duke in that same rulemaking proceeding and they're dated July 17, 2020?

A. Yes, ma'am.

Q. All right.

MS. FORCE: I'd ask that this exhibit be marked as AGO Hatcher Cross Exhibit 4, please.

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

(AGO Hatcher Cross Exhibit 4 was marked for identification.)

Q. And just -- Mr. Hatcher, turning to page 18, would you agree with me that the comments there say that, if the Commission approves the Public Staff's proposed rule, the Companies note that they could not begin such a project until late 2022 or early 2023 after full implementation and stabilization of Customer Connect?

A. Yes, ma'am.

Q. All right. So the distinction being that customers would be able to use, as you've pointed out, the programs that Duke has offered, but will not have the same options for working with third parties in order to use third-party programs through some -- an automatic -- a more flexible process that allows them to do that; that's available as a standard; would you agree?

A. Well, the customer can get their data if they want to obtain their data, and they're welcome to go to any third party to use their data.

Q. And the way it's established under the protocol that Duke has used, then, if the customer does that, they would need to download the data and provide it to that third party each time they want to take a look with the application that they're using; is that right?

A. Yes, ma'am, currently.

Q. Okay. I have -- I already talked about the Commission's order in the last case. I'd ask one more thing, and that there's a transcript that's included and -- I am trying to find the number. AGO Exhibit 30. It's the transcript from the rate case.

A. Okay.

Q. Volume 18 in this docket, 1146 case; do you have that?

A. Yes, ma'am.

Q. Pages 250 to the end address these same issues, would you agree, Ms. Hunsicker's testimony and Mr. Schneider's from the last rate case?

A. Let me find the page.

(Witness peruses document.)

You said 250?

Q. Yes. I may be mistaken. I believe that the Commissioners provided a copy that has page 1 of that volume and then it starts again on 250 to the end. Anyway.

MS. FORCE: I'd ask that this volume be marked as AGO Hatcher Cross Exhibit 5.

THE WITNESS: Okay. I have it in front of me. Could you repeat your question, please?

Q. Would you agree with me --

CHAIR MITCHELL: All right. Give me an opportunity to --

MS. FORCE: I'm sorry.

CHAIR MITCHELL: -- identify the document. It will be marked as AGO Hatcher Cross Examination Number 5.

(AGO Hatcher Cross Exhibit 5 was marked for identification.)

CHAIR MITCHELL: All right. Ms. Force, proceed with your question.

MS. FORCE: Thank you.

Q. Mr. Hatcher, would you agree that this is the transcript of testimonies from witness Hunsicker on the Customer Connect project and cost, followed by testimony on witness Schneider on AMI meter rollout in the last -- dated 2018 in that transcript?

A. Yes, ma'am.

MS. FORCE: Okay. I don't plan to take up hearing time going through the transcript, but I would ask that the transcript be admitted into evidence and available.

CHAIR MITCHELL: Ms. Force, just so I'm clear, are you moving that AGO Hatcher Cross Examination 5 be admitted into evidence?

MS. FORCE: So that the testimony in that transcript is available in this case as evidence as well; that's right.

CHAIR MITCHELL: All right. Please restate your motion, Ms. Force, just for purposes of clarity in the record. I want to make sure I understand what you're asking.

MS. FORCE: Sure. I'd ask that these pages from the transcript of the testimony from witnesses Hunsicker on Customer Connect, and witness Schneider on AMI meter rollout, that were addressed in the last rate case, be admitted in this case for use in this case.

CHAIR MITCHELL: All right. And --

MR. ROBINSON: Chair Mitchell, if I may. The Company just notes for the record that it objects again, as I indicated before, as it pertains to this transcript being levied into testimony in the prior case, and it really has no bearing on this particular case, in terms of the cost or AMI or Customer Connect investments in general.

CHAIR MITCHELL: All right. I'm going to overrule the objection, Mr. Robinson, and Commission will give the evidence the weight it's due.

And, Ms. Force, just again, your motion that AGO Hatcher Cross Examination Exhibit Number 5 be admitted into evidence is allowed.

(AGO Hatcher Cross Exhibit 5 was admitted into evidence.)

MS. FORCE: Thank you. And with that, I don't have any other questions for this witness.

REDIRECT EXAMINATION BY MR. ROBINSON:

Q. So I'll start with Mr. Hatcher first, and then I'll just transition over to Mr. De May.

So, Mr. Hatcher, do you recall questions from the Attorney General's Office counsel regarding the Green Button standard?

A. (Larry E. Hatcher) Yes, sir.

Q. Do you recall that Ms. Force, in particular, stated in response to my objection that her questions pertain to the prudence of a Company's investments in Customer Connect and AMI?

A. Yes, sir.

Q. Mr. Hatcher, are you aware of some of the benefits that AMI currently provides to customers?

A. I am. So the AMI technology really gives the customer a little bit more insight and control over their energy usage. So they have the ability to run reports that gives them information up to the almost minute level of their energy usage throughout the day; and then they can use that information with other apps or the third-party applications to determine if there's opportunities for them to be more efficient.

In addition to that, it provides capabilities for the customer to pick their own due date for their bill; it has the capability that they can get usage alerts if they want to be able to set that up so that it would give them notification that their energy usage is getting to a certain point in a billing cycle.

There's other applications where they can, if it's a start/stop service, they can get status updates on the start/stop service based on the year being activated or stopped. Those types of applications, yes.

Q. Thank you, Mr. Hatcher. Are there any benefits to AMI with regards to storm response, for example?

A. Absolutely. In terms of storm response, gives us a better indication as to whether the electricity is still on in a customer's residence. We can ping that meter and know if there's power at the meter or not. It also gives us the ability to better communicate with the customers on a more personal basis. So instead of kind of having a zoned electrical outage and put that information out there with an estimated time of recovery for that customer, really it gets more localized so that individual customer has a bread idea of when the power will be restored.

Q. Mr. Hatcher, is there anyone else this case that could speak to additional benefits of AMI?

A. Mr. Schneider; yes, sir.

Q. Thank you. Mr. Hatcher, questions with regard to the Customer Connect.

Are you aware of the benefits -- or any of the benefits that Customer Connect will be able to provide?

A. Yes, sir. So, you know, if you look at Customer Connect, we've already implemented some of those benefits. So if you look at the -- being able to get the data loaded and being able to see how the customers are interacting with us on a routine basis. So are they interested in certain products or services; are they having questions about their bill; are they looking for certain information on our web page; we can be able to see that now so we give a more personal experience to that customer when they interact with us digitally or to call the call center for information.

And additionally, we talked about the AMI meters and how that interfaces with the Customer Connect, so I won't repeat those benefits. But it really gives the customer more a customized experience with Duke Energy versus the way we've had to operate with the legacy systems in the past.

Q. Thank you, Mr. Hatcher. And to speak on the synergy between Customer Connect and AMI for a brief second, is it true -- or are you aware of whether the foundational investments of AMI and Customer Connect are needed for innovate rate designs?

A. That's my understanding; yes, sir.

Q. Thank you, Mr. Hatcher. I have some

MR. ROBINSON: And finally, there's -- per the same Stipulation, there are five cross examination exhibits that the Company stipulated from the DEC case. I'm happy to walk through them right now.

COMMISSIONER CLODFELTER: If you'd like -- if you'd like to do so, please do.

MR. ROBINSON: Sure. The first one were the Initial Joint Comments of DEC and DEP in Docket Number E-100, Sub 161. This was prefiled as AGO Cross Exhibit Number 46, which was introduced as Hatcher AGO Cross Examination -- excuse me- Cross Examination Exhibit 1. The next one is DEC and DEP response to Public Staff Data Request 1 in Docket Number E-100, Sub 161 prefiled as AGO Cross Exhibit Number 45, which was introduced as Hatcher AGO Cross Examination Exhibit 2. The third one being Duke Energy Green Button Position and Cost Benefit Analysis prefiled as AGO Cross Exhibit Number 48, which was introduced as Hatcher AGO Cross Examination Exhibit 3. The fourth one being Joint Reply Comments of DEC and DEP in Docket Number E-100, Sub 161 prefiled as AGO Cross Exhibit Number 47, which was introduced as Hatcher AGO Cross Examination Exhibit 4. And finally, the fifth one, E-7, Sub 1146 transcript volume 18 from pages 250 through the end of that volume prefiled as AGO Cross Exhibit Number 30, which was introduced as Hatcher AGO Cross Examination Exhibit 5. We would move all -- we would identify them as so referenced, Commissioner Clodfelter, and move those into the record at this time.

COMMISSIONER CLODFELTER: Mr. Robinson's motion is that the five exhibits he has described be given the same designations in this case for identification purposes as given in the prior case and that they be admitted into the record at this time in this case. Is there any objection to any of those five exhibits? Hearing none. The motion is granted.

(WHEREUPON, Hatcher AGO Cross Examination Exhibits 1 - 5 were marked for identification as prefiled and received into evidence.)

COMMISSIONER CLODFELTER: Mr. Robinson.

MR. ROBINSON: Thank you, Commissioner Clodfelter. That's it for me. The panel is now available for cross examination.

COMMISSIONER CLODFELTER: All right. Before we proceed to cross examination, let me note that I have been advised that we have two new parties who wish to announce appearances. I believe I've been told we have someone who's joined us now appearing on behalf of the North Carolina Clean Energy Business Alliance. If so, will you announce your appearance?

(Pause)

Apparently I was incorrectly advised. I've also been advised that someone is now appearing for the North Carolina League of Municipalities. If so, would you announce your appearance?

(Pause)

MR. MERTZ: Commissioner Clodfelter, this is Derrick Mertz.

COMMISSIONER CLODFELTER: Yes, Mr. Mertz.

MR. MERTZ: I just wanted to note that Karen Kemerait with Fox Rothschild and Deborah Ross with Fox Rothschild reached out via email to inform the Commission that they were in attendance. I'm not sure whether or not they're having any issues with mute at this moment and continue to have those issues, but they did reach out and indicate that they were present at the time previously stated. I don't know if we need to give them an opportunity to resolve that, their computer issues, or whether they're still on.

COMMISSIONER CLODFELTER: Well, I think we need to know whether they wish to make an appearance in the docket or whether they simply wish to listen to the proceedings. And, Mr. Mertz, I'm going to say that responsibility rests with the parties. If they intend to make an appearance in these proceedings, then they need to let you and Mr. McCoy know that. And if they merely wish to monitor the proceedings and attend without participating that's perfectly fine, but I can't have them walking in a gray area.

So, Mr. Mertz, if you'll let those attorneys for those parties know that if they wish to appear in the proceedings they need to take appropriate steps with you and with Mr. McCoy. All right.

Okay. We will proceed with cross examination. The parties who have indicated to me they wish to reserve a cross examination right include first the Attorney General's Office. Ms. Townsend. Ms. Townsend, you're on mute.

MS. TOWNSEND: Yes, thank you. Thank you, Commissioner Clodfelter. Yes, first of all, I wanted to announce that the AGO is part of the Stipulation that was identified by Mr. Robinson. And in reference to that particular exhibit we will be discussing the same in this case, also, but I will use the AGO identifier that was given by Mr. Robinson.

CROSS EXAMINATION BY MS. TOWNSEND:

Q And good morning, gentlemen, Mr. Hatcher and Mr. De May. My questions are for you, Mr. De May.

A Good morning.

Q During the DEC case, as you may recall, we discussed Duke Energy's complaint against the insurance companies that was filed in March 2017, which was designated in the DEC case as AGO De May Direct Cross Exhibit 1. Do you recall that exhibit?

A I do.

Q You don't need to have it in front of you for the sake of these questions. I just have a few. But I would ask if you were aware that in September 2011, a Progress Energy attorney reached out to the attorneys for the insurance companies to provide them with an updated notice letter in which Progress Energy advised that it considered the ash pond issues relating to project -- to Progress Energy were then ripe for resolution. Were you aware of that letter?

A Would you say the last sentence of your question was --

Q Ripe.

A Did you say ripe?

Q Ripe, yes. I did use the word ripe. Ripe for resolution.

A I'm not aware of that, no.

Q Okay. If I may refer you to Hart Exhibit 34, please.

(Pause)

MS. TOWNSEND: Commissioner Clodfelter, you'll note that Hart Exhibit 34 is otherwise confidential. Although it's marked as such, both the Duke Energy attorneys and the AG's attorneys, the attorneys have agreed that that demarcation is no longer applicable.

COMMISSIONER CLODFELTER: Mr. Robinson, will you confirm that the designation is no longer applicable?

MR. ROBINSON: That is correct, Commissioner Clodfelter. Confirmed.

COMMISSIONER CLODFELTER: Okay, Ms. Townsend, you may proceed. Ms. Townsend, you're a little bit garbled. We're getting a little bit of muddiness in some of your audio.

MS. TOWNSEND: Let's see how it works now. Is that better?

COMMISSIONER CLODFELTER: Better.

MS. TOWNSEND: Okay.

Q If you would -- have you seen this letter before, Mr. De May?

A Ms. Townsend, we're having a hard time putting our hands on this. Would you repeat the exhibit number, please?

Q Yes. Hart Exhibit 34, 34.

A An AGO exhibit, correct?

Q No. It is part of Mr. Hart's testimony and exhibits. You will find it under Hart Exhibit 34.

A Okay. Just a moment.

COMMISSIONER CLODFELTER: Ms. Townsend, to be clear, this is Exhibit 34 to Mr. Hart's prefiled testimony; is that correct?

MS. TOWNSEND: That's correct, Commissioner Clodfelter. Thank you.

A I have it. I have it now. Thank you.

Q Have you seen this letter before?

A Is this the Eisenstein Malanchuk letter.

Q Correct.
A I don't recall seeing it.
Q If you'd like to take a minute -- if you would like to take a minute to review it please do so, otherwise, we can just go through the portions that are most relevant.
A I'd like to look at it for a minute and then we can do that.

COMMISSIONER CLODFELTER: Ms. Townsend, if you are going to examine the witness about this document we need to have it properly marked for identification.

MS. TOWNSEND: Okay. Last -- I'm sorry, Commissioner Clodfelter, I believe last time we were using prefiled testimony exhibits and I did not mark any of them as AGO documents.

COMMISSIONER CLODFELTER: Do you intend to offer this as an exhibit?

MS. TOWNSEND: Yes. Well, it's already -- yes, I do.

COMMISSIONER CLODFELTER: Okay. Then let's get it marked for identification --

MS. TOWNSEND: Okay.

COMMISSIONER CLODFELTER: -- in the

proceeding itself.

MS. TOWNSEND: All right. Sorry. Then this would be -- we would mark it AGO De May Cross -- Direct Cross Exhibit -- and I'm not sure whether to make it 1 or 2 because of the previous exhibit we did in DEC. I guess we mark it 1.

COMMISSIONER CLODFELTER: We will mark it -- again, these Stipulations are creating some interesting issues. We will mark this as AGO DEP De May Direct Cross Exhibit 1.

MS. TOWNSEND: All right. Thank you.

(WHEREUPON, AGO DEP De May Direct Cross Exhibit 1 is marked for identification.)

COMMISSIONER CLODFELTER: Again, parties, here we're working this through for the first time here. We want to keep the integrity of the designations of the exhibit numbers from the prior proceeding so they are properly referenced in the stipulated live testimony. But we also have to make a proper record in this proceeding of the exhibits used in this proceeding.

MS. TOWNSEND: Understood.

COMMISSIONER CLODFELTER: So help me work through this and be patient with me as we work through it. This is something new.

MS. TOWNSEND: Thank you.

COMMISSIONER CLODFELTER: Ms. Townsend, you may proceed.

Q Are you ready?

A I have scanned the document. I haven't spent time with it obviously, but I have scanned it.

Q All right. If you would go to the first paragraph, that's virtually what the letter is about. It says *following up our recent meeting I'm writing to provide further information to explain why we believe that the ash pond issues relating to Progress Energy are now ripe for resolution, and specifically why action is going to be required in the near term to remediate ash facilities*; is that correct?

A You read that correctly, yes.

Q All right. And this is a letter is dated September 7th, 2011; is it not?

A Yes.

Q If you could just read the first two sentences of the second paragraph for us.

A *First, let me emphasize that what led Progress*

Energy to renew discussions on the ash ponds, and to provide an updated notice letter, was the increased aggressive regulatory oversight by the State of North Carolina. Regardless of when the EPA may act, or what other States may do, North Carolina is taking aggressive action on coal ash facilities, commencing with the boundary well monitoring that was required at the end of 2010.

Q Okay. Thank you. It then states in the last sentence of that paragraph that *North Carolina is already is actively commencing work on ash pond issues, and as we indicated at the meeting exceedances are already being detected at the relevant Progress Energy ash ponds*; is that correct?

A You read that correctly. Yes.

Q Just a couple more questions. It appears from the letter that DEP's attorneys not only worried about the State's aggressive actions, but indicates in the third paragraph at, starting at about the sixth or seventh word, *there is a very active network of non-governmental organizations in North Carolina which is specifically pressing for remedial action on North Carolina ash ponds.*

This, of itself, creates a significant driver that is even more pressing than the lobbying on federal side. And based on the various lawsuits that we discussed in the DEC case that were filed in 2013, he appears to be correct about that concern, is he not?

A I don't know about the connection between the two, but he very clearly is identifying NGO activism.

Q Thank you. That's all the questions I have. Thank you, Mr. De May. I appreciate your time.

A Thank you.

MS. FORCE: This is Margaret Force.

COMMISSIONER CLODFELTER: Ms. Force, you're recognized. I believe you have questions for Mr. Hatcher; is that correct?

MS. FORCE: That's right. And in light of the Stipulation and the items that have been introduced already we would not have any questions, but I do have two points of clarification that I think it's appropriate to make at this point.

First, that I won't have any questions for Mr. Hatcher or for Mr. Schneider, so that addresses the motion that Mr. Robinson made earlier.

Also, we have stipulation items that are live testimony and exhibits, and it would be helpful at this point to make clarification about who will be putting that -- introducing those in the docket later so that the clerk is not faced with two or more parties introducing the same thing. And I have a very good paralegal who works with us who will be pleased that I've made this inquiry. If Mr. Robinson wants to do that, and Duke wants to do that for all of the items that they've stipulated to we're agreeable to that, or we will introduce it at this point for these two witnesses.

COMMISSIONER CLODFELTER: All right, folks. Again, we are navigating some unchartered waters here. Ms. Force, it was my understanding that Mr. Robinson moved in all of the stipulated testimony for this witness regardless of which party to the Stipulation had requested that testimony.

MS. FORCE: Okay.

COMMISSIONER CLODFELTER: Is that not correct, Ms. Force?

MS. FORCE: So that would suggest that Duke will file it. And we will just double check and correct the record if there's any problem with it. I just wanted to clarify that.

I do have one more point of clarification.

COMMISSIONER CLODFELTER: Well, let's stay with that one for just a minute.

MS. FORCE: Oh, I'm sorry.

COMMISSIONER CLODFELTER: Let's be clear about this. This is again the first time this question has come up so let's be clear about it as we go forward.

If there is testimony that has been stipulated to come into this record from the DEC record, then the party offering the witness whose testimony has been stipulated should move the admission of all the stipulated testimony for that witness so that it appears in the transcript at that point in time. We don't want to break this up into multiple motions and multiple parts of the case.

So, Ms. Force and Mr. Robinson, I ask you both to confirm that Mr. Robinson's earlier motion embraced all of the stipulated party, whether it was stipulated to at the request of Duke Energy Progress or at the request of the Attorney General's Office; is that correct, Mr. Robinson?

MR. ROBINSON: That's correct, Commissioner

Clodfelter. That's what I did.

COMMISSIONER CLODFELTER: Stipulated testimony comes in at the time the witness whose testimony is being stipulated is before the Commission.

MS. FORCE: That's correct. But there were also exhibits that had been cross examination exhibits that were Attorney General exhibits that were also admitted because Mr. Robinson admitted them, and I'd like just to clarify that that means that Mr. Robinson will also be filing those so that the clerk has them in the record and that the court reporter has them; otherwise we will do it.

COMMISSIONER CLODFELTER: All right. Folks, I'm going to ask that during our morning break and our lunch break today that the Stipulating Parties talk some more about this exhibit issue. It was not addressed in the Stipulations and we need to have a clear road map going forward. I think that it is in the interest of all the parties that any exhibits that the parties wish to move in that were part of the stipulated testimony should all come in together at the same time. This is the most important thing in terms of keeping an efficient, clear and clean transcript.

So, Ms. Force, if you have exhibits that Mr. Robinson did not move in for Mr. Hatcher's testimony, I need to know about that right now. Let's get that cleared up right now. We don't want that later in the record.

MS. FORCE: I'm sorry. I didn't mean to confuse the record. They were all introduced. It was satisfactory. We had no objection. The Stipulation was -- Mr. Robinson followed the Stipulation exactly, and those exhibits have now been admitted. I just wanted to clarify, since they were originally our exhibits, that those will also be filed by Duke so that we don't double count.

COMMISSIONER CLODFELTER: That is correct. That is the procedure I think we should be following. Mr. Robinson?

MR. ROBINSON: Agreed. We have no objection to that.

MS. FORCE: Okay. Thank you.

COMMISSIONER CLODFELTER: Clarification number one. What's your second clarification?

MS. FORCE: I just wanted to clarify that when Ms. Townsend used the exhibit from our witness who will appear later, that was an exhibit that was part of his prefiled testimony and it has now been identified also as a cross examination exhibit because we don't yet have his testimony in the record, and I just wanted to clarify that's how you'd like for us to do this going forward.

COMMISSIONER CLODFELTER: That is correct. Yes.

MS. FORCE: Okay. Thank you. No other questions.

COMMISSIONER CLODFELTER: Anything further? Okay. CUCA had indicated an interest in reserving cross examination.

MR. PAGE: Good morning, again, Commissioner Clodfelter. I first need, I think, to tell you that CUCA is also a Stipulating Party to the testimony of Mr. De May and that's going to reduce my amount of requested cross time significantly. I'm hoping in the nature of 10 minutes rather than 30 minutes. And it's basically going to center on a new exhibit, cross examination exhibit, which is not a part of any record we've made heretofore, and I've discussed and offered that to Mr. Robinson. My understanding is he has no objection to my exploring that exhibit with Mr. De

May.

COMMISSIONER CLODFELTER: Mr. Page, has a copy of that exhibit been provided to all other parties, intervenors, and other parties as well?

MR. PAGE: Yes, it has.

COMMISSIONER CLODFELTER: Thank you. You may proceed.

CROSS EXAMINATION BY MR. PAGE:

Q Good morning, Mr. De May.

A (Mr. De May) Good morning, Mr. Page.

Q You will recall, I believe, that when we last talked on the record you had agreed with me that the large industrial manufacturing and high-load customers were an important load for Duke to serve; is that correct?

A Yes, of course.

Q And I had asked you specifically a question dealing with whether or not in the last 20 years or so those industrial manufacturing loads for Duke had been shrinking. And correct me if I'm wrong, but I think your answer was you did not recall that they were or you just didn't remember; is that a correct interpretation of your testimony?

A I believe that industrial load had been growing if only slowly. I don't recall the time period that you mentioned. But I -- it had 20 years if that's what you said the question was.

Q Mr. De May, have you been furnished a copy of the one-page proposed CUCA cross examination exhibit?

A I have it in front of me. Yes.

MR. PAGE: Commissioner Clodfelter, we'd like to request that this document be identified as it was when filed with the Commission and the parties as CUCA De May Cross Exhibit Number 1.

COMMISSIONER CLODFELTER: My space bar is not working today. It will be so identified, Mr. Page.

MR. PAGE: Thank you, sir.

(WHEREUPON, CUCA De May Cross Exhibit 1 is marked for identification.)

Q Mr. De May, looking at the exhibit, will you agree -- well, first of all, let me represent to you, Mr. De May, that this exhibit was taken from a portion of the testimony of CUCA witness Kevin O'Donnell in the 2018 Duke rate cases. Will you accept that subject to check?

A Yes.
Q And would you agree with me that the middle portion of the cross examination exhibit purports to show the DEC and DEP industrial sales in megawatt hours from 2005 to 2019?
A Yes, those are the two years that bookend this schedule. Yes.
Q And would you agree that the two graphs shown at the top of the page, the top one being Duke Carolinas and the bottom one being Duke Progress, they are simply a graphic illustration of the trim lines shown by the figures in the middle of the page?
A It appears that way, yes.
Q All right, sir. And at the bottom of the page, the exhibit shows the amount of 2005-megawatt hour industrial sales for DEC and DEP as well as the 2019 industrial sales for DEC and DEP, and then simply calculates a percentage of the difference; is that correct?
A That's what it does, yes.
Q And do you have any reason at this point to dispute the sales figure shown or the graph lines, the trim lines in the graph or the math at

the bottom of the page?
A No. I have no reason to dispute that, Mr. Page. I would --
Q So --
A I would doubt that any trim line depends on where you start and where you went.
Q I absolutely accept it. This particular trim line, however, shows for DEC a reduction in industrial sales between 2005 - 2019 of 16.2 percent, and a similar reduction for DEP of 17.5 percent; does it not?
A Yes, it does.
Q Now, just one other question. Would you agree with me that the most current Duke Energy Integrated Resource Plan, the IRP, shows that Duke anticipates that its industrial sales will continue to decline in the future?
A I don't know the IRP assumption on industrial sales.
Q All right. Would you accept subject to check that the IRP shows a future decline in industrial sales of 0.02 percent sign?
A Subject to check, yes.
Q Thank you very much, Mr. De May.

And Commissioner Clodfelter, that's all the questions I have.

COMMISSIONER CLODFELTER: Thank you, Mr. Page. I do not have any indication of any other party reserving cross examination but I'll ask now. Does any other party have any cross examination for this panel?

(No response)

All right. Mr. Robinson, redirect?

MR. ROBINSON: No redirect, Commissioner Clodfelter.

COMMISSIONER CLODFELTER: All right. Are there questions from the Commission? I'll begin with Commissioner Brown-Bland.

COMMISSIONER BROWN-BLAND: No questions.

COMMISSIONER CLODFELTER: Commissioner Gray.

COMMISSIONER GRAY: No questions.

COMMISSIONER CLODFELTER: Chair Mitchell.

CHAIR MITCHELL: No questions.

COMMISSIONER CLODFELTER: Commissioner Duffley, any questions?

COMMISSIONER DUFFLEY: Yes, I have a few questions. I apologize.

EXAMINATION BY COMMISSIONER DUFFLEY:

Q These questions are for Mr. De May. The questions I have are similar to the ones that I asked you in the DEC rate case; however, the DEP history is a bit different. So if you will just indulge me in going through those questions again based on the DEP history.

So in the last rate case E-2, Sub 1142, DEP requested a run rate of approximately 129 million to be added to the revenue requirement in base rates as an ongoing expense to assist in the payment of ongoing coal ash remediation costs; is that accurate?

A (Mr. De May) Yes.

Q And would you agree that this number was based on upon the actual test year spend for 2016?

A I would, yes.

Q And then parties like the Sierra Club opposed the run rate because the full scope of remediation was not understood at the time; is that correct?

A That's right. They thought the pattern of spend would be unpredictable and uncertain for sure.

Q But the scope of remediation for each site is understood at this point based upon DEP's settlement with NC DEQ; is that accurate?

A Well, I think there are two factors that add to the certainty. One is the settlement so we know what the closure methodologies will be, but the other is our experience in actually closing some of these basins. And so we have now had experience closing the high risk basins and that experience gives us considerable certainty around the cost to do the remaining basins.

Q Thank you. And going back to the Sub 1142 docket, EDIT was not an issue because of the timing of the rate case in relation to the passage of Tax Cuts and Jobs Act; is that correct?

A Yeah. The timing worked out in such a way that I think the Commission deemed it in the best interest of all parties to defer the issue until the next rate case or three years, whichever came first.

Q And so in the present DEP rate case I'm aware of the initial testimony of both DEP and the Public Staff regarding their respective positions on the return of the unprotected federal EDIT which totals approximately 354 million. But in the end in the Second Agreement and Stipulation of

Partial Settlement, you and the Public Staff have agreed to flow back the unprotected federal EDIT, is that correct, over a five-year amortization period?
A That's correct.
Q And the deferred North Carolina portion of the ARO coal ash cost being sought in this case through August of 2020 is approximately $440 million? Does that number sound accurate?
A That feels accurate.
Q Okay. And then DEP's position related to the deferred coal ash cost from September of 2017 through August of 2020 is to recover the coal ash -- is to recover these costs over a five-year amortization period with a return. Is that DEP's --
A Could you restate the period of time, please?
Q Is it September 2017 through August 2020? Is that the update period? What's the update period?
A I think the update period -- well, I know the -- I think the update period for coal ash ends in February of '20.
Q February. Okay. That's what I thought, too.

Someone else told me it was August. So I have February. Okay. So both the unprotected federal EDIT and the deferred coal ash expenditures have a five-year amortization period and under what you, DEP, have presented to the Commission; is that accurate?

A That is correct.

Q Okay. And so, like I asked you in the last DEC rate case, did the Company consider doing a full offset where you'd be offsetting the full amount of the unprotected federal EDIT to cover a portion of the deferred ARO coal ash expenditures within the context of this rate case?

A You know, we knew that there were a number of ways of dealing with the EDIT benefit for customers and we chose to enter into a settlement on that with the Public Staff which would support to flow back those benefits over a period of five years. And the five-year coal ash period that you are referring to I think still presents an offset opportunity. They're just running through the revenue requirement separately rather than just offsetting balance sheet accounts.

Q Okay. So if you did do this type of offset just -- oh, Mr. De May, can you still hear me?

COMMISSIONER CLODFELTER: Mr. De May, we've lost your video.

Q Mr. De May, you're on mute.

A Sorry.

Q So if the Commission were to do this type of offset, just fully offset within the context of this rate case, is that another appropriate way of handling these two aspects of the case, or would you find that this would be handling the tax issue in a haphazard manner or somehow causing rate volatility harm to the customers or harm to the Company?

A If we were to change the amortization periods or to offset them, which one?

Q Just if we were to offset -- fully offset the EDIT with the coal ash cost within the context of this rate case with no amortization period.

A I may have this wrong and I will look to Kim Smith to do a little clean up here if I have this wrong. But if you were to have a regulatory asset and a regulatory liability of roughly the same amounts, I believe one way you could deal with those is just to offset them. Debit one, credit the other and they would be gone. Another way would be to amortize those balances. And if you were to amortize those identical balances over the same period of time, the net impact to customer rates would still be zero. And so I think the difference comes in when you start to amortize things over different periods of time. I don't know if that's responsive to your question. But I think that what you've described is a legitimate way of offsetting the asset against the liability but so to is an amortization over identical periods of time.

Q Okay. Thank you, Mr. De May. And the Commission is going to issue the Order; we've requested or I've requested a late-filed exhibit as well as Commissioner Clodfelter requested a late-filed exhibit, and the Order will go out probably this week requesting -- and so what it's going to request for me, and I'll let Commissioner Clodfelter speak for himself, is a late-filed exhibit, and it's a request to both DEP as well as to Public Staff so you'll each be preparing this exhibit, showing the revenue requirement impact of offsetting a portion of the coal ash expenditures in this present case with the unprotected federal EDIT, as well as showing the effects of the EDIT rider that the parties agreed to in their Second Stipulation of Partial Settlement.

So, with that, I have no further questions, Commissioner Clodfelter.

COMMISSIONER CLODFELTER: Thank you, Commissioner Duffley.

Mr. De May, and Ms. Downey, Mr. Robinson, let me just, since we're on that subject of the late-filed requests, to say the piggyback on that is a second alternative revenue requirement analysis of offsetting a portion of the EDIT against the accelerated depreciation expense being requested for early closure of the coal plants. So it will be the same request. And that's a second iteration. All right? And that Order will, as Ms. -- Commissioner Duffley says, that Order will go out in the next day or so.

Commissioner Hughes, any questions?

COMMISSIONER HUGHES: None. Sorry. No questions.

COMMISSIONER CLODFELTER: Commissioner

McKissick.

COMMISSIONER McKISSICK: No questions.

COMMISSIONER CLODFELTER: All right. We're back to questions on Commissioner's questions? Ms. Force? Ms. Townsend? Mr. Robinson?

MR. ROBINSON: Thank you, Commissioner Clodfelter. I just have really very brief clarifying questions. These are to Mr. De May.

EXAMINATION BY MR. ROBINSON:

Q Mr. De May, do you recall questions from Commissioner Duffley just now asking you about the cost recovery period that we are seeking in this rate case pertaining to coal ash?

A (Mr. De May) Yes, I do.

Q And you stated that the cost recovery period is through February 2020, correct?

A Yes.

Q And while that may be true, are you aware of whether the return on our ash costs are through August 2020?

A I believe they are, yes. Thank you.

Q Thank you. No further questions.

COMMISSIONER CLODFELTER: Anybody else?

MR. PAGE: Mr. Clodfelter, is this the

appropriate time for me to move into the record the CUCA Cross Examination Exhibit?

COMMISSIONER CLODFELTER: Assuming I have no one else who wants to ask a question on the Commissioners' questions, it is the appropriate time. I'll take motions at this point, Mr. Page.

MR. PAGE: Commissioner Clodfelter, CUCA requests that its cross examination exhibit be admitted into evidence in the record.

COMMISSIONER CLODFELTER: Without objection, it will be so ordered.

(WHEREUPON, CUCA De May Cross Examination Exhibit 1 is admitted into evidence.)

COMMISSIONER CLODFELTER: Any other motions?

MS. TOWNSEND: Yes. Commissioner Clodfelter, Terri Townsend, we would move for AGO DEP De May Direct Cross Exhibit Number 1 be entered into the record.

COMMISSIONER CLODFELTER: Any objection to the motion?

(Pause)

Hearing none, the motion is granted.

(WHEREUPON, AGO DEP De May Direct

Cross Exhibit 1 is admitted into evidence.)

MS. TOWNSEND: Thank you.

COMMISSIONER CLODFELTER: Any other motions?

MR. ROBINSON: Commissioner Clodfelter, if no other parties have anything then I have a few.

COMMISSIONER CLODFELTER: All right, Mr. Robinson.

MR. ROBINSON: Thank you. Commissioner Clodfelter, at this time we would move to excuse Mr. Larry Hatcher from the hearing.

COMMISSIONER CLODFELTER: Hearing no objection, Mr. Hatcher, you are excused. You're the first one out of all three phases. Congratulations!

(The panel is excused from the witness stand)

MR. ROBINSON: Thank you. Commissioner Clodfelter, next the Company at this time, pursuant to the Stipulation as well as the admission into evidence of Mr. Hatcher's stipulated live testimony and cross examination exhibits, we would move to now excuse Mr. Don Schneider and enter his testimony into the record.

COMMISSIONER CLODFELTER: All right. This was the motion we had under consideration and I believe we need to hear from Ms. Force on that motion. Are you satisfied at this point? Ms. Force, you're on mute. You're on mute.

MS. FORCE: Can you hear me?

COMMISSIONER CLODFELTER: Now, yes.

MS. FORCE: Okay. Sorry. The screen appears a little different this week. I don't have any objection. Thank you.

COMMISSIONER CLODFELTER: Any other party have any objection to having Mr. Schneider excused? Mr. Robinson, that motion is granted.

MR. ROBINSON: Thank you, Commissioner Clodfelter. And one separate procedural item, I inadvertently earlier excluded from, with regards to Shana Angers, I excluded from moving into the record her supplemental testimony and two exhibits. I did not include that in my earlier motion so at this time I would like to add that to my motion from earlier, Commissioner Clodfelter.

COMMISSIONER CLODFELTER: We'll take that motion from Mr. Robinson. Is there any objection to that motion? Hearing none, the motion is allowed.

(WHEREUPON, Angers Supplemental Exhibits 1 and 2 are marked for identification as prefiled and received into evidence.)

(WHEREUPON, the prefiled direct testimony of Don Schneider and the supplemental testimony of Shana Angers is copied into the record as if given orally from the stand.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1219

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

I. INTRODUCTION AND SUMMARY

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Donald L. Schneider, Jr., and my business address is 400 South Tryon Street, Charlotte, North Carolina 28202.

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

A. I am employed by Duke Energy Business Services, LLC ("DEBS"), as General Manager, Advanced Metering Infrastructure ("AMI") Program Management. DEBS provides various administrative and other services to Duke Energy Progress, LLC ("DE Progress" or the "Company") and other affiliated companies of Duke Energy Corporation ("Duke Energy").

Q. PLEASE BRIEFLY DESCRIBE YOUR DUTIES AS GENERAL MANAGER, AMI PROGRAM MANAGEMENT, FOR DUKE ENERGY.

A. My duties and responsibilities include managing the project execution of all AMI related projects for all Duke Energy jurisdictions, including DE Progress. I am also responsible for reporting and mapping related to AMI, as well as system integrations and upgrades involved in the control of AMI communication networks.

Q. PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL QUALIFICATIONS.

A. I received a Bachelor of Science Degree in Electrical Engineering from the University of Evansville (Indiana) in 1986. Upon graduation, I was employed by Duke Energy Indiana (then known as Public Service Indiana) as an electrical engineer. Throughout my career with Duke Energy, I have held various positions of increasing responsibility in the areas of engineering and operations, including distribution planning, distribution design, field operations, and capital budgets. In 2006, I was named General Manager, Midwest Premise Services, responsible for managing all of Duke Energy's Midwest premise service and meter reading departments. Following this, in 2008, prior to the Duke Energy/Progress Energy merger, I was promoted to a position responsible for managing the project execution for all Grid Modernization projects in the field, including both AMI and Distribution Automation ("DA") devices, for all legacy Duke Energy jurisdictions. In 2012, following the Duke Energy/Progress Energy merger, I was named to my current position. Additionally, I have been registered as a professional engineer with the State Board of Registration for Professional Engineers in the state of Indiana since 1995.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION OR ANY OTHER REGULATORY BODIES?

A. Yes. I have testified before this Commission in connection with the general rate case proceeding in Docket No. E-2, Sub 1142. I also submitted testimony in connection with the current Duke Energy Carolinas' ("DE Carolinas") general rate case proceeding in Docket No. E-7, Sub 1214 as well as the 2017 DE Carolinas general rate case proceeding in Docket No. E-7, Sub 1146. Additionally, I have testified for DE Progress and DE Carolinas before the Public Service Commission of South Carolina; Duke Energy Ohio before the

Public Utilities Commission of Ohio; Duke Energy Kentucky before the Kentucky Public Service Commission; and Duke Energy Indiana before the Indiana Utility Regulatory Commission in cases related to AMI and smart grid topics.

I. SUMMARY OF TESTIMONY

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. In my testimony, I describe the Company's implementation of AMI technology in the DE Progress North Carolina service territory, discuss the option available for customers who do not want a smart meter, and highlight the costs included in this case. I also describe the customer facing benefits of the AMI program that provide customers with greater convenience, control and transparency.

II. AMI IMPLEMENTATION

Q. WHAT IS AMI?

A. AMI refers to a comprehensive metering solution – including meters, communication devices, communication networks, and back office systems – used to create two-way communications between customer meters and the utility. AMI meters - often referred to as "smart meters" - are digital electricity meters that have advanced features and capabilities beyond traditional electricity meters. Some of the advanced features include the capability for two-way communications, interval usage measurement, tamper detection, voltage and reactive power measurement, net metering capability, and an internal remotely operable connect/disconnect switch. The system utilizes a radio frequency ("RF") mesh architecture, which is flexible in that the meters within the mesh network establish an optimized RF communication path to a collection point either through other meters or, in some cases, through network range extenders.

Q. PLEASE DESCRIBE THE IMPLEMENTATION OF AMI ACROSS THE DE PROGRESS SYSTEM.

A. As of August 2019, DE Progress installed about 723,000 smart meters in its North Carolina service territory. The plan is to continue AMI implementation through early 2021 for the remaining approximately 694,000 DE Progress North Carolina meters in scope.

Q. IS THE COMPANY FOLLOWING THE SAME PROCESS FOR DEPLOYING AMI THAT WAS USED BY DE CAROLINAS?

A. Overall, the process is the same. Based on lessons learned from the DE Carolinas deployment, DE Progress adopted some changes to the door hangers left at customers' residences such as including the messaging in both English and Spanish. Additionally, DE Progress incorporated more Duke Energy logos onto the contractors' trucks and vests so customers would know who was on their property.

Q. IS THERE AN ALTERNATIVE SOLUTION FOR CUSTOMERS WHO DO NOT WISH TO HAVE A SMART METER?

A. Yes. The Commission approved the Company's request to revise the Meter Related Optional Programs Rider MROP to include a Manually Read Metering option on January 23, 2019 (hereinafter the "opt-out program"), which addresses the customers who have objected to the installation of a smart meter. The Company began enrolling customers in the opt-out program in April 2019. Through August 2019, 0.16% of DE Progress customers opted out of receiving a smart meter.

Q. ARE COSTS FOR THE AMI IMPLEMENTATION INCLUDED IN THIS RATE CASE?

A. Yes. Costs of smart meter implementation are included in this rate case. Since the last rate case through June 30, 2019, the Company invested $158.3 million across the system in North and South Carolina. From July 1, 2019 through February 29, 2020, the Company is projected to invest $53.3 million across the system.

III. <u>AMI BENEFITS TO CUSTOMERS</u>

Q. DOES THE IMPLEMENTATION OF AMI DELIVER BENEFITS TO THE COMPANY'S CUSTOMERS?

A. Yes. The AMI technology is customer-focused; it directly provides and enables greater convenience, control and transparency over a customer's energy consumption.

Q. HOW DOES AMI DELIVER THE BENEFIT OF CONVENIENCE TO CUSTOMERS?

A. With remote disconnect/reconnect capability, AMI technology directly provides customers the convenience of not needing to schedule a technician to visit their premise when they request their electric service be connected or disconnected. Likewise, customers who become eligible for disconnection for non-payment will have power restored more quickly through the remote reconnect capability than they would if DE Progress had to send a technician on site. Additionally, customers benefit from the greater convenience provided by the capability for DE Progress to perform regular meter reads and off-cycle meter reads remotely, avoiding customer appointments in some cases.

The AMI technology also enables customer convenience through Pick Your Due Date. This optional program allows eligible customers to select their desired billing due date as any date from the 1st to the 31st of the month, better aligning customers' needs and giving them the convenience to choose the day of the month they want to pay their bill. Just over 2,000 of DE Progress's customers are enrolled in Pick Your Due Date, which launched in February 2019.

Q. ARE THERE BENEFITS DELIVERED BY AMI THAT GIVE CUSTOMERS MORE CONTROL OVER THEIR ENERGY USAGE?

A. Yes. Usage Alerts is another program enabled by the AMI technology. The Usage Alerts program provides eligible customers with an alert at the midpoint of their billing cycle showing their accumulated charges and a forecast of their month-end bill. Through Usage Alerts, customers can customize their experience by choosing to receive threshold alerts that notify them when their charges are approaching/exceeding their monthly budget. Customers have the option to further set and change their alert preferences in the usage alert management tool, set a budgeted dollar amount, and change their alert channel to text message. There are currently more than 399,000 customers in DE Progress enrolled in Usage Alerts, which was launched in July 2019.

Q. HOW DOES AMI DELIVER THE BENEFIT OF INCREASED TRANSPARENCY AND COMMUNICATION WITH CUSTOMERS?

A. The AMI technology directly provides customers with a smart meter access to view and download detailed information about their hourly and daily usage patterns through the Duke Energy customer portal, allowing them to closely monitor their usage, so they can make more informed choices regarding how they use energy and potentially change their energy usage behaviors to help reduce energy costs.

Similarly, Duke Energy has developed a new program for customers to download their usage data in a format consistent with the Green Button "Download My Data" standard. This program, that Duke Energy plans to deliver in early 2020, has advantages over other formats as it will allow customers to download usage data in the format consistent with Green Button standards, thus making it compatible with many third parties with whom a customer may choose to share their data. As a Duke Energy-developed solution, it also has security advantages over a third-party product. On September 5, 2019, the Commission approved the Company's joint application with DE Carolinas for approval of a smart meter usage application pilot in Docket Nos.

E-7, Sub 1209 and E-2, Sub 1213 that will provide customers access to real-time energy usage on their smart device.

Finally, AMI is being integrated into the Company's efforts to increase communications with customers about outages and restoration timelines after a storm.

Q. YOU MENTIONED THE COMPANY IS UTILIZING AMI DURING STORM OUTAGES AND RESTORATION. HOW SO?

A. DE Progress has the capability to interrogate individual smart meters to determine if customers have power. During the damage assessment phase of a storm, the mass meter interrogation capability allows the Company to have a better view of where outages are located on the system. This functionality helps reduce the assessment time, thus reducing outage durations for customers. During the power restoration phase of a storm, the capability of mass meter interrogation enables the Company to determine whether power has been restored to each meter before leaving an area. Lastly, during the cleanup phase of a storm, the capability of interrogating individual meters can tell the Company when a customer's power has already been restored, saving a truck roll to confirm power has been restored.

During Hurricane Florence in September 2018, the Company successfully interrogated 225 meters and avoided the need to send trucks to determine whether power had been restored to those locations. During Hurricane Michael in October 2018, the Company successfully interrogated

193 meters and during Winter Storm Diego in December 2018, the Company successfully interrogated 538 meters. During Hurricane Dorian in September 2019, the Company successfully interrogated 2,156 meters in North Carolina.

IV. CONCLUSION

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

A. Yes.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1219

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

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

A. My name is Shana W. Angers, and I am employed by Duke Energy Business Services, LLC as Accounting Manager for Duke Energy Progress, LLC ("DE Progress" or the "Company").

Q. WHAT IS THE PURPOSE OF YOUR SUPPLEMENTAL TESTIMONY?

A. The purpose of my supplemental testimony is to describe revisions to the Lead Lag Study prepared by Ernst & Young LLP that was originally submitted as Angers Exhibit 3 to my Direct Testimony. The updated Lead Lag Study is included as Angers Supplemental Exhibit 3. These revisions also impact Angers Exhibit 2 to my Direct Testimony, which presents the amount of investor funds for operations included in rate base, calculated on the basis of the Lead Lag Study. A summary of the calculation of investor funds for operations based on the updated Lead Lag Study is included as Angers Supplemental Exhibit 2.

Q. WERE ANGERS SUPPLEMENTAL EXHIBITS 2 AND 3 PREPARED OR PROVIDED HEREIN BY YOU, UNDER YOUR DIRECTION AND SUPERVISION?

A. Yes. They were.

Q. PLEASE DESCRIBE THE REVISIONS TO THE LEAD LAG STUDY THAT ARE REFLECTED IN ANGERS SUPPLEMENTAL EXHIBIT 3.

A. Ernst & Young details the changes they made to the Lead Lag Study in the Background Section of the updated Lead Lag Study (see Section 1.3 of Angers

Supplemental Exhibit 3). In sum, as compared to the original report, the Company's 2017 Total Cash Working Capital Requirements decreased by $7.4 million, as a result of the following adjustments:

- Payroll deductions and payroll taxes – Within payroll deductions and payroll taxes, amounts related to incentive compensation were identified. The service period related to these amounts was adjusted to correspond to the service period for incentive compensation. Adjustments to payroll deductions result in a $5.4 million decrease, while adjustments to payroll taxes result in a $2.5 million decrease;
- O&M Fuel expense – The Company updated the contract allocation percentages for coal delivery contracts, updating the weighting applied to different contract payment terms. This adjustment results in a $275,000 increase;
- Regulatory commission expense – Regulatory commission expense related to the South Carolina Public Service Commission was included in the original study. Removing this item resulted in a $149,000 increase; and
- Pension and benefits – For account 1B410 (Undergrad Tuition Reimbursement), the payment date was adjusted for a January payment. This adjustment results in a $42,000 increase.

Q. PLEASE EXPLAIN WHAT CHANGES YOU MADE IN ANGERS SUPPLEMENTAL EXHIBIT 2 TO REFLECT THE UPDATES TO THE LEAD LAG STUDY.

A. Angers Supplemental Exhibit 2 reflects updates to include the revised lead lag days for Operations and Maintenance Expense (line 2) and Taxes Other Than Income (line 4). The Company's 2018 Total Cash Working Capital Requirements decreased by $12.8 million, as a result of these changes.

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

A. Yes.

COMMISSIONER CLODFELTER: Anything further?

MR. ROBINSON: That's it from me, Commissioner Clodfelter. Thank you.

COMMISSIONER CLODFELTER: Mr. Robinson, I believe your next witness is Ms. Turner; is that correct?

MR. ROBINSON: Yes, sir.

MS. KELLS: Commissioner Clodfelter, this is Andrea Kells for Duke Energy Progress. And the Company now calls Julie Turner to the stand.

COMMISSIONER CLODFELTER: Ms. Kells, I think we do have some parties who have reserved cross examination on this witness. And looking at the time, let's go ahead and take the morning break now and we'll come back at -- let's come back at 10:55. That way we're not breaking the testimony of the witness. We can start Ms. Turner clean after the break and not break up her testimony. All right?

MS. KELLS: Thank you.

COMMISSIONER CLODFELTER: And let's, Mr. Robinson, and Ms. Downey, and others, let's see if we can have some discussion among everyone so we're all on the same page during the break about how you want to move in exhibits that were part of stipulated

DEC testimony, and just be sure that we're all on the same page about that again. We want to get the stipulated testimony moved into the record at the time when the witness in these proceedings offers oral testimony in these proceedings. I think that's probably also the appropriate time to move into the record any exhibits that were referenced or discussed in the stipulated testimony in the prior case. So if y'all can all just be sure we're all in agreement on that and we'll come back and do a reality check as it were after the break. Okay?

MR. ROBINSON: Commissioner Clodfelter, one request for clarification on that.

COMMISSIONER CLODFELTER: Sure.

MR. ROBINSON: Is that a conversation that the Commission wants to be involved in or is that a party-to-party conversation?

COMMISSIONER CLODFELTER: I think -- I think -- the Commission's objective is, again, to have everything appear in the natural sequence of things in the transcript. So if we're having stipulated testimony come into the transcript at a certain point, it would be beneficial to have any exhibits that were discussed or referenced in that stipulated testimony also come into the record at that point. That makes the cleanest transcript for the court reporter, for the Commission Staff, for the Commissioners, and for any reviewing court should there be one. All right?

MR. ROBINSON: Thank you.

COMMISSIONER CLODFELTER: I just want to be sure all the parties share the same understanding. And if you have a different proposal or if you think that's wrong-headed I'll hear that right after the break, okay?

MR. ROBINSON: Thank you.

COMMISSIONER CLODFELTER: We will be in recess until 10:55.

(A recess was taken at 10:42 a.m., until 10:55 a.m.)

COMMISSIONER CLODFELTER: Let's come back on the record. And before we begin with the next witness, we had some discussion about the naming convention here we need to use for these exhibits that are coming into this case, being imported from the Duke Energy Carolinas case, and I'm going to propose that we use this naming convention.

Ms. Townsend, I apologize to you, you were the guinea pig on how we name exhibits that are being imported from another case and then how we use them in this case and what's the sequence.

We're going to propose we use the following naming convention going forward.

And, Ms. Townsend, your exhibit is already in the record and it has its designation so I think it would be more confusing to go back and clean that up again so we'll just leave it alone the way it is.

But going forward we're going to suggest the following naming convention that when the party who's responsible for moving in stipulated testimony is also going to be moving in exhibits accompanying that testimony, because those exhibits from the DEC case were referenced in that stipulated testimony, we will bring those exhibits in with their existing designation they were given in that case but we will add a prefix called DEP such and such and such and such and such and such exhibit. It will become a DEP exhibit.

We'll then pick up with -- the new exhibits offered in this case, we'll pick up with the next number in sequence for that witness. So, for example, in the case of Mr. Hatcher, we had exhibits 1 through 5 from the DEC transcript that were brought into this case. Those will now become DEP Hatcher Exhibits 1 through 5, and the next exhibit had there been one for Mr. Hatcher would then be DEP exhibit number 6 for Mr. Hatcher.

That may be the simplest naming convention. And we've talked among ourselves about how to manage that during the break. I would invite reaction from the parties. We are still at a stage where I think the next time we may confront this is with the panel of Pirro, Huber and Hager. That may give you a little bit of time to think through that. But we talked about several other different ways to name these exhibits. That may be the simplest.

Again, Ms. Townsend, we didn't have that worked out in advance and you were the guinea pig so we'll leave yours, because it's already in the record. It's got a name. We won't go back and try to change that in the record if that's agreeable. And since Mr. De May and Mr. Hatcher are now off the stand.

MS. TOWNSEND: It's agreeable.

COMMISSIONER CLODFELTER: Any reactions?

(Pause)

All right. What that means though, that means that when you're offering a new exhibit in this case and there have been stipulated exhibits brought into the case from the DEC case, you need to be sure you know what's the next number in that sequence. That's what it's going to require the parties to do. All right?

MS. DOWNEY: Commissioner Clodfelter.

COMMISSIONER CLODFELTER: Yes, Ms. Downey.

MS. DOWNEY: Just a quick question.

COMMISSIONER CLODFELTER: Yes.

MS. DOWNEY: And this is going to come up pretty quickly with the panel of Pirro, Huber and Hager.

COMMISSIONER CLODFELTER: I think it might, yes.

MS. DOWNEY: So that cost of service stipulation, for instance, I guess Ms. Jagannathan will present the DE Carolina witnesses, that panel, at the same time she offers their stipulated testimony she will also offer the stipulated cross exhibits, even though those cross exhibits were from other parties so that everything is all together, correct?

COMMISSIONER CLODFELTER: That's right.

MS. DOWNEY: Okay. Thank you.

COMMISSIONER CLODFELTER: And then let's say that there was, for example, Public Staff had cross exhibits 1 through 3 for that panel, then, Ms. Downey, those would come in as DEP Public Staff Cross Exhibits 1 through 3 for that panel. And then if you then use a new exhibit with that panel, the new exhibit in this case would then be designated as DEP Public Staff cross examination exhibit 4.

MS. DOWNEY: Okay.

COMMISSIONER CLODFELTER: Again, we're in a new process here that we've not followed before so we're testing this out as we go. We propose that as a simple process. If the parties overnight or over lunch break rebel, I will hear you on your rebellion.

MR. ROBINSON: Commissioner --

MS. DOWNEY: Thank you, Commissioner.

COMMISSIONER CLODFELTER: Yes.

MR. ROBINSON: Hi, Commissioner Clodfelter, Camal Robinson.

COMMISSIONER CLODFELTER: Yes, Camal.

MR. ROBINSON: Definitely no rebelling. But we would propose when the parties and I have an opportunity - at least I don't think so - to confer over that break, we'd propose maybe having the parties have and confer over the lunch break discuss your proposal and provide a reaction after lunch, if that's amenable to the other parties? I'm happy to could set up a call then.

COMMISSIONER CLODFELTER: I think that's amenable. Again, thank you all for being patient with us. These stipulations came in on Friday and yesterday, and so this is something we hadn't had a lot of time to work out in advance of the hearing. We appreciate the Stipulations, don't get me wrong, but we're having to sort of muddle through this procedural issue. Okay?

And with that, Ms. Kells, I think we're ready for your witness.

MS. KELLS: All right. Duke Energy Progress now calls Julie Turner to the stand.

JULIE K. TURNER;
having been duly affirmed,
testified as follows:

COMMISSIONER CLODFELTER: Ms. Kells.

DIRECT EXAMINATION BY MS. KELLS:

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

A My name is Julie K. Turner and my business address is 411 Fayetteville Street in Raleigh,

North Carolina.
Q By whom are you employed and in what capacity?
A I'm the Vice President of Carolinas coal and I'm employed by Duke Energy Progress and Duke Energy Carolinas.
Q Did you cause to be prefiled in this docket on October 30th, 2019, 12 pages of direct testimony?
A I did.
Q Did you also cause to be prefiled in this docket on May 4th, 2020, 17 pages of rebuttal testimony and one ask exhibit?
A I did.
Q Do you have any changes or corrections to your testimonies or exhibit?
A I do not.
Q If I were to ask you the same questions that appear in your testimonies today, would your answers be the same?
A Yes, they would.
Q Ms. Turner, did you prepare a summary of your direct and rebuttal testimonies?
A Yes, I did.

MS. KELLS: Commissioner Clodfelter, at this time I move that the prefiled direct and rebuttal testimonies of Ms. Turner and her summary of her testimonies be copied into the record as if given orally from the stand, and that her one rebuttal exhibit be marked for identification as prefiled.

COMMISSIONER CLODFELTER: Hearing no objection to the motion, the motion is allowed, Ms. Kells.

MS. KELLS: Thank you.

(WHEREUPON, Turner Rebuttal Exhibit 1 is marked for identification as prefiled.)

(WHEREUPON, the prefiled direct and rebuttal testimony and summary of JULIE K. TURNER is copied into the record as if given orally from the stand.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1219

In the Matter of:	)	
	)	**DIRECT TESTIMONY OF**
Application of Duke Energy Progress, LLC	)	**JULIE K. TURNER**
for Adjustments of Rates and Charges	)	**FOR DUKE ENERGY**
Applicable to Electric Service in North Carolina	)	**PROGRESS, LLC**

I. INTRODUCTION AND OVERVIEW

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Julie K. Turner and my business address is 411 Fayetteville Street, Raleigh, North Carolina.

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

A. I am Vice President of Carolinas Natural Gas Generation for Duke Energy Progress, LLC ("DE Progress" or the "Company").

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I graduated from North Carolina State University with a Bachelor of Science degree in Mechanical Engineering and received a Master's degree in Business Administration from the University of Colorado. My career began with Duke Energy (d/b/a Carolina Power & Light) in 1991 as a staff engineer at DE Progress' Harris Nuclear Station. Since that time, I have held various roles of increasing responsibility in the generation engineering, maintenance, and operations areas, including the role of Station Manager, first at DE Progress's Lee Energy Complex, followed by leading six DE Progress natural gas generating stations. I assumed my current role in 2016.

Q. WHAT ARE YOUR DUTIES AS VICE PRESIDENT OF CAROLINA NATURAL GAS GENERATION?

A. In this role, I am responsible for providing safe, reliable and event-free operations of Duke Energy's fleet of natural gas generation facilities in North Carolina and South Carolina, which produces over 10,000 MWs. My responsibilities include operating and maintaining the fleet within design parameters and implementing safe work practices and procedures to ensure the safety of our employees.

Q. HAVE YOU TESTIFIED BEFORE THIS COMMISSION IN ANY PRIOR PROCEEDINGS?

A. No.

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

A. The purpose of my testimony is to support DE Progress' request for a base rate adjustment. My testimony will describe the Company's Fossil/Hydro/Solar generation assets; provide operational performance results for the period of January 1, 2018 through December 31, 2018 ("Test Period"); update the Commission on capital additions through February 29, 2020; and explain the key drivers impacting operations and maintenance ("O&M") expenses.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A**.** The remainder of my testimony is organized as follows:

II. FOSSIL/HYDRO/SOLAR FLEET

III. CAPITAL ADDITIONS

IV. O&M AND OTHER ADJUSTMENTS

V. PERFORMANCE

VI. CONCLUSION

II. FOSSIL/HYDRO/SOLAR FLEET

Q. PLEASE DESCRIBE DE PROGRESS' FOSSIL/HYDRO/SOLAR GENERATION FLEET.

A. The Company's Fossil/Hydro/Solar fleet consists of 9,204 MWs of owned generating capacity, made up as follows:

Coal-fired -	3,544 MWs
Combustion Turbines -	2,816 MWs
Combined Cycle -	2,568 MWs
Hydro -	227 MWs
Solar -	49 MWs[1]

The 3,544 MWs of coal-fired generation resources represent three generating stations and a total of seven units. These units are equipped with emission control equipment, including selective catalytic reduction ("SCR") equipment for removing nitrogen oxides ("NO_x"), flue gas desulfurization ("FGD" or "scrubber") equipment for removing sulfur dioxide ("SO_2"), and low NO_x burners. This inventory of coal-fired assets with emission control equipment enhances the Company's ability to maintain current environmental compliance and concurrently utilize coal with increased sulfur content, thereby

[1] This value represents the relative dependable capacity contribution to meeting summer peak demand, based on the Company's integrated resource planning metrics. The nameplate capacity of the Company's solar facilities is 141 MWs.

providing flexibility for DE Progress to procure the most cost-effective options for fuel supply.

DE Progress has a total of 32 simple cycle combustion turbine ("CT") units, the larger 14 of which provide 2,183 MWs. These 14 units are located at the Asheville (NC), Darlington (SC), Smith Energy (NC), and Wayne County (NC) facilities, and are equipped with water injection and/or low NO_x burners for NO_x control. The 2,568 MWs shown above as "Combined Cycle" ("CC") represent four power blocks. The HF Lee Energy Complex CC power block ("HF Lee CC") has a configuration of three CTs and one steam turbine. The two power blocks located at the Smith Energy Complex ("Richmond CC") consist of two CTs and one steam turbine each. The Sutton Combined Cycle at Sutton Energy Complex ("Sutton CC") consists of two CTs and one steam turbine. The four CC power blocks are equipped with SCR equipment, and all nine CTs have low NOx combustors.

The Company's hydro fleet consists of 15 units providing 227 MWs of capacity and its solar fleet consists of four sites with 141 MWs of nameplate capacity, which provide 49 MWs of relative dependable capacity.

Q. WHAT CAPACITY CHANGES HAVE OCCURRED WITHIN THE FLEET SINCE THE 2017 RATE CASE?

A. The Company's anticipated addition of two new Asheville Combined Cycle ("Asheville CC") units in late 2019 will provide an additional 560 MWs of capacity to the Company's fleet. The Asheville CC, which consists of two efficient 280 MW combined-cycle dual fuel 1x1 power blocks, is located in

Buncombe County at the site of the Asheville Steam Electric Generating Plant. In addition, DE Progress will retire the two Asheville Steam Electric Generating Plant units by the end of 2019, which will reduce capacity by 378 MWs, and retired Darlington Combustion Turbine Unit 5, which reduced capacity by 51 MW, in May 2018.

III. CAPITAL ADDITIONS

Q. PLEASE DESCRIBE THE MAJOR FOSSIL/HYDRO/SOLAR CAPITAL PROJECTS COMPLETED SINCE THE COMPANY'S LAST RATE CASE PROCEEDING.

A. Since the Company's 2017 Rate Case, the Company has made capital investments in its Fossil/Hydro/Solar fleet totaling approximately $1.6 billion. The costs of construction of the Asheville CC units are expected to total approximately $820 million, featuring state-of-the-art technology for increased efficiency and reduced emissions. The Company has also made significant investments within its coal fleet to meet environmental regulations to allow for the continued operation of active plants, including the Coal Combustion Residual ("CCR") Rule, the Coal Ash Management Act ("CAMA") and Effluent Limitations Guidelines ("ELG"), totaling approximately $402 million. These investments included the capital additions at Roxboro Station to convert to a dry bottom ash system to comply with the CCR, totaling approximately $96 million, and the Flue Gas Desulfurization ("FGD") Wastewater Treatment replacement, to comply with National Pollutant Discharge Elimination System program and ELG, totaling approximately $130 million.

Q. DID THE COMPANY RECEIVE REGULATORY APPROVAL FOR THE CONSTRUCTION OF THE COMPLETED GENERATION FACILITIES INCLUDED IN THIS CASE?

A. Yes. The Asheville CC were granted a certificate of public convenience and necessity ("CPCN") by the North Carolina Utilities Commission ("NCUC") in Docket No. E-2, Sub 1089.

Q. MS. TURNER, WILL THESE CAPITAL ADDITIONS BE USED AND USEFUL IN PROVIDING ELECTRIC SERVICE TO DE PROGRESS' ELECTRIC CUSTOMERS IN NORTH CAROLINA BY THE CAPITAL CUTOFF DATE?

A. Yes. The DE Progress capital additions at Roxboro Station to convert to a dry bottom ash system and the FGD Wastewater Treatment replacement are completed. The Company's new Asheville CC is expected to be in-service and providing electric service to customers by late 2019.

Q. IN YOUR OPINION, HAVE THE COSTS RELATED TO THE COMPANY'S CAPITAL ADDITIONS BEEN PRUDENTLY INCURRED?

A. Yes. The Company controls costs for capital projects and O&M utilizing a cost management program. The Company controls costs through routine executive oversight of project budget and activity reporting with new projects requiring approval by progressively higher levels of management depending on total project cost. The Company controls ongoing project and O&M costs through strategic planning and procurement, efficient oversight of contractors by a trained and experienced workforce, rigorous monitoring of work quality, thorough critiques to identify process improvement, and industry benchmarking to ensure best practices are being utilized.

Q. HOW DO CUSTOMERS BENEFIT FROM THE COMPANY'S MODERNIZATION EFFORTS FOR THE FOSSIL/HYDRO/SOLAR FLEET?

A. Our customers benefit from DE Progress' modernization efforts in multiple ways. Initially, as demonstrated by the Company's resource planning analyses, the Company's fleet modernization efforts have enabled it to continue to provide safe, efficient and reliable service to DE Progress' customers at least reasonable cost. These efforts have also reduced the Company's environmental footprint by adding state-of-the-art technology for reducing emissions, retiring older facilities that lacked environmental equipment and were not economically positioned for needed capital expenditures, and expanding the use of natural gas generation at a time when the natural gas market is providing historically low prices.

IV. O&M AND OTHER ADJUSTMENTS

Q. PLEASE DESCRIBE THE O&M EXPENSES FOR THE FOSSIL/HYDRO/SOLAR FLEET.

A. For the fossil units, approximately 87 percent of DE Progress' required O&M expenditures are fuel-related for the Test Period. The majority of non-fuel expenditures are for labor costs from Company or contract resources that operate, maintain, and support the Fossil/Hydro/Solar facilities.

Q. HOW DOES THE COMPANY CONTROL AND MITIGATE O&M EXPENSE INCREASES? PLEASE PROVIDE EXAMPLES.

A. The Company has many efforts in place for controlling and/or minimizing costs. For example, DE Progress optimizes outages based on run time, which has been affected by: (1) changes in the gas market; and (2) new generation resources that further increased DE Progress' use of natural gas. This effort has provided savings with labor and material costs.

Duke Energy joined forces with other power companies to share best practices and learning opportunities with the Fossil Networking Group ("FNG"). The FNG includes Southern Company, Dominion Energy, American Electric Power, and the Tennessee Valley Authority, who along with the Company, have seen benefits around safety and operations.

The Company runs its business in a disciplined manner and continuously balances cost management with safety and reliability to provide energy to our customers. Cost to customers is a key concern and the Company's diverse portfolio allows us to reduce overall fuel expense and take advantage of low natural gas prices.

V. PERFORMANCE

Q. PLEASE DISCUSS THE OPERATIONAL RESULTS FOR DE PROGRESS' FOSSIL/HYDRO/SOLAR FLEET DURING THE TEST PERIOD.

A. The Company's Fossil/Hydro/Solar generating units operated efficiently and reliably during the Test Period. Several key measures are used to evaluate the operational performance depending on the generator type: (1) equivalent availability factor ("EAF"), which refers to the percent of a given time period a facility was available to operate at full power, if needed (EAF is not affected by the manner in which the unit is dispatched or by the system demands; it is impacted, however, by planned and unplanned maintenance (*i.e.*, forced) outage time); (2) equivalent forced outage rate ("EFOR"), which represents the percentage of unit failure (unplanned outage hours and equivalent unplanned derated hours); a low EFOR represents fewer unplanned outage and derated hours, which equates to a higher reliability measure; and (3) starting reliability ("SR"), which represents the percentage of successful starts.

The chart below provides operational results categorized by generator type, as well as results from the most recently published North American Electric Reliability Council ("NERC") Generating Unit Statistical Brochure ("NERC Brochure") representing the period 2014 through 2018. The NERC data reported for the coal-fired units represents an average of comparable units based on capacity rating. Overall, the data in the chart reflects that DE Progress results were comparable or better than the NERC 5-year comparisons.

Generator Type	Measure	Review Period	2014-2018	Nbr of Units
		DEP Operational Results	NERC Average	
Coal-Fired Test Period	EAF	70.4%	80.7%	399
	EFOR	4.4%	8.2%	
2018 Summer	Coal-Fired EAF	93.1%	n/a	n/a
	Combined Cycle EAF	85.1%	n/a	n/a
Total CC Average	EAF	81.6%	84.9%	333
	EFOR	3.90%	5.1%	
Total CT Average	EAF	77.3%	87.5%	750
	SR	97.7%	98.3%	
Hydro	EAF	86.4%	80.2%	1,063

Q. HOW MUCH GENERATION DID EACH TYPE OF GENERATING FACILITY PROVIDE FOR THE TEST PERIOD?

A. For the Test Period, DE Progress' system total generation was approximately 61.1 million megawatt-hours ("MWHs"). The Fossil/Hydro/Solar fleet provided approximately 33.6 million MWHs, or approximately 55 percent. The breakdown includes approximately 26 percent contribution from the coal-fired stations, 71 percent from gas facilities, and approximately 3 percent from renewable facilities, primarily hydro.

Q. IN YOUR OPINION, HAS DE PROGRESS PRUDENTLY OPERATED ITS FOSSIL/HYDRO/SOLAR FLEET DURING THE TEST PERIOD?

A. Yes. The Company's performance data supports the conclusion that DE Progress has reasonably and prudently operated and maintained its Fossil/Hydro/Solar resources to maximize unit availability, minimize fuel costs and provide safe and reliable service to its customers.

VII. CONCLUSION

Q. IS THERE ANYTHING YOU WOULD LIKE TO SAY IN CLOSING?

A. Yes. The Company has a proven history of experience-based, safe, quality, and cost competitive operations of a diverse generation portfolio. The Company has been active and diligent in its modernization efforts to ensure the right investments, which continue, and build on, DE Progress' solid history of safely providing reliable, efficient and cost-effective generation, while reducing environmental impacts and ensuring compliance with state and federal regulations. The diversity of the Company's generation assets provides significant benefit to customers in an economic dispatch environment, especially with the natural gas market continuing to experience low prices. DE Progress is positioned to continue as a leader in the industry with a solid base of knowledge and experience. This base rate increase will allow the Company to continue the tradition of operational excellence and focus on safe operations and reliable generation.

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

A. Yes.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1219

In the Matter of:	)	
	)	**REBUTTAL TESTIMONY OF**
Application of Duke Energy Progress, LLC	)	**JULIE K. TURNER**
for Adjustments of Rates and Charges	)	**FOR DUKE ENERGY**
Applicable to Electric Service in North Carolina	)	**PROGRESS, LLC**

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Julie Turner and my business address is 411 Fayetteville Street, Raleigh, North Carolina.

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

A. I am Vice President of Carolinas Coal Generation for Duke Energy Progress, LLC ("DE Progress" or the "Company") and Duke Energy Carolinas, LLC ("DE Carolinas"). I assumed this role on April 1, 2020; previously I was Vice President of Carolinas Natural Gas Generation for the Company.

Q. DID YOU PREVIOUSLY FILE DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes. I did.

II. PURPOSE AND SCOPE

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to address:

- Public Staff Witness Dorgan's removal of $8.065 million needed to operate the Company's new Asheville Combined Cycle ("Asheville CC") units (the "Asheville CC Project");
- Public Staff Witness Metz's recommendations regarding (i) the Asheville CC Project, (ii) collaboration with the Company on project documentation, and (iii) scheduling periodic independent third party audits of the Company's materials and supplies ("M&S") inventory and program controls;

- Sierra Club Witness Wilson, including her recommended disallowances of the Company's capital investments in its coal fleet; and
- NC WARN Witness Powers' testimony regarding the Asheville CC Project.

Q. DOES YOUR TESTIMONY INCLUDE ANY EXHIBITS?

A. Yes. I have one rebuttal exhibit. As discussed below, Turner Rebuttal Exhibit 1 is a graphic presentation of the hourly generation profile for the steam turbine generator component of power block 2 ("PB2") of the Asheville CC Project over April 4-5, 2020.

Q. WAS THIS EXHIBIT PREPARED BY YOU OR UNDER YOUR DIRECTION AND SUPERVISION?

A. Turner Rebuttal Exhibit 1 was prepared by the Company's project management & construction ("PMC") organization. I have reviewed and support this exhibit.

III. PUBLIC STAFF RECOMMENDATIONS

A. Asheville CC Project

Q. PLEASE DESCRIBE THE ASHEVILLE CC PROJECT, INCLUDING ITS CURRENT STATUS.

A. The Asheville CC Project comprises two 1x1 combined cycle dual fuel units ("power blocks" or "PB") located on the site of the Company's now-retired coal units in Asheville, North Carolina. Each combined cycle power block contains a combustion turbine ("CT") generator and a steam turbine generator and has a capacity of 280 megawatts ("MW"). The Company's investment in the

Asheville CC Project was made consistent with the North Carolina Mountain Energy Act of 2015, which extended the deadline for closing the coal combustion residual surface impoundments at the Asheville Steam Electric Generating Plant ("Asheville Plant") by three years if, on or before August 1, 2016, the Commission issued a certificate of public convenience and necessity ("CPCN") to the Company for a new natural gas-fired facility to replace the coal units at the Asheville Plant. The Commission approved a CPCN for the Asheville CC Project on March 28, 2016, finding that its construction was needed to meet the projected growth in the Company's Western Region and to meet DE Progress's total system needs.[1] The Commission also found that the project would allow the Company to: (1) retire 379 MWs of coal capacity at the Asheville Plant; (2) avoid significant capital investments and environmental controls that would otherwise be required; (3) avoid construction of 147 MWs of fast start CT capacity shown as a resource need in the Company's 2014 integrated resource plan; (4) realize cost saving synergies by participating at incremental cost in a new intrastate natural gas pipeline project being constructed in western North Carolina; (5) serve projected energy and demand growth in the Company's western region while maintaining sufficient reserve transmission capacity into the region to comply with reliability standards; and (6) achieve systemwide fuel and other cost savings by dispatching generation resources more efficiently.

[1] *Order Granting Application in Part, with Conditions, and Denying Application in Part*, Docket No. E-2, Sub 1089 (Mar. 28, 2016).

As of April 5, 2020, all components of the Asheville CC Project have been placed in-service and are capable of providing a combined 560 MWs of capacity.

Q. WHAT IS PUBLIC STAFF WITNESS DORGAN'S RECOMMENDATION REGARDING THE COMPANY'S PROJECTED OPERATING AND MAINTENANCE ("O&M") EXPENSES NEEDED TO OPERATE THE ASHEVILLE CC UNITS?

A. Witness Dorgan argued that with the addition of the Asheville CC Project, other Company resources will operate less frequently or at lower levels of output, and thus incur fewer non-fuel variable O&M expenses. Based on that assertion he proposed to reduce non-fuel variable O&M expenses to prevent inclusion in cost of service of an amount that he concluded was higher than necessary.

Q. DO YOU AGREE WITH THIS RECOMMENDATION?

A. No. The Asheville CC Project represents the addition of two new combined cycle facilities to the DE Progress fleet that need to be operated and maintained. In addition to meeting the Company's obligations under the Mountain Energy Act, which I discuss further below, the Asheville CC units will also serve a growing number of customers in the surrounding area and the associated growth of energy and peak demand requirements. For these reasons, a displacement adjustment is not warranted.

Q. WHAT OTHER RECOMMENDATIONS DID THE PUBLIC STAFF MAKE WITH REGARD TO THE ASHEVILLE CC PROJECT?

A. Public Staff Witness Metz encouraged the Company to continue negotiations with the Original Equipment Manufacturer ("OEM") to obtain a "no cost" extended warranty on at least the new steam turbine and its associated generator that experienced damage events earlier this year, which have since been remedied.

Q. WHAT IS YOUR RESPONSE TO WITNESS METZ'S RECOMMENDATION REGARDING THE EXTENDED WARRANTY?

A. I will note first that the repairs performed by the OEM restored the steam turbine generator component of PB2 to new condition. Additionally, the existing contract with the OEM provides for a two-year warranty on both power blocks. With regard to the Public Staff's recommendation, the Company's negotiations with the OEM regarding the PB2 are ongoing and include representatives from the Company's legal, supply chain, and PMC organizations.

Q. DID THE PUBLIC STAFF MAKE OTHER RECOMMENDATIONS REGARDING THE ASHEVILLE CC PROJECT?

A. Yes. Witness Metz also recommended that the Commission require that the Company file a letter in this docket once the repair to the PB2 steam turbine is "completed (i.e., commercially operational), has passed testing, has been connected to the electrical grid, has operated at approximately 100 percent of nameplate rating for at least 24 continuous hours without interruption, has supplied all generated energy to the "grid," and is available for full economic dispatch by the Company's Energy Control Center." Witness Metz suggested that the filing should provide hourly generation profiles showing the hourly megawatts (MW) delivered to the grid, along with realized heat rates and/or steam usage with incoming pressures for the minimum continuous 24-hour period.

Q. WHAT IS YOUR RESPONSE TO THIS RECOMMENDATION?

A. Subsequent to the completion of the repair to the PB2 steam turbine, the Company submitted an update to the Commission on April 6, 2020, in Docket No. E-2, Sub 1089 on the status of the Asheville CC Project. That update notified the Commission that the PB2 steam turbine generator went into commercial operation on April 5, 2020. Attached to my rebuttal testimony as Turner Rebuttal Exhibit 1 is the graphic presentation of the hourly generation profile for the PB2 ST, which operated at approximately 100% load over a 24-hour continuous period on April 4-5, 2020, along with incoming pressures. Following this 24-hour continuous period the Company placed the steam turbine generator component of PB2 in service making it available for dispatch. Based on discussion with the Public Staff conducted subsequent to the filing of Witness Metz's testimony, the Company believes the April 6, 2020, letter and Turner Rebuttal Exhibit 1 meet the Public Staff's recommendation in this regard.

B. <u>Other Public Staff Recommendations</u>

Q. WHAT WAS THE PUBLIC STAFF'S PROPOSAL REGARDING PROJECT DOCUMENTATION?

A. Witness Metz testified that to assist the Public Staff in evaluating the Company's decisions to make significant capital investments in its electric system, including consideration of alternative investments considered and not chosen, the Public Staff recommended that the Commission direct the Company to begin collaborating with the Public Staff within three months following the conclusion of the rate case to clarify expectations for project evaluation and selection and document creation and retention. He stated that this collaboration will allow both the Company and Public Staff to be more efficient in requesting and reviewing project specific documentation going forward.

Q. WHAT IS YOUR RESPONSE TO THIS PROPOSAL?

A. The Company does not oppose this recommendation.

Q. WHAT WAS THE PUBLIC STAFF'S PROPOSAL REGARDING AUDITS OF FHO AND NUCLEAR FACILITIES?

A. Witness Metz recommended that the Company complete an independent audit of M&S inventory for at least one nuclear station, one fossil station, and one hydro station by the time of its next general rate case filing, or within the next three years, whichever is sooner, and establish a long term schedule for a continuous independent audit cycle (<u>e.g.</u>, a three to five year rotational cycle).

Q. WHAT IS YOUR RESPONSE TO THIS RECOMMENDATION?

A. The Company does not oppose Witness Metz's recommendation. However, DE Progress believes that the Company should utilize Duke Energy's own independent Corporate Audit Services department to meet this recommendation. The Corporate Audit Services department is required by its charter to maintain independence and objectivity in its work. It reports to the Audit Committee of the Board of Directors and to Duke Energy's senior ethics and compliance officer. The department is authorized to have full, unrestricted access to all Duke Energy functions, records, property, and personnel, and to obtain the necessary assistance of personnel in audited units, as well as other specialized services from within or outside the Duke Energy enterprise. Company Witness Henderson will address this recommendation with respect to DE Progress' nuclear facilities.

IV. REASONABLENESS AND PRUDENCE OF THE COMPANY'S CAPITAL INVESTMENTS IN ITS FOSSIL/HYDRO/SOLAR FLEET

Q. PLEASE REITERATE THE SCOPE OF THE COMPANY'S CAPITAL INVESTMENTS REFLECTED IN YOUR DIRECT TESTIMONY.

A. My direct testimony supported capital investments in the Company's Fossil/Hydro/Solar Operations ("FHO") fleet that the Company has made since its previous rate case in order to continue to provide safe and reliable generation for customers. One example of those investments is the addition of the aforementioned Asheville CC Project. Another example is the approximate

$402[2] million that the Company invested in its coal fleet to meet environmental regulations to allow for the continued operation of active coal plants.

Q. DID THE PUBLIC STAFF RECOMMEND ANY DISALLOWANCE OF THE COMPANY'S REQUEST FOR RECOVERY OF ITS FHO CAPITAL INVESTMENTS BASED ON UNREASONABLENESS OR IMPRUDENCE?

A. No. The Public Staff conducted a thorough investigation of these investments. As Witness Metz stated in his testimony, he "looked at multiple aspects of capital spend to evaluate for reasonableness and prudence," and his investigation included review of not only direct testimony, but also an audit of specific expenditures, hundreds of discovery responses, teleconferences with the Company, site visits and interviews with Company witnesses and staff, and review of overall projects with Company management.

Q. DID ANY OTHER PARTY RECOMMEND DISALLOWANCE OF THE COMPANY'S CAPITAL INVESTMENTS IN FHO?

A. Yes. Sierra Club Witness Wilson recommended disallowance of all the Company's capital expenditures made between the 2017 rate case (E-2, Sub 1142) and the current case, "until DEP provides evidence of an analysis demonstrating the value of investment done at time investment decision made." Based on the substance of her testimony, I interpret this recommendation to be directed at investments in DE Progress' coal fleet. Witness Wilson also recommended disallowance of ongoing O&M expenses at the Company's coal

[2] As of February 2020, this amount is now approximately $415 million.

units, based on her conclusion that those units are projected to have future negative value. NC WARN Witness Powers asserted that the cost for the Asheville CC Project was not reasonably and prudently incurred and should be disallowed.

Q. HOW DID YOUR DIRECT TESTIMONY SUPPORT THE COMPANY'S CAPITAL INVESTMENTS IN ITS COAL FLEET AS REASONABLY AND PRUDENTLY INCURRED?

A. Consistent with testimony provided in prior rate cases, my direct testimony explained how these capital investments were or would soon be used and useful in providing electric service to the Company's customers as they provide customers reliable low-cost generation, and position the Company to provide safe, reliable, and efficient operation of these assets with high quality performance. I also testified that these costs were prudently incurred and explained the various ways in which the Company controls project and O&M costs for capital projects. Finally, I noted how customers benefit from the Company's investments as they have enabled DE Progress to continue to provide safe, efficient, and reliable service to customers at least reasonable cost and reduced the Company's environmental footprint by adding state of the art technology for reducing emissions, retiring older facilities that lacked environmental equipment and were not economically positioned for needed capital expenditures, and expanding the use of natural gas generation at a time when the natural gas market is providing historically low prices.

Q. WHAT OTHER EVIDENCE ARE YOU PRESENTING IN SUPPORT OF THESE PROJECTS?

A. In my rebuttal testimony, I provide additional support for these capital investments, discuss the scope of information regarding these projects provided through discovery in this case, and address specific assertions made by intervenors with respect to the reasonableness and prudency of these investments and other assertions.

Q. CAN YOU DESCRIBE THE SCOPE OF THE ADDITIONAL INFORMATION PROVIDED BY THE COMPANY THROUGH DISCOVERY?

A. Yes. Through discovery, the Company provided numerous narrative responses and voluminous documentation and analyses in support of the reasonableness and prudency of the Company's capital investments in FHO, including the capital investments specifically addressed by my direct testimony. Specifically, the Company provided:

- For all environmental capital projects with total project costs $1 million or more, initial and final budget and actual spend, timing of project (expected and actual), project description, and explanation of why each project was necessary;
- For all environmental capital projects with total project costs less than $1 million but more than $100,000, actual cost, completion date, and project description;

- Additional information for all environmental and certain other capital projects including proposal, bid, and contract information, funding approval documentation, detailed cost breakdowns, and risk registers; and
- Detailed cost and operational information for the Asheville CC Project, including: itemized cost breakdowns, explanation of change orders and nuances of the EPC contract, and discussion of the causes and progression of the repairs to the PB2 steam turbine.

Q. WHAT IS YOUR RESPONSE TO CLAIMS MADE BY SIERRA CLUB THAT QUESTION THE PRUDENCE OF INVESTMENTS IN THE COMPANY'S COAL UNITS DUE TO THOSE UNITS BEING "UNECONOMIC"?

A. Witness Wilson spent a large portion of her testimony discussing what she terms the "negative net value" of the Company's coal units. She did not, however, recognize the full picture of how the Company dispatches its coal fleet to maximize value for customers. The Company's economic dispatch model supports active management of the fleet in order to provide reliable cost-effective generation for its customers. The model, which produces unit commitment and dispatch projections, utilizes variable costs rather than fixed costs, which are contractually required to be spent whether the units run or not. The variable costs utilized in the model, for example, include but are not limited to fuel, variable O&M, reagents, emission allowances, and startup fuel and wear and tear.

The economic dispatch model will economically optimize total system variable cost over a 7-day forecast period. Witness Wilson's study does not appear to account for the requirement of day-ahead planning reserves. On a day-ahead basis, the Company is required to plan on at least 1,195 MW of capacity above and beyond DE Progress' expected peak load. Capacity must be online (or available within 10 minutes). A coal unit will provide energy and capacity during the peak. If a needed coal unit were not online then the Company would have to start additional CTs and/or purchase energy and capacity from the market, assuming capacity was available during such a time.

Q. WITNESS WILSON ALSO DISCUSSED HER "FORWARD-LOOKING ANALYSIS OF DEP COAL UNITS." IS THIS ANALYSIS A VALID EXERCISE IN A GENERAL BASE RATE CASE?

A. No. Witness Wilson's testimony in this regard concerned forward-looking IRP-related issues. The rate case docket is the proper proceeding to determine whether the Company's capital expenditures sought for recovery were reasonable and prudent. Conversely, the IRP docket is the proper proceeding in which to determine the appropriate generation mix to serve the Company's projected load under varying assumptions around carbon pricing.

Q. DID THE SIERRA CLUB MAKE ANY OTHER RECOMMENDATIONS WITH REGARD TO FUTURE COSTS RELATED TO THE COMPANY'S COAL FLEET?

A. Yes. Witness Wilson recommended that the Company's future capital expenditures "intended to prolong the lives of coal units" be limited and that "utilities" be required to come for approval of any expenditure that exceeds the cap before recovery. She also recommended that the Commission disallow "ongoing O&M expenses" at the Company's coal units based on her assertion that these units are projected to have future net negative value, and that, in future cases, the Company be required to demonstrate that its gas units are "providing positive net value" to customers "before being granted recovery of capital and O&M costs."

Q. WHAT IS YOUR RESPONSE TO THESE RECOMMENDATIONS?

A. With regard to her cap proposal, Witness Wilson did not elaborate as to how such a cap would be determined. In addition, these investments are not made to "prolong" the life of particular units but rather to maximize their remaining useful life. Specifically, the Company's environmental investments in its coal fleet are required to meet ongoing regulatory requirements and continue to provide reliable service to customers.

More broadly, the Company is already doing what Witness Wilson is suggesting with these recommendations, right here in this rate case. That is, the Company is requesting to recover the costs of capital investments made in its coal fleet during the test year through February 29, 2020, and O&M costs incurred during the Test Period. The Company cannot recover these costs from customers unless and until the Commission permits it to do so. The same is true of DE Progress's natural gas units – the Commission will determine through this rate case whether the Company's investments in its natural gas units were reasonable and prudent.

Finally, while the Company provided estimates of future capital investments to Sierra Club through discovery, DE Progress also explained in those discovery responses that future capital investments are not relevant to this proceeding.

Q. WOULD YOU LIKE TO ADDRESS ANY OTHER ASPECTS OF WITNESS WILSON'S TESTIMONY?

A. Yes. Witness Wilson discussed the requirement that facilities be used and useful in providing service to customers to be recoverable through rates. She suggested that a facility may not be "useful" if it was planned in a prudent manner but "operate[s] at costs significantly higher than the economic value of the output for reasons beyond the utility's control and ability to reasonably foresee."

To the extent that she intended this discussion to criticize the Company's capital investments as not being used and useful, as stated above, I am not a lawyer, however, in my experience I have not seen the term "useful" applied in this way. Additionally, Witness Wilson did not identify any specific capital investment operated by the Company as not "useful."

Q. WHAT IS YOUR RESPONSE TO NC WARN'S ASSERTION THAT THE ASHEVILLE CC WAS NOT NEEDED?

A. NC WARN Witness Powers claimed that existing regional merchant combined cycle and hydroelectric plants could supply Duke Energy with lower-cost power than can be obtained from the Asheville CC Project. He did not, however, offer a credible and specific explanation of how the Company could have replaced the approximately 560 MW of reliable generation provided by the Asheville CC, with purchased power and renewable resources, or otherwise credibly challenge the Company's reasonable and prudent decision to invest in this project.

Moreover, NC WARN ignores several additional factors that support the reasonableness and prudence of this investment. As I explained earlier in my testimony, the Asheville CC Project was required by the North Carolina Mountain Energy Act, which specifically contemplates the Company constructing a new natural gas fired generating facility at the Asheville site. In addition, the Commission determined that the Asheville CC Project was needed in its order granting the Company a CPCN for the project (Docket No. E-2, Sub 1089).

V. CONCLUSION

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

My direct and rebuttal testimony support the costs of capital investments and operations and maintenance expenses that the Company has incurred for its fossil/hydro/solar operations or "FHO" fleet since DEP's previous North Carolina rate case. As discussed in my testimony, the Company reasonably and prudently incurred the costs for these investments, as they were necessary for DEP to continue to provide safe, reliable, and cost-effective electric service for customers while continuing to maintain efficient operation of the assets with high quality performance.

The Company's FHO generation portfolio consists of approximately 9,204 megawatts of generation capacity. This portfolio includes a diverse mix of generation facilities to meet our customers' load requirements. These facilities operated efficiently and reliably during the test period. Since DEP's last rate case, a significant portion of critical investments were made to meet environmental regulations and were necessary to maintain the Company's history of safely providing efficient, reliable, and cost-effective generation. DEP also added two new combined cycle units at its Asheville station, which will provide an additional 560 MW of capacity to the fleet now that the Asheville coal fired units have been retired.

In rebuttal, I explain how the arguments raised by parties in opposition to our coal plant investments misunderstand the realities of operating our system and fail to capture the full picture of how DEP dispatches its coal fleet. These arguments also disregard the capacity value these units offer. No party presented prudent alternatives that DEP reasonably could have chosen to replace the approximately 3500 MW of reliable capacity that our coal plants represent, instead of making these investments.

MS. KELLS: And now the witness is available for cross examine.

COMMISSIONER CLODFELTER: All right. Let me check first. Ms. Downey, I do not have any indication that the Public Staff reserved any cross examination. Is there any for the Public Staff?

MS. DOWNEY: No cross from the Public Staff. Thank you.

COMMISSIONER CLODFELTER: Ms. Force and Ms. Townsend, any cross examination from the Attorney General's Office?

MS. TOWNSEND: No, sir.

COMMISSIONER CLODFELTER: I do have an indication that there was testimony or cross examination reserved by Sierra Club. Ms. Lee.

MS. LEE: Yes, Commissioner Clodfelter. Thank you and good morning, and good morning to the other Commissioners.

CROSS EXAMINATION BY MS. LEE:

Q And good morning to you, Ms. Turner. My name is Bridget Lee. I represent the Sierra Club in these proceedings. I have a few questions for you this morning.

The Company's oldest coal unit

came online in 1966; is that correct?
A I do not know the date exactly of when the oldest one came online.
Q Okay. Subject to check, would you agree with me subject to check that the Roxboro Unit 1 came online in 1966?
A Yes.
Q And when does the Company expect to retire the Roxboro station.
A In the 2020 IRP it provides a new retirement date and I will look at my fact sheet so I can have the --
Q Thank you.
A The Roxboro unit is scheduled to retire in the 2020 IRP at the end of 2028, along with Roxboro 2 and then Roxboro 3 and 4 at the end of 2027.
Q Thank you. I'm sorry. For 3 and 4, did you say 2027?
A Yes. I'm looking at the IRP most economic date. That is correct.
Q Okay.
A The end of 2027 and the first of 2028.
Q Okay. So for units 3 and 4, that retirement date is six years sooner than was assumed in the prior

IRP update; is that correct?
A That's correct.
Q And when does the Company plan to retire the Mayo plant?
A At the end of 2028.
Q Okay. And so that is also six years sooner than was assumed in the 2019 IRP update; is that right?
A I believe it's a little bit more than that.
Q Okay. All right. Turning to your rebuttal testimony, I'm looking at page 4, lines 12 to 13, and here you refer to "significant capital investments and environmental controls" that the Company avoided by retiring at the Asheville coal plant; is that right?
A That's correct.
Q Okay. And by retiring the Asheville coal units ahead of schedule, the Company was able to avoid about $90 million in environmental compliance costs; is that right?
A I do not have those numbers in front of me.
Q No problem. Are you aware of whether the costs that were avoided had to do with the construction of a new dry bottom ash handling system?

A That would be correct. When the Mountain Energy Act was approved, and we constructed the new combined cycle there to replace the older coal units, we did not have to construct the dry bottom ash management system; however, we still had to deal with the ash that was in place from historical use at that plant.

Q Okay. And was the Company also able to avoid costs associated with stormwater rerouting?

A No. With any of the plants we would have to have the stormwater reroute in the ash basin line.

Q Okay. How about upgrades to the plants' scrubber wastewater treatment system. Were there any avoided costs with respect to that?

A There would have been, yes, because the plant would be retired.

Q Thank you. And you've testified about the capital investments at the coal units undertaken by the Company during the test period. Those include new dry bottom ash handling and stormwater rerouting, correct?

A That's correct.

Q And those investments, they total approximately $402 million at the Roxboro and Mayo plants.

Does that sound right? I'm looking at your direct, page 6, line 18.

A I keep forgetting to unmute, sorry. Yes, it was a little bit more than $402, but $402 is accurate in my testimony.

Q Okay.

A In my testimony.

Q And, Ms. Turner, do you know about how much was spent at each plant of that $402?

A I do.

Q Okay. If you could let us know.

A So for -- are you just asking in total capital or just for the environmental projects?

Q Let's start with total and then work our way through the environmental projects.

A Okay. At Roxboro $478 million and at Mayo $100 million and Asheville was $5 million.

Q Okay. And then for the environmental projects, do you have handy the total spent at Roxboro to convert from wet to dry handling of bottom ash?

A I have the total spent for the environmental projects, it was $337, which included more than just converting from -- to a dry bottom ash system. It also addressed the processed water reroute, the stormwater reroute, and the ash basin lining. At Mayo, it was $87 million and there was none at Asheville.

Q Thank you. And does the Company expect to incur other significant capital expenditures at the Roxboro plant between now and when it retires?

A It would depend on any other regulations that may come into policy between now and the time that those plants are retired. And from a capital expenditure, if we have maintenance that is required because of normal wear and tear on the assets we would anticipate capital expenditures from that as well.

Q Okay. Do you know offhand whether any of the Roxboro units are due for a boiler replacement or any other big upgrades?

A Not off the top of my head --

Q Fair enough. Before undertaking the retrofits we just discussed, specifically the environmental compliance projects, the Company didn't conduct a comprehensive evaluation of whether retiring any of the Roxboro units would be cost-effective, did it?

A We did not conduct a comprehensive retirement analysis specifically for making a decision as to whether or not we should invest in these environmental projects. However, we did have a similar analysis performed for Mayo which is in the same general vicinity, would require the same projects to be environmentally compliant. At that time that analysis was done for the purpose of the Company's strategy to achieve its ongoing reduction in carbon as part of the coal-to-gas strategy and did a thorough analysis. And in that analysis it would have been performed very similar to what we would do for a retirement analysis, and out of the seven cases in that analysis none of them proved to be economical for the customer to retire Mayo. And if Mayo is 700 megawatts then Roxboro is 2400 megawatts, if it's not economical for Mayo it would not be economical for Roxboro, because at the time of the decision all those -- that energy was required for us to reliably serve our customers.

Q Okay. And in the -- I believe you mentioned seven scenarios that were considered for Mayo. Were each of those scenarios looking at the same replacement generation option?

A They were looking at gas as the alternative for replacing it.

Q Okay. So the Company in doing that analysis didn't consider either renewable energy options, or storage, or how demand-side management might play a role?

A We considered gas as the alternative because it's -- we looked at the most recent IRP. And in the IRP that plan is really looking at what is the most economical way for us to provide installed generation, and gas is or was at that time the most economical; therefore, that was alternative chosen.

Q Do you know is gas still the most economical option?

A I believe it is at this point.

Q Okay. If you could please check your rebuttal page 11. I'm looking at lines 19 through 21. And you've testified here that ratepayers have benefited when the company's retired older facilities "that lack of environmental equipment and were not economically positioned for needed capital expenditures". Are you referring to the Asheville coal plant there?

A I am referring to -- this is -- this section is referring to prior rate cases. So you may be aware that we have actually retired 14 units in DEP which has enabled us to reduce our carbon emissions by 40 percent. And I'm referring to those older facilities in this section in my testimony.

Q Okay. Thank you. And you speak there of facilities that are not economically positioned. Did the Company evaluate the economic position of the Roxboro coal plant before undertaking the recent capital investments at that plant?

A I would answer it the same way I did previously which is we did a comparative analysis to the Mayo, but we also have to consider the timing of the decision. And at the time the decision was made the generation was necessary in order for us to widen to serve our customers and we would have a short window of time in order to replace that generation, and it just wasn't a viable option to retire the asset because we couldn't replace the generation in that period of time.

Q Okay. And for the Roxboro unit was the option for replacement generation considered a combined

cycle gas plant? Would that would have been what was needed for the Company's --
A I would have to speculate that that's what we would put in that case, but there was no particular retirement analysis for Roxboro.
Q Understood. I believe those are all my questions. Thank you for your time, Ms. Turner.
A Thank you.

COMMISSIONER CLODFELTER: Does any other party -- any other intervenor have any cross examination for this witness?

(No response)

All right. If not, Ms. Kells we're back to you on redirect.

MS. KELLS: Thank you.

REDIRECT EXAMINATION BY MS. KELLS:

Q Ms. Turner, a few minutes ago Ms. Lee was asking you about the level of investment that the Company has made in the Mayo and Roxboro stations. And you were discussing a $402 million amount, do you recall that?
A I do.
Q And you mentioned that the amount of that at Roxboro and Mayo that was related to

environmental investments, how would you describe the portion of the investments in these stations that was related to environmental compliance as opposed to maintenance capital? Was it more or less than?

A It was much more.

Q And by "it" you mean the environmental investments.

A The environmental investments. So, for example, for coal we spent approximately $420 million for environmental projects compared to $150 in routine maintenance capital.

Q Thank you. And are you -- can you also say does that total for environmental investments include investments for projects that I believe you said would have needed to be done at the stations regardless of whether they kept running or not?

A That's correct. If -- even if we had retired those assets we would have to invest about half of that $400 in order to be compliant with the environmental regulations.

Q And Ms. Lee also asked you a few questions about the Company's evaluation of the Roxboro station and whether it did an evaluation of that station;

do you recall that?
A I do.
Q Would you speak a little bit more to how the Company evaluates whether to make investments at its coal units; what that process looks like?
A Certainly. We have a, I would say, a very disciplined process associated with making investments. And it really starts from the plants doing an assessment, a condition assessment of the equipment as well as if there are any new regulations we would enter projects and then across DEP those projects would be prioritized. And the first projects to be prioritized would be those that are regulatory required through their compliance projects.
And the second would be anything that's a commitment, meaning we have entered into a contractual agreement and we are legally bound to fulfill those commitments for maybe a longer term maintenance, for example. And then we would prioritize safety and environmental improvement projects. And then we would prioritize reliability projects. And in all of those cases, for reliability, there is an economic analysis

that's performed to look at pay back life of that investment, and then we try to make decisions on how can we optimize the dollars that we have to minimize the risk.

Q Thank you. And when you're going through that process of evaluating investments, does the Company operate and make the decision based on, you know, information available at the time?

A Absolutely.

Q And in your opinion has the Company's decisions to make these investments in its coal fleet benefited customers?

A Yes. The coal assets have been very valuable since those investments have made -- been made. I'd like to explain that a little bit more if I can. You know, the capacity factor for the coal fleets have declined over the years. And while the capacity factors are lower, if we look at the first week of January in 2018, the capacity factor for those Roxboro and Mayo units is 94 percent. And if we had not invested in those assets and were not able to run them, we would not be able to serve our customers with a least cost. And, you know, the capacity is, and by capacity I mean the ability to run them when our customers need them, is critical to our system.

Q Thank you. And just -- it was in -- is the Company required -- you had talked with Ms. Lee about making environmental investments to be in environmental compliance and that's an obligation with the Company to remain environmental compliant, correct?

A Yes.

Q And does the Company also have an obligation to provide safe and reliable service to customers?

A Yes, we do at least reasonable cost.

Q And in your opinion did these investments allow the Company to meet those goals?

A Yes, it did.

Q And you talked just a little bit with Ms. Lee about the advancing retirement dates for the coal units that's reflected in the 2020 IRP; do you recall that?

A I do.

Q And are you familiar with the proposal in this case as well to accelerate depreciable lives of the coal units?

A Yes, I am.

Q Are -- in your opinion, are the updated plans
that are shown in the 2020 IRP consistent with
that proposal for accelerated depreciation in
this case?
A Yes. I think it's further evidence that supports
the need for the acceleration -- accelerated
depreciation, because the most recent IRP takes
into account the fuel forecast; it's taking into
account technologies that are available; and it's
taking in account carbon policies that we're
facing. So as we continue into the future we are
seeing that acceleration.
Q And just, last thing, you discussed the Asheville
unit with Ms. Lee or the CC project that came
online and how the Company retired the steam
station that had been now put in the CC; do you
recall that conversation?
A Yes.
Q Why was the Company able to, you know, retire the
steam station when it was near Asheville and put
in the CC?
A We had the Mountain Energy Act that enabled us to
retire the coal plant and construct the new
combined cycle once we achieved a CPCN by a

particular date. It's in my testimony but I just don't recall the date. And so we were able to construct it to serve our customers for the needed load in that area as well as take advantage of the interstate gas pipeline that was going to be built in that area.

Q And at Mayo and Roxboro, was there an interstate gas pipeline that's there or planned to be there?

A No, not at the time.

Q Thank you. Ms. Turner.

And, Commissioner Clodfelter, that was all I had.

COMMISSIONER CLODFELTER: Thank you. Let's see if we have questions from the Commission, beginning with Commissioner Brown-Bland.

COMMISSIONER BROWN-BLAND: I have no questions.

COMMISSIONER CLODFELTER: Commissioner Gray.

COMMISSIONER GRAY: I have no questions.

COMMISSIONER CLODFELTER: Chair Mitchell.

CHAIR MITCHELL: No questions for the witness.

COMMISSIONER CLODFELTER: Commissioner Duffley.

COMMISSIONER DUFFLEY: No questions.

COMMISSIONER CLODFELTER: Commissioner Hughes, any questions?

COMMISSIONER HUGHES: No questions.

COMMISSIONER CLODFELTER: Commissioner McKissick.

COMMISSIONER McKISSICK: No questions, Mr. Chair.

COMMISSIONER CLODFELTER: Ms. Turner, we can't let you off that easy so I'm going to have some questions.

EXAMINATION BY COMMISSIONER CLODFELTER:

Q I am correct, am I not, that the Sutton -- the coal-fired units at Sutton were retired in 2013? Does that sound right?

A That sounds right.

Q In line with the process that you've described to Ms. Kells, was there a retirement analysis or decommissioning study made with respect to the retirement of those units?

A For the Sutton units?

Q Yes, ma'am.

A I would have to guess. I'm not familiar. I would think so but I just don't know.

Q You would -- I'm sorry, I didn't catch the first part of your answer.
A I assume that there was something similar to the coal-to-gas strategy analysis but I don't know.
Q Do you know when the decision was made by the Company to retire those coal-fired units?
A No, I do not.
Q With respect to the Cape Fear plant, am I correct that the last of the coal-fired units at that plant were retired in 2012; is that right?
A I do not have those dates in front of me.
Q Okay. I don't mean to trap you. I'm just -- I'm reading from some exhibits to Ms. Bednarcik's testimony, but she's a coal ash witness and you're the fossil hydro witness, so I need to also confirm these things with you. She indicates that that's the retirement date.
My question to you, though, is do you know if there was a retirement analysis or a decommissioning study done for those retirements of the coal units at Cape Fear station?
A I don't know.
Q Don't know? How long have you been in the current position you hold?

A Since April 1st of this year.
Q Of this year. Who was your predecessor?
A Steve Immel.
Q Okay. With respect to the H.F. Lee station, again I'm reading from some of the exhibits to Ms. Bednarcik's testimony, indicates that the coal-fired units there were retired in September of 2012 -- do you know whether there was a retirement analysis or a decommissioning study done in connection with the retirement of those units?
A I do not know if there was -- what was done there.
Q And would I be correct then if I surmise that you also don't know when the decision was made to retire those units?
A That would be correct.
Q Okay. I've got to go through them all so bear with me. I need to ask you next about the Weatherspoon steam station which, again, from the exhibits indicated that that -- that the coal-fired units there were retired it looks like in October of 2012. Do you know from your own knowledge is that correct?

A I do not.
Q And if I asked you, also, do you know whether there was a retirement analysis or a decommissioning study done with respect to the Weatherspoon coal-fired units, would you know whether there was or was not?
A I would not know.
Q And you would not know -- would I be correct that you don't also know when the decision was made to retire those coal-fired units?
A You would be correct.
Q Okay. Remind me, because I don't have these materials in front of me, is there -- are there coal-fired units still at the Robinson plant? I think there was only one, wasn't there?
A No. There are no coal-fired units in Robinson.
Q Do you know when the last coal-fired unit at Robinson was retired?
A No, I do not.
Q I can't help you on that because I don't have any exhibits in front of me. But, and so, would I be correct, also, that you're not -- or are you aware that when the decision was made to retire the last coal-fired unit at the Robinson plant?

A No, I do not know.

Q And do you know whether there was a decommissioning study or a retirement analysis done in connection with the decision to retire those units?

A I do not know.

Q Okay. I'll leave you alone, Ms. Turner.

COMMISSIONER CLODFELTER: But, Ms. Kells, I'm going to ask for late-filed exhibits for each of the plants I've named which would be any decommissioning studies or retirement analyses with respect to the coal-fired units at the Sutton, Cape Fear, Weatherspoon, H.F. Lee, and Robinson plants.

MS. KELLS: Yes. And so the exhibit will be for each of those plants that you mentioned whether there was a decommissioning or retirement study done.

COMMISSIONER CLODFELTER: Correct.

MS. KELLS: Okay.

COMMISSIONER CLODFELTER: Those may have been produced in data requests, I don't know. But since I don't have access to all the data requests I need to ask for those as late-filed exhibits. All right?

MS. KELLS: All right. Yes. Got it.

COMMISSIONER CLODFELTER: Okay. And that's all I have. Thank you, Ms. Turner.

THE WITNESS: Thank you.

COMMISSIONER CLODFELTER: All right. Are there questions on the Commission's questions?

MS. KELLS: No, sir.

COMMISSIONER CLODFELTER: First, Ms. Lee, anything from you?

MS. LEE: No. Thank you, Commissioner.

COMMISSIONER CLODFELTER: Okay. From any other party, other than the Company? All right. Ms. Kells, back to you.

MS. KELLS: No, I don't have any questions. Thank you.

COMMISSIONER CLODFELTER: Okay. I don't know that we had any exhibits. Ms. Kells, do we need to have any motions at this point?

MS. KELLS: We actually do. Ms. Turner had one rebuttal exhibit and I move that that be admitted into evidence at this time.

COMMISSIONER CLODFELTER: Okay. That it be marked as it was marked when prefiled and that it be admitted into evidence, correct?

MS. KELLS: Yes, sir. Thank you.

COMMISSIONER CLODFELTER: Any objection to that motion? Hearing none, the motion will be granted.

(WHEREUPON, Turner Rebuttal Exhibit 1 is admitted into evidence.)

MS. KELLS: And I would also move that Ms. Turner be excused.

COMMISSIONER CLODFELTER: Does any other party object to the motion to excuse Ms. Turner? If not, it will be so ordered. And, Ms. Turner, thank you for being with us. Appreciate it.

(The witness is excused)

COMMISSIONER CLODFELTER: Mr. Robinson, I think my memory of my notes are that we previously granted the motion to excuse Mr. Spanos so I believe we're next with the panel of Mr. Pirro, Mr. Huber and Ms. Hager.

MR. ROBINSON: That's correct, Commissioner Clodfelter.

MR. MEHTA: Commissioner Clodfelter, this is Kiran Mehta.

COMMISSIONER CLODFELTER: Mr. Mehta, good morning.

MR. MEHTA: Good morning. And this is not in the nature of rebellion, but I did want to ask you before we get together with the parties whether it -- what I'm concerned about is if we add a DEP moniker in front of all of the exhibits that were previously marked in the DEC case that are coming in as part of the live testimony given in that case they will be referred to differently in the live testimony than they would be in the quote, DEP record. So I'm wondering if we should just leave the exhibits as identified in the DEC case in the live testimony that's coming in as part of the Stipulations. But then I think it's a very good suggestion to start with any new exhibit that's introduced in the DEP case with the next number whatever that number is.

COMMISSIONER CLODFELTER: Mr. Mehta, as has often been the case of our respective careers, you are more precise than I am, and I believe you are correct. The suggestion about putting a prefix was really for just to have parties be able to identify what we were talking about at the time we were describing the process. I think the designation remains the same and that we don't have the prefix designation. I was just trying to describe to the parties that the DEP exhibits, that is to say the DEP exhibits would be a DEP group from the stipulated and a DEP group from the current oral hearing. But I think you are correct that the actual designation or marking in the original designations given in the DEC case will be the designations in this case, and then going forward in this case additional exhibits for the same witness will pick up with the next succeeding number. You are more precise in your statement. I think that's correct.

MR. MEHTA: Okay. So just -- just so I'm clear. The new exhibits is not an issue, I mean, we just start with the next number, whatever the next number is.

COMMISSIONER CLODFELTER: Yes. You are correct about the prefix. We will not be using the prefix. The prefix was a shorthand way for me of describing the group of exhibits we were talking about.

MR. MEHTA: So when the exhibits are moved into -- the exhibits related to the DEC live testimony are moved into evidence, they should be moved into evidence with the same identifier as --

COMMISSIONER CLODFELTER: The same --

MR. MEHTA: -- they have.

COMMISSIONER CLODFELTER: -- identifier as they had in the DEC case. They now become DEP exhibits but they have the same identifier as in the DEC case.

MR. MEHTA: Thank you, Commissioner Clodfelter. And my rebellion is now ceased.

COMMISSIONER CLODFELTER: Oh, it's not rebellion at all, Mr. Mehta, it's a -- we're just trying to get this thing as clear as we can and you've helped us in that and I appreciate it.

MR. MEHTA: Thank you, sir.

COMMISSIONER CLODFELTER: The important point -- the important point is that the numbering sequence will begin with the next number after the last exhibit that's brought in from the stipulated testimony.

MR. MEHTA: Understood and completely agree with that.

COMMISSIONER CLODFELTER: Got it. All right. Okay. Are we making any progress on this issue? All right, folks, are we ready for the next panel?

MS. JAGANNATHAN: Yes. Commissioner

Clodfelter, this is Molly Jagannathan here on behalf of Duke Energy Progress, and we'd like to call witnesses Janice Hager, Michael Pirro, and Lon Huber to testify as a panel.

COMMISSIONER CLODFELTER: Ms. Hager, Mr. Pirro, and Mr. Huber, will you raise your right hands?

JANICE HAGER, MICHAEL PIRRO and LON HUBER,
as a panel,
having been duly affirmed,
testified as follows:

COMMISSIONER CLODFELTER: All right. Ms. Jagannathan, the witnesses are with you.

MS. JAGANNATHAN: Thank you, Commissioner Clodfelter.

DIRECT EXAMINATION BY MS. JAGANNATHAN:

Q Ms. Hager, I'll start with you. Would you please state your name and business address for the record?

A (Ms. Hager) My name is Janice Hager. My business address is 2049 Mount Lion Church Road, Alexis, North Carolina.

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

A I am President and owner of Janice Hager Consulting.

Q On October 30th, 2019, did you cause to be prefiled in this docket direct testimony consisting of 18 pages?

A I did.

Q And on May 4th, 2020, did you cause to be prefiled in this docket rebuttal testimony consisting of 27 pages?

A I did.

Q Ms. Hager, do you have any changes or corrections to your prefiled testimony?

A I do have one change to my rebuttal testimony which is included in the errata page provided with my testimony summary.

Q And with the corrections to your rebuttal testimony that are noted in your errata, if I were to ask you the same questions today, would your answers be the same?

A They would.

MS. JAGANNATHAN: Commissioner Clodfelter, I would move that Ms. Hager's prefiled direct testimony and her rebuttal testimony, as corrected by the errata, as well as her testimony summary and errata sheet be entered into the record as if given orally from the stand into the record as if given orally from the stand.

COMMISSIONER CLODFELTER: All right. Without objection, it will be so ordered.

MS. JAGANNATHAN: Thank you.

(WHEREUPON, the prefiled direct and rebuttal testimony, errata, and summary of Janice Hager is copied into the record as if given orally from the stand.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1219

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

I. INTRODUCTION AND PURPOSE

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

A. My name is Janice Hager, and my business address is 2049 Mount Zion Church Road, Alexis, North Carolina. I am President of Janice Hager Consulting, LLC.

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL EXPERIENCE.

A. I have extensive experience with Duke Energy Corporation ("Duke Energy") over a 34-year career with Duke Energy. I am a civil engineer, having received a Bachelor of Science in Engineering from the University of North Carolina at Charlotte. During my time at Duke Energy, I was a registered professional engineer in North Carolina and South Carolina. I worked in Duke Energy's (formerly, Duke Power) Rates and Regulatory Affairs area for ten years, the last three of which I was Vice President of the department. Following the merger of Duke Energy and Progress Energy, Inc., I led Duke Energy's integrated resource planning process for all of Duke Energy's regulated utilities, including Duke Energy Progress ("DE Progress" or the "Company") and Duke Energy Carolinas, LLC ("DE Carolinas"). At the time of my retirement in December 2014, I was Vice President of Integrated Resource Planning and Analytics for Duke Energy.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes. I have filed testimony and appeared before this Commission many times, including on matters of Fuel Adjustment Clauses, Integrated Resource Planning, Certificates of Public Convenience and Necessity, general rate cases, and other issues. I most recently testified before this Commission in the DE Progress and DE Carolinas general rate cases in Docket Nos. E-2, Sub 1142 and E-7, Sub 1146, respectively, and have filed testimony in DE Carolinas' pending rate case in Docket No. E-7, Sub 1214. I have also appeared before the Public Service Commission of South Carolina, the Indiana Utilities Regulatory Commission, and the Federal Energy Regulatory Commission ("FERC").

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

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

II. <u>COST OF SERVICE STUDY OVERVIEW</u>

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

A. The purpose of a cost of service study is to align the total costs incurred by DE Progress in the test period with the jurisdictions and customer classes responsible for the costs. The study directly assigns or allocates the

Company's revenues, expenses, and rate base among the regulatory jurisdictions and customer classes served by the Company based upon the service requirements of those respective jurisdictions and customer classes. These service requirements are based on several factors, including differences in usage patterns and size.

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

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

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

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

III. <u>REVIEW OF DE PROGRESS' COST OF SERVICE STUDY</u>

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

A. Yes. As referenced by Company witness Kim Smith in her pre-filed direct testimony, I have reviewed DE Progress' cost of service studies that were prepared and filed as Item 45 in the Company's Form E-1 filing in this case.

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

A. The cost of service study is based on the official accounting books and records of DE Progress, supported in this proceeding by Company witness Shana Angers. The cost components are comprised of the Company's electric operating expenses and original cost rate base and are based on the historical 12-month period covering January 1, 2018 through December 31, 2018 (the "Test Period").

IV. <u>COST OF SERVICE STUDY PREPARATION</u>

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

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

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

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

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

A. Functionalizing Costs

Q. PLEASE EXPLAIN HOW TO FUNCTIONALIZE COSTS.

A. The Company accounts for its costs using the Uniform System of Accounts ("USOA") of the FERC. The USOA assigns the costs of the Company's plant investment into the primary categories of production (generation), transmission, distribution, and general and intangible plant. Similarly, the USOA categorizes the Company's operating costs into production, transmission, distribution, customer services, and administrative and general functions.

B. Classifying Costs

Q. PLEASE EXPLAIN HOW COSTS ARE CLASSIFIED.

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

Q. PLEASE DEFINE DEMAND-RELATED COSTS.

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

Q. PLEASE DEFINE ENERGY-RELATED COSTS.

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

Q. PLEASE DEFINE CUSTOMER-RELATED COSTS.

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

C. Allocation and Direct Assignment of Costs

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

A. Cost components identified as having a direct relationship to a jurisdiction or customer class are directly assigned to that jurisdiction or class before any allocations occur. For example, many distribution-related costs are directly assigned to a jurisdiction based on their state location. For these costs and for the remaining unassigned costs, specific allocation factors are developed that relate to the (1) demand, (2) energy, and (3) customer-related classifications identified above.

1. Demand Allocators

Q. WHAT DEMAND ALLOCATORS ARE USED TO ASSIGN DEMAND COSTS TO JURISDICTIONS AND CUSTOMER CLASSES IN THIS CASE?

A. There are two categories of demand-related costs used in the cost of service study:

a. <u>Production & Transmission Demand</u> – Production & Transmission demand costs are allocated using the Summer Coincident Peak ("SCP") method.

b. <u>Distribution Demand</u> – Distribution plant investments are directly assigned to the jurisdictions. At the customer class level, substations, and a part of poles, lines and transformers that have been designated as demand-related are allocated based on the Non-Coincident Peak Demand ("NCP").

a. Production and Transmission Costs

Q. PLEASE EXPLAIN THE CONCEPT OF ALLOCATING COSTS BASED ON COINCIDENT PEAK.

A. A coincident peak ("CP") allocator assigns the fixed demand-related costs (for example, a portion of production and all transmission-related costs) to the jurisdictions and customer classes in proportion to their respective contribution to the system's peak hourly demand during the Test Period. Each jurisdiction and customer class' cost responsibility (*i.e.*, the percentage of the fixed portion of production and transmission demand costs assigned to each jurisdiction and customer class) is equal to the ratio of their respective demand in relation to the total demand placed on the system. The cost of service study supporting the Company's proposed rate design in this proceeding allocates the fixed portion of production and transmission demand-related costs based upon a jurisdictions and customer class' coincident peak responsibility occurring during the summer, otherwise known as the Summer Coincident Peak or SCP Allocator.

Q. WHAT WAS THE SUMMER COINCIDENT PEAK DEMAND IN 2018 AND WHEN DID IT OCCUR?

A. The DE Progress summer peak generation and transmission demand used in this study occurred on June 19, 2018 at the hour ending 5:00 PM, when the DE Progress system peak was 12,841 MWs.

Q. IS THE PEAK JUST DESCRIBED THE SAME ONE USED IN THE COST OF SERVICE STUDIES?

A. No. The DE Progress system peak is adjusted when developing production demand allocators for the cost of service. These adjustments remove demands related to Company use and other transactions not considered part of native load, including a peaking NCEMC sale.

Q. WAS THE 2018 SUMMER PEAK ALSO THE SYSTEM PEAK FOR 2018?

A. No. The DE Progress system peak occurred on January 7th in the hour ending 8:00 AM. This DE Progress system peak was 15,322 MWs. Given that the Company's generation and transmission investments being considered for cost recovery in this case were primarily based on summer peak planning, for consistency we have continued to use the summer peak for cost allocation. However, Company witness Michael Pirro has given some consideration to the winter peak in rate design.

Q. WAS THE SUMMER CP TYPICAL WHEN COMPARED TO OTHER SUMMER CPs?

A, Yes. In 14 of the last 25 years, the Company's coincident peak occurred in the months of June through August. In all of the last 25 years, the summer peak occurred between hour ending 3:00 PM and hour ending 5:00 PM. The 2018 summer peak is within the range of these past occurrences and it is therefore appropriate to assign fixed demand-related costs to the Company's jurisdictions and customer classes based upon the SCP.

b. Distribution Costs

Q. HOW ARE DISTRIBUTION COSTS ALLOCATED?

A. Most distribution investments are first identified and directly assigned to the state in which they are located. Then those distribution costs identified as customer-related are allocated based on customer allocation factors, as discussed below. The remainder of the distribution costs are designated as demand-related and allocated to the customer classes based on NCP demand allocators.

The NCP allocators are developed by taking the ratio of the non-simultaneous peak demands of the customers in each class whenever that peak occurred during the test period and comparing that to the sum of all customers' non-simultaneous peak demand. Several different NCP allocators are developed to account for the different levels of the distribution system where customers may take service (substation and below, primary and below, secondary, etc.). For example, only the NCP demand of customers who take service at secondary voltage are included in the development of the NCP allocator used to allocate secondary distribution lines and poles.

Q. WHY IS A NON-COINCIDENT PEAK USED FOR ALLOCATING DEMAND-RELATED DISTRIBUTION INVESTMENT?

A. Distribution facilities serve individual neighborhoods, rural areas, and commercial districts. They do not function as a single integrated system in meeting system peak demand. Instead, the distribution system serving each neighborhood, rural area, or commercial district must be able to meet the peak demand in the area it serves whenever the peak occurs. Accordingly, contribution to NCP is the appropriate measure of determining customers' responsibility for these costs because it best measures the factors that drive investment to support that part of the system.

2. Energy Allocators

Q. WHAT ALLOCATOR WAS USED TO ASSIGN ENERGY-RELATED COSTS TO JURISDICTIONS AND CUSTOMER CLASSES?

A. Energy-related costs reflect the variable cost of producing, transmitting, and delivering electricity. Examples of costs allocated on this basis are fuel costs and variable production costs incurred at generating stations. DE Progress' kWhs of generation and deliveries during the Test Period have been used to allocate these variable costs. The kWh sales information is collected, and then adjusted for the level of losses attributable to each class and jurisdiction, to derive the level of kWhs at the generator attributable to that class or jurisdiction.

3. Customer Allocators

Q. WHAT TYPES OF COSTS HAS DE PROGRESS INCLUDED FOR ALLOCATION AS CUSTOMER-RELATED?

A. DE Progress has included operating expenses in FERC accounts 901-917. These expenses include meter reading, billing and collection, and customer information and services. In addition, DE Progress has included in this category a portion of distribution costs that the Company has identified as customer-related, including the costs of the service drop and meter (FERC

Accounts 369-370) and a portion of the costs for distribution lines, poles, and transformers (FERC Accounts 364-368).

Q. DO YOU BELIEVE INCLUSION OF A PORTION OF DISTRIBUTION LINE, POLE, AND TRANSFORMER COSTS IN CUSTOMER ALLOCATIONS IS REASONABLE AND APPROPRIATE?

A. Yes. The National Association of Regulatory Utility Commissioners ("NARUC") Electric Utility Cost Allocation Manual ("CAM") states that a portion of distribution costs related to FERC Accounts 364-368 are customer-related. These FERC accounts include the costs of poles, towers, fixtures, overhead and underground conductors, and transformers. The two-methods the CAM discusses for allocating these customer-related distribution costs are:

1) Minimum System Method (called Minimum-Size Method in the NARUC Manual); and

2) Zero-Intercept Method (called Minimum-Intercept Method in the NARUC Manual).

Both methods recognize that some portion of the distribution system is necessary to serve customers, regardless of whether the customers take any energy from the system. The Minimum System Method seeks to determine the minimum size distribution system that can be built to serve the minimum loading requirements of customers. The Minimum System Method develops the cost of the minimum set of distribution assets that would be needed to serve customers and allocates those costs based on the number of customers.

Similar to the Minimum System Method, the Zero-Intercept Method allocates a portion of the same distribution accounts on the basis of the number of customers. The Zero-Intercept method seeks to identify the portion of distribution plant that is associated with no load using regression techniques.

Q. WHICH METHOD DID DE PROGRESS CHOOSE AND WHY?

A. DE Progress incorporated the concept of Minimum System into its COS Study for allocating costs to customers, which is appropriate for allocation of customer-related distribution costs. The zero-intercept method is generally considered to be a more complex and time-consuming methodology that often can produce results that are not materially different from the Minimum System method. The theory behind the use of a minimum system study is sound and consistent with cost causation, which is the foundation of COS studies. DE Progress' Minimum System Study allowed DE Progress to classify the distribution system into the portion that is customer-related (driven by number of customers) and the portion that is demand-related (driven by customer peak demand levels). Every customer requires some minimum amount of wires, poles, transformers, etc. to receive service; therefore, every customer "caused" DE Progress to install some amount of such distribution assets. The concept DE Progress used to develop its Minimum System Study was to consider what distribution assets would be required if every customer had only some minimum level of usage (e.g., one light bulb). This methodology allows the utility to assess how much of its distribution system is installed simply to ensure that electricity can be delivered to each customer, if and when the customer chooses to use electricity. Once minimum system costs have been identified, all distribution costs over the minimum system costs and direct assignments are determined to be driven by demand.

Q. WHAT IS THE BASIC CUSTOMER METHOD AND WHY DID THE COMPANY CHOOSE NOT TO USE THIS METHOD?

A. The Basic Customer Method is not included in the CAM, but has been advocated by intervening parties participating in recent general rate cases. The Basic Customer Method classifies 100% of all poles, wires, and line transformers as demand-related costs. All other costs (those related to meters and service connections) are classified as customer-related. This method produces lower allocation to customer-related costs and thus, in rate design, a lower fixed customer charge. As mentioned previously, all costs are allocated; the issue is which are designated demand-related, energy-related, or customer-related. By designating a lower amount as customer-related, the Basic Customer method necessarily allocates more costs to the demand-related portion of distribution costs. A higher allocation to demand-related costs means higher demand charges for customers whose electric rate includes demand charges and higher energy charges for those without demand charges. Without the use of the Minimum System allocation methodology, low use customers avoid paying for the infrastructure necessary to provide service to them which is counter to cost causation principles.

Q. HAVE YOU REVIEWED THE PUBLIC STAFF'S REPORT ON THE MINIMUM SYSTEM METHODOLOGY FILED IN DOCKET NO. E-100, SUB 162 ON MARCH 28, 2019?

A. Yes. I have reviewed the report. The Public Staff concluded that the use of the Minimum System Method for classifying and allocating distribution costs is reasonable for establishing the maximum amount to be recovered in the fixed or basic facilities charge.[1]

Q. WHAT ARE YOUR IMPRESSIONS OF THE PUBLIC STAFF'S REPORT?

A. I observe that the Public Staff recognizes that the NARUC CAM "continues to be considered an important resource for the calculation and allocation of electric utility cost of service for regulatory commissions, consumer advocates, and parties before the Commission testifying on issues of cost-of-service and rate design."[2] I also observe that the Public Staff agrees with the Company that distribution related costs have both demand-related and fixed characteristics. The Public Staff concludes that "[w]hile distribution related costs must be sized to meet some level of maximum demand, there is also a <u>minimum</u> cost for the distribution system that must be incurred regardless of demand."[3] (Emphasis in original.)

The Public Staff also has several observations regarding setting the Basic Customer Charge. For example, the Public Staff differentiates between

[1] Report of the Public Staff on the Minimum System Methodology of North Carolina Electric Public Utilities, March 280, 2019, Docket No. E-100, Sub 162, p 16-17.
[2] Ibid, p. 4.
[3] Ibid, p. 8.

the considerations in a COSS and Rate Design, the latter of which the Public Staff states should take additional things into consideration, such as policy objectives and appropriate price signals. Similar to Public Staff, I believe it is appropriate to keep a COSS free of biases and focus on cost causation.

4. Excess Deferred Income Tax Rider Rate Allocations

Q. CAN YOU EXPLAIN THE ALLOCATION FACTORS USED IN THE COMPANY'S EXCESS DEFERRED INCOME TAX RIDER?

A. Yes. The Company has allocated the benefits in the Excess Deferred Income Tax ("EDIT") rider also referred to as "EDIT-2" in Rate Design exhibits, to the classes based on the Accumulated Deferred Income Tax ("ADIT") allocator. I have reviewed this allocation and believe it is reasonable based on cost causation principles. Since the EDIT amounts were previously part of ADIT as explained by Company witnesses Smith and John Panizza, this is consistent with how the amounts were allocated prior to the federal tax rate change and reasonably reflect how the benefits were created.

5. Conclusion on Allocation Methodology

Q. ARE THE COMPANY'S CHOSEN METHODOLOGIES TO ALLOCATE ITS DEMAND-RELATED, ENERGY-RELATED AND CUSTOMER-RELATED COSTS REASONABLE AND APPROPRIATE UNDER THE CIRCUMSTANCES?

A. Yes. They are.

V. CONCLUSION

Q. DOES THE COMPANY'S COST OF SERVICE STUDY USED FOR THIS CASE PROPERLY DISTRIBUTE COSTS OF PROVIDING ELECTRIC SERVICE TO CUSTOMER CLASSES?

A. Yes. It does. The cost of service study provides a proper foundation for distributing costs among the jurisdictions and customer classes because it recognizes cost causation and dist ributes costs accordingly. This study also provides a proper basis for determining cost-based rates and is a major component of fair and equitable rate design. The cost of service study also provides an accurate measure of profitability among classes of customers.

Q. DID YOU VERIFY THAT THE COST OF SERVICE INFORMATION YOU ARE TESTIFYING TO WAS USED IN DETERMINING HOW TO DESIGN PROPOSED RATES?

A. Yes. The North Carolina retail cost of service information, including the separation of the demand, energy, and customer components of cost, was used in developing the rate design proposed by DE Progress.

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

A. Yes.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1219

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

I. INTRODUCTION AND PURPOSE

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

A. My name is Janice Hager, and my business address is 2049 Mount Zion Church Road, Alexis, North Carolina. I am President of Janice Hager Consulting.

Q. DID YOU SUBMIT DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes. I caused to be pre-filed direct testimony supporting the allocation of Duke Energy Progress, LLC's ("DE Progress" or the "Company") electric operating revenues and expenses and original cost rate base assigned to the North Carolina retail jurisdiction and to each customer class according to the cost of service studies performed by the Company.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to rebut various points and issues raised by intervenors in this docket regarding:

1) Allocation of demand-related production costs in the Company's Cost of Service ("COS") studies. Specifically, I address Public Staff witness James McLawhorn's summary/exhibits of COS methodologies and recommendation of Summer/Winter Peak and Average ("SWPA") for allocation of demand-related production costs and Carolina Industrial Group for Fair Utility Rates II ("CIGFUR") witness Nicholas Phillips' recommendation of use of Winter Peak for allocation of demand-related production costs;

2) Allocation of distribution costs, specifically DE Progress's design and use of the minimum system study approach to allocate customer-related distribution system costs;

3) Allocation of uncollectible costs;

4) Allocation of Grid Improvement Plan costs;

5) Allocation of coal ash compliance costs; and

6) Cost of service energy allocation within MGS sub-classes.

II. ALLOCATION OF DEMAND-RELATED PRODUCTION COSTS

Q. PUBLIC STAFF WITNESS MCLAWHORN DISCUSSES THE VARIOUS METHODOLOGIES FOR ALLOCATING DEMAND-RELATED PRODUCTION COSTS. PLEASE ADDRESS THOSE.

A. In response to the Commission's January 22, 2020 *Order Directing the Public Staff to File Testimony*, the Public Staff analyzed the differences between and among the various COS methodologies. The Public Staff analyzed the following methodologies:

SWPA – Summer/Winter Coincident Peak and Average Demand, which allocates a portion of the costs based on the average of the summer and winter peaks and a portion based on energy usage (expressed as average demand, the factor is total energy divided by the number of hours in the year)

SCP – Summer Coincident Peak

WCP – Winter Coincident Peak

SWCP – Summer/Winter Coincident Peak – an average of the summer and winter peaks

4CP – Four Coincident Peaks – an average of the four highest monthly peaks

12CP – Twelve Coincident Peaks – an average of the peaks for each month.

The analysis shows the methods dramatically shift the allocations between customer classes.[1] For example, moving from SCP to WCP to allocate demand-related production costs increases the allocation factor from 49.60% to 64.30% of the North Carolina Retail allocation for Residential customers while reducing the allocation factor from 28.18% to 20.21% for MGS customers.

Q. WHICH DEMAND ALLOCATOR DID THE COMPANY USE TO ASSIGN DEMAND-RELATED PRODUCTION AND TRANSMISSION COSTS TO JURISDICTIONS AND CUSTOMER CLASSES IN THIS CASE?

A. Demand-related production and transmission costs are allocated using the Summer Coincident Peak (SCP) method.

Q. PLEASE SUMMARIZE THE CONCEPT OF ALLOCATING COSTS BASED ON COINCIDENT PEAK.

A. A coincident peak ("CP") allocator assigns the fixed demand-related production and all transmission-related costs to the jurisdictions and customer classes in

[1] DE Progress has reviewed Mr. McLawhorn's calculations. While the Company may have calculated them a little differently, his analysis is useful for making general observations about the various methods.

proportion to their respective contribution to the system's peak hourly demand during the Test Period. Each jurisdiction and customer class' cost responsibility (*i.e.*, the percentage of the fixed portion of production and transmission demand costs assigned to each jurisdiction and customer class) is equal to the ratio of their respective demand in relation to the total demand placed on the system. The cost of service study supporting the Company's proposed rate design in this proceeding allocates the fixed portion of production and transmission demand-related costs based upon a jurisdiction's and customer class' coincident peak responsibility occurring during the summer, otherwise known as the Summer Coincident Peak or SCP Allocator.

Q. WHY DO YOU SUPPORT THE USE OF THE SCP ALLOCATOR?

A. Some of the reasons I support the use of SCP by DE Progress are:

1. The application of the summer peak load to allocate demand-related production and transmission costs is consistent with the Single Coincident Peak Method identified in the National Association of Regulatory Utility Commissioners ("NARUC") Electric Utility Costs Allocation Manual ("CAM")[2] with the recognition that an unusual situation was not addressed in the CAM. The unusual situation is the shifting from historically summer peak planning to winter peak planning, which I discuss below;
2. The predominance of the summer peak in DE Progress service territory.

[2] *Electric Utility Cost Allocation Manual*, National Association of Regulatory Utility Commissioners, January 1992.

As I noted in my direct testimony, in 14 of the last 25 years the system peak occurred in the summer[3];

3. The historical significance of the summer peak in DE Progress's expansion planning such that the majority of DE Progress's embedded generation fleet was built in response to summer peaks, thus making it appropriate to allocate these historically incurred costs;
4. The benefit of a cost allocation methodology that encourages the shifting of usage to off-peak times;
5. The value of sending consistent pricing signals by using a method that has been approved by this Commission for many years; and
6. The importance of a consistent cost allocation methodology among DE Progress's jurisdictions so that the Company does not under- or over-recover its costs.

Q. WHICH METHODOLOGY DOES THE PUBLIC STAFF RECOMMEND?

A. Witness McLawhorn testifies that the Public Staff recommends the use of a summer/winter coincident peak and average demand (SWPA) methodology for allocation of demand-related production plant and plant-related costs based on the belief that SWPA "more accurately reflects generation planning and customer usage than does SCP."[4] Witness McLawhorn states that "the SWPA

[3] The 2019 system peak was a winter peak; thus in 14 out of 26 years, the system peak has occurred in the summer.
[4] McLawhorn Direct Testimony, p. 6, lines 6-10.

methodology recognizes that some production plant costs are incurred primarily to provide sufficient capacity during peak periods, while other production plant costs are incurred because of the need to provide the lowest cost energy to customers during all hours."[5] He further states that an approach (such as SCP) "without an average component in the allocation factor … assumes that the Company's total production plant investment was made **only** to serve the peak load that occurs during one hour on a single day during the year."[6]

Q. DO YOU AGREE WITH HIS ASSESSMENT OF THE TWO METHODOLOGIES?

A. No. Witness McLawhorn's assertion that the SCP methodology only addresses the peak requirement of the capacity expansion planning process and places no value on the plants' requirement to produce energy at any time other than the peak hour is not the complete picture. Witness McLawhorn is focused on allocation of the demand-related production costs and ignores the energy-related costs, which the Company clearly takes into account when allocating production costs as described below. Looking at all production costs together provides the complete picture.

In developing a cost of service study, production costs are classified into demand and energy related costs. Plant capacity is considered fixed to meet demand and therefore, the cost of plant capacity was assigned to customers on the basis of their contribution to the summer coincident peak. Plant output in

[5] McLawhorn Direct Testimony, p.10, lines 11-15.
[6] McLawhorn Direct Testimony, p. 11, lines 10-15 (emphasis in original).

terms of kWh generation varies with the system energy requirements; therefore, all variable costs of production are assigned to customers based on their energy usage. In supporting the SWPA methodology, witness McLawhorn fails to acknowledge that the cost of service study in this proceeding already classifies over $2 billion of production costs (fuel, purchased power, O&M, etc.) as variable, and allocates these costs to the jurisdiction and customer classes using an energy allocator.

Q. WHAT ABOUT THE PUBLIC STAFF'S ARGUMENT THAT SOME PORTION OF BASE LOAD PLANT SHOULD BE CLASSIFIED AS ENERGY-RELATED?

A. Witness McLawhorn correctly describes the integrated resource planning process, which looks at total costs in choosing the appropriate mix of generation resources. DE Progress's generation system includes a robust mix of baseload, intermediate, and peaking resources. Baseload plants have historically had higher capital costs and lower energy costs than peaking resources. This tradeoff is a key reason for integrated resource planning, which analyzes the total cost of resource mix options to choose the mix that produces the best overall least cost option. The resulting generation capital costs in rate base, which are being allocated for ratemaking purposes are a compilation of all the resources, almost all of which were placed into rate base prior to the shift to a winter emphasis in integrated resource planning in 2016. At the same time, the energy and energy-related production costs that are being allocated for ratemaking purposes in this case are tied to the generation mix that produces the energy.

Q. WHAT IS THE PRACTICAL IMPACT OF THE PUBLIC STAFF'S PROPOSED METHODOLOGY?

A. If adopted, the SWPA method would allocate approximately 54% of DE Progress's fixed demand costs using an energy allocator. This approach leads to a higher portion of the fixed costs being assigned to higher load factor customers. Advocates for this method feel this is equitable on the theory that high load factor customers benefit from the lower energy costs that result from the operation of base load plants as opposed to the higher energy costs of peaking plants. But proponents never carry this argument to its logical conclusion. That is, those customers allocated the higher capital costs based on energy usage, should be allocated the lower variable operating costs of those same base load facilities. If the primary theory behind the use of the SWPA allocation methodology is that fixed production plant costs are incurred to meet both capacity and energy requirements, then consideration should also be given to the variable operating costs. It seems only fair and equitable that high load factor customers should be allocated more of the lower variable energy costs, while low load factor customers should be allocated more of the higher variable energy costs.

The SWPA method allocates more of the demand-related production costs to higher load factor customers. Did higher load factor customers *cause* the Company to build base load plants and lower load factor customers *cause* peaking plants? I contend the answer to both questions is "no." All customers in aggregate "caused" the whole of the resource mix and should share equally in the costs based on their contribution to the recognized demand allocator, this is, peak demand.

Witness McLawhorn points to the Electric Vehicle (EV) Pilot pending before the Commission in Docket No. E-2, Sub 1197, as an example of a rate class inappropriately benefiting from the SCP methodology. He states that "under the SCP methodology, none of the energy needs for EV load that is managed at the time of the summer peak would be used to allocate production plant to that class, even though the load will be present during the remainder of the year."[7] In fact, it is common sense that it is beneficial for customers to charge their vehicles at night when there is excess capacity available, and that customers should get a reduced rate when doing so because they are not driving any incremental capacity/demand-related costs on the system. The EV Pilot would require all participants to use the Company's Time of Use rates for metering the EV load. These rates encourage the shifting of load not just one hour of the year, but each and every day. However, the Public Staff's proposal that more than half of demand related costs should be allocated based on energy would reduce participants' incentives to reduce load. Under the energy component of the Public Staff's proposal, an electric vehicle owner who

[7] McLawhorn Direct Testimony, p. 15, line 15 – p. 16, line 11.

charges in the middle of the night would be allocated the same amount of fixed plant costs as someone who uses the same amount of electricity in the middle of a hot summer afternoon. Intuitively, we know this is not right, which illustrates why the Public Staff's proposed SWPA method should be rejected. The allocation of DEMAND-related production costs based on DEMAND and ENERGY-related production costs based on ENERGY is the appropriate allocation methodology in my opinion.

Q. THE PUBLIC STAFF POINTS TO THE INTRODUCTION OF WINTER PEAK FOR INTEGRATED RESOURCE PLANNING PURPOSES. PLEASE ADDRESS.

A. Historically, DE Progress and Duke Energy Carolinas, LLC ("DE Carolinas") conducted their integrated resource planning by focusing on the summer peak demand and the resources needed to meet that load plus an adequate planning reserve margin. One factor that helped to ensure that meeting a summer peak ensured adequate resources for a winter peak is the fact that natural gas-fired resources historically had significantly greater potential MW output in the winter due to the colder, drier intake air. Therefore, even if the summer and winter peaks were close, planning focused on the need to meet the summer reserve margin. However, beginning in 2016, DE Progress began focusing more on the winter-peak generation resource planning. A key driver for this change is the fact that the load and resource balance has changed drastically in the past few years, driven primarily by the high penetration of solar resources as well as the significant load response to recent cold weather. High levels of solar penetration do not contribute to DE Progress's or DE Carolinas' ability to meet winter peak load. Therefore in 2016, DE Progress's and DE Carolinas' integrated resource planning transitioned to winter capacity planning. By focusing on the winter peak load and the required winter reserve margin, Duke Energy can assure that summer peak loads are met as well. While winter peak planning will likely continue, both summer and winter peaks are important in the planning process. And, as noted earlier, the assets for which cost recovery is sought in this case are largely the result of an emphasis on summer peak planning.

Q. HAS THE PUBLIC STAFF INTRODUCED ANY NEW EVIDENCE IN THIS PROCEEDING TO JUSTIFY COMMISSION ADOPTION OF THE SWPA METHODOLOGY COMPARED TO PREVIOUS PUBLIC STAFF RECOMMENDATIONS?

A. Not in my opinion. Witness McLawhorn points to Commission orders in DE Progress and Dominion Energy North Carolina ("DENC") and concludes, "Thus, what the Commission has found in past rate cases for DEP and DENC holds true today for DEC – the appropriate cost-of-service methodology must consider overall energy consumption and peak demand."[8] In each of these cases, the Commission found that use of SWPA was most appropriate in each case based on the testimony and circumstances of *that particular case*; however,

[8] McLawhorn Direct Testimony, p. 22, lines 28-31.

the Commission has also found the use of Summer CP to be appropriate based on the testimony and circumstances in other cases. In fact, in the recent Commission order in the DENC Rate Case in Docket No. E-22, Sub 562, the Commission found and concluded "that cost allocation does not lend itself to a one size fits all approach, and the specific circumstances of each utility must be considered when determining the appropriate cost allocation methodology for that utility."[9] Here, as explained throughout my testimony and as the Commission held in the 2012 DE Progress rate case, the circumstances specific to DE Progress demonstrate that SCP is the most appropriate allocation methodology for the Company. Indeed, while witness McLawhorn references DE Progress rate cases from the 1980s, he fails to mention the Commission's more recent order on this issue for DE Progress. In the Commission's order in DE Progress's 2012 rate case (Docket No. E-2, Sub 1023), the Commission ruled that SCP was the most appropriate method for DE Progress, not SWPA, despite the Public Staff making many of the same arguments that they have made in this case. The Commission found and concluded, "that the summer coincident peak (1 CP) method is the most appropriate method for allocating costs between jurisdictions and between customer classes within the North Carolina retail jurisdiction for DEP in this proceeding. The Commission,

[9] *Order Accepting Public Staff Stipulation in Part, Accepting CIGFUR Stipulation, Deciding Contested Issues, and Granting Partial Rate Increase,* issued on February 24, 2020, in Docket No. E-22, Sub 562, p. 72.

having considered all of the evidence presented, finds that the 1 CP methodology is just and reasonable to all parties."[10]

I would also note that DE Progress has been consistent in its allocation of production costs for many years. The Company has not switched methodologies to maximize allocation to a specific jurisdiction from case to case. The Company has sought to have a consistent methodology between jurisdictions to the extent possible.

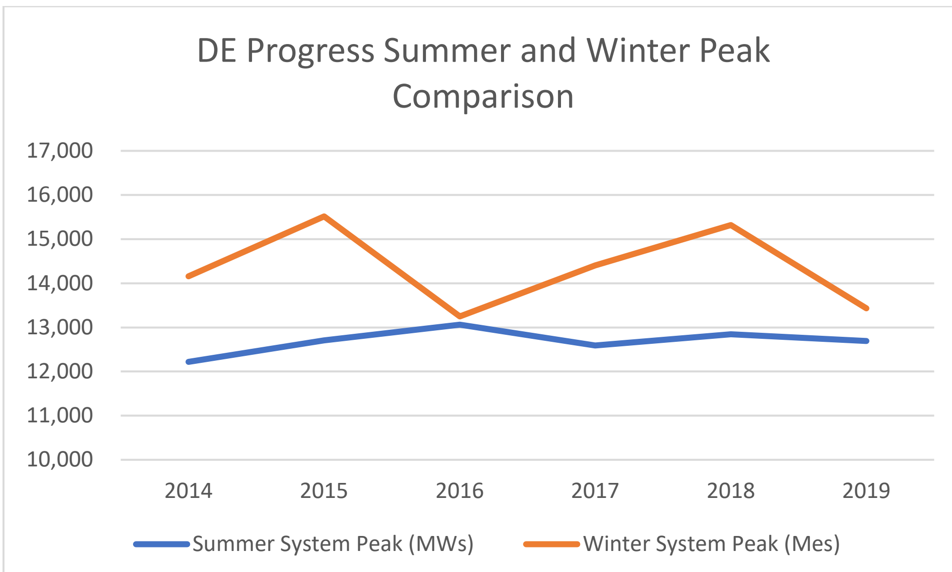
I continue to believe the Company's proposal to allocate demand-related production costs based on Summer CP is sound as explained in my direct and in this rebuttal testimony.

Q. CIGFUR WITNESS PHILLIPS RECOMMENDS USE OF THE WINTER PEAK FOR ALLOCATION OF DEMAND-RELATED PRODUCTION AND TRANSMISSION COSTS. DO YOU AGREE WITH HIS RECOMMENDATION?

A. No. First, given that the generation and transmission asset costs to be recovered in this proceeding were constructed based upon customers' contribution to the Summer CP, the proper response to this situation is to use the Summer CP in this case for cost of service and to focus on the converging summer and winter peaks in the rate design as has been done by Company witness Michael Pirro.

[10] *Order Granting General Rate Increase*, issued on May 31, 2013, in Docket No. E-2, Sub 1023, p. 14. While the Commission allowed DE Progress to continue to use SCP in the Company's last rate case, it was a result of a stipulation between the Public Staff and the Company in that case and is not precedential. *See Order Accepting Stipulation, Deciding Contested Issues and Granting Partial Rate Increase*, issued on February 23, 2018, in Docket No. E-2, Sub 1142, p. 104.

Second, I have concerns with the volatility of the winter peak and the volatility that using a single winter peak could introduce into customer rates. Witness McLawhorn's testimony demonstrates this. He notes that the Company had forecasted the 2018 peak to be in the winter, 283 MWs higher than the summer peak but, instead, the winter peak was more than 2400 MWs higher than the summer peak that year.[11] The graph below depicts the summer and winter peaks over the past 6 years. This volatility in the single winter peak makes it less than optimal for use in cost allocation.



Third, even in the future, an appropriate allocation method would need to give some weight to the summer peak. For example, some of the demand related production costs are costs of solar generation. This generation does not typically generate energy at the time of the winter peak, and so to allocate its costs based on a winter peak would be inappropriate. Also, the summer peaks

[11] McLawhorn Direct Testimony, p. 8, lines 5-8.

continue to be strong in the DE Progress service territory. In the test year, three of the four highest monthly peaks occurred in the summer. This trend continued in 2019, and while the highest peak during 2019 was in the winter, it was 740 MW higher than the summer peak, versus the greater than 2,400 MW difference observed in 2018. This is an important consideration for the utility when looking at the volatility of allocators.

I recommend that the Company continue to monitor the projected and actual monthly peaks and the key drivers for and the amount of investments in production plant in order to identify when and if a different allocation method should be proposed in future rate cases. The Company is open to looking at allocation methods that appropriately reflect the nature of its system demands and that also do not introduce excessive volatility into cost allocations and customer rates in future proceedings. Some of these methods the Company may evaluate in future rate cases may include the 4CP or 12CP allocation approaches also mentioned in the testimony of witness McLawhorn. These methods continue to give some weight to the summer months, are less volatile than the WCP method, and do not allocate demand costs based on an energy allocator. As witness McLawhorn noted, the 12CP method has historically been utilized by the Federal Energy Regulatory Commission for its COS purposes. The 4CP method is a common alternative. While the appropriate method will depend on the unique characteristics of a specific utility's load, these are two methods that the Company could evaluate as its demand profile changes.

III. MINIMUM SYSTEM STUDY

Q. WHAT ISSUES ARE RAISED BY INTERVENORS REGARDING USE OF A MINIMUM SYSTEM STUDY TO ALLOCATE A PORTION OF DE PROGRESS'S DISTRIBUTION COSTS TO CUSTOMERS?

A. North Carolina Justice Center, North Carolina Housing Coalition, Natural Resources Defense Council, and Southern Alliance for Clean Energy ("NCJC, et al.") is the only party objecting to the Company's use of the Minimum System Concept in allocating distribution costs. NCJC, et al. witness Jonathan Wallach testified that the Commission should direct the Company to discontinue use of the minimum system method for classifying distribution costs for cost of service purposes.[12] CIGFUR witness Phillips agreed with the Company's use of the minimum system method.[13]

Q. WHAT IS THE THEORY BEHIND MINIMUM SYSTEM?

A. The theory behind the use of a minimum system study is sound and consistent with cost causation which is the bedrock of COS studies. DE Progress's Minimum System Study allowed DE Progress to classify the distribution system into the portion that is customer-related (driven by number of customers) and the portion that is demand-related (driven by customer peak demand levels). Every customer requires some minimum amount of wires, poles, transformers, etc. to receive service; therefore, every customer "caused"

[12] Wallach Direct Testimony, p. 3, lines 18-20.
[13] Phillips Direct Testimony, p. 14, lines 3-12.

DE Progress to install some amount of such distribution assets.[14] The concept DE Progress used to develop its minimum system study was to consider what distribution assets would be required if every customer had only some minimum level of usage (e.g., one light bulb). This methodology allows the utility to assess how much of its distribution system is installed simply to ensure that electricity can be delivered to each customer, regardless of the customer's frequency of use. Without the minimum system, low use customers could avoid paying for the infrastructure necessary to provide service to them which is counter to cost causation principles. Once minimum system costs have been identified, all distribution costs over the minimum system costs are determined to be driven by demand.

Q. WHAT ARE WITNESS WALLACH'S SPECIFIC OBJECTIONS TO THE MINIMUM SYSTEM METHOD, AND WHAT IS YOUR RESPONSE TO THOSE OBJECTIONS?

A. Witness Wallach urges the Commission to reject the Company's proposed allocations used in justifying its base revenue increase. His recommendation is based on his conclusion that the Company's cost of service allocates too much cost to residential customers because it has relied on the concept of minimum system and because of how the Company has allocated the remaining

[14] On page 13 and 14 of his testimony, Mr. Wallach offers an example of an apartment building and a large commercial load as illustrative examples of the unfairness of the minimum system concept. Allocation of costs and rate designs are based on creating large "buckets" of costs and large groups of similarly situated customers. Naturally, within each bucket, the cost of serving an individual customer will be, in some cases, greater than the costs allocated to the customer and, in other cases, less than the costs allocated to the customers. This fact does not make the methodology unfair.

distribution costs based on non-coincident peak.[15] He urges the Commission to "give no weight" to the Public Staff's endorsement of minimum system classification method, because Mr. Wallach believes that Public Staff's recommendations are based on the "unsubstantiated belief that there is a minimum portion of the cost of the distribution grid which is incurred regardless of demand."[16]

I disagree that the Public Staff's belief is "unsubstantiated." On the contrary, the NARUC CAM substantiates the concept.

Q. WHAT DOES THE NARUC CAM SAY ABOUT ALLOCATION OF DISTRIBUTION COSTS TO CUSTOMERS?

A. The NARUC CAM specifically states in the section on allocation of embedded costs that "the number of poles, conductors, transformers, services, and meters are directly related to the number of customers on the utility's system"[17] The Public Staff recognizes that the NARUC CAM "continues to be considered an important resource for the calculation and allocation of electric utility cost of service for regulatory commissions, consumer advocates, and parties before the Commission testifying on issues of cost-of-service and rate design."[18] The

[15] Wallach Direct Testimony, p.3, lines 10-17.
[16] Wallach Direct Testimony, p.50, lines 6-9.
[17] NARUC CAM, p. 90. It is only in the marginal cost allocation section that the basic customer method is included in the NARUC CAM. Most utilities, including DE Progress, have traditionally allocated costs using an embedded cost, as opposed to a marginal cost, methodology. The major problem with allocating costs based on marginal costs is that marginal-cost based rates will only "by rare coincidence" yield allowed revenue requirements, thus requiring some form of reconciliation. (NARUC CAM, page 14.) No party in this proceeding (even NCJC, et al. as far as I can tell) is advocating moving from an embedded cost of service to a marginal cost of service.
[18] Ibid, p. 4.

Manual suggests two methods of allocating embedded distribution costs, both of which would identify a portion of FERC distribution asset accounts 364 to 368 as customer-related and a portion as demand-related. Therefore, Mr. Wallach's proposal suggesting the Company adopt the basic customer method and all of accounts 364-368 should be allocated based on demand, with none allocated to the customer component, is inconsistent with the NARUC CAM.[19]

Q. IN ADDITION TO THE NARUC CAM, WHAT ARE OTHER REASONS THAT THE USE OF A MINIMUM SYSTEM STUDY IS APPROPRIATE TO ALLOCATE A PORTION OF THE DISTRIBUTION COSTS?

A. The three utilities in North Carolina have a long history of using minimum system studies to identify the portion of distribution costs that are customer-related. In addition, as I noted in my Direct Testimony, in its Report on the Minimum System Methodology in NCUC Docket No. E-100, Sub 162, the Public Staff concluded that the use of the Minimum System Method for classifying and allocating distribution costs is reasonable for establishing the maximum amount to be recovered in the fixed or basic customer charge.[20] The Public Staff agrees with the Company that distribution related costs have both demand-related and fixed characteristics. The Public Staff concludes that "[w]hile distribution related costs must be sized to meet some level of

[19] Wallach Direct Testimony, p.17, lines 21-22. While Mr. Wallach calls the Basic Customer Method "a best practice" on page 15 of his testimony, his only citation is to a very recently published work by the Regulatory Assistance Project.
[20] Report of the Public Staff on the Minimum System Methodology of North Carolina Electric Public Utilities, March 28, 2019, Docket No. E-100, Sub 162, p 16-17.

maximum demand, there is also a minimum cost for the distribution system that must be incurred regardless of demand."[21] (Emphasis in original.)

The Public Staff also has several observations regarding setting the Basic Customer Charge. For example, the Public Staff differentiates between the considerations in a COS study and Rate Design, the latter of which the Public Staff states should take additional things in consideration such as policy objectives and appropriate price signals. Similar to Public Staff, I believe it is appropriate to keep a COS study free of biases and focus on cost causation.

Q. WHAT DOES MR. WALLACH SAY ABOUT THE COST THAT A NO-LOAD CUSTOMER WOULD IMPOSE ON THE SYSTEM?

A. Mr. Wallach offers that 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."[22] I would first note that the minimum system methodology is based on a small load, not zero load. However, his example serves to make my point as well. Suppose the Company had built a distribution system for customers who subsequently stopped placing any load on the system. If costs have been allocated and rates designed to recover costs on volumetric or demand rates, then there is no opportunity for the Company to recover these costs.

[21] Ibid, p. 8.
[22] Wallach Direct Testimony, p. 32, lines 6-8. Mr. Wallach includes a footnote on page 11 of his testimony which says, "In fact, it is unlikely that DEP would incur the cost to connect a zero- or minimum-load customer under the Company's line extension policies and would instead require the zero-load customer to bear any such connection costs." He then references the Company's Line Extension Plan. However, there is no mention of connection of a zero load customer in the Company's Line Extension Plan, probably because it is such a ludicrous scenario.

Distribution equipment with "zero load" that was installed to ensure a customer could receive electricity still has a cost that must be borne by someone under utility ratemaking principles. If these costs are recovered using a demand allocator instead of minimum system study, customers with higher usage are subsidizing those with lower usage. Under the minimum system concept, all customers are appropriately allocated costs for equipment that stands ready to provide their electrical needs.

In reality, a customer that has no demand for electricity would have no need to be connected to the distribution system. Frankly, a customer who does not intend to use any electricity wouldn't be a customer and wouldn't be billed at all. But if someone, for whatever reason, wants electricity to light a single 100-Watt light bulb, that customer will require distribution assets such as poles and conductors and transformers to deliver that electricity.

Q. HOW DOES WITNESS WALLACH ATTEMPT TO JUSTIFY HIS OPPOSITION TO THE ALLOCATION OF MINIMUM SYSTEM COSTS TO THE CUSTOMER CLASS?

A. Witness Wallach contends that 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."[23] His next sentence quotes Bonbright's *Principles of Public Utility Rates* to support his argument noting that the text says that metering and billing expenses are "the most

[23] Wallach Direct Testimony, p. 28, p. 17-19.

obvious examples" of customer costs.[24] He fails to mention that the quoted text does not say these are the only costs.

While it is true that Dr. Bonbright recognizes the difficulty of determining the proper allocation for the minimum system costs, he concludes that the exclusion of minimum system costs from demand-related costs is on "much firmer ground" than its exclusion from customer costs.[25] Ultimately, however, he recognizes that utilities must distribute all costs among the classes of customers in a fully-distributed cost analysis.[26] But, even more important, is the NARUC CAM that was developed after Dr. Bonbright's work. The CAM, developed by a large group of mostly state utility commission and FERC staff members (including North Carolina representatives Dennis Knightingale and Ben Turner), moved from the theoretical world of Dr. Bonbright to the reality of utilities' needs to move from development of revenue requirements to rate structures. The full allocation of all costs is a critical step in the cost of service study process. As I noted in earlier in this testimony, the CAM states that a portion of the distribution costs ARE customer-related.

[24] James C. Bonbright, *Principles of Public Utility Rates.* Columbia University Press (1961 edition), p. 311.
[25] Bonbright, pp. 348.
[26] Bonbright, pp. 348-349. "Fully distributed cost analysis" is a synonym for cost analyses based on embedded instead of marginal costs.

IV. ALLOCATION OF UNCOLLECTIBLE COSTS

Q. IS IT APPROPRIATE TO INCLUDE UNCOLLECTIBLE COSTS IN THE CUSTOMER CLASSIFICATION FOR INCLUSION IN THE BASIC CUSTOMER CHARGE?

A. Yes. Witness Wallach makes an unsupported claim that these costs "tend to vary with revenues and thus with usage."[27] DE Progress has historically treated these as a customer cost in the same category as other FERC Customer Accounting Accounts. This is a reasonable assumption.

V. ALLOCATION OF GRID IMPROVEMENT PLAN INVESTMENTS

Q. THE PUBLIC STAFF RECOMMENDS THAT THE COMMISSION DIRECT DE PROGRESS TO STUDY THE ALLOCATION OF GRID IMPROVEMENT PLAN INVESTMENTS BASED ON THE ALLOCATION OF THE REALIZED BENEFITS OF THOSE INVESTMENTS AND REPORT ITS FINDINGS IN THE NEXT RATE CASE.[28] HOW DO YOU RESPOND?

A. The Company has proposed allowing the investments associated with the Grid Improvement Plan to follow the same cost causation principles that are applied to the investments in the same FERC accounts as reflected in the COS Study. While I have not looked at these costs in particular, it is my opinion that attempting to allocate ANY investment costs for ratemaking purposes based on perceived benefits realized by customers, as differentiated from cost causation

[27] Wallach Direct Testimony, p. 30.
[28] Thomas Direct Testimony, p. 55.

to the utility, is likely to be very subjective and thus controversial. One need look no further than Public Staff witness Jeff Thomas's own testimony, which analyzes the customer benefits discussed by DE Progress witness Jay Oliver to see there are differing opinions on how to quantify customer benefits.[29]

VI. ALLOCATION OF COAL ASH COSTS

Q. HAS ANY INTERVENOR QUESTIONED THE COMPANY'S ALLOCATION OF COAL ASH COMPLIANCE COSTS?

A. Yes. Carolina Utility Customers Association witness Kevin O'Donnell suggests that it is more appropriate to allocate coal ash costs consistent with the allocation of fuel in its most recent fuel case, a fixed equal percent share method.[30]

Q. WHAT IS DE PROGRESS'S RESPONSE?

A. DE Progress does not support this proposed method. DE Progress used an energy allocation factor in compliance with the Commission's Order in DE Progress's most recent rate case.[31] The method proposed here by witness O'Donnell is not consistent with that order, nor does it follow cost causation principles. Costs are not "caused" by the relative impact of rates on classes of customers.

[29] See, for example, Thomas Direct Testimony, p. 12, line 3, through p. 13, line 4.
[30] O'Donnell Direct Testimony, p. 51, lines 21-22.
[31] *Order Accepting Stipulation, Deciding Contested Issues and Granting Partial Rate Increase*, issued on February 23, 2018, in Docket No. E-2, Sub 1142, pp. 19, 219-21.

VII. ENERGY ALLOCATIONS WITHIN MGS SUB-CLASSES

Q. DO YOU AGREE WITH COMMERCIAL GROUP WITNESS STEVE CHRISS'S RECOMMENDATION THAT THE COMPANY RE-RUN ITS COST OF SERVICE STUDY USING REVISED ENERGY ALLOCATORS WITHIN THE MGS RATE CLASSES?

A. No. As the Commercial Group pointed out, the Company did inadvertently transpose energy billing determinants used to calculate energy unit costs between the SGS-TOU and other MGS rate classes.[32] However, as the Company clarified in its response to the Commercial Group's data request noting this error,[33] this transposition was isolated to the calculation of billing determinants and did not impact the Company's cost of service allocations or its filings under E-1, Item 45 which reflected the correct allocators for those classes. In addition, those energy billing determinants were not used by Mr. Pirro in rate design.

VIII. CONCLUSION

Q. IN CONCLUSION, DO YOU CONTINUE TO BELIEVE THE METHODOLOGIES USED BY DE PROGRESS IN CONDUCTING ITS COST OF SERVICE STUDY FOR THIS CASE ARE APPROPRIATE AND REASONABLE?

A. Yes.

[32] Chriss Direct Testimony, p.18, line 15 – p. 19, line 2.
[33] DE Progress's Supplemental Response to Commercial Group Data Request 1-4.

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

A. Yes.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1219

In the Matter of: Application of Duke Energy Progress, LLC For Adjustment of Rates and Charges Applicable to Electric Service in North Carolina	))))))))	**DUKE ENERGY PROGRESS, LLC'S CORRECTIONS TO REBUTTAL TESTIMONY OF JANICE HAGER**

CORRECTIONS TO REBUTTAL TESTIMONY OF JANICE HAGER

PAGE 19, FOOTNOTE 18 SHOULD READ:	REASON FOR CHANGE:
~~Ibid, p. 4.~~ Report of the Public Staff on the Minimum System Methodology of North Carolina Electric Public Utilities, March 28, 2019, Docket No. E-100, Sub 162, p. 4.	Replaced "Ibid." with full citation since reference to this source had not yet been made.

I am the Cost of Service witness for Duke Energy Progress. Utilities use Cost of Service Studies to spread to customer classes the revenue requirements identified by the Company for recovery. Using the principle of cost causation, revenues, expenses, and rate base costs are assigned to the specific jurisdictions and customers classes that "caused" such costs to be incurred.

Parties in this case are not challenging many of the cost allocation methods proposed by the Company. While the Public Staff initially opposed Duke Energy Progress's proposal to use the Summer Coincident Peak (SCP) method to allocate production and transmission demand-related costs, this issue has since been resolved by the Second Partial Settlement between the parties. The North Carolina Justice Center group of intervenors (NCJC, et al.) is challenging the Company's continued use of the minimum system method of allocating some distribution costs.

Duke Energy Progress has used the summer coincident peak demand to allocate production and transmission demand-related costs since the Commission approved this methodology in the Company's 2013 rate case. I continue to believe that SCP is the most appropriate methodology for Duke Energy Progress for a number of reasons, including: the predominance of the summer peak in the Company's service territory, the historical significance of the summer peak in Duke Energy Progress's planning process, the fact that the majority of the Company's embedded generation fleet was built in response to summer peaks, and the benefit of a cost allocation methodology that encourages the shifting of usage to off-peak times. In its Second Partial Settlement with the Company, the Public Staff has agreed, for purposes of settlement, that the Company may use the SCP methodology in this case.

As I explain in my rebuttal testimony, all customers in aggregate "caused" the whole of the resource mix and should share equally in the costs based on their contribution to the recognized demand allocator, that is, peak demand. CIGFUR agrees that it is appropriate for the Company to use a coincident peak methodology, but proposes that the Company switch to a Winter Peak demand allocator. While it is true that the Company has shifted to winter planning, the assets included for cost recovery in this case were incurred based on summer peak planning. The Company is open to looking at other allocation methods in the future, looking for methods that would appropriately reflect the nature of system demands and that also do not introduce excessive volatility into cost allocations and customer rates in future proceedings. For instance, in its Settlement Agreement with CIGFUR, the Company has agreed to consider and file the results of a class cost of service study using the Summer/Winter Coincident Peak method in its next general rate case, and in its Second Partial Settlement with the Public Staff, the Company has agreed to analyze and develop cost of service studies under at least six different methodologies.

NCJC, et al. witness Jonathan Wallach testified that the Commission should direct the Company to discontinue use of the Minimum System Method for classifying distribution costs for cost of service purposes. The concept of minimum system is that some minimum amount of assets classified as distribution assets are in place in order to be available to serve customers, regardless of customer demand. Therefore, distribution asset costs should be allocated partly on the basis of the number of customers and partly based on the demand of those customers. In its report on Minimum System ordered by this Commission, the Public Staff concluded that the use of the Minimum System Method for classifying and allocating distribution costs is reasonable for establishing the maximum amount to be recovered in the fixed or basic customer charge.

In conclusion, I continue to believe the methodology used by Duke Energy Progress in conducting its Cost of Service Study for this case is appropriate and reasonable.

BY MS. JAGANNATHAN:

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

A (Mr. Pirro) Michael J. Pirro, 550 South Tryon Street, Charlotte, North Carolina.

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

A Duke Energy Carolinas, employed as Director of Pricing and Regulatory Solutions transitioning into Director of Load Forecasting.

Q Thank you, Mr. Pirro. And on October 30th, 2019, did you cause to be prefiled in this docket direct testimony consisting of 36 pages as well as eight exhibits to that testimony.

A I did.

Q And on November 22nd, 2019, did you cause to be filed a corrected version of Pirro Exhibit 2?

A That is correct.

Q And on March 4th, 2020, did you cause to be filed a corrected version of Pirro Exhibit 4.

A I did.

Q On March 13th, 2020, did you cause to be prefiled in this docket supplemental direct testimony consisting of five pages as well as Pirro

Supplemental Exhibit 2 and Pirro Supplemental Exhibit 4?

A I did.

Q On May 4th, 2020, did you cause to be prefiled in this docket rebuttal testimony consisting of 23 pages?

A Yes, that's correct.

Q On July 2nd, 2020, did you cause to be prefiled in this docket second supplemental testimony consisting of three pages?

A I did.

Q On August 21st, 2020, did you cause to be prefiled in this docket second supple -- sorry, second settlement testimony consisting of four pages as well as Pirro Second Settlement Exhibit 4 and Pirro Second Settlement Exhibit 8?

A I did.

Q And, finally, on September 23rd, 2020, did you cause to be prefiled in this docket joint supplemental rebuttal testimony with Lon Huber consisting of eight pages?

A Yes, that is correct.

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

A I do not.

Q And if I were to ask you the same questions included in your prefiled testimony here today, would your answers be the same?

A Yes, they would.

Q And did you prepare a summary of your prefiled testimony?

A Yes.

Q Okay.

Commissioner Clodfelter, I would move that Mr. Pirro's prefiled testimony as well as his summary of that testimony be entered into the record as if given orally from the stand and that his exhibits be marked for identification as prefiled.

COMMISSIONER CLODFELTER: Hearing no objections, it will be so ordered.

MS. JAGANNATHAN: Thank you.

(WHEREUPON, Pirro Exhibits 1 - 8, Pirro Revised Exhibit 2, Pirro Corrected Exhibit 4, Pirro Supplemental Exhibits 2 and 4, and Pirro Second Settlement Exhibits 4 and 8 are marked for

identification as prefiled.)
(WHEREUPON, the prefiled direct, supplemental direct, rebuttal, second supplemental, second settlement testimony, and summary of Michael Pirro is copied into the record as if given orally from the stand.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1219

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

I. <u>INTRODUCTION AND PURPOSE</u>

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

A. My name is Michael J. Pirro, and my business address is 550 South Tryon Street, Charlotte, North Carolina 28202. I am Director, Southeast Pricing & Regulatory Solutions for Duke Energy Business Services with responsibilities for Duke Energy Progress, LLC ("DE Progress" or the "Company"), Duke Energy Carolinas, LLC ("DE Carolinas"), and Duke Energy Florida, LLC ("DE Florida").

Q. WHAT ARE YOUR RESPONSIBILITIES AS DIRECTOR, SOUTHEAST PRICING & REGULATORY SOLUTIONS?

A. My primary responsibility is to provide rate analysis, tariff administration and to develop the rates and charges contained in tariffs and electric service contracts for Duke Energy Corporation's ("Duke Energy") Southeast utility operating companies, including DE Progress.

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

A. I received a Bachelor of Science degree in Business Administration from Le Moyne College in 1989. In August 1989, I began work for Niagara Mohawk in Syracuse, New York in its Rates & Regulatory Department as a Senior Analyst responsible for the Company's operating revenue forecast. In 1996, I accepted a position as Senior Special Contract Analyst for Niagara Mohawk. In 1999, I joined Niagara Mohawk's Customer Accounting organization where I held the position of Manager, Complex Billing. In 2005, I joined the Collections organization as a

Principal Collection Specialist. In 2008, I joined the Operations Department as Principal Settlement Analyst responsible for New York Independent System Operator settlement. In 2013, I left Niagara Mohawk and accepted a position in the Customer Care section of Pacific Gas and Electric's General Rate Case core team. I began my employment with Duke Energy in 2016, and currently, I am the Director, Southeast Pricing and Regulatory Solutions, overseeing rate design for DE Carolinas, DE Progress, and DE Florida.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION OR OTHER STATE UTILITY REGULATORY COMMISSIONS?

A. Yes. I testified before the North Carolina Utilities Commission (the "Commission") in DE Carolinas' last general rate case proceeding in Docket No. E-7, Sub 1146 and recently filed testimony in DE Carolinas' pending rate case in Docket No. E-7, Sub 1214. Also, I testified before the South Carolina Public Service Commission in DE Carolinas' last general rate case proceeding in Docket No. 2018-319-E.

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

A. My testimony demonstrates that the rates DE Progress proposes reflect appropriate rate making principles and result in an equitable basis for recovery of the Company's revenue requirements across and within its various customer classes and rate schedules. My testimony: (1) describes the changes to the Company's retail electric rate schedules; (2) quantifies the effect of these proposed changes on the Company's North Carolina retail electric customers; (3) discusses how DE Progress proposes to implement the tariffs approved by the Commission in this proceeding; and (4) describes other requested changes to the Company's tariffs and service regulations.

Q. PLEASE DESCRIBE THE EXHIBITS ATTACHED TO YOUR TESTIMONY.

A. The exhibits to my testimony are as follows:

- Pirro Exhibit 1 consists of the North Carolina Retail Electric Rate Schedules and Service Regulations that DE Progress proposes to be effective for service rendered on and after November 29, 2019. In the event the Commission suspends rates in this proceeding, the Company requests rates to be effective no later than September 1, 2020. This exhibit is the same as Exhibit B to the Company's Application in this docket.
- Pirro Exhibit 2 sets forth the North Carolina retail rate design revenues under the Company's present and proposed rate schedules, including the effects of the proposed change in the North Carolina Excess Deferred Income Tax Rider 1 ("EDIT-1 Rider"), the Excess Deferred Income Tax Rider ("EDIT-2 Rider") and the Regulatory Asset and Liability Rider RAL-1 ("RAL-1").
- Pirro Exhibit 3 shows bill comparisons between the Company's present and proposed rates.
- Pirro Exhibit 4 provides a comparison of rate of return by rate class.
- Pirro Exhibit 5 provides a historical comparison of return on rate base by rate class.
- Pirro Exhibit 6 provides a statement regarding the probable effect of proposed rates on peak demand and sales. This exhibit is the same as Exhibit D to the Company's Application in this Docket.

- Pirro Exhibit 7 describes the cost basis and proposed Basic Customer Charges for the major customer classes.
- Pirro Exhibit 8 provides the derivation of the Company's proposed EDIT-2 Rider that describes rate credits associated with changes in federal and North Carolina corporate income tax rates.

Q. WERE PIRRO EXHIBITS 1 THROUGH 8 PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes. They were.

II. SUPPORT OF PRO FORMA ADJUSTMENTS

Q. DID YOU PROVIDE ANY DATA USED IN CONNECTION WITH THE PRO FORMA ADJUSTMENTS MADE TO THE TEST PERIOD IN THIS PROCEEDING?

A. Yes. I provided the retail sales and number of customers to Company Witness Kim Smith for use in calculating the pro forma adjustment to growth in customers in this proceeding.

Q. WAS ANY INFORMATION PROVIDED UNDER YOUR RESPONSIBILITY USED IN CONNECTION WITH THE PRO FORMA ADJUSTMENTS MADE TO THE TEST PERIOD IN THIS PROCEEDING?

A. Yes. I provided the annualized revenue under current rates which was used in connection with the pro forma adjustments. This adjustment was used to establish annual revenues in the cost of service study. Revenue is exclusive of revenues derived from (1) Fuel Deficiency Rider FED and Fuel Experience Modification Factor ("EMF") rates, both approved in Docket No. E-2, Sub 1142, (2) Demand-

Side Management ("DSM") and Energy Efficiency ("EE") rates, (3) Joint Agency Asset Rider JAA rates and (4) EDIT-1 Rider. This type of adjustment is required to establish the level of revenue that would be received assuming that annual rate adjustments in effect on and after September 1, 2019 had applied for all 12 months of the Test Period.

Q. ARE YOU SPONSORING A PRO FORMA ADJUSTMENT BASED UPON THE REQUESTED RATES APPLICABLE FOR MISCELLANEOUS REVENUES?

A. Yes. Based upon the proposed rates contained primarily in the Service Regulations, a pro forma adjustment reducing miscellaneous revenues by $4,155,389 should be included in cost of service. A discussion of the changes in these rates is addressed later in my testimony.

Q. HOW DID THE COMPANY DETERMINE THE NUMBER OF CUSTOMERS SERVED AND THE ATTENDANT ANNUALIZED SALES AT THE END OF THE EXTENDED PERIOD?

A. The "Extended Period" for this proceeding is from January 1, 2019 through February 29, 2020. Projected numbers of residential, small general service, and lighting class customers served at the end of the Extended Period were derived by updating the Test Period regression analysis to include additional data from the Extended Period. The attendant annualized sales were recalculated using the new projected number of customers and further adjusted for changes observed in customer usage during the Extended Period.

The Extended Period customer-by-customer approach for the medium and large general service classes is executed similarly to the Test Period customer-by-customer approach. Each customer is individually analyzed during the Extended Period to determine its status as a new or lost customer. For new customers, all available usage data in the Extended Period is used to estimate a full year of usage data to be added. For customers that are lost during the Test Period, all associated usage during the Test Period is removed.

Q. WAS THE CUSTOMER GROWTH DATE ADJUSTED FOR WEATHER?

A. Yes. I incorporated a weather normalization adjustment into the calculations.

Q. WHAT IS THE RATIONALE FOR THE CUSTOMER GROWTH AND WEATHER NORMALIZATION ADJUSTMENTS THAT YOU SPONSOR?

A. In the rate design process, the revenue increase is spread over test period billing determinants (kilowatt-hour ("kWh"), kilowatt ("kW"), etc.) to determine the rate increases. If the revenue increase is adjusted for weather and growth, but the billing determinants are not, in an extreme weather test period, the kWh would be abnormally high, resulting in a rate per kWh that is too low. Conversely, in a mild weather test period, the kWh would be abnormally low, resulting in a rate per kWh that is too high. The adjustments made have an equivalent effect of adjusting the test period billing determinants for weather and customer growth, and therefore, are appropriate in developing the target revenues to be used in the rate design process. The proposed revenue increases by rate class were used in the development of the rate design used in this case.

III. RATE DESIGN APPROACH

Q. HOW DID YOU DESIGN THE VARIOUS RATE SCHEDULES IN THIS CASE?

A. I used the cost of service information prepared by the Company and supported by Company Witness Janice Hager as a major component for the rate design. As Witness Hager describes in her testimony, the cost of service study allocates costs to the jurisdictions and various rate classes and separates the customer, demand, and energy components of cost. I also reviewed and considered the rates of return across the customer classes derived from the cost of service study. Additionally, I reviewed the Company's load research data to examine customers' usage characteristics and to determine relationships between energy and demand, both on a coincident peak and non-coincident peak basis that might prove pertinent to the design of the Company's rates. I used marginal cost information to assess the merits of seasonal and time-of-use pricing relationships that are appropriate to be considered in the final rate design. As noted in the Company's last rate case, marginal cost data supports a reduced emphasis on on-peak energy rates as the difference between on-peak and off-peak marginal energy cost has narrowed over the past years. It also no longer supports a substantial emphasis on summer pricing. As noted in the Company's Integrated Resource Plan, recent data indicates winter peak demand should also be considered in resource planning and consequently should be a consideration when designing rates.

Q. PLEASE ELABORATE ON HOW YOU DEVELOPED THE PROPOSED RATES.

A. First, each rate class' target total proposed change in revenue requirement was determined. Then, the rate schedules within each rate class were designed to sum to the total proposed change in revenue target for that respective rate class.

Q. WHAT DID YOU CONSIDER BESIDES THE REVENUE REQUIREMENT IN THE DESIGN PROCESS?

A. In addition to the revenue requirement, consideration was given to current rates and their structure, impacts upon customers, equitable pricing structures, simplicity of the rate design, administrative complexity, along with rate and revenue stability when establishing DE Progress' proposed rates. There are three basic cost categories: customer cost, demand cost, and energy cost. Efficient rate design considers and reflects the component costs within each category. The unit cost study justifies an increase to the monthly Basic Customer Charge to better reflect customer-related costs and minimize customer cross-subsidization. However, the Company is not proposing to raise the Basic Customer Charge in this proceeding.

Q. WHAT ARE DE PROGRESS' RATE DESIGN OBJECTIVES FOR THE RATES PROPOSED IN THIS PROCEEDING?

A. As discussed by Company Witness Stephen De May, DE Progress is requesting a rate increase to recover its costs of providing safe and reliable electric service and to maintain a strong financial position as it remains in a period requiring major capital expenditures. In doing so, the Company aims to better reflect the cost to serve customers within its residential, general service, and lighting rate classes.

Q. WHAT ARE THE COMPANY'S SERVICE CLASSIFICATIONS AND MAJOR RETAIL ELECTRIC RATE SCHEDULES?

A. The Company's retail customers are separated into major service classifications: Residential, Small General Service, SGS Constant Load, Medium General Service, Large General Service, Seasonal and Intermittent Service, Traffic Signal Service, Outdoor Lighting and Sports Field Lighting. The Company's major retail electric rate schedules include: Rates RES, R-TOUD, and R-TOU – Residential Service; Rates SGS and SGS-TOUE– Small General Service; Rate SGS-TOU-CLR - SGS Constant Load; Rates MGS, SGS-TOU, GS-TES, APH-TES, CH-TOUE, CSE and CSG – Medium General Service; Rates LGS, LGS-TOU and LGS-RTP – Large General Service; Rate SI - Seasonal and Intermittent Service; Rates TFS and TSS - Traffic Signal Service; Rates ALS, SLS and SLR - Outdoor Lighting; and Rate SFLS - Sports Field Lighting. Together, these rate schedules comprise the Company's retail electric revenue requirement.

Q. PLEASE EXPLAIN HOW THE REVENUES PRODUCED UNDER CURRENT RATES COMPARE TO THE REVENUES THAT WOULD BE PRODUCED BY THE PROPOSED RATES.

A. As required by Commission Rule R1-17(b)(9), Pirro Exhibit 2 sets forth a comparison of the revenue produced by the present schedules during the Test Period with the revenue that would be produced under the proposed schedules. For purpose of comparison, both the present and proposed revenues reflect the base fuel and fuel-related costs component discussed by Company Witness Kimberly McGee in her testimony. The revenues produced by the schedules shown in Columns (a) and (b) were calculated using the North Carolina retail sales for the Test Period, and excludes annual clause revenues. The clauses include the December 2018 Fuel EMF, the January 2019 DSM and EE rates, the EDIT-1 Rider approved in the prior rate case and the December 2018 Joint Agency Asset rate. Proposed revenues include the effect of Riders EDIT-1, EDIT-2 and RAL-1 which I discuss later in my testimony. Column (c) shows the amount of additional revenue produced by the proposed rates. The percentage increase for each rate schedule exclusive of riders is shown in Column (d). Column (h) shows the percentage increase for each rate schedule with Clause Riders.

Q. HOW DO YOU PROPOSE TO ALLOCATE THE REVENUE INCREASE AMONG THE RATE CLASSES?

A. The base rate increase has been allocated to the rate classes on the basis of rate base. This allocation methodology distributes the increase equitably to the classes while gradually moving each class' deficiency or surplus contribution to return to the retail average rate of return within a band of reasonableness of +/- 10%, if possible.

Q. DID THE COMPANY CONSIDER THE RESULTS OF A UNIT COST STUDY IN DESIGNING THE PROPOSED RATES?

A. Yes. The unit cost study from the cost of service study provides customer, demand, and energy related unit costs that are important in establishing cost-based rates. Setting rates that are aligned with unit cost minimizes cross-subsidization within a rate class, as well as providing a price signal to these customers what is the true cost impact of their usage. The unit cost study also indicates it is appropriate to raise the monthly Basic Customer Charge to better reflect all customer-related costs. To do otherwise results in customer cross-subsidization. Therefore, the Company would normally propose the Basic Customer Charge for all rate classes be set to recover approximately 50 percent of the difference between the current rate and the full customer-related unit cost incurred to serve these customer groups. This approach would be taken because current rates significantly understate the current unit cost of service related to the customer component of cost. This recommendation reduces subsidization while moderating the rate impact on low usage customers. However, the Company has decided, in this rate proceeding, not to increase the Basic Customer Charges and to leave the Basic Customer Charges at current rates due to past concerns raised by low income and other advocates with respect to the level of the charge. Instead of requesting an increase to that charge in this proceeding, the Company has instead requested that a collaborative stakeholder process be formed to discuss opportunities to address low income, fixed income and low usage customer concerns. Once the Company has the benefit of that collaborative process, the Basic Customer Charges will be addressed in future proceedings to properly reflect equitable cost-based rates that provide accurate price signals to our customers.

Q. WHAT OTHER CONSIDERATIONS IMPACT DE PROGRESS' RATE DESIGN?

A. When moving rate schedules and riders closer to a more cost-justified basis, it is important to consider the impact upon customers and to employ the principle of "gradualism." This principle was applied in this proceeding to update price relationships and levelize the percentage change in revenues on participants within the rate class while still moving toward a more equitable pricing structure. This approach also minimizes rate migration concerns as the pricing reflected in each rate schedule moves gradually towards the requested rate class rate of return. In most cases, the percent change in rates for all schedules within the rate class was increased by the same percentage. In anticipation that more sophisticated designs may be practical with full deployment of Smart Meter technology and the Customer Connect billing system, only minimal changes to current rate designs are proposed in this proceeding.

Q. IS THE COMPANY PROPOSING ANY NEW PEAK TIME PRICING RATE DESIGNS OFFERING REAL TIME PRICE SIGNALS IN THIS PROCEEDING?

A. No, not at this time. However, the Company is actively monitoring DE Carolinas' recently implemented dynamic pricing pilots to evaluate the effectiveness of dynamic pricing on residential and small nonresidential customers. The pilots review and analyze rate designs that offer customers opportunities to respond to price signals to achieve a lower cost for electric service. The Company is upgrading its billing system infrastructure to better support these types of designs. Smart Meters, currently being installed for the majority of customers, will provide the interval level data that is required to develop and bill these innovative designs, as discussed in the testimony of Witness Don Schneider. The Rate Design Team is also actively working with the Customer Connect billing project to ensure that it will support the types of rate designs that will benefit our customers in the future. It is important to note that the Company presently offers time-of-use rate designs to all metered customer classes to encourage load shifting and offers several DSM programs to control customer appliances to aid in reducing system peak demands.

IV. RETAIL ELECTRIC RATE SCHEDULES AND RIDERS

Q. HOW WILL THE PROPOSED REVENUE INCREASE IMPACT THE RESPECTIVE REVENUE CLASSES?

A. The proposed revenue increase is distributed among customer rate classes by increasing the respective rate schedules as shown in Pirro Exhibit 4, Column N. Pirro Exhibit 4 illustrates the rate class changes and incorporates the effects of other riders.

Q. PLEASE DISCUSS PIRRO EXHIBITS 4 AND 5 AND DE PROGRESS' CONCERNS REGARDING THE HISTORIC RATE DISPARITY AMONG CUSTOMER CLASSES.

A. Pirro Exhibit 4 illustrates the rates of return across classes emanating from the Company's class cost of service study. Pirro Exhibit 5 compares the historical per books rate of return indices as measured by the ratio of class rate of return to retail rate of return, and it shows that over a lengthy period, residential customers have been subsidized. This historical subsidy has, in the past, been beyond the range of reasonableness, which we define as class rates of return within 10 percent of the total Company rate of return. The updated comparison through the Test Period year now shows significant convergence of the class rate of return over all classes towards the band of reasonableness demonstrating the success of the strategy of gradually reducing the subsidy/excess by 25 percent. Continuation of this trend would be encouraging and desirable. The Company remains committed to monitoring subsidy/excess levels and making improvements to ensure its rates are fair across the classes of customers served.

V. RETAIL ELECTRIC RATE TARIFFS

1. SERVICE REGULATIONS

Q. ARE THE RATES CONTAINED WITHIN THE SERVICE REGULATIONS BEING UPDATED?

A. Yes. The Company is seeking changes to several charges to better reflect current cost studies. While the Company's deployment of Smart Meter technology is not yet complete, the Company believes that it is appropriate to reflect cost savings realized with this technology in rates. By year-end 2019, 60% of all customers will be served using Smart Meter technology; therefore, the Service and Reconnect charges are calculated to recognize cost savings gained with fewer site visits by utilizing the capabilities of Smart Meter technology to provide these services. Proposed changes include:

1. The Service Charge is requested to be decreased from $17.00 to $9.14, while the Landlord Service Charge is requested to be decreased from $5.35 to $2.00.
2. The Reconnect Charge is requested to be decreased from the current rate of $19.00 to $12.94, while the Reconnect Charge outside of normal business hours is decreased from $55.00 to $19.48.
3. The charge for a customer-requested duplicate meter test is requested to increase from $40 to $45 for non-demand meters and from $50 to $57 for demand meters to reflect the cost of this service.

4. The monthly facilities charge associated with Extra Facilities under the contributory option is requested to be reduced from 0.4 percent to 0.3 percent. This same change is also being reflected in the monthly facilities charge applicable to interconnection facilities installed pursuant to the Terms and Conditions for the Purchase of Electric Power under a Purchase Power Agreement executed under the Purchased Power Schedule PP.

Q. PLEASE DESCRIBE THE PROPOSED CHANGE TO THE NON-RESIDENTIAL RATE SCHEDULES RELATED TO BILL PAYMENT DUE DATE.

A. In response to requests from nonresidential customers for additional time to process electric invoices, the Company is proposing to change when bills are past due and delinquent from fifteen days to twenty-five days to match the current requirement for residential customers. Late payment charges continue to apply after 25 days.

2. <u>RESIDENTIAL SERVICE RATE CLASS</u>

Q. PLEASE DESCRIBE THE PROPOSED CHANGES TO THE RESIDENTIAL RATE CLASS.

A. Residential Service Schedule RES will continue to be the basic service schedule available to all residential customers. The Company proposes to retain the current Customer Charge of $14.00 in Schedule RES to reflect the customer-related cost of serving these customers. The Time-of-Use Customer Charge is unchanged and matches Schedule RES plus a rate differential of $2.85 to recover the additional cost incurred for TOU meter-related costs.

Q. PLEASE DESCRIBE THE RATES PROPOSED UNDER SCHEDULE RES.

A. The Schedule RES kWh energy rates are adjusted to achieve the resultant revenue target net of the Customer Charge, retaining the current energy block structure that offers a 5 percent lower energy rate during non-summer billing months.

Q. WHAT CHANGES ARE PROPOSED FOR RESIDENTIAL SCHEDULE R-TOUD?

A. No structural change in TOU hours and rate seasons is proposed for the residential TOU schedules at this time. The rates stated in Residential Service Time-of-Use Schedule R-TOUD are adjusted to achieve approximately the same increase as recommended for Schedule RES. The demand and energy prices in R-TOUD are adjusted by the same percentage to achieve the revenue target. The current pricing structure continues to reflect marginal cost.

Q. WHAT CHANGES ARE PROPOSED FOR THE RESIDENTIAL SERVICE TIME-OF-USE SCHEDULE R-TOU?

A. No changes are sought to the overall rate structure of Schedule R-TOU. The current 5 percent emphasis on summer on-peak rates and the 2.5 percent emphasis on summer shoulder rates are retained. At the close of the test year, there were 3,426 participants under this rate design that was first approved in the 2013 rate case. The rate period price relationships continue to encourage off-peak usage. Over seventy percent of the consumption of current participants during the test year occurred during off-peak hours. After setting the Customer Charge to match Schedule R-TOUD, all rates are proposed to increase to achieve the same overall percentage increase as proposed for Schedule RES.

3. SMALL GENERAL SERVICE RATE CLASS

Q. PLEASE DESCRIBE THE PROPOSED CHANGES TO THE SMALL GENERAL SERVICE RATE CLASS.

A. The small general service rate class includes all nonresidential customers with demand requirements below 30 kW. Tariffs within the class include Small General Service Schedule SGS and Small General Service All-Energy Time-of-Use Schedule SGS-TOUE. The Company proposes to retain the current Customer Charge of $21.00 for both schedules.

Q. HOW ARE THE PROPOSED SMALL GENERAL SERVICE SCHEDULE ENERGY RATES CHANGED?

A. The current kWh energy block structure is retained with the second block being 16.54 percent and the third block being 21.04 percent less than the block 1 kWh energy rate. Schedule SGS energy rates are adjusted to recover the requested revenue increase.

Q. HOW ARE THE PROPOSED RATES APPLICABLE TO SCHEDULE SGS-TOUE CHANGED?

A. No changes are sought to the overall rate structure of Schedule SGS-TOUE. The current 10 percent emphasis on summer on-peak rates and the 5 percent emphasis on summer shoulder rates is retained. At the close of the test year, there were 637 participants under this rate design that was first approved in the 2013 rate case. The rate period price relationships continue to encourage off-peak usage with in excess of seventy-six percent of the consumption of current participants during the test year occurring during off-peak hours. All rates are proposed to increase to achieve the same overall percentage increase as proposed for Schedule SGS.

4. SMALL GENERAL SERVICE (CONSTANT LOAD) RATE CLASS

Q. PLEASE DESCRIBE THE CHANGES REQUESTED FOR THE SMALL GENERAL SERVICE (CONSTANT LOAD) SCHEDULE SGS-TOU-CLR.

A. The proposed Schedule SGS-TOU-CLR retains the current Customer Charge of $21.00 and adjusts the energy rate to recover the allocated revenue requirement. This schedule applies primarily to over 6,000 cable television amplifiers that exhibit a constant electrical requirement.

5. MEDIUM GENERAL SERVICE RATE CLASS

Q. PLEASE DESCRIBE THE PROPOSED CHANGES TO THE MEDIUM GENERAL SERVICE RATE CLASS.

A. The medium general service rate class includes all nonresidential customers with demand requirements from 30 kW to 1,000 kW. Tariffs within the class include Medium General Service Schedule MGS, Small General Service Time-of-Use Schedule SGS-TOU, General Service (Thermal Energy Storage) Schedule GS-TES, Church Time-of-Use Schedule CH-TOUE, Church and School Service Schedule CSE and Church and School Service Schedule CSG. The Company proposes to retain the current Customer Charge without change for these schedules.

Q. HOW ARE THE MGS RATES PROPOSED TO BE REVISED?

A. After adjusting the Customer Charge, the kW demand and kWh energy rates are increased by the same percentage to achieve the requested revenue. There are no other changes requested to this basic rate form.

Q. PLEASE DESCRIBE THE PROPOSED SGS-TOU SCHEDULE.

A. The Customer Charge is unchanged at $35.50, which is consistent with the current design to reflect the MGS Customer Charge of $28.50 plus the $7.00 rate applicable to three-phase service. Marginal cost continues to support the current seasonal and TOU price relationships; therefore, no structural changes are proposed. The summer on-peak demand rate continues to exceed the non-summer rate by 19 percent during the months of June through September while the on-peak energy rate continues to exceed the off-peak energy rate by 23.4 percent to incent load shifting to off-peak hours. The Company realizes a lower than class average return under Schedule SGS-TOU; therefore, the SGS-TOU rates are increased by 10 percent more than the increase to Schedule MGS to better match the cost of serving these customers. The on-peak and off-peak kWh energy and demand rates are adjusted by the same percentage to recover the requested revenue requirement. The off-peak excess kW charge is increased to reflect the MGS distribution-related unit cost to better ensure that customers using electricity primarily during off-peak hours pay the cost of distribution facilities necessary to deliver electricity to the customer.

Q. HOW ARE RATES IN SCHEDULES GS-TES AND APH-TES REVISED?

A. These schedules offer a reduced number of on-peak hours to encourage the installation of thermal storage equipment and currently have 8 participants in North Carolina. The Customer Charge is retained at $35.50, which matches the SGS-TOU rate design. The energy and demand charges in Schedule GS-TES and Schedule APH-TES are adjusted to achieve the same overall percentage increase on a combined basis as recommended under Schedule MGS.

Q. PLEASE DESCRIBE THE REQUESTED CHANGES TO SCHEDULE CH-TOUE.

A. No structural changes are requested to Schedule CH-TOUE and the current Customer Charge is requested to be retained at $35.50. The current rate design with a 6.2% higher summer on-peak energy rate than the non-summer on-peak energy rate is retained. The energy rates are adjusted to achieve the same overall increase as being requested for Schedule MGS.

Q. HOW WERE RATES ADJUSTED FOR THE TWO FROZEN SCHEDULES CSE AND CSG?

A. The schedules are recommended to retain the current Customer Charge of $28.50, matching the MGS class schedules, with an energy rate necessary to recover the allocated revenue requirement. Consistent with past practice for frozen schedules, the CSE and CSG rates were increased by 15 percent more than Schedule MGS to encourage migration to a standard tariff. These schedules have not been available to new participants since 1977 and the Company continues to automatically transfer participants to other schedules whenever annual usage results in a lower bill. The customers were reviewed to determine whether it is appropriate to switch these customers to an alternate schedule; however, our review indicates that this would result in a significant percentage increase and is therefore not being proposed, at this time.

Q. SEVERAL MGS CLASS SCHEDULES INCLUDE A MINIMUM BILL PROVISION. HOW ARE THE MINIMUM BILL PROVISIONS PROPOSED TO BE REVISED?

A. The Company proposes to continue to offer a uniform minimum bill provision under schedules SGS-TOU, GS-TES, APH-TES, CH-TOUE, CSE and CSG. The minimum bill recovers the tariff Customer Charge; three-phase charge, if applicable; an energy charge recovering the MGS class energy cost from the unit cost study; and a demand charge based upon the higher of the current or previous 12 months maximum demand or contract demand times the distribution-related unit cost. No change is proposed to the minimum bill structure in this proceeding, but the minimum bill rates are updated to reflect current unit cost plus any adjustment riders.

Q. WAS THE REVENUE REQUIREMENT ADJUSTED FOR THE IMPACT OF THE MGS CLASS MINIMUM BILL PROVISION?

A. Yes. The minimum bill provision is expected to result in an overall increase in MGS class revenues; therefore, an adjustment was made to the proposed MGS class revenue requirement to reflect this impact.

6. LARGE GENERAL SERVICE RATE CLASS

Q. WHAT SCHEDULES ARE INCLUDED IN THE LGS RATE CLASS?

A. The large general service rate class includes all nonresidential customers with demand requirements of 1,000 kW or greater. The LGS Class includes the Large General Service Schedule LGS, the Large General Service Time-of-Use Schedule LGS-TOU, and the Large General Service (Real Time Pricing) Schedule LGS-RTP.

The majority of usage under LGS-RTP is billed as the Customer Baseline Load ("CBL") under Schedules LGS or LGS-TOU; therefore, it is not shown separately in the Company data, but is included within the schedule used for billing the CBL.

Q. PLEASE DESCRIBE THE REQUESTED CHANGES TO THE LGS SCHEDULE.

A. The current LGS Customer Charge is proposed to be retained at $200.00. The demand rates are presently blocked to recognize that customers with larger load are typically served from fewer delivery-related facilities. The current demand block structure of $1 per kW reduction for loads above 5,000 kW and a $2 per kW reduction for loads above 10,000 kW is proposed to continue, as supported by the unit cost study. After adjusting the Customer Charge, the kW demand and kWh energy rates are increased by the same percentage to achieve the requested revenue. There are no other changes requested to this basic rate form.

Q. PLEASE DESCRIBE THE PROPOSED LGS-TOU SCHEDULE.

A. As noted in the earlier discussion of TOU tariffs, the Company is not proposing changes to the TOU period hours reflected in Schedule LGS-TOU until additional customer usage data can be secured from deployment of more advanced metering and the new Customer Connect billing system is available. The overall LGS-TOU rate structure continues to be supported by marginal cost; therefore, no structural changes are proposed. The LGS-TOU Customer Charge is retained at $200.00. The on-peak demand rates are increased by of the same percentage as the energy rate adjustment. The off-peak excess kW charge is increased to reflect the LGS distribution-related unit cost study to better ensure that customers pay the cost of facilities necessary to deliver electricity to them. The kWh energy rates are adjusted to reflect the increase in revenue, retaining the current half cent per kWh differential between the on-peak and off-peak energy rates. The increased energy rates reflect an emphasis on on-peak rates when marginal costs are higher.

Q. IS THE TRANSFORMATION-OWNERSHIP DISCOUNT UPDATED IN THE LGS CLASS SCHEDULES?

A. Yes. The energy and demand credit rates applicable to customers that own the transformation normally provided by the Company are adjusted to reflect the unit cost study associated with the avoidance of transmission-to-distribution and distribution-to-secondary transformation.

Q. PLEASE DESCRIBE THE CHANGES REFLECTED IN THE LARGE GENERAL SERVICE REAL TIME PRICING SCHEDULE LGS-RTP.

A. The majority of usage received under LGS-RTP is billed in the Customer Baseline Load, or CBL, at standard tariff rates; however, the schedule includes several charges that are updated. The current RTP Administration Charge is retained at $165.00 per month to recover the ongoing cost incurred to support the development of daily hourly rates and other cost required to support this unique rate design. The Facilities Demand Charges are adjusted based upon the unit cost study to more accurately recover the cost of delivering electricity to the customer's site. The tax factor applicable to the hourly rate is also revised to recover the current Regulatory Fee of 0.13 percent since these incremental costs are incurred with the sale of electricity.

7. SEASONAL AND INTERMITTENT SERVICE RATE CLASS

Q. HOW ARE RATES ADJUSTED FOR THE SEASONAL AND INTERMITTENT SERVICE RATE CLASS?

A. The seasonal and intermittent service rate class includes only Seasonal and Intermittent Service Schedule SI. Since participants have a similar load requirement as MGS class customers, the current SI Customer Charge is retained at $28.50 to match Schedule MGS. The Customer Seasonal Charge seeks to recover approximately 3 months of the Basic Customer Charge since no bill is rendered when service is not used during the billing month. Accordingly, the Customer Seasonal Charge is retained without change at $41.00 per month. The per kW Facilities Charge is also unchanged since an updated study continues to support the current $1.84 per kW rate. The kWh energy rates are then adjusted by a fixed percentage to achieve the requested change in revenue for the rate class.

8. SPORTS FIELD LIGHTING SERVICE RATE CLASS

Q. HOW ARE RATES ADJUSTED FOR THE SPORTS FIELD LIGHTING SERVICE RATE CLASS?

A. The sports field lighting service rate class includes only Sports Field Lighting Service Schedule SFLS. Customers service under Schedule SFLS have demands of 30 kW or greater like MGS class customers; therefore, the Customer Charge is unchanged at $28.50 to be consistent with MGS class tariffs. The energy and demand rates are then increased by a fixed percentage to achieve the targeted change in revenue. The charge applicable for disconnection of service after less than one-full month is requested to be decreased from $17.00 to $9.14 to match the Service Charge requested in the Service Regulations for a similar activity.

9. TRAFFIC SIGNAL SERVICE RATE CLASS

Q. PLEASE DESCRIBE THE CHANGES REQUESTED FOR THE TRAFFIC SIGNAL SERVICE RATE CLASS.

A. The traffic signal service rate class includes the Traffic Signal Service (Metered) Schedule TFS and Traffic Signal Service Schedule TSS, a schedule that offers unmetered electricity based upon the signal configuration. TFS customers have a similar service requirement as the SGS class; therefore, no change is recommended to the current $21.00 TFS Customer Charge and TSS Minimum Bill Customer Charge to match the proposed rate for Schedule SGS. The TSS fixture rates are then adjusted by a fixed percentage to achieve the requested revenue adjustment. The Schedule TFS energy rate is adjusted to achieve the same overall percentage change in revenue as proposed under Schedule TSS.

10. OUTDOOR LIGHTING RATE CLASSES

Q. PLEASE DESCRIBE HOW RATES ARE ADJUSTED FOR THE OUTDOOR LIGHTING SCHEDULES.

A. The Company provides outdoor lighting service under Area Lighting Service Schedule ALS, Street Lighting Service Schedule SLS and Street Lighting Service (Residential Subdivisions) Schedule SLR. The Company has a long-term goal of offering similar monthly rates for the same lighting product regardless of whether the fixture is installed on a public street or private property. Movement toward this goal began in the 2017 rate case when all ALS and SLS fixture rates were set at an identical amount. Currently, all ALS and SLA rates match with three exceptions. The SLS wood, metal/fiberglass, and system metal pole/post rates are priced at a lower rate than comparable poles/posts in Schedule ALS. The rates requested in the proposed outdoor lighting schedules have been adjusted to achieve the combined outdoor lighting revenue target while each schedule realizes approximately the same percentage increase.

Q. HOW IS THE AVAILABILITY OF HIGH PRESSURE SODIUM VAPOR ("HPS") FIXTURES CHANGING?

A. The Company is requesting that HPS vapor fixtures no longer be available for new installations to continue the Company's emphasis on LED technology for all new installations. This change is requested for all three outdoor lighting schedules. LED technology offers improved energy efficiency and provides excellent color and light quality. To aid in this transition, HPS will continue to be available to sites with contiguous HPS lighting. Upon failure of an HPS ballast or fixture, it will be replaced at no charge to the customer with a comparable LED fixture, as identified in a table included in each lighting schedule.

Q. WHAT IS THE STATUS OF THE COMPANY'S MERCURY VAPOR TECHNOLOGY REPLACEMENT PROGRAM?

A. In 2007, the Commission approved the Company's plan to no longer offer mercury vapor fixtures and to slowly phase them out as fixtures failed. The plan was modified in 2014 to proactively replace all standard mercury vapor fixtures with LED technology, which would leave only decorative fixtures that would be replaced only at failure. Presently, mercury vapor technology is used in only 2 percent of outdoor fixtures. Since comparable decorative fixtures are now available using LED technology, the Company now proposes to revise Schedules ALS, SLS and SLR to require replacement of the remaining mercury vapor and retrofit sodium vapor fixtures that utilize mercury vapor technology by December 31, 2023. This change will encourage customers to pursue more energy efficient lighting.

Q. PLEASE DESCRIBE THE CHANGES BEING REQUESTED FOR THE STREET LIGHTING SERVICE SCHEDULE.

A. A marginal cost review was undertaken to compare the monthly rate to the current cost of providing each fixture and pole. This review aids in understanding subsidies that may exist within the current pricing structure. The review indicates that pole/post rates are significantly less than the current costs of providing these facilities; therefore, they should also be increased by a larger amount than fixture rates. All fixture rates were increased by a fixed percentage to achieve the revenue target with the pole/post rates being increased by twice the percentage increase in fixture rates to better reflect marginal cost. The SLS rates for wood, metal/fiberglass, and system metal poles/posts were increased by slightly more than other poles/posts to achieve the same percentage increase in rates under both ALS and SLS. The one-time charge for underground service of $521 is requested to be increased to $580 to better reflect the cost to extend underground service to a fixture.

Q. HOW ARE SCHEDULE SLR RATES ADJUSTED?

A. All monthly rates were adjusted by the same percentage to realize the same percentage increase in revenues under SLR as realized for Schedules ALS and SLS.

Q. PLEASE DESCRIBE CHANGES BEING REQUESTED IN AREA LIGHTING SERVICE SCHEDULE ALS.

A. Area Lighting Service Schedule ALS offers various types of lighting fixtures and poles for security and other purposes on customer premises. As noted above, the requested rate for certain charges, fixtures and poles continue to match the corresponding monthly rate requested under Schedule SLS to maintain uniformity between Schedules ALS and SLS.

Q. HOW WERE OTHER SCHEDULE ALS RATES AND TERMS ADJUSTED?

A. All fixtures and the monthly underground charge were increased by a fixed percentage to achieve the revenue target. Consistent with Schedule SLS, the optional one-time charge for underground service of $521.00 was increased to $580.00 to better reflect the current additional cost incurred when providing underground service to lighting. The contract term for area lights installed on existing distribution poles and served with overhead distribution lines is requested to increase from one to three years to minimize subsidization that occurs with short-term lighting installations. The contract term for fixtures installed with underground service remains at 5 years; however, all non-standard and decorative fixtures requiring a basic rate plus a monthly facilities charge and LED site lighter and shoe-box fixtures will now require a ten-year contract term.

Q. WHAT CHANGES WERE PROPOSED UNDER THE LED STANDARD OFFER OPTION IN SCHEDULES SLS AND ALS?

A. The Company proposes to no longer offer the LED 205 Site Lighter for new installations under both schedules. For customers desiring this type of fixture, the

Company is proposing a new LED 220 Shoe Box fixture under its Basic Rate option in both schedules ALS and SLS. The LED 220 Shoe Box fixture will be offered at a fixed monthly instead of a monthly rate plus a monthly facility charge as currently being offered under the standard offer option for the LED 205 Site Lighter. The proposed monthly rate for the LED 220 Shoebox is comparable to the current monthly rate LED 205 Site Lighter, plus the same percentage increase being sought for other fixtures.

Q. WHY ARE THE STREET LIGHT SERVICE REGULATIONS BEING REVISED?

A. They are being retitled as "Outdoor Lighting Service Regulations" and will now apply to both street and area light installations. This change aligns the same basic practices and procedures for all outdoor lighting installations and supports the Company's long-term objective of offering all outdoor lighting products under similar terms and rates to all customers. The Service Extensions, Extra Facilities, Nonrefundable Contributions sections, currently identical in Schedules ALS and SLS, are relocated to the Outdoor Lighting Service Regulations to allow the tariffs to better emphasize monthly rates and billing issues. The Delinquent Bills section in the Outdoor Lighting Service Regulations is removed since it duplicates a section presently contained in the individual Schedules.

11. SERVICE RIDERS

Q. WHAT CHANGES ARE REQUESTED TO THE COMPANY'S SERVICE RIDERS?

A. Service riders are offered to modify standard service under the Company's rate schedules to better reflect the cost of meeting unique or special customer requirements. The Company revised several service riders to better reflect current cost of service. A description of the requested changes to each rider follows.

Q. PLEASE DESCRIBE THE REQUESTED CHANGES TO THE CUSTOMER CHARGE APPLICABLE UNDER NON-FIRM SERVICE RIDERS.

A. The Company offers several service riders that require the customer to curtail their electrical usage upon notification from the Company to aid in reducing load during hours with generation constraints. These Riders include Large Load Curtailable Rider LLC, Dispatched Power Rider No. 68, Incremental Power Service Rider IPS, and Supplementary and Non-Firm Standby Service Rider NFS. The Customer Charge identified in each of these riders recovers the cost associated with a customer notification system that is necessary to alert customers of curtailment events. This charge has been increased from $50.00 to $65.00 to recover the current cost of notification technologies to support e-mail, pagers, text messaging and telephone communications to multiple customer recipients to alert participants of impending curtailment events.

Q. WHAT OTHER CHANGES ARE BEING REQUESTED FOR LARGE LOAD CURTAILABLE RIDER LLC?

A. In addition to the Customer Charge, the Discount Rate for curtailable load is requested to be increased from $5.40 to $5.60 per kW of non-firm demand to better reflect the current avoided cost benefit. The cost basis for the Discount Credit reflects the Company's three-year levelized marginal generation cost and annual fuel credit calculated pursuant to the methodology reflected in DE Progress' current avoided cost rates approved effective May 2018 in Docket No. E-100, Sub 148. Correspondingly, the charge for the use of Premium Demand during a Level 1 Curtailment event is increased from $2.70 to $2.80 per kWh. The Level 2 Capacity Curtailment Premium Demand Charge is unchanged at $50.00 per kW.

Q. WHAT OTHER CHANGES ARE BEING SOUGHT TO SUPPLEMENTARY AND NON-FIRM STANDBY SERVICE RIDER NFS AND SUPPLEMENTARY AND FIRM STANDBY SERVICE RIDER SS?

A. In addition to the Customer Charge, the Non-Firm Standby Service Delivery Charges are adjusted to reflect the unit cost of service for service from distribution and transmission facilities. The Generation Reservation and Standby Service Delivery Charges are both updated to reflect current cost of service in Rider SS.

Q. WHAT CHANGES ARE SOUGHT IN THE METER-RELATED OPTIONAL PROGRAMS RIDER?

A. The TotalMeter and NonStandard Metering rates are updated to better reflect current cost estimates. The Manually Read Meter provision is requested to be revised to allow this option for all Schedule SGS customers.

Q. HAS THE COMPANY RECALCULATED THE COSTS ASSOCIATED WITH ITS MANUALLY READ METER PROGRAM?

A. Yes. As directed by the Commission in its January 23, 2019 order in Docket No. E-2, Sub 834, the Company recalculated the costs associated with the manually read meter program. The Company's analysis supports an Initial Set-up Fee of $180.52 and a reoccurring monthly rate of $20.75. However, this optional service has been in effect less than one year and the Company believes adjusting the fees associated with manual meter reading is premature. The Company is not proposing an adjustment of the fees of the program, which currently includes a $170.00 Initial Set-up Fee and a reoccurring $14.75 monthly rate. As of August 1, 2019, there were 938 customers requesting the manual read option, with 551 of those customers providing medical forms to have the fees waived.

12. <u>LINE EXTENSION PLAN LEP</u>

Q. ARE CHANGES PROPOSED TO THE LINE EXTENSION PLAN?

A. No significant changes are being requested at this time; however, Paragraph IV.D. is revised to clarify that the installation of conduit in situations where obstructions prevent the use of standard construction practices. The provision is revised to make clear that conduit must be properly installed by the customer; otherwise, the customer is responsible for any added cost the Company may incur to extend electric service.

VI. <u>TEMPORARY RIDERS</u>

1. <u>EDIT-1 Rider</u>

Q. WHY HAS THE DECREMENTAL RATE REFLECTED IN EDIT-1 RIDER CHANGED?

A. In its last general rate case in Docket No. E-2, Sub 1142, the Commission approved a four-year State EDIT rider to return excess deferred income taxes resulting from reductions in state tax rate in prior years. As explained in the testimony of Witness Smith, the Rider amount is being revised to adjust the gross-up in the rider to reflect the 21 percent federal tax rate. Accordingly, I have updated EDIT-1 Rider to reflect the revised decremental rider set forth in Smith Exhibit 3. The proposed Rider EDIT-1A tariff is provided in the Company's proposed tariffs filed as Application Exhibit B.

2. <u>EXCESS DEFERRED INCOME TAX RIDER EDIT-2</u>

Q. PLEASE DESCRIBE THE PROPOSED YEAR 1 CREDIT RATES FOR THE NEW EDIT-2 RIDER.

A. As described in the testimony of Witness Smith, the Company will refund amounts owed to customers due to reductions in corporate federal and state income tax rates through a new EDIT Rider. The Year 1 rate credit impact has been included in the revenue increase target used to establish proposed rates in this proceeding. The EDIT-2 Rider Year 1 rates will expire November 30, 2021, and, upon Commission approval, will be replaced December 1, 2021 by the Year 2 rate credit, following the approach outlined in Witness Smith's testimony.

Q. HOW WAS THE YEAR 1 EDIT-2 RATE DETERMINED?

A. The Year 1 revenue requirement was provided by Witness Smith as shown in Smith Exhibit 4. The rate class revenue requirement was then allocated to each rate class using the factors appropriate for Accumulated Deferred Income Taxes and divided by test year retail billed sales for each rate class to establish class the year 1 credit rates. The derivation of the credit rate applicable to each rate class is provided on Pirro Exhibit 8. The proposed Rider EDIT-2 tariff is provided in the Company's proposed tariffs filed as Application Exhibit B.

3. <u>RAL-1</u>

Q. PLEASE DESCRIBE THE PROPOSED REGULATORY ASSET LIABILITY RIDER.

A. As described in the testimony of Witness Smith, the Company is proposing a new Regulatory Asset and Liability Rider to return to customers net revenue received under expired amortizations. A proposed uniform rate of $0.00005 per kWh is derived in Smith Exhibit 5 and will be effective for 12 months. The proposed Rider RAL-1 tariff is provided in the Company's proposed tariffs filed as Application Exhibit B.

VII. <u>IMPLEMENTATION</u>

Q. HOW DOES THE COMPANY PROPOSE THAT THE COMPANY'S TARIFFS, INCLUDING THE PREVIOUSLY DISCUSSED RATES AND CHARGES, BE IMPLEMENTED?

A. DE Progress will file with the Commission revised tariffs consistent with the rates and charges approved in the Commission's final order in this case. These compliance tariffs shall become effective on the implementation date set by the Commission unless the Commission suspends the rates or takes other action to prevent implementation of the rates.

VII. CONCLUSION

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

A. Yes.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1219

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

I. INTRODUCTION AND PURPOSE

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

A. My name is Michael J. Pirro, and my business address is 550 South Tryon Street, Charlotte, NC 28202. My current position is Director, Southeast Pricing & Regulatory Solutions for Duke Energy Progress, LLC ("DE Carolinas" or the "Company") and its affiliated utility operating companies.

Q. DID YOU PREVIOUSLY FILE DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes. I filed direct testimony supporting DE Progress's overall rate design and sponsoring the proposed tariffs in this proceeding. I also filed corrected versions of Pirro Exhibit 2 on November 22, 2019 and Pirro Exhibit 4 on March 4, 2020.

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

A. The purpose of my testimony is to support modifications to the Company's customer growth, usage, and weather normalization adjustments to align with the changes I agreed to in my rebuttal testimony filed on March 4, 2020 in Duke Energy Carolinas, LLC's ("DE Carolinas") rate case pending in Docket No. E-7, Sub 1214. I also support Pirro Supplemental Exhibit 2 and Pirro Supplemental Exhibit 4, which reflect the most recently approved base fuel adjustment in Docket No. E-2, Sub 1204, effective December 1, 2019.

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

A. Yes.

Q. DID YOU PROVIDE ANY INFORMATION INCLUDED IN EXHIBITS SPONSORED BY OTHER COMPANY WITNESSES?

A. Yes. For the reasons I describe below, I sponsor the following adjustments that are presented in Smith Supplemental Exhibit 1:

Line 1 – Annualize retail revenues for current rates

Line 3 – Normalize for weather

Line 4 – Annualize revenues for customer growth.

Additionally, my updates to reflect the most recently approved base fuel adjustment impact the following adjustment presented in Smith Supplemental Exhibit 1:

Line 2 – Update fuel costs to approved rate.

II. CUSTOMER GROWTH, CHANGE IN USAGE AND WEATHER NORMALIZATION ADJUSTMENTS

Q. PLEASE DESCRIBE THE MODIFICATIONS YOU AGREED TO IN YOUR DE CAROLINAS' REBUTTAL TESTIMONY.

A. In his direct testimony filed in Docket No. E-7, Sub 1214, Public Staff Witness Scott Saillor recommended the following modifications to DE Carolinas' Adjustments to Annualize Revenues for Customer Growth and Change in Usage:

- Modifying the Customer-by-Customer Approach for Openings in the Test Period by determining average monthly usage through taking the average of the 12 months of billing data following initial month of service;

- Modifying the Customer-by-Customer Approach for Openings in the Extended Period by removing the initial month of service from the average usage calculation;
- The removal of Basic Facilities Charge ("BFC") revenues from the change in usage calculations;
- The removal of the change in usage revenue adjustment for the Lighting rate class; and
- The inclusion of a change in usage adjustment for the General and Industrial rate classes.

Public Staff Witness Saillor also recommended the following modifications to DE Carolinas' Weather Normalization Adjustment:

- The removal of BFC revenues from the calculations of average customer class rates; and
- Summing of the monthly NC Retail kWh weather adjustments within the test period for each customer class in place of multiplying the test period System Retail kWh weather adjustment times the annual NC Retail-to-System sales ratio.

In my rebuttal testimony, I indicated that DE Carolinas agrees in principle with these proposed recommendations from Public Staff Witness Saillor.

Q. DOES DE PROGRESS AGREE TO THESE SAME MODIFICATIONS?

A. The Company expects that Mr. Saillor will make the same recommendations for DE Progress and, therefore, has elected to proactively make the modifications listed above to DE Progress's Adjustments to Annualize Revenues for Customer

Growth and Change in Usage, as well as its Weather Normalization Adjustment that it agreed to in the DE Carolinas rate case. DE Progress agrees that these modifications are appropriate in this case.

III. SUPPLEMENTAL EXHIBITS

Q. PLEASE DESCRIBE THE CHANGES REFLECTED IN PIRRO SUPPLEMENTAL EXHIBIT 2.

A. Pirro Supplemental Exhibit 2 was updated to reflect the new base fuel rates that were effective on and after December 1, 2019 as approved in Docket No. E-2, Sub 1204.

Q. PLEASE DESCRIBE THE CHANGES REFLECTED IN PIRRO SUPPLEMENTAL EXHIBIT 4.

A. Pirro Supplemental Exhibit 4 was also updated to reflect the new base fuel rates that were effective on and after December 1, 2019 as approved in Docket No. E-2, Sub 1204.

IV. CONCLUSION

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

A. Yes.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1219

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

I. INTRODUCTION AND PURPOSE

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

A. My name is Michael J. Pirro, and my business address is 550 South Tryon Street, Charlotte, North Carolina 28202. My current position is Director, Southeast Pricing & Regulatory Solutions for Duke Energy Progress, LLC ("DE Progress" or the "Company") and its affiliated utility operating companies.

Q. DID YOU PREVIOUSLY FILE DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes. I filed direct testimony supporting DE Progress's overall rate design and sponsoring the proposed tariffs in this proceeding. I also filed supplemental direct testimony on March 13, 2020.

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

A. The purpose of my testimony is to rebut various points and issues raised by intervenors in this docket regarding:

1) RESIDENTIAL BASIC CUSTOMER CHARGE ("BCC") as discussed in the testimony of North Carolina Justice Center, North Carolina Housing Coalition, Natural Resources Defense Council, and Southern Alliance for Clean Energy (collectively, "NCJC, et al.") witnesses Jonathan Wallach and John Howat;

2) CUSTOMER GROWTH and WEATHER NORMALIZATION ADJUSTMENTS as discussed in the testimony of Public Staff witness Scott Saillor;

3) SCHEDULE R-TOUD and RIDER MROP (MANUAL READ OPTION) as discussed in the testimony of Public Staff Witness Jack Floyd;

4) SCHEDULE SGS-TOU PRICING as discussed in the testimony of Harris Teeter witness Justin Bieber and Commercial Group witness Steve Chriss;

5) SCHEDULES LGS AND LGS-TOU PRICING as discussed in the testimony of Carolina Industrial Group for Fair Utility Rates II ("CIGFUR") witness Nicholas Phillips and Carolina Utility Customers Association ("CUCA") witness Kevin O'Donnell; and

6) REAL-TIME PRICING (SCHEDULE LGS-RTP) as discussed in the testimony of CIGFUR witness Phillips, CUCA witness O'Donnell, and Hornwood witness Brian Coughlan.

II. RESIDENTIAL BASIC CUSTOMER CHARGE

Q. DID THE COMPANY PROPOSE AN ADJUSTMENT TO THE RESIDENTIAL BASIC CUSTOMER CHARGE IN THIS CASE?

A. No. DE Progress has proposed no change to the current residential BCC of $14.00. The Company generally supports setting the BCC to recover approximately 50 percent of the difference between the current rate and the full customer-related unit cost incurred to serve the residential class, as current rates significantly understate the current unit cost of service related to the customer component of cost. However, the Company has decided in this case to leave the BCC at current rates due to past concerns raised by low-income and other advocates with respect to the level of the charge. Instead, the Company supports a collaborative to discuss opportunities to address low-income, fixed income, and low-usage customer concerns. The BCC may be addressed in future proceedings to properly reflect equitable cost-based rates that provide accurate price signals to our customers.

Q. NCJC, ET AL. ALLEGES THAT THE COSTS IDENTIFIED BY THE MINIMUM SYSTEM METHODOLOGY ARE NOT CUSTOMER COSTS AND SHOULD NOT BE INCLUDED IN THE BCC. DO YOU AGREE WITH THAT ALLEGATION?

A. No. The rates and rate design supported by my testimony are based upon the cost of service study, including the minimum system cost study, performed by the Company, accepted by Public Staff, and approved in previous rate cases by the Commission. The Company's cost of service studies indicate that these costs are Customer Costs and therefore the BCC was designed to recover them.

Q. DO YOU AGREE WITH NCJC, ET AL.'S POSITION OF REDUCING THE CURRENT RESIDENTIAL BCC?

A. No. The Company's current residential BCC, which was approved by the Commission in DE Progress's last rate case in Docket No. E-2, Sub 1142, should remain in effect in this proceeding.

Q. RATE SCHEDULE RES, THE COMPANY'S PRIMARY RESIDENTIAL RATE SCHEDULE, DOES NOT HAVE A DEMAND COMPONENT; RATHER, IT ONLY HAS A BCC AND VOLUMETRIC PER KWH CHARGES. WOULD IT BE APPROPRIATE TO SHIFT SOME OF THE COSTS CURRENTLY INCLUDED IN THE BCC TO A VOLUMETRIC RATE?

A. No. As NCJC, et al. witnesses Howat and Wallach recognize in their direct testimony, the distribution facilities costs in question represent poles, conductors, conduit, and transformers. These costs are fixed in nature and do not vary with customer consumption just like the metering, service drops, and billing costs for which they support and recognize the appropriateness of a per customer charge. Importantly, they are unlike variable operation and maintenance costs and fuel costs which vary directly with energy consumption and are properly recovered via the volumetric kWh rate. Thus, recovering such costs via a kwh charge would provide an incorrect pricing signal.

Q. ARE WITNESSES WALLACH AND HOWAT CORRECT IN ASSERTING THAT THE CURRENT BCC DISCOURAGES DISTRIBUTED GENERATION AND ENERGY EFFICIENCY?

A. No. Failing to properly recover customer-related costs via a fixed monthly charge would provide an inappropriate price signal to customers and would fail to adequately reflect cost causation. Shifting customer-related costs to a volumetric per kWh rate further exacerbates this concern and overcompensates energy efficiency and distributed generation for the cost avoided by their actions, thereby skewing the market for such measures.

Q. DOES THE CURRENT BCC DISPROPORTIONATELY HARM LOW-INCOME CUSTOMERS AS ARGUED BY WITNESS HOWAT?

A. The Company is mindful of the impact of any rate increase on our customers, particularly low-income customers; however, the Company does not design rates based upon customer incomes, but rather applies cost causation principles to the extent practical. There are other means of addressing the financial needs of low-income customers, such as Company, state, and local programs, which are more effective than biasing the rate design to aid low-usage customers.

For example, energy efficiency programs, including the Company's Residential Low-Income Weatherization Pay-For-Performance Program Pilot and Neighborhood Energy Saver program, aid low-income customers in reducing their consumption of energy at no cost to the consumer. Other Company programs, such as budget billing and payment arrangements, are available to assist low-income customers and others in managing their cost for electricity. For instance, the Energy Neighbor Fund is promoted by the Company and raises funds for local aid agencies to assist low-income customers.

Finally, inappropriately pricing the BCC below cost tends to subsidize all low-usage customers, and not just low-income customers. Not all low-usage customers are low-income customers, and not all low-income customers are low-usage customers.

Q. WITNESS HOWAT ALSO SEEKS CHANGES TO THE COMPANY'S ENERGY EFFICIENCY PROGRAMS TARGETING LOW-INCOME CUSTOMERS. ARE SUCH PROGRAMS INCLUDED IN THE COMPANY'S PROPOSAL?

A. No. Rate design involves allocating a utility's actual generation, transmission, distribution, and customer costs determined by a cost of service study to the utility's customer classes and developing rates to recover those costs. In designing proposed customer rates to generate DE Progress's revenue requirement, it is inappropriate to consider energy efficiency programs that have not been approved by the Commission. Revenues for energy efficiency programs are intentionally excluded from rate case revenues since they are considered annually in a demand-side management and energy efficiency ("DSM/EE") cost recovery proceeding. The issue of whether DE Progress should propose additional energy efficiency programs or modify existing energy efficiency programs should be addressed in DE Progress's DSM/EE proceedings.

III. CUSTOMER GROWTH AND WEATHER NORMALIZATION ADJUSTMENTS

Q. DOES THE COMPANY AGREE WITH THE METHODOLOGY PUBLIC STAFF WITNESS SAILLOR USED TO CALCULATE THE KWH CHANGES USED IN THE COMPANY'S CUSTOMER GROWTH AND WEATHER NORMALIZATION ADJUSTMENTS?

A. Yes. In my supplemental direct testimony, the Company agreed with the formulaic changes suggested by witness Saillor. However, the Company inadvertently did not address witness Saillor's calculation methodology to weather-normalize sales for the SGS rate class. The Company also agrees with the methodology witness Saillor used to weather-normalize sales for the SGS rate class.

Q. WITNESS SAILLOR BASES HIS CUSTOMER GROWTH PROJECTIONS THROUGH FEBRUARY 2020 IN HIS SUPPLEMENTAL TESTIMONY AND EXHIBITS. DOES THE COMPANY AGREE THIS IS APPROPRIATE?

A. No. While the Company generally agrees with witness Saillor's calculation methodology and understands why he based his customer growth projections on usage through February 2020, the Company is experiencing a significant reduction in its load and associated revenues due to many commercial and industrial customers as well as schools and colleges scaling back operations, if not closing completely, during the COVID-19 state of emergency. The Company believes that some of the changes in load we are currently experiencing may be permanent and reflecting these changes closer in time to the hearing will result in a more accurate depiction of the Company's load forecast. Accordingly, due to these significant, known and measurable kilowatt hour changes, the Company believes it is inappropriate to reflect the adjustments recommended in witness Saillor's supplemental testimony and exhibits at this time. For purposes of my rebuttal testimony, the Company's position is to support the adjustment as reflected in witness Kim Smith's supplemental testimony and exhibits filed on March 13, 2020. The Company will then update its customer growth, change in usage and weather normalization adjustments closer to the hearing.

Q. DO YOU HAVE ANY OTHER COMMENTS RELATING TO THE PUBLIC STAFF'S CUSTOMER GROWTH AND WEATHER NORMALIZATION ADJUSTMENTS?

A. Yes. There appears to be a spreadsheet issue with the change in the number of bills displayed in Public Staff witness Dorgan's Supplemental Exhibit 1, Schedule 3-1(b) compared to the change in number of bills displayed in Saillor Supplemental Exhibit 3. Line 15 in Dorgan Supplemental Exhibit 1, Schedule 3-1(b) contains an incorrect entry of 415,178 for the change in the number of customer bills as of February 29, 2020. Saillor Supplemental Exhibit 3 reflects the correct figure of 473,731. The change in the number of customer bills impacts the calculation of the revenue requirement as described in Company witness Kim Smith's rebuttal testimony. It is my understanding that the Public Staff agrees that the number of bills displayed on Line 15 in Dorgan Supplemental Exhibit 1, Schedule 3-1(b) should be 473,731 consistent with Saillor Supplemental Exhibit 3.

IV. SCHEDULE R-TOUD

Q. PLEASE DESCRIBE RATE SCHEDULE R-TOUD.

A. The Company's Rate Schedule R-TOUD is a residential time-of-use rate whereby customers are billed a Basic Customer Charge, on-peak demand, and energy based on on-peak and off-peak usage monthly.

Q. PLEASE DESCRIBE THE AVAILABILITY OF RATE SCHEDULE R-TOUD.

A. R-TOUD is available for existing residential customers if (1) service is also received under Net Metering for Renewable Energy Facilities Rider NM or (2) if served under the Residential Service Time-of-Use Schedule R-TOUD before December 1, 2013 until service is terminated or service is elected under another available schedule.

Q. WHY WAS RATE SCHEDULE R-TOUD CLOSED TO NEW PARTICIPANTS ON DECEMBER 1, 2013?

A. In Docket No. E-2, Sub 1023, the Company created a new time-of-use tariff, R-TOU, and wanted a single rate design for residential time-of-use customers. At that time, restricting the availability of R-TOUD allowed the Company to more effectively communicate with customers regarding the benefits of a TOU rate design and minimize potential customer confusion regarding the new TOU hours and the billing determinants.

Q. WHAT ARE THE ADVANTAGES OF RATE SCHEDULE R-TOU?

A. In comparison to Schedule R-TOUD, Schedule R-TOU offers improved time periods, improved pricing signals, and no demand charges.

Q. DOES THE COMPANY AGREE WITH WITNESS FLOYD'S RECOMMENDATION TO RE-OPEN R-TOUD?

A. The Company does not disagree with witness Floyd that the Company should provide customers with more choices regarding their energy consumption. However, the Company did not contemplate re-opening R-TOUD at the onset of its rate case planning. Had the Company contemplated re-opening R-TOUD, the Company would have likely recommended other changes to the R-TOUD tariff and/or to the R-TOU tariff. Also, a migration adjustment would be required to give the Company an opportunity to realize its full revenue requirement. The Company believes that re-opening R-TOUD and/or creating another residential time-of-use tariff should be considered in the comprehensive rate design study recommended by witness Floyd.

V. RIDER MROP (MANUAL READ OPTION)

Q. PLEASE DESCRIBE RIDER MROP.

A. Rider MROP is the tariff for Meter-Related Optional Programs, which are available upon request and on a voluntary basis to those customers as described in the tariff, subject to the availability of appropriate metering and meter-related equipment.

Q. PLEASE DESCRIBE THE MANUAL READ OPTION IN RIDER MROP.

A. Customers served under residential Schedules RES, R-TOU or R-TOUD or nonresidential Schedule SGS (only without a demand meter) may request metering that either does not utilize radio frequency communications to transmit data, or is otherwise required to be read manually.

Q. ARE CUSTOMERS CHARGED A FEE FOR THE MANUAL READ OPTION IN RIDER MROP?

A. Yes. The Rider MROP describes the fees to be charged to customers to set up a manual read option. Currently, the initial set-up fee is $170.00 and the monthly rate is $14.75. However, the initial set-up fee and monthly rate is waived and does not apply to customers providing a notarized statement from a medical physician stating that the customer must avoid exposure to radio frequency emissions.

Q. DID THE COMPANY PROPOSE A RATE CHANGE FOR THE MANUAL READ OPTION IN RIDER MROP IN THIS RATE CASE?

A. No. As witness Floyd stated in his testimony, the Company did perform a cost study which showed the rates should be increased, but the Company chose not to propose an increase to these rates as the Manual Read Option was recently approved by the Commission in 2019.

Q. WITNESS FLOYD SUGGESTS THAT THE RECOVERY OF ANY COSTS ASSOCIATED WITH THE AMI OPT-OUT OPTION NOT RECOVERED BY THE RIDER ITSELF SHOULD BE SOCIALIZED AND RECOVERED FROM ALL CUSTOMERS IN THE FUTURE. HOW DO YOU RESPOND?

A. Based on the current cost study, witness Floyd is correct in concluding that the rates would have increased significantly had the Company proposed a change. However, the Company would prefer to wait and see if the next study produced prior to a rate case shows a similar pattern in terms of a significant increase before determining whether costs not covered by the rider should be socialized and recovered from all customers

VI. SMALL GENERAL SERVICE TIME-OF-USE SCHEDULE PRICING

Q. HOW DOES THE COMPANY PROPOSE TO ADJUST RATES UNDER SCHEDULE SGS-TOU?

A. The Customer Charge for SGS-TOU remains unchanged at $35.50, which is consistent with the current design to reflect the MGS Customer Charge of $28.50 plus the $7.00 rate applicable to three-phase service. Marginal cost continues to support the current seasonal and TOU price relationships; therefore, no structural changes are proposed. The summer on-peak demand rate continues to exceed the non-summer rate by 19 percent during the months of June through September while the on-peak energy rate continues to exceed the off-peak energy rate by 23.4 percent to incent load shifting to off-peak hours. The Company realizes a lower than class average return under Schedule SGS-TOU; therefore, in this case, the Company has proposed to increase the SGS-TOU rates by 10 percent more than the increase to Schedule MGS to better match the cost of serving these customers. The Company has adjusted the on-peak and off-peak kWh energy and demand rates by the same percentage to recover the requested revenue requirement. The off-peak excess kW charge is increased to reflect the MGS distribution-related unit cost to better ensure that customers using electricity primarily during off-peak hours pay the cost of distribution facilities necessary to deliver electricity to the customer.

Q. DOES THE COMPANY'S DESIGN INCENT CUSTOMERS TO MIGRATE BETWEEN THE STANDARD AND TOU RATE OPTIONS AVAILABLE TO THE MGS CLASS WITH THIS DESIGN?

A. No. The load factor at which customers would realize a lower bill under SGS-TOU remains at roughly 30 percent under both the current and proposed rate design; therefore, the Company does not expect a significant number of customers to switch rate schedules without changing their usage patterns.

Q. HARRIS TEETER WITNESS BIEBER AND COMMERCIAL GROUP WITNESS CHRISS ARGUE THAT THE PROPOSED SGS-TOU DEMAND RATES SHOULD BE INCREASED AND ENERGY RATES SHOULD BE DECREASED TO BETTER REFLECT THE EMBEDDED UNIT COSTS. DO YOU AGREE WITH THEIR RECOMMENDATION?

A. No. Witnesses Bieber and Chriss argue that the Company's rates should better reflect unit cost from the embedded cost of service study. Further, they argue that shifting demand costs to energy harms high load profile customers. Witnesses Bieber and Chriss ignore that the Company is not proposing to base its rate designs solely upon embedded unit cost, nor is it advisable. Instead DE Progress's design considers both embedded and marginal demand cost. DE Progress considered the embedded unit cost in its rate design, but does not recommend that the results be accepted without judgment. As explained in my direct testimony, marginal cost was also considered in setting the overall rate levels of all tariffs as well as seasonal and time of day price relationships. Consideration of marginal cost is important in any rate design to ensure that the customer is provided efficient price signals regarding their electrical consumption decisions. A consideration of both embedded and marginal cost was used. The current SGS-TOU demand rates exceed marginal cost. Therefore, significantly increasing these rates close to embedded unit cost is inappropriate. DE Progress therefore increased both demand and energy rates by the same percentage to better recognize both the rate class embedded unit cost and marginal cost.

Q. DO THE SGS-TOU RATES PROPOSED WITNESS BIEBER HAVE AN EQUITABLE IMPACT ON CUSTOMERS SERVED UNDER THE SCHEDULE?

A. No. As shown on Bieber Direct Exhibit No. 3, SGS-TOU, Witness Bieber's proposed rate design increases bills by 7.5 to 12.1 percent depending upon load factor. This approach greatly benefits high load factor customers such as Harris Teeter, to the detriment of lower load factor customers. The Company is proposing a uniform rate increase of approximately 10 percent.

Q. WHAT OTHER EFFECTS OF WITNESS BIEBER'S PROPOSAL NEED TO BE CONSIDERED?

A. Customer migration needs to be considered. All customers in the MGS class have the option to receive service under the standard MGS design or under the SGS-TOU design. While little rate migration is anticipated with the Company's design, witness Bieber's proposal changes the load factor where SGS-TOU could be beneficial thereby encouraging customers to switch to Schedule MGS to realize a lower bill. If witness Bieber's design is accepted, a migration adjustment is required to give the Company an opportunity to realize its full revenue requirement.

Q. WHY SHOULD WITNESS BIEBER'S PROPOSED SGS-TOU DESIGN BE REJECTED?

A. Witness Bieber's design should be rejected because it fails to properly consider the marginal cost from a revenue requirement view, has a disparate impact on customers served under the schedule, and encourages migration away from a TOU design thereby discouraging load shifting.

Q. IS IT APPROPRIATE TO INCREASE REVENUES FOR SCHEDULE SGS-TOU BY MORE THAN THE MGS CLASS?

A. Yes. Schedule SGS-TOU earns a return of 6.02 percent. Schedule MGS earns a return of 3.11 percent. The adjustment was intended to move the SGS-TOU (10.3 percent) and the MGS (9.1 percent) Schedules toward rate parity, without causing economic hardship to Schedule SGS-TOU participants. The Company requested an 9.9 percent rate increase for the MGS Class. Therefore, the Company does not agree with Commercial Group witness Chriss that the Commission should require the percentage base rate increase for each subclass to equal the overall increase for the MGS class.

Q. DOES THE COMPANY AGREE WITH WITNESS CHRISS THAT THE COMMISSION SHOULD REQUIRE ANY REMAINING INCREASE TO SGS-TOU TO BE ALLOCATED ONLY TO THE ON-PEAK DEMAND CHARGES?

A. No. As stated above, DE Progress believes that a uniform rate increase for both energy and demand that maintains seasonal relationships is more appropriate and is fair.

VII. LARGE GENERAL SERVICE AND LARGE GENERAL SERVICE TIME-OF-USE PRICING RATES

Q. HOW DOES THE COMPANY PROPOSE TO ADJUST RATES UNDER SCHEDULE LGS?

A. The current LGS Customer Charge is proposed to be retained at $200.00. The demand rates are presently blocked to recognize that customers with larger load are typically served from fewer delivery-related facilities. The current demand block structure of $1 per kW reduction for loads above 5,000 kW and a $2 per kW reduction for loads above 10,000 kW is proposed to continue, as supported by the unit cost study. After adjusting the Customer Charge, the kW demand and kWh energy rates are increased by the same percentage to achieve the requested revenue.

Q. HOW DOES THE COMPANY PROPOSE TO ADJUST RATES UNDER SCHEDULE LGS-TOU?

A. The Company is not proposing changes to the TOU period hours reflected in Schedule LGS-TOU until additional customer usage data can be secured from deployment of advanced metering infrastructure and the new Customer Connect billing system is available. The overall LGS-TOU rate structure continues to be supported by marginal cost; therefore, no structural changes are proposed. The LGS-TOU Customer Charge is retained at $200.00. The on-peak demand rates are increased by of the same percentage as the energy rate adjustment. The off-peak excess kW charge is increased to reflect the LGS distribution-related unit cost study to better ensure that customers pay the cost of facilities necessary to deliver electricity to them. The kWh energy rates are adjusted to reflect the increase in revenue, retaining the current half cent per kWh differential between the on-peak and off-peak energy rates. The increased energy rates reflect an emphasis on on-peak rates when marginal costs are higher.

Q. WHY DID THE COMPANY PROPOSE TO INCREASE DEMAND (ON-PEAK DEMAND FOR SCHEDULE LGS-TOU) AND ENERGY BY THE SAME PERCENTAGES FOR SCHEDULES LGS AND LGS-TOU?

A. This approach recovers the requested revenue requirement in a manner that is equitable to current customers, minimizes disparity in the percent impact on customer bills, and does not unduly incent customers to migrate to an alternative schedule to gain a lower bill. As evidenced in Pirro Exhibit 3 to my direct testimony, LGS and LGS-TOU customers with low and high load factors typically served under LGS and LGS-TOU, respectively, realize approximately the same percentage change in billing.

Q. DOES THE COMPANY AGREE WITH CIGFUR WITNESS PHILLIPS THAT THE COMMISSION SHOULD APPROVE A REDUCTION IN THE ENERGY RATE FOR LGS AND LGS-TOU TO BETTER REFLECT THE EMBEDDED UNIT COSTS FOR ENERGY AND DEMAND?

A. No. The same arguments raised under the SGS-TOU discussion above apply to witness Phillips' arguments. He ignores that the Company is not proposing to base its rate designs solely upon embedded unit cost. Instead DEP's design considers both embedded and marginal demand and energy cost.

Q. WITNESS PHILLIPS STATES IN HIS TESTIMONY THAT THE COMPANY'S PROPOSED RATES DO NOT REFLECT THE WINTER PEAK DEMAND USED BY THE COMPANY FOR PLANNING. DID THE COMPANY MAKE ANY ADJUSTMENTS TO THE LGS-TOU RATE DESIGN TO ADDRESS WINTER PEAK?

A. Yes. On Schedule LGS-TOU, the non-summer tiered demand rates were adjusted on a slightly higher percentage than the summer tiered demand rates. The Company generally takes a gradual approach to rate design changes to lessen the impact to customers. The Company will consider new rate designs during its comprehensive rate design study.

VII. <u>REAL-TIME PRICING RATES</u>

Q. PLEASE DESCRIBE THE REAL-TIME HOURLY PRICING FOR INCREMENTAL LOAD (SCHEDULE LGS-RTP) THAT IS AVAILABLE TO THE COMPANY'S LARGE CUSTOMERS.

A. Schedule LGS-RTP (Real-Time Pricing) is a voluntary rate option that offers customers the opportunity to purchase incremental energy differing from a baseline load at rates that more closely match the Company's incremental cost of providing the kWh in the given hour. Participants understand that hourly rates will vary throughout the year and therefore offer opportunities to change consumption and benefit from the variable pricing. It is available to nonresidential customers with a contract demand requirement of 1,000 kW or greater and allows usage above or below a baseline amount to be billed at a rate that varies each hour to reflect the Company's marginal cost. Hourly rates are provided to participants on the prior business day. Baseline usage is billed under an applicable standard tariff selected by the customer, while the incremental use is billed at the hourly rate. The hourly rate includes the expected marginal production costs including line losses and other directly-related cost. An incremental demand charge and incentive margin also apply to incremental load additions.

Q. HOW ARE HOURLY RATES UNDER SCHEDULE LGS-RTP CALCULATED?

A. Hourly rates are calculated based upon the marginal or dispatch cost of the generator that is expected to serve the next kWh of system load based upon all available generating plants. Hourly rates are based on variable production cost data from an industry standard production cost model which is updated daily to reflect the latest available information such as weather and load forecast, unit availability, heat rates, and variable commodity and emission costs. Hourly rates derived from the production cost model data reflect the change in the Company's fuel and other directly related variable costs that would be anticipated if the customer decides to exceed or reduce load from their baseline load. The determination of the marginal cost is also consistent with the methodology used by the Company to price opportunity sales into the wholesale market.

Q. DO YOU AGREE WITH THE RECOMMENDATION OF CIGFUR WITNESS PHILLIPS THAT CUSTOMERS SHOULD BE ALLOWED TO ADJUST THEIR BASELOAD ON RATE SCHEDULE LGS-RTP FOR EXISTING LOAD?

A. No. Schedule LGS-RTP was established to provide customers with an opportunity and flexibility to respond directly, through usage behavior, to short-term costs, meaning a customer could benefit from reducing load under temporarily high prices and increasing usage when prices are low. Applying hourly pricing to existing baseload usage would discriminately provide a discount to few customers, thereby shifting costs to the remaining customers on the standard tariff schedule.

Q. IS THE RECOMMENDATION OF CUCA WITNESS O'DONNELL THAT THE HOURLY RATE BE SET AT THE LOWER OF THE COMPANY'S MARGINAL COST OR A WHOLESALE MARKET RATE APPROPRIATE?

A. No. The Schedule LGS-RTP hourly rates are fundamentally based on the Company's system production costs and are not designed to represent or be a proxy for market-based pricing. The rate is designed to afford customers the opportunity and flexibility to respond directly, through usage, to short term system costs. It is more analogous to a synthetic bi-directional demand response product than a market-based product. Customers can increase usage as befits their process during periods of low system costs or decrease their usage during periods of higher system costs. DE Progress actively participates in the wholesale energy market to the practical limitations of system reliability, transmission availability, and market liquidity, and customers benefit in the aggregate from those market purchases. The Real-Time Pricing product is not a market product and was never intended to provide some customers with optionality beyond the ability of the Company to provide appropriately priced service. Applying hourly rates that are lower than the Company's marginal system cost would result in other customers subsidizing Real-Time Pricing customers. The current methodology best reflects the Company's expected fuel cost and is therefore the appropriate basis under which to set hourly rates.

Q. DO YOU AGREE WITH HORNWOOD WITNESS COUGHLAN'S RECOMMENDATIONS TO INCREASE THE NUMBER OF PARTICIPANTS ON LGS-RTP, LOWER THE ENTRY TO 75 KW, AND TO CALL THE TARIFF THE "GENERAL SERVICE RTP TARIFF"?

A. No. The LGS-RTP is available for up to 85 nonresidential customers with a contract demand requirement of 1,000 kW or more. A change in the rate design of the LGS-RTP tariff as suggested by Witness Coughlan would require significant analysis and stakeholder engagement. The Company will be performing a comprehensive rate design study as discussed in DE Progress witness Lon Huber's rebuttal testimony. The Company will be seeking stakeholder engagement to optimize AMI data and Customer Connect for future rate design.

VIII. CONCLUSION

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

A. Yes.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1219

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

I. INTRODUCTION AND PURPOSE

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

A. My name is Michael J. Pirro, and my business address is 550 South Tryon Street, Charlotte, NC 28202. My position with Duke Energy Progress, LLC ("DE Progress" or the "Company") recently changed to Director, Load Forecasting and Fundamentals.

Q. DID YOU PREVIOUSLY FILE TESTIMONY IN THIS PROCEEDING?

A. Yes. I filed direct testimony and exhibits on October 30, 2019, supplemental direct testimony and exhibits on March 13, 2020, and rebuttal testimony on May 4, 2020.

Q. WHAT IS THE PURPOSE OF TESTIMONY?

A. The purpose of my second supplemental direct testimony is to support the Company's proposed update to its customer growth adjustment to incorporate certain known and measurable changes through May 31, 2020.

Q. DID YOU PROVIDE ANY INFORMATION INCLUDED IN EXHIBITS SPONSORED BY OTHER COMPANY WITNESSES?

A. Yes. For the reasons I describe below, I sponsor the following adjustment presented in Smith Second Supplemental Exhibit 1:

Line 4 – Annualize revenues for customer growth.

Q. WHY IS THE COMPANY UPDATING ITS CUSTOMER GROWTH ADJUSTMENT?

A. As I noted in my rebuttal testimony, the Company is experiencing a significant reduction in its load and associated revenues due to many commercial and industrial customers as well as schools and colleges scaling back operations, if not closing completely, during the COVID-19 state of emergency. I also indicated that the Company would update its customer growth adjustment closer to the hearing to provide a more accurate depiction of customer usage. In addition to the reduction in non-residential load referenced above and in my rebuttal testimony, the Company has experienced an increase in residential usage. Accordingly, the Company has updated its pro forma adjustment for customer growth to reflect known and measurable kilowatt hour changes in both residential and non-residential usage through May 31, 2020.

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

A. Yes.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-2, SUB 1219
DOCKET NO. E-2, SUB 1193

In the Matter of: DOCKET NO. E-2, SUB 1219 In the Matter of Application of Duke Energy Progress, LLC For Adjustment of Rates and Charges Applicable to Electric Service in North Carolina DOCKET NO E-2, SUB 1193 In the Matter of Application by Duke Energy Progress, LLC, for an Accounting Order to Defer Incremental Storm Damage Expenses Incurred as a Result of Hurricanes Florence and Michael and Winter Storm Diego	)	**SECOND SETTLEMENT TESTIMONY OF MICHAEL J. PIRRO FOR DUKE ENERGY PROGRESS, LLC**

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

A. My name is Michael J. Pirro, and my business address is 550 South Tryon Street, Charlotte, North Carolina 28202. My position with Duke Energy Progress, LLC ("DE Progress" or the "Company") recently changed to Director, Load Forecasting and Fundamentals.

Q. DID YOU PREVIOUSLY FILE TESTIMONY IN THIS PROCEEDING?

A. Yes. I filed direct testimony and exhibits on October 30, 2019, supplemental direct testimony and exhibits on March 13, 2020, rebuttal testimony on May 4, 2020, and second supplemental direct testimony on July 2, 2020.

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

A. My second settlement testimony provides updates to Pirro Exhibit 4 and Pirro Exhibit 8 to reflect the First Agreement and Stipulation of Partial Settlement between the Company and the Public Staff filed on June 2, 2020 ("First Partial Settlement"), the Second Agreement and Stipulation of Partial Settlement between the Company and the Public Staff filed on July 31, 2020 ("Second Partial Settlement"), and the Company's Agreement and Stipulation of Settlement with CIGFUR II filed on June 26, 2020, as amended on August 6, 2020 ("CIGFUR Settlement").

Q. WERE THE EXHIBITS TO YOUR SECOND SETTLEMENT TESTIMONY PREPARED BY YOU OR UNDER YOUR DIRECTION AND SUPERVISION?

A. Yes.

Q. PLEASE DESCRIBE THE UPDATE TO PIRRO EXHIBIT 4.

A. Pirro Direct Exhibit 4 illustrates the rates of return across classes emanating from the Company's class cost of service study and shows how the proposed revenue increase is distributed among customer rate classes. Pirro Second Settlement Exhibit 4 updates Pirro Direct Exhibit 4 to reflect the revised revenue requirement resulting from the Second Partial Settlement and the Company's position on unsettled items, as further supported by Company witness Kim Smith's second settlement testimony. This update shows the rate increase by customer class and proposed spread to customer classes, both with and without the proposed Excess Deferred Income Tax ("EDIT") Rider. The EDIT Rider amounts reflected in Columns Z and AA of this exhibit have been updated as described below.

Q. PLEASE DESCRIBE THE UPDATE TO PIRRO EXHIBIT 8.

A. Pirro Direct Exhibit 8 provides the derivation of the Company's original proposed EDIT Rider. As a result of the Company's First Partial Settlement with the Public Staff, the Company has agreed to return protected federal EDIT to customers through base rates instead of the EDIT Rider. In addition, as described in the Second Partial Settlement, the Company and the Public Staff have agreed that all unprotected federal EDIT should be returned to customers over a five-year amortization period and that North Carolina EDIT and deferred revenues related to the provisional overcollection of federal income taxes should be returned to customers over a two-year amortization period. Under the CIGFUR Settlement, the Company has agreed to refund unprotected EDIT and deferred revenues to customers on a uniform cents per kilowatt-hour basis. Pirro Second Settlement Exhibit 8 recalculates the proposed EDIT Rider rate credits to reflect these provisions of the First Partial Settlement, Second Partial Settlement, and CIGFUR Settlement.[1]

Q. DOES THIS CONCLUDE YOUR SECOND SETTLEMENT TESTIMONY?

A. Yes.

[1] Pirro Second Settlement Exhibit 8 displays the two-year decrement rider amounts resulting from the settlements as "EDIT-3" and the decrement rider amounts as "EDIT-4."

My direct testimony explains how the rates and charges that Duke Energy Progress proposes are based upon appropriate and sound ratemaking principles and that they result in an equitable basis for recovery of the Company's revenue requirement across and within its various rate schedules. My testimony also describes changes to the Company's retail electric schedules and quantifies the effect of these changes to retail customers. The proposed rates appropriately reflect the cost of service within the three major rate classes: residential, general service, and lighting.

I used the cost of service information prepared by the Company and supported by witness Hager as a major component for the rate design. As witness Hager describes in her testimony, the cost of service study allocates costs to the jurisdictions and various rate classes and separates the customer, demand, and energy components of cost. I also reviewed and considered the rates of return across the customer classes derived from the cost of service study.

The Company did not propose any structural changes within each tariff. As detailed in the rebuttal testimony of witness Huber and agreed to in the Second Partial Settlement with the Public Staff, the Company is planning a comprehensive rate design study following the conclusion of this rate case, which will include consideration of a number of new and innovative rate design issues.

The rate adjustments proposed by the Company in this proceeding are intended to move all rate schedules closer to a more equitable pricing structure. The Company is seeking to achieve an equitable pricing structure in steps in recognition that the imbalance in class and rate schedule returns did not occur overnight and should not be corrected overnight. A framework that reflects these rate design concepts – gradualism and parity – is also reflected in the Second Partial Settlement.

In my rebuttal testimony, I address a number of rate design issues raised by various intervenors, many of which have since been resolved by settlement agreements with those intervenors. In addition, I respond to the only intervenor group that took issue with the residential Basic Customer Charge, noting that the Company purposefully did *not* propose any increase to the Basic Customer Charge in this case due to concerns raised by this group and other advocates for low-income customers in the Company's last rate case.

I also filed supplemental testimony supporting the Company's proposed update to its customer growth adjustment to incorporate certain known and measurable changes through May 31, 2020. In the Second Partial Settlement, the parties agreed to limit any resulting increase in revenues to 75% of the difference between the May update and the Company's February 2020 update to recognize the uncertainty regarding the effects of COVID-19. Finally, I filed settlement testimony to update my exhibits to reflect the impact of various settlement agreements and also filed supplemental rebuttal testimony, jointly with Mr. Huber, to support the rate design aspects of the Company's settlements with CIGFUR, Harris Teeter, and the Commercial Group.

This concludes the summary of my pre-filed testimony.

BY MS. JAGANNATHAN:

Q And, finally, Mr. Huber, would you please state your name and business address for the record?

A (Mr. Huber) Lon Huber, 550 South Tryon Street, Charlotte, North Carolina.

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

A I'm employed by Duke Energy Business Services as Vice President - Rate Design and Strategy Solutions.

Q And on May 4th, 2020, did you cause to be prefiled in this docket rebuttal testimony consisting of 8 pages and a one-page appendix describing your experience and qualifications?

A Yes, I did.

Q And on September 23rd, 2020, did you cause to be prefiled in this docket joint supplemental rebuttal testimony with Michael Pirro consisting of eight pages?

A That is correct.

Q And, Mr. Huber, do you have any changes or updates to your prefiled testimony?

A Yes. I have two updates to my testimony that are included in the errata page provided with my testimony summary.

Q Thank you, Mr. Huber. And with the updates to your testimony that are noted in your errata sheet, if I asked you the same questions here today, would your answers be the same?

A Yes, they would.

MS. JAGANNATHAN: Commissioner Clodfelter, I would move that Mr. Huber's prefiled rebuttal testimony, Appendix A, the joint supplemental rebuttal testimony Mr. Huber filed with Mr. Pirro, and Mr. Huber's testimony summary and errata sheet be entered into the record as if given orally from the stand.

COMMISSIONER CLODFELTER: All right. If there is objection, the motion is allowed.

MS. JAGANNATHAN: Thank you, Commissioner Clodfelter.

(WHEREUPON, the prefiled rebuttal, Appendix A, joint supplemental rebuttal with Mr. Pirro, errata, and summary of LON HUBER is copied into the record as if given orally from the stand.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1219

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

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS.

A. My name is Lon Huber, and my business address is 550 South Tryon Street, Charlotte, NC 28202.

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

A. I am employed by Duke Energy Corporation ("Duke Energy"). My role is Vice President, Rate Design and Strategic Solutions. In this capacity, I am responsible for rate design and pricing for all of Duke Energy's affiliated utility operating companies, including Duke Energy Progress ("DE Progress" or "Company") and Duke Energy Carolinas, LLC ("DE Carolinas").

Q. DID YOU PREVIOUSLY FILE DIRECT TESTIMONY IN THIS PROCEEDING?

A. No.

Q. PLEASE DESCRIBE YOUR BUSINESS BACKGROUND AND EXPERIENCE.

A. My career in the energy industry began in 2007, when I started work at a solar energy research institute housed within the University of Arizona. From 2010 to 2013, I held positions in the solar industry working on matters both local to Arizona and across the United States. Subsequently, I served as a consultant for Arizona's consumer advocate, the Residential Utility Consumer's Office ("RUCO"), on energy-related issues. I then joined RUCO as a full-time employee. At RUCO, I was the staff lead on significant dockets involving net metering, resource procurement, and rate design. I decided to rejoin the consulting space in 2015, where I worked for numerous consumer advocates, state utility commissions, and energy companies across the country. A major topic of my work was around pricing and rate design with a specialty in time-varying rates and subscription-based pricing. I have also been a regular instructor at the Financial Research Institute Transformational Pricing course held at the University of Washington. Due to my work on rate design and other matters like energy storage, I have garnered recognition for my creative win-win solutions including Utility Dive's 2018 Innovator of the Year award. I assumed my current position with Duke Energy in November of 2019.

In terms of educational background, I obtained a Bachelor of Science degree in Public Policy and Management from the University of Arizona. I also received a Master of Business Administration from the Eller College of Management at the same university. I completed NARUC rate school in 2014. My full resume is included as Appendix A.

Q. HAVE YOU TESTIFIED BEFORE THE NORTH CAROLINA UTILITES COMMISSION BEFORE?

A. While I submitted pre-filed rebuttal testimony in DE Carolinas' pending rate case in Docket No. E-7, Sub 1214, I have not yet appeared before this Commission.

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

A. My rebuttal testimony responds to:

- COMPREHENSIVE RATE DESIGN STUDY as discussed in the testimony of Public Staff witness Jack Floyd;

- EV-SUPPORTIVE RATE DESIGN as discussed in the testimony of the North Carolina Sustainable Energy Association ("NCSEA") witness Justin Barnes; and
- MULTI-SITE AGGREGATION RATE STUDY as discussed in the testimony of Harris Teeter witness Justin Bieber.

II. COMPREHENSIVE RATE DESIGN STUDY

Q. DO YOU AGREE WITH PUBLIC STAFF WITNESS FLOYD THAT THE COMPANY SHOULD CONDUCT A COMPREHENSIVE RATE DESIGN STUDY?

A. Yes. The Company supports an open, data-driven process that does not preclude or favor any predetermined conclusions. Historically, DE Progress's rate offerings have adequately served customers, with all rate classes being able to choose between a standard and time-of-use rate schedules. However, changes in customer interests, political and regulatory priorities, and increasing adoption of new technologies demand a rethinking of DE Progress's rate designs.

Q. DO YOU AGREE WITH WITNESS FLOYD'S OPINION ON THE REQUIRED COMPONENTS OF A COMPREHENSIVE RATE DESIGN STUDY?

A. Yes. A comprehensive rate design study should result in new designs that better meet the state's public policy goals. Thus, the Company agrees with witness Floyd's six broad principles for a comprehensive rate design study, including that it:

1) Be forward-looking and reflect long-run marginal cost;

2) Be focused on the usage components of service that are the most cost- and price-sensitive;

3) Be simple and understandable;

4) Recover system costs in proportion to how much electricity consumers use, and when they use it;

5) Give consumers appropriate information and the opportunity to respond to that information by adjusting the usage; and

6) Where possible, be dynamic.

Q. DO YOU AGREE WITH WITNESS FLOYD'S COMMENTS THAT A COMPREHENSIVE RATE DESIGN STUDY SHOULD SEEK TO HARMONIZE THE RATE DESIGN STRUCTURES OF DE PROGRESS AND DE CAROLINAS?

A. Yes. Both utilities have retained the same basic rate design structure from before the merger. As witness Floyd mentioned, this is confusing and often frustrating for customers. Better aligning the rate designs may create some synergies for the Company, as the differences also present operational challenges. A comprehensive rate design study should explore how creating a unified pricing theory and better aligning the two utilities would help achieve the aforementioned rate design goals.

Q. WHAT FACTORS NEED TO BE CONSIDERED IN SETTING A TIMEFRAME FOR A COMPREHENSIVE RATE DESIGN STUDY?

A. Witness Floyd suggested that the Company undertake a comprehensive rate design study prior to the filing of its next rate case. He noted that such a study is "no trivial matter," and will be a "serious and lengthy undertaking" which will involve many stakeholders and will likely require a significant amount of time to develop and implement. While DE Progress does not currently know the timing of its next rate case, the Company has already begun analyzing data and plans to convene stakeholders in a collaborative process before refining its rate design proposals. The Company notes that it cannot cost-effectively implement any rate design changes until the new Customer Connect billing system is in use. Because it is more cost-effective to implement new rates concurrently with the new billing system, DE Progress strongly favors using the time prior to implementation to analyze data, convene stakeholders, and refine its proposals. Customer Connect is scheduled to be implemented in DE Progress for the spring of 2022. Once the new Customer Connect system is fully deployed and post-deployment stabilization is achieved approximately six months later, the Company will be ready to begin implementing new rate designs.

Q. WHAT TIME FRAME DOES THE COMPANY RECOMMEND?

A. Given the considerations noted previously, the Company proposes to complete the comprehensive rate design study by the end of the second quarter of 2021. The Company believes that this is an aggressive timeline that will allow the new rate designs to be implemented as soon as Customer Connect is ready to support any proposed changes. In addition, deployment of smart meters throughout DE Progress is nearly complete, offering an additional level of insight and data that will be used to design refreshed rates.

Q. IS DE PROGRESS CURRENTLY COLLECTING DATA THAT WILL BE BENEFICIAL FOR A COMPREHENSIVE RATE DESIGN STUDY?

A. Yes. DE Progress will incorporate lessons learned from DE Carolinas' nine new dynamic pricing pilots, which were implemented on October 1, 2019 in compliance with the Commission's July 2, 2019 *Order Approving Pilots* in Docket No. E-7, Sub 1146. The Commission is also currently considering the Company's Proposed Electric Transportation Pilot in Docket No. E-2, Sub 1197, and, if approved, DE Progress will incorporate lessons gleaned from this pilot as well.

III. <u>ELECTRIC VEHICLE-SUPPORTIVE RATE DESIGN</u>

Q. IS DE PROGRESS OPEN TO LOOKING INTO RATE DESIGNS THAT SUPPORT THE ADOPTION OF ELECTRIC VEHICLES, AS SUGGESTED BY NCSEA WITNESS BARNES?

A. Yes. DE Progress understands that increasing the adoption of electric vehicles is a state policy goal that could provide significant system benefits. However, the Company believes that it is inappropriate for the Commission to expedite the filing of electric vehicle-specific tariffs within 60 days of the final order in this case, as recommended by witness Barnes. Rather, a study of rate designs that facilitate the adoption of electric vehicles that provide system benefits for all customers should be a part of the comprehensive rate design study discussed above. In the context of a comprehensive study, any new or altered offerings can be crafted to work in concert with the other components of DE Progress' rate designs.

IV. MULTI-SITE AGGREGATE COMMERCIAL RATE

Q. IS THE COMPANY WILLING TO INVESTIGATE A POTENTIAL MULTI-SITE AGGREGATE COMMERCIAL RATE, AS SUGGESTED BY HARRIS TEETER WITNESS BIEBER?

A. Witness Bieber recommends that the Commission order the Company to study the feasibility of a multi-site aggregate commercial rate and propose a pilot program it its next rate case that would allow commercial customers to participate in a multi-site rate applicable to the portion of the demand charge associated with fixed production costs. Without having studied such a rate offering, DE Progress believes that it is premature for the Commission to order the Company to propose a multi-site aggregation pilot in its next rate case; however, the Company is certainly willing to consider witness Bieber's proposal in the context of the comprehensive rate design study discussed above.

V. CONCLUSION

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

A. Yes.

Lon Huber

Lon.Huber@Duke-Energy.com

Experience

Vice President – Rate Design and Strategic Solutions
Nov 2019 -
Duke Energy – Charlotte, NC

Director – North American Retail Regulatory Offering
July 2018 – Nov 2019
Navigant Consulting – New York, NY

Vice President – Head of Consulting
MAR 2015 – JULY 2018
Strategen Consulting – Berkeley, CA

Special Projects Advisor
APR 2013 – MAR 2015
Arizona's Residential Utility Consumer Office (RUCO) – Phoenix, AZ

Founder
DEC 2010 – JAN 2014
Next Phase Energy – Tucson, AZ

Manager – Policy Specialist
SEP 2011 – DEC 2012
Suntech America – San Francisco, CA

Finance & Policy Lead
SEP 2010 – SEP 2011
TFS Solar – Tucson, AZ

Congressional Energy Fellow
JAN 2009 – MAY 2009
Washington DC

Policy Program Associate
AUG 2007 – SEP 2010
University of Arizona Research Institute for Solar Energy – Tucson, AZ

EDUCATION

Masters of Business Administration
Eller College of Management, 2011

BS, Public Policy and Management,
University of Arizona, 2009

EDUCATION/CERTIFICATIONS

Instructor – FRI's Transformational rate design course

Microsoft Office Excel Specialist

NARUC Utility Rate School Graduate

AWARDS

Fortnightly Under 40 and Top Innovator Honor Roll – Public Utilities Fortnightly

2018 Innovator of the Year – Utility Dive

The Phil Symons Award – Energy Storage Association

40 under 40 – Arizona Daily Star

Young Alumni Award and Outstanding Professional Staff Member – University of Arizona

Congressional Recognition Award – US House of Representatives

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-2, SUB 1219
DOCKET NO. E-2, SUB 1193

In the Matter of:	)	
	)	
DOCKET NO. E-2, SUB 1219	)	
	)	
In the Matter of	)	
Application of Duke Energy Progress, LLC	)	
For Adjustment of Rates and Charges	)	**JOINT SUPPLEMENTAL**
Applicable to Electric Service in North	)	**REBUTTAL TESTIMONY**
Carolina	)	**OF**
	)	**MICHAEL J. PIRRO AND**
DOCKET NO E-2, SUB 1193	)	**LON HUBER**
	)	**FOR DUKE ENERGY**
In the Matter of	)	**PROGRESS, LLC**
Application by Duke Energy Progress, LLC, for	)	
an Accounting Order to Defer Incremental	)	
Storm Damage Expenses Incurred as a Result of	)	
Hurricanes Florence and Michael and Winter	)	
Storm Diego	)	

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

A. My name is Michael J. Pirro, and my business address is 550 South Tryon Street, Charlotte, North Carolina 28202. My position with Duke Energy Progress, LLC ("DE Progress" or the "Company") recently changed to Director, Load Forecasting and Fundamentals.

Q. DID YOU PREVIOUSLY FILE TESTIMONY IN THIS PROCEEDING?

A. Yes. I filed direct testimony and exhibits on October 30, 2019, supplemental direct testimony and exhibits on March 13, 2020, rebuttal testimony on May 4, 2020, second supplemental direct testimony on July 2, 2020, and second settlement testimony and exhibits on August 21, 2020.

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

A. My name is Lon Huber, and my business address is 550 South Tryon Street, Charlotte, NC 28202. I am Duke Energy Corporation's Vice President, Rate Design and Strategic Solutions.

Q. DID YOU PREVIOUSLY FILE TESTIMONY IN THIS PROCEEDING?

A. Yes. I filed rebuttal testimony supporting the proposed comprehensive rate design study on May 4, 2020.

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

A. Our supplemental rebuttal testimony responds to the Second Supplemental Testimony of Jack Floyd and supports the Company's Settlement Agreement with Harris Teeter, LLC filed on June 8, 2020, as amended on August 6, 2020 ("Harris Teeter Settlement"); the Company's Settlement Agreement with the Commercial Group filed on June 9, 2020, as amended on August 5, 2020 ("Commercial Group Settlement); and the Company's Agreement and Stipulation of Settlement with CIGFUR II filed on June 26, 2020, as amended on August 6, 2020 ("CIGFUR Settlement").

Q. MR. FLOYD DISAGREES WITH THE PROVISION OF THE CIGFUR SETTLEMENT WHICH PROVIDES THAT THE COMPANY WILL RETURN UNPROTECTED EXCESS DEFERRED INCOME TAXES ("EDIT") AND DEFERRED REVENUE THROUGH ITS EDIT RIDER ON A UNIFORM CENTS PER KILOWATT HOUR BASIS. MR. PIRRO, HOW DO YOU RESPOND?

A. As I note in my direct testimony, the residential class has historically been subsidized by non-residential rate classes. Returning federal unprotected EDIT and deferred revenues on a uniform cents per kWh basis helps balance out this subsidy. In addition, the uniform cents per kWh flowback is consistent with how rates were designed for the North Carolina EDIT rider that the Commission approved in the Company's last rate case.

Q. MR. FLOYD BELIEVES THAT THE RATE DESIGN CHANGES PROPOSED IN THE HARRIS TEETER AND COMMERCIAL GROUP SETTLEMENTS WOULD CONSTRAIN THE ABILITY TO CONDUCT A FUTURE COMPREHENSIVE RATE DESIGN STUDY. DO YOU AGREE, MR. PIRRO?

A. No. Sections 3 and 4 of the Harris Teeter and Commercial Group Settlements provide for the following rate design changes relating to the Small General Service – Time of Use ("SGS-TOU") rate:

- DE Progress agrees, with certain conditions, to design rates such that the percentage base rate increase for Rate Schedule SGS-TOU and Rate Schedule MGS shall be the same;
- DE Progress agrees that the SGS-TOU on-peak and off-peak energy charges shall be increased by a percentage that is no greater than half of the approved overall increase percentage for the SGS-TOU rate schedule; and
- DE Progress agrees that the demand charges for the SGS-TOU rate schedule shall be adjusted by the amount necessary to recover the final SGS-TOU revenue target.

These provisions apply only to the SGS-TOU rates proposed in *this* rate case. These provisions do not bind the Company to any particular rate design structure in a future rate case and do not limit the Company's ability to study alternative rate designs. The Company views the comprehensive rate design study as a "blank slate." In addition to evaluating new and innovative rate designs and exploring the topics discussed in the direct testimony of witness Floyd as well as witness Huber, DE Progress plans to use the study as an opportunity to review and reevaluate all of its existing tariffs with a fresh eye.

Q. MR. PIRRO, DO YOU THINK THAT THESE CHANGES TO THE SGS-TOU RATE DESIGN IN THIS RATE CASE ARE REASONABLE?

A. Yes. As stated in my direct testimony, the Company uses the cost of service information as a major component for rate design. The Company's unit cost study indicates that the demand charges for SGS-TOU should be $18.15 per kW and energy charges should be 3.835 cents per kWh. Current rates on Schedule SGS-TOU-62 are $11.28 per kW and 5.905 cents per kWh for on-peak usage and 4.643 cents per kWh for off-peak usage. Based on cost causation, the changes to the SGS-TOU rate design agreed to in the settlements with Harris Teeter and the Commercial Group in this rate case are reasonable.

Q. THE HARRIS TEETER, COMMERCIAL GROUP, AND CIGFUR SETTLEMENTS INCLUDE PROVISIONS RELATING TO THE PROPOSED ALLOCATION OF DEFERRED COSTS RELATING TO THE GRID IMPROVEMENT PLAN ("GIP"). MR. PIRRO, DO THESE PROVISIONS HAVE ANY APPLICABILITY TO THE RATES APPROVED IN THIS RATE CASE?

A. No. If the Commission approves the Company's request to defer costs relating to certain GIP programs, the Commission will address recovery of those costs in the Company's next general rate case. In that future rate case, the

Commission would evaluate whether the Company's proposed allocation methodology is the appropriate way to allocate GIP costs both amongst customer classes, as well as within each individual rate schedule. Of course, the various parties are free to intervene and advocate the positions they believe are appropriate in the next rate case.

Q. MR. HUBER, DO YOU BELIEVE A STAKEHOLDER PROCESS WOULD ACHIEVE UNANIMITY WITH RESPECT TO WHICH CLASS COST OF SERVICE STUDY SHOULD BE USED?

A. No. The comprehensive rate design study as contemplated by the Company and the Public Staff does not encompass discussion of which cost allocation methodology the Company should propose in its next rate case. While the Company has agreed to consider and prepare cost of service studies using a number of methodologies in its settlements with CIGFUR and the Public Staff, these cost of service studies are separate and apart from the comprehensive rate design study, and for good reason. The comprehensive rate design study is designed to be a stakeholder process, and given the different perspectives of intervenors with respect to the appropriate cost of service methodology, it is very unlikely that the interested stakeholders would reach consensus of the cost of service methodology; attempting to include this discussion in the rate design study could grind the collaborative stakeholder process to a halt before it really even begins. Therefore, the Company recommends that cost allocation methods (e.g., cost of service allocators) not be included in the rate design study to ensure the parameters of the study are reasonable enough to produce focused results. Instead the focus of the comprehensive rate design study should remain on "rate design questions," as outlined in the Second Partial Stipulation with the Public Staff.

Q. OUTSIDE OF COST OF SERVICE ALLOCATOR METHODOLOGY, WILL THE COMPREHENSIVE RATE DESIGN STUDY INTERFACE WITH COST TO SERVE DATA AND TOPICS?

A. Absolutely. One of the key approaches to judge a rate design is by its impacts and alignment with both embedded cost to serve metrics as well as marginal cost to serve evaluations. I fully intend to bring both those lenses to the comprehensive rate design study as we balance them with other criteria such as understandability and stability.

Q. MR. HUBER, HOW DO YOU ENVISION THE PROCESS AND TIMELINE UNFOLDING FOR THE COMPREHENSIVE RATE DESIGN REVIEW?

A. The Company envisions the review and implementation of new rate designs as an iterative process, with a focus for the first year on creating a detailed actionable roadmap and prioritization for tariff changes over time, including emerging end-use considerations. The inclusive stakeholder process will first require alignment on goals, principles and process, as well as building a shared level of knowledge amongst the parties. Stakeholders will then be equipped to evaluate and recommend changes in a number of areas, provided consideration of topics is thoughtfully sequenced. Major topic areas include, but are by no means limited to, rate design elements such as customer classes, time-of-use windows, treatment of riders, end uses such as rooftop solar and electric vehicles, alignment of legacy rate schedules, etc. Where feasible and supported by broad consensus, pilots, research, or other improvements can and should be pursued during the process, even in advance of future rate cases. In addition to the implementation roadmap at the end of one year, the Company supports periodic updates to the Commission detailing progress, challenges, and implications for subsequent phases and topics. Commission guardrails covering scope, sequencing, and timelines would provide clarity for all stakeholders and support a focused and efficient study overall.

Q. DOES THIS CONCLUDE YOUR JOINT SUPPLEMENTAL REBUTTAL TESTIMONY?

A. Yes.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1219

In the Matter of: Application of Duke Energy Progress, LLC For Adjustment of Rates and Charges Applicable to Electric Service in North Carolina	))))))))	**DUKE ENERGY PROGRESS, LLC'S CORRECTIONS TO REBUTTAL TESTIMONY OF LON HUBER**

CORRECTIONS TO REBUTTAL TESTIMONY OF LON HUBER

PAGE 6, LINE 11 SHOULD READ:	REASON FOR CHANGE:
is scheduled to be implemented in DE Progress for November 2021~~the spring of 2022~~. Once the	The expected implementation of Customer Connect has been changed from spring of 2022 to November 2021.
PAGE 6, LINES 16 AND 17 SHOULD READ:	REASON FOR CHANGE:
A. Given the considerations noted previously, the Company proposes to complete the comprehensive rate design study ~~by the end of the second quarter of 2021~~within 12 months of the issuance of the final order in this case.	Duke Energy Progress initially proposed to complete the comprehensive rate design study by the end of the second quarter of 2021, which would have given the Company a year to engage stakeholders and complete the study had the hearing proceeded as originally scheduled. In light of the delays caused by the unprecedented events of 2020, the Company proposes to complete the study within twelve months from the date of the final order in this proceeding.

I joined Duke Energy less than a year ago as Vice President of Rate Design and Strategic Solutions. In this role, I am responsible for rate design and pricing for all of Duke Energy's affiliated utility operating companies, including Duke Energy Progress. While Mr. Pirro's testimony covers the rate designs filed as part of this rate case, I cover forward-looking rate design topics that have been raised by intervenors, including the opportunity to revamp the Company's rate design in a comprehensive rate design study, as well as rate design issues relating to electric vehicles.

While I may be new to my role at Duke Energy, the core issues at hand are not new to me. As a former consultant, I have worked across the country on rate design topics, mainly for public utility commissions and state consumer advocates. In those roles, I saw how converging trends in the industry are driving the need for rate design modernization. I was fortunate to be able to see consumer and technological trends firsthand in states on the front lines of change. For example, I was a consultant for four years at the Hawaii Public Utilities Commission, I worked on rate design for Xcel and Minnesota Power, I was an employee and consultant of the Arizona consumer advocate office for five years, I have advised the New York Public Service Commission, and I consulted for the Attorney General's office in Massachusetts for several years. I aim to bring these experiences and insights to my role at Duke Energy and work collaboratively with stakeholders to analyze current North Carolina rate designs, and where appropriate, modernize the Company's offerings.

To that end, in my rebuttal testimony, I agree with Public Staff witness Jack Floyd that the time is right for the Company to undertake a comprehensive rate design study following this rate case. While historically, the Company's rate offerings have served its customers well, changes in customer interests, political and regulatory priorities, and increasing adoption of new technologies demand a rethinking of Duke Energy Progress's rate designs. In addition, deployment of smart meters throughout Duke Energy Progress is nearly complete, offering an additional level of insight and data that will be used to design refreshed rates. Lessons learned from recently filed dynamic pricing pilots and the Company's proposed electric vehicle pilot will also be used to inform future rate design proposals.

The Company has already begun analyzing data and plans to convene stakeholders in a collaborative process before refining its rate design proposals. Duke Energy Progress initially proposed to complete the comprehensive rate design study by the end of the second quarter of 2021, which would have given the Company about a year to engage stakeholders and complete the study had the hearing proceeded as originally scheduled. In light of the delays caused by the unprecedented events of 2020, the Company proposes to complete the study within twelve months from the date of the final order in this proceeding. This is an aggressive timeline that will allow the new rate designs to be implemented once the Company's new Customer Connect billing system is ready to support any proposed changes.

In my supplemental rebuttal testimony, filed jointly with Mr. Pirro, I clarify certain aspects of the scope and timing of the comprehensive rate design study.

This concludes the summary of my pre-filed testimony.

MS. JAGANNATHAN: And, finally, pursuant to the Joint Stipulation of Live Testimony and Exhibits of certain rate design and cost allocation witnesses which was filed with the Commission on September 24th, 2020, I would move that the live testimony of witnesses Hager, Huber and Pirro in Docket Number E-7, Sub 1214 be copied into the record as if given orally from the stand. And those transcript pages are transcript volume 12, page 296, line 5 through page 306, line 23; and transcript volume 13, page 16, line 10 through page 132, line 8.

COMMISSIONER CLODFELTER: All right. Is there any objection from any party not a party to the Stipulation?

(Pause)

Hearing no objection, the motion is allowed.

(WHEREUPON, the stipulated testimony of Janice Hager, Michael Pirro and Lon Huber from Docket Number E-7, Sub 1214 is copied into the record as if given orally from the stand.)

Panel of
Janice Hager, Michael J. Pirro, Lon Huber
Stipulated Testimony from DEC Evidentiary Hearing

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219

MS. JAGANNATHAN: The panel is now available for cross examination.

CHAIR MITCHELL: All right. Public Staff, you're up.

CROSS EXAMINATION BY MS. DOWNEY:

Q. Good afternoon to the panel. My name is Dianna Downey with the Public Staff. With me this afternoon is Lucy Edmondson. I will be directing my questions to Ms. Hager, and Ms. Edmondson will be directing questions to Mr. Pirro. Mr. Huber, you're going to be off the hook from us for this time.

Ms. Hager, I want to turn to your rebuttal testimony. Specifically, on page 5, you refer to the National Association of Regulatory Utility Commissioners, known as NARUC; electric utility cost allocation manual, and you refer to it as a CAM, I believe, correct?

A. (Janice Hager) That's correct.

Q. And do you agree that that manual was produced in 1992; isn't that right?

A. I do.

Q. Have you heard of the electric cost allocation manual published in January of this year by the Regulatory Assistance Project, or RAP?

A. I have.
Q. What's your familiarity with it?
A. I have -- it was referenced by witness Wallach in his testimony the past year or so, and I have reviewed it and spent a little time with it. I'm certainly no expert on it, but I have spent some time with it.
Q. Understood.
MS. DOWNEY: Chair Mitchell, I would like to mark Public Staff 41 as Public Staff Pirro/Hager Cross Examination Exhibit 1. And this is the manual we were just discussing.
CHAIR MITCHELL: All right. Bear with me one moment, Ms. Downey, while I access the document. The document will be marked Public Staff Hager Cross Exhibit 1.
MS. DOWNEY: And, Chair Mitchell, I think we're marking these Pirro/Hager since --
CHAIR MITCHELL: Okay.
MS. DOWNEY: -- we're addressing these to the panel.
CHAIR MITCHELL: All right. The document will be marked Public Staff Pirro/Hager Cross Exhibit Number 1.

(Public Staff Pirro/Hager Cross Examination Exhibit Number 1 was marked for identification.)

Q. Ms. Hager, do you have that in front of you?

A. I do.

Q. And I just have one question about this.

Would you agree that it's fair to say that the authors of this manual suggest a different approach to aspects of cost of service allocation than the approach used in the CAM?

A. They do suggest a number of different approaches from what's used in the CAM. Oftentimes, intervenors will suggest different approaches. In this case, the manual which is put out by the Regulatory Assistance Project comes from a very specific viewpoint of wanting to encourage energy efficiency and distributed energy resources. And therefore, the manual is definitely -- favors policies and methods that would drive that.

Q. Understood. In your rebuttal testimony on page 23 -- do you have that in front of you?

A. Just -- give me just a second.

Q. Sure.

(Pause.)

A. Okay. I have it.
Q. And I'm specifically referring to your discussion and your response to Mr. James McLawhorn's recommendation that the Commission direct the Company to study the allocation of grid improvement plan investments.
In your response, as I read it, is that any allocation based on perceived benefits realized by customers is likely to be very subjective and controversial.
Did I state that correctly?
A. Absolutely.
Q. Acknowledging that there is -- there are differences in opinions on this issue, what's the harm in a study that could potentially resolve or at least result in a better understanding of this issue?
A. I just don't believe that it is an effort that's likely to yield fruit. And I think the concept of allocated costs based on benefits is -- has so many downfalls that to go forward with it would simply, I think, actually just be a waste of time. If you'll allow me, I'll talk a little bit about why I think that. The --
Q. I think I'm just asking you what's the harm

in a study?

A. Uh-huh. And I think --

Q. Just talk about it.

A. So I believe -- as I said, I think the harm in a study is I don't believe it would produce anything that would be useful for the purposes of cost of service. I do think there's a place for looking at benefits, and that's how the Company has done it in this case, which is in deciding what -- you know, what projects to pursue and what -- you know, how to prioritize those projects. I think where -- to try to allocate costs based on benefits is, first of all, very much a departure from traditional cost allocation methodologies.

It is -- if you think about what we do in cost of service, we essentially look at -- you know, we have generation transmission distribution customer costs, and then we're looking at how customers use that electricity. You know, what their actual load is. And then we say, okay, how did that load cause costs? We don't look beyond the meter to say what benefits those customers receive. I think if you start doing that, I think there's a real question of, you know, where do you stop? How do you measure those benefits?

You know, I think we'd all agree what we've heard in this hearing is that there's a lot of different opinions on what those benefits would be. I would suggest they change frequently. I think they would be lots and lots of different arguments on how to quantify those. And I also think, if you think about what Mr. Oliver talked about in his testimony, you know, he made pretty clear that the grid improvement program is a program that addresses a lot of things. You know, it's designed to address the megatrends. And it happens -- as he would say it, it happens to be a program that also provides some reliability benefits, and those benefits happen to be something that can be most easily quantified for industrial and commercial industrial customers.

And that's not to say that there aren't benefits for residential customers. They're just more difficult to quantify. And there -- it's -- it's -- benefits are convenient for the purposes of selecting projects, but I would suggest that they really don't have a place for the purposes of cost of service.

Q. I think you just made my point, so I'll just move on.

MS. JAGANNATHAN: I'd like to mark

another exhibit, please. Chair Mitchell, I'd like to mark Public Staff 37 as Public Staff Pirro/Hager Cross Examination 2.

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

(Public Staff Pirro/Hager Cross Examination Exhibit Number 2 was marked for identification.)

Q. Ms. Hager, are you there?
A. I am.
Q. Can we agree this is the settlement agreement between the Company and CIGFUR III?
A. It is.
Q. Are you familiar with this document?
A. Yes.
Q. Let's look at page 4, paragraph 3B.
A. Okay. I'm there.
Q. So, in this paragraph, the Company agreed it will propose to allocate GIP costs consistent with distribution allocation methodologies proposed in this docket in the next rate case.
Did I represent that correctly?
A. Yes.
Q. Now, do you know what the current

distribution allocation methodologies would result, and what percentage of GIP costs being charged to residential and small general service customers?

A. I do not.

Q. Would it surprise you to know that, under the current distribution allocation methodologies, that 64 percent would allocated to residential customers?

A. That wouldn't be surprising.

Q. And that 10 percent would be allocated to OBT large commercial and industrial customers?

A. That's probably a number I would be less familiar with, in terms of the percentage.

Q. Do you think it would be smaller than that, or much different from what I just represented to you?

A. I don't have any reason to believe it would be much different.

Q. Okay. Thank you. Let's turn to the same stipulation, 5A.

A. I'm there.

Q. Okay. Thank you. And in this paragraph, the parties agreed to meet to discuss potential cost of service methodologies, and also requires the Company to file the results of a class cost of service study with production and transmission costs allocated on the basis of summer/winter coincident peak method, and consider such results for the sole purpose of proportionment of the change in revenue to the customer classes.

Did I read that correctly?

A. Yes, you did.

Q. Isn't it true that the use of a summer/winter coincident peak would, relative to summer coincident peak, allocate more production and transmission costs to lower load factor customers, such as residential customers, and fewer costs to higher load factor customers?

A. Yes, that's correct.

Q. And finally, let's look at 5B on page 5.

A. I'm there.

Q. In this provision, the customer -- it requires the Company to adjust its peak demand to remove curtailable nonfirm load, even if it doesn't call it; is that right?

A. That's correct.

Q. Now, during the test year in this case, the Company did not the activate DSM during either the system summer or winter peak, right?

A. I don't recall.

Q. Do you have any reason to doubt that?

A. No.

Q. If that's the fact -- if that's true, isn't it also true that if they didn't -- if you did not, there was no impact of DSM on the cost allocation factors in this case?

A. Let me think about that a moment.

Q. Okay.

A. Would you restate the question, please?

Q. Sure. Let's assume that Duke did not activate DSM during either the system summer or winter peak, okay? If that's the case, then there would be no impact to DSM on cost allocation factors in this case.

A. I believe that's correct.

Q. Thank you. Similarly, it's my understanding that the Company did not call on their curtailable customers to curtail either at the system summer or winter peak; is that right?

A. Again, I would not know, but I will take your word for it.

Q. Okay. Thank you. It's what Mr. Floyd told me.

If that's the case, and by not doing so, then there was no impact of curtailable load on the cost allocation factors in this case, right?

A. That's definitely true for the test year cost of service. I don't recall that any adjustments were made.

Q. Okay. Isn't it true that adjusting peak demand as agreed upon in this provision with CIGFUR would result in reducing the amount of production plant allocated to industrial; i.e., high load factor customers, and increase the amount allocated to residential and commercial customers, that is low-load factor customers?

A. The -- I can't say definitively right now. The -- the settlement speaks to curtailable/nonfirm load, but it doesn't specify specifically which curtailable nonfirm load. But to the extent that residential curtailable load was included in that, I believe that the residential curtailable load is probably lower than the industrial -- commercial industrial curtailable load. And if that is the case, then it would result in cost -- more costs being allocated away from commercial industrial.

Q. Thank you. Ms. Edmondson will now question Mr. Pirro. Thank you, Ms. Hager.

CHAIR MITCHELL: All right. Before you

go ahead and proceed with the Barnes/Schneider panel as planned. Any other preliminary matters before we get started?

(No response.)

CHAIR MITCHELL: Hearing none, Ms. Edmondson, you may proceed.

JANICE HAGER, LON HUBER,
and MICHAEL J. PIRRO; Having been previously affirmed,
Testified as follows:

CROSS EXAMINATION BY MS. EDMONDSON:

Q Good morning. I'm Lucy Edmondson with the Public Staff. And as Ms. Downey indicated yesterday, my questions are directed to Mr. Pirro. Good morning, Mr. Pirro. Mr. Pirro, you're familiar with the settlements between Duke Energy Carolinas and Harris Teeter and Duke Energy Carolinas and the Commercial Group?

A Yes, I am.

Q All right.

MS. EDMONDSON: I'd like to mark Public Staff 38 as Public Staff Pirro/Hager Cross Examination Exhibit Number 3 and Public Staff 39 as Public Staff Pirro/Hager Cross Examination Exhibit Number 4.

CHAIR MITCHELL: All right, Ms. Edmondson. The documents will be so marked.

(Whereupon, Public Staff Pirro/Hager Cross Examination Exhibit Numbers 3 and 4 were marked for identification.)

Q And Mr. Pirro, Public Staff Pirro/Hager Cross Examination Exhibit Number 3 is the original Settlement Agreement between Duke Energy Carolinas and Harris Teeter, correct?

A I have that.

Q Excuse me?

A I have that -- yes. I have that in front of me.

Q Okay. And Mr. Pirro, Public Staff Pirro/Hager Cross Examination Exhibit Number 4 is the original Settlement Agreement between Duke Energy Carolinas and the Commercial Group, correct?

A Yes. That is correct.

Q And would you agree that these two settlements are very similar?

A Yes, they are.

Q Now, the provisions of the two settlements I'd like to discuss involve rate OPT-V.

MS. EDMONDSON: Madam Chair, I'd like to mark Public Staff 40 as Public Staff Pirro/Hager Cross

Examination Exhibit Number 5.

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

(Whereupon, Public Staff Pirro/Hager Cross Examination Exhibit Number 5 was marked for identification.)

Q Mr. Pirro, do you have that exhibit before you?

A Yes, I do.

Q And Mr. Pirro, would you agree this cross examination exhibit is not the complete set of proposed rates, but the first page of Exhibit B to the Application as well as the tariff for OPT-V?

A Yes. That is correct.

Q And Mr. Pirro, could you give us a general description of the OPT-V rate?

A Sure. Well, the OPT-V rate was developed back out of case -- I believe it was Docket E-7, Sub 1026. It was a combination of OPT-G, H, and I, and this new OPT-V offering was formed. There was a fully vetted process with CUCA and CIGFUR as part of that, along with Public Staff. And this design has seven different options based on voltage level, Transmission Primary and Secondary, and within the Primary and Secondary offerings there’s three different size levels, Small, Medium, Large.

Q Okay. And what is the OPT-VSS rate?
A That would be Secondary service Small customer.
Q And on that exhibit -- Cross Examination Exhibit Number 5, where is the VSS rate on the tariff page?
A That would be on page 2.
Q Okay. And is that at Roman Numeral III?
A That is correct.
Q And we are only discussing the -- the Settlement Agreements only deal with the Small; is that correct?
A Yes. The Settlement Agreements with the Commercial Group and Harris Teeter deal with Secondary Small.
Q And would I assume that they are -- they only fall under that category?
A That is correct.
Q All right. In the two Settlement Agreements that we have marked as Public Staff Pirro/Hager Cross Examination Exhibits Number 3 and 4, paragraph -- if you could look at paragraph 2 of each of those agreements.
A Yes. I have that in front of me.
Q They both state that any Grid Improvement Plan cost allocated to OPT-V customers shall be recovered

through the OPT-V demand charges?

A Yes. That is correct.

Q Could the demand charges be avoided by the OPT-V customer?

A Was the question can the demand charges be avoided?

Q Yes. Could they avoid the demand charges to some extent?

A No.

Q Couldn't they lower their peak demand?

A Yeah. They could lower their peak demand, but the customers within this Secondary Small are generally similar type of customers who are typically high load factor customers.

Q Wouldn't you agree that the higher the demand charge, the more cost that they could avoid?

A If I heard the question correctly, the higher the demand charge, the more cost that they could avoid. Well, if they were to reduce any demand billed units, then, yes, they could reduce cost.

Q It's simple logic, right?

A (Witness nods affirmatively.)

Q And wouldn't this provision also lower the energy charge for all hours?

A No. So this section to the settlement is referring to how the Company would recover Grid Improvement Plan cost, and so for the OPT-V class, since these customers have demand meters and they're billed on demand, we find it reasonable to be able to allocate and recover those costs through a demand bill type component.

Q So are they all going to be recovered through these customers one way or the other?

A All OPT-V customers, whether they're Transmission, Primary, or Secondary Serve, any Grid Improvement Plan cost would be recovered via demand charge.

Q And none of these charges would be recovered from any other customers?

A That is correct. Any cost allocated to OPT-V would be recovered via demand, and there would be no subsidization to any other customers within any other classes.

Q And if we could look at paragraph 3 of both of these agreements regarding the OPT-VSS rate.

A Yes. I'm looking at that now.

Q The off-peak energy charge is set at 3.0222 cents per kWh and the on-peak rate shall be increased at half a percent?

A Yes. What that section says is that the off peak would be set at .030222, and the on-peak energy shall be increased by a percentage amount that is equal to half of the overall percentage increase awarded to the OPT-V Secondary Small rate schedule.

Q Now, did DEC already include this provision in the interim rates it filed August 13th, 2020?

A Yes, it did.

Q And that only applied to VSS Small customers; is that correct?

A That is correct.

Q And the Medium and Large customers, their rates in the interim rates, they went up more than --

A Yes. And Ms. Edmondson, it's important to know that -- so like when we do rate design, it's a zero-sum gain, so within the OPT-V class, Secondary Small has its own revenue requirement, so those customers being served under Secondary Small, it's just how we have agreed to recover those revenues, so there's no shifting of revenues or recoveries to any other customers within any other -- any of the other six options within OPT-V.

Q Without these settlements, the off-peak energy charge would have been higher than 3.0222 cents, wouldn't it?

A Actually, that's a great question. And, you know, I'm glad you brought that up. Actually, no. When I go -- when I went back and took a look at our original filing, the intent of the OPT-V class was to offer attractive off-peak energy pricing for customers to run their operations more efficiently -- remember, these are high load factor type customers -- and to allow them to plan their business operations, shift load maybe more to the off peak. That was the spirit and the intent of the original 2014 OPT-V final offering. So in our previous rate case, we used a 4-to-1 percent ratio increase in the on peak 4 percent, off peak 1 percent. With this case we applied more a uniform increase to both on peak/off peak. In looking back at that, this agreement is more in line with the true intent of the OPT-V offering.

So I've agreed, and actually this is a 2 percent increase based on the settlement terms to the off-peak rate, and based on the final award of the revenue requirement OPT-V on peak would be increased 50 percent of that overall percentage increase.

Q Did you only do this for the Small customers?

A Within this settlement we did, but, you know, I am totally open to taking a look at all the OPT-V off-peak rates and adjusting that during our compliance filing.

Q And is this -- do you need to look back at any of the other rate schedules besides OPT-V?

A No, Ms. Edmondson. No.

Q All right.

A And I know listening to -- if I may just, you know, interject here for a second, listening to Mr. Floyd's testimony, I know he had concerns about the comprehensive rate study and, you know, setting a price. By no means does this exclude any of the seven different options within OPT-V from being part of any comprehensive rate study. This is just for this moment in time while these rates are in effect.

Q But how did you come to settle on the 3.0222 as being a correct number?

MS. JAGANNATHAN: Objection. I don't want Mr. Pirro to get into the confidential settlement discussions.

Q Well, can I ask, is there any basis? Is there a calculation that supports it as being based on particular data? Is it just an agreed-upon number?

CHAIR MITCHELL: Mr. Pirro, if you can answer the question without -- answer Ms. Edmondson's questions without going into confidential information, please do so.

A Sure. As I previously mentioned, Ms. Edmondson, you know, the spirit and the intent of the OPT-V class is to provide attractive off-peak pricing for customers to make business decisions in their operations accordingly. The increase to .030222 was a 2 percent increase which puts that off-peak energy in a very attractive price and along with an increase that's in line with our previous rate case compliance filing.

Q But that's the only rate that you decided to apply just a 2 percent increase to?

A So the way this section reads for Harris Teeter, Section 3, is that 2 percent was applied to the off-peak energy rate, 50 percent of the overall percentage increase to OPT-V Secondary Small; 50 percent of that percentage increase will go to the on peak, and then the remaining revenue requirement would be collected via demand charges.

Q All right.

A Yeah. Ms. Edmondson --

Q I'm sorry. Go ahead.

A I was going to say, Ms. Edmondson, actually, I'm like very comfortable with where these rates have fallen out, and like I mentioned, within the compliance filing I would be more than agreeable to address the other off-peak energy rates because they all should be in line with the original intent of the rate offering.

Again, this rate offering is well received by our Large Commercial/Industrial customers.

Q Now, you've also put a constraint on how much the on-peak energy charges could go up; is that correct?

A Yes, I did. And that was to, again, to stay in line with the current integrity of the rate structure and the differentiation between on peak and off peak.

Q And the annual fuel charges -- fuel costs are recovered through the OPT-V energy charge?

A There is a -- yes. There is a base component of fuel that is recovered within all our energy charges.

Q Isn't it true that besides the cost of fuel, there are other items typically recovered in the energy charge, such as fixed demand cost and variable O&M and other costs that vary per unit of consumption?

A Yes. That is correct. You know, because there's different types of customers within our -- like we don't have one rate for each customer we serve, right? Our rates, again, are designed to be fair, just, and reasonable for a segment of customers within a rate schedule. So there are some other components within the energy charge, but the energy charge as proposed are above the base fuel component.

Q If there is an increase in fuel cost that are above the current fuel rate and there's an underrecovery of fuel cost, how would that underrecovery be recovered?

A That's recovered through the annual fuel adjustment proceedings and adjusted accordingly.

Q But where would that -- who -- how would it be recovered? Through the EMF?

A Yeah. Through -- I believe it's -- I don't have it in front of me handy, but I believe it's Rider 50 through the fuel adjustment and along with the EMF.

Q Would that have to be picked up by the other OPT-V customers?

A No. Each segment has a fuel adjust--- each rate class has their own specific fuel adjustment.

Q Mr. Pirro, isn't it true that in your original calculation of the EDIT Rider you developed class-specific EDIT credit rates?

A That is correct.

Q And why did you do that?

A That was in line with the cost allocation method used.

Q And by calculating the rider that way, you returned the excess deferred taxes to each class in proportion to how much each class had paid, didn't you?

A Yes. The revenue requirement for EDIT was provided to us. Due to billing constraints that we have and how we have to adhere to how our billing team administers, we consolidate certain rate schedules into four different buckets and then they are aggregated up and then rates were developed.

Q But in your settlement with CIGFUR, the Company agreed to pay back EDIT to each class at a uniform rate?

A Yes. Yeah. Within the settlement that was agreed upon by the Company. And going back to our first EDIT in our original -- well, in our previous rate case, it falls along the same methodology. It was based on a uniform method.

Q But under a uniform rate, all customer classes do not get the same amount of refunds that they -- as they paid in, do they?

A The revenue requirement would be a uniform and it would be allocated one factor across all customers.

Q And isn't it true that the OPT-V class would receive more than it paid in?

A OPT-V would receive more of a credit, that is correct; however, when we looked at the settlement and the terms, within our original base -- current base rates and our revenue requirement, residential customers have been and continue to be subsidized by non-residential customers. And this was a way to sort of balance that. You know, rate design is sort of an art, and you try to be fair, just, and reasonable and find balances, so this was just a way of trying to balance that.

Q So you're combining it in the base rates with the EDIT? You don't consider them separately?

A No. They're definitely separate, but, again, trying to balance and not have further subsidies just continue.

Q And Mr. Pirro, what's the impact of the CIGFUR/Harris Teeter/Commercial Group settlements on the class rate of returns -- rates of return?

A In regards to?

Q How do they affect the class rates of return on the OPT-V?

A We continue to move all our rate schedules closer to parity, meaning closer to the retail average rate of return, so this just continues to move all our rate schedules closer. I don't believe it favored OPT-V by any means.

Q All right. And you -- the Company does support the rate study that's discussed by Mr. Floyd in his testimony?

A Absolutely. You know, that was one of the reasons why we have decided to keep things status quo. Whenever you make changes to rate design, there's definitely going to be winners and losers just from making a change through rate design. And, you know, we're very concerned and cautious about that. Same with the low-income collaborative and the comprehensive rate design study. You know, Mr. Floyd and I are constantly having discussions, and we're both totally in support of that study.

Q All right.

MS. EDMONDSON: Thank you.

WITNESS PIRRO: Thank you, Ms. Edmondson.

CHAIR MITCHELL: Anything further from you, Ms. Edmondson?

MS. EDMONDSON: No, thank you.

CHAIR MITCHELL: Okay. All right. Mr. Page?

MR. PAGE: Yes, ma'am. Thank you, Madam Chair.

CHAIR MITCHELL: You are up.

CROSS EXAMINATION BY MR. PAGE:

Q Good morning, members of the Panel. When I first crafted these questions, I believed that I would be addressing them primarily to Mr. Pirro, but I think instead I would rather start with Ms. Hager. Good morning, Ms. Hager.

A (Hager) Good morning, Mr. Page.

Q Nice to see you again. I want to encourage Mr. Pirro and Mr. Huber, if they have anything to contribute to the discussion you and I are about to have, to feel free to do so. The first set of questions I have for you are a gift from your friend Mr. Oliver who a few days ago when I asked him about a cost of service study, he told me he did not know what a cost of service study was, but I'll bet you do, don't you?

A Yes, sir.

Q Could you give us a quick, easy, layman-oriented explanation for what a cost of service study is and what it does?

A Yes. I'm happy to do that. A cost of service study takes the revenue requirements that have been developed by the Company and it spreads them to customers by customer class. So if you think about it, the revenue requirement is the size of the pie that the Company is asking for total -- for the opportunity to recover. And then cost of service says how do I slice that pie? And the -- this is something, obviously, that's been done since the very beginning of making rates. You've had to decide how to, you know, how to allocate those costs. The -- sort of the seminal work on that was Dr. Bonbright's study in 1961. It was then sort of implemented, I would say, in a rigorous way by the NARUC Cost Allocation Manual in 1992. And in that study it sort of became the thing that utilities look at to begin to do cost of service studies.

And so what you want to do is you want to say I've got generation, I've got transmission, I've got distribution, I've got customer cost in this revenue requirement, and I want to look to see how each load, each customer caused those assets, those costs to be incurred. And so you look at -- you have different methods for doing each -- each bucket of that. But the idea is to be -- to do it equitably, to do it in a manner that doesn't -- isn't biased. It's not intended to implement policies or implement public policy beyond what has already been taken into account in the development of the revenue requirements. And it's sort of -- I look at it as, you know, how do the electrons flow and what caused those electrons to flow in that manner.

So I'd say that's the basics of cost of

service. And one of the things that I find very interesting is that in every proceeding, folks are -- have a focus on their slice of the pie, and unlike in the real world everyone wants a smaller slice of the pie in the cost of service world. No, no, no. Give my slice of pie to that person. I'll take a smaller slice. And so that's what -- we have sort of a push and a pull all the time in dealing with various customer classes, is everyone has an opinion on how cost of service should be done on the basis -- and, you know, perfectly understandable on the basis of how their constituents would most be benefitted.

Q Would I be correct in saying that in doing a cost of service study, one applies well developed and understood principles of engineering, accounting, and perhaps economics?

A Absolutely.

Q All right. Just to take a couple of simple examples, in a cost of service study, if one were to -- for Duke, for example -- to allocate the cost of meters and meter reading, would it come as any surprise to find that a majority of those costs were allocated to the Residential class of customers simply because there are so many more of them than any other class where I said

meters and meter reading?
A I would agree.
Q All right. Now, when the distribution of AMI meters becomes universal, that cost allocation could change, could it not?
A I'm not saying that it will change, but I think that it could, potentially.
Q Because the total cost of reading meters should go down once you install the AMI meters?
A The cost of meter reading should go down, yes.
Q And to take another example, if one were to allocate the cost of providing a direct transmission grade interconnection with a customer, wouldn't you imagine that all of those costs would be allocated to large users rather than residential customers?
A This would be a dedicated substation? Is that what you're saying?
Q Yeah. If a customer has a transmission grade direct interconnection to the Duke grid, is that going to be a residential customer ordinarily?
A No, sir.
Q So, you know, again, the underlying point is what you're trying to do in the cost of service study is allocate costs to the customer or class of customers

responsible for imposing that cost on the system; is that correct?

A Yes, sir.

Q Are you aware of any cost of service methodology that operates by attempting to allocate benefits rather than costs?

A The only thing that I would say falls into that category would be we allocate DSM costs -- you could say it’s on the basis of benefits -- but in essence we look at demand response as a substitute for generation, therefore, we allocate those costs on the basis of generation and energy efficiency as a substitute for energy on the basis of energy. Some -- I don’t know if any utilities do that, but I think there is some concern that because those are customer type programs, would they be allocated on the basis of customer. We do not do that. But as far as I know, Mr. Page, that is the only area where we would use “benefits,” and I’m not aware of any other utility that allocates cost on the basis of benefit.

Q All right. Let me switch over to Mr. Pirro for a second because I think this question maybe falls a little bit more into his bailiwick and would encourage you, Ms. Hager, and you, Mr. Huber, if you have something to add, please feel free to do so. Good morning, Mr. Pirro.

A (Pirro) Good morning, Mr. Page.

Q Mr. Pirro, at some point in time with regard to the cost of the GIP program, Duke will come back to the Commission and seek to incorporate those costs into rates, will they not?

A That's correct.

Q And is it your understanding that the basis for allocation of those costs will be the cost causation principle or will it be some form of comparable benefits analysis?

A It would be -- my understanding, it would be based on cost causation, and I would ask Ms. Hager to add anything if she feels the need.

A (Hager) I would agree, cost causation.

Q So Ms. Hager, since I have you there, let me just follow up with you. Would you consider it appropriate or inappropriate to spend a whole lot of time and effort exploring an alternative cost of service methodology that's based on allocating benefits?

A As I said yesterday, I don't believe it would be productive. I said it was a waste of time, and I believe it is.

Q And that's because such a study would depart from principles of cost causation?

A It would depart from principles of cost causation. And in addition, it's certainly not done within the industry in any mainstream way. And it is so subjective, you know. Benefits are very individualized. They are impossible -- not impossible -- they're very difficult to measure. Anything to do with it is basically an estimate. I think you could spend a tremendous amount of time and energy, and the result would be one that would also be discussed at length in hearings and would -- really, would it produce something that is beneficial, helpful, makes -- I just do not believe it is a productive thing to do.

Q In the cost of service study that Duke employed in this rate case, Ms. Hager, could you tell me the basis on which generating plant is allocated?

A Yes. Generating plant is allocated on the basis of Summer Coincident Peak.

Q All right. There are alternative methods for making that allocation, are there not?

A There are.

Q Why does Duke support the Summer Coincident Peak methodology for allocating generating plant?

A Duke has historically allocated cost on the basis of Summer Coincident Peak both in Duke Energy Progress and Duke Energy Carolinas. And if you look at the assets that the Company is allocating the cost for, the vast majority of those were inferred on the basis of Summer Coincident Peak. The Company has -- there's a benefit to allocating costs consistently across jurisdictions, and so the Company has used Summer CP historically for many years in all of its jurisdictions, and so it's continuing that, but it recognizes that things are changing, and that as part of that the Company has committed to look at a number of different methodologies in advance of the next rate case.

But the Summer CP is a -- it's the -- the Summer Peak is very important in cost causation, and the Company continues to support that as the allocation method for generation.

Q All right. Thank you very much, Ms. Hager. Let me switch back to Mr. Pirro. Mr. Pirro, would you agree with me that in the design of rates, it's part science and it's part art and it's part judgment? Do you agree with that?

A (Pirro) I do for the most part.

Q So you have this cost of service study in any given case for which you're asked to design rates. That's basically just your starting point, isn't it? I mean, it doesn't dictate the final design of the rates by any means, does it?

A That's correct. A perfect example would be from the cost of service we have a unit cost study, and we just don't use the unit cost study in design rates.

Q All right. That's where judgment comes in; is that correct?

A That's correct. That goes back to my conversation with Ms. Edmondson. We have different types of customers, different characteristics, different load factors within certain rate schedules, and we have to balance that, design rates that are fair and reasonable across the board.

Q The rates that you have proposed in this case are based, however, upon the Duke cost of service study that Ms. Hager and I were talking about; is that correct?

A That is the -- that is correct. That is the starting point, yes.

Q Would you agree with her testimony regarding the Summer Coincident Peak method of allocating generating plant?

A I would never disagree with anything that Ms.

Hager proposes. She's the expert.

Q And I would do so with great trepidation, Mr. Pirro. The different types of cost of service studies that Duke has agreed in its second settlement with the Public Staff to look at, those are not factors in your rate design in this case; is that correct? You just agree to look at them for the future.

A That is correct. They're not part of this rate case.

MR. PAGE: Thank you, Mr. Pirro, and Panel. Madam Chair, that's all I have.

WITNESS PIRRO: Thank you, Mr. Page.

CHAIR MITCHELL: All right. Thank you, Mr. Page. Mr. Ledford, you are up next. All right. Mr. Ledford, you're on mute.

MR. LEDFORD: Thank you, Madam Chair.

CROSS EXAMINATION BY MR. LEDFORD:

Q Mr. Huber, I believe that most of these questions are going to be directed to you, but Ms. Hager and Mr. Pirro, please feel free to chime in if you have responses as well. Mr. Huber, are you familiar with the testimony that was filed by NCSEA witness Barnes regarding EV rate design?

A (Huber) Yes, I am.

Q And beginning on page 7, line 24 of your rebuttal testimony, you state that "A study of rate designs that facilitate the adoption of electric vehicles that provide system benefits for all customers will be a part of any comprehensive rate design study." Is that accurate?

A That is accurate.

Q And witness Barnes recommended that the Commission establish an investigatory docket to receive information and permit discussion of EV-specific rates. Do you agree that the Commission should open a docket to examine EV-specific rates?

A I think it would probably be better to have this discussion all in one house so that we can see where EV rates fit in the broader context and make sure that we have a consistent ideology as it pertains to rates. So, you know, you don't want to necessarily create some silos, that you treat one type of technology, you know, dissimilar than other types. And so in terms of rate design, I would advocate for folding in EV's -- EV rate design into the comprehensive rate design review.

Q So do you believe that the Commission should open a docket to address this comprehensive rate design study?

A Hmm. You know, I think that a, you know, third-party facilitated comprehensive rate design review that has, you know, broad stakeholder engagement, report outs, and a submittal to the Company is likely sufficient; however, I'm completely open if the Commission feels that -- that, you know, a formal docket is necessary.

Q Thank you. I wanted to address a few of the specific recommendations that witness Barnes made in his testimony and get your responses to that. Witness Barnes breaks down his testimony into characteristics for EV or -- excuse me -- residential EV specific rates and nonresidential EV specific rates. So starting with residential specific rates, do you agree that price -- excuse me -- that the duration of any lowest pricing period should be at least eight hours to allow customers time to charge their vehicles?

A And so this is why I feel that these rate design conversations have to happen in a much bigger dialogue, because it's very hard for me to say what that off-peak time period should be without data and the analytics to make sure that is correct. And so I would want to make sure, hey, you know, is that length durable? Like -- so first, is it correct, but how long can it last? And I believe Mr. Barnes says that the rate has to be locked in for 10 years. And so that -- you know, that presents a tricky subject where I can't guarantee that a specific off-peak rate can last, you know, can be eight hours, and that is in line with system need and where the data points should be, you know, from now to 10 years forward. So that's where I would love to have a more comprehensive conversation with data behind it before, you know, locking in a certain time period or price ratio.

Q Well, I guess stepping back, do you agree that submetering is an effective way of metering EV specific charge -- EV charging?

A It's probably the least effective way, but it is a way to do it.

Q Could you please expand upon why you think it's the least effective way of doing it?

A Sure. A few reasons. One, technology is evolving so that we can actually determine some charging characteristics through AMI disaggregation or through a plug-in to a car's OBD II port. So there's more cost effective ways to gauge when an EV is charging. And I also think there's probably more transparent and cost effective ways to reward a customer for charging at times that are more beneficial to the grid and to nonparticipants.

You know, a submeter, in that work it costs money, it requires an electrician, right, and so any savings that you would get would be eroded by those submeter costs. And so, you know, for instance, you know, when you switch from gasoline to electric, you're saving maybe 800 to $1,000 just switching to electricity. And, you know, trying to go from that switch down to TOU -- so take our DEC rate, for example. Our DEC rate is probably around 8.5 cents a kWh for Residential, you know, with adders, and it's a very low cost rate, one of the lowest cost rates I've actually have ever been on for Residential. So that's $1,000 of savings, give or take.

If you move to a submeter TOU rate, maybe you go from eight and a half to four, eight and a half to five. That's maybe seven incremental dollars different per month. And that meter cost will likely be around $5. That's where many utilities have it. So, you know, you're really netting not very much in terms of the participant savings, and the nonparticipant is -- would be eroded by the off peak of the TOU rate.

Q Thank you, Mr. Huber. And you mentioned that the Utility could use AMI disaggregation to determine EV specific load. Would you agree that it would be appropriate for customers to have access to that data as well so that they could do their own analytics?

A I believe that -- this isn't my subject, but I believe that's, you know, where Duke is going with the app and the usage on the app and so forth, but, again, not my subject.

Q Understood. Thank you. And one last question about EV specific rates. Recognizing that the Company recommends a big picture comprehensive rate design study, do you agree that demand charges can be prohibitive to customers, both residential and nonresidential, in charging their electric vehicles?

A Great question. And with rate design, as always, it depends, unfortunately. I can't give you the straight answer because it depends on utilization, you know, where are the customers, their sophistication. There could be times where on-peak demand charges actually greatly help the price for a customer as long as they stay off that peak time frame, which is, of course, what we want, because that demand charge is going to lower the volumetric rate, and so they'll have a better economics on that off-peak volumetric rate than they would otherwise. And so unfortunately, it depends on utilization and it depends on the rate structure.

Q Thank you, Mr. Huber. Ms. Hager, I do have a couple of questions for you, so I'm going to transition at this time. Ms. Hager, you've -- both yesterday and today you have said that including benefits in cost allocation is subjective. Is that the case? Does that reflect your testimony?

A (Hager) Yes.

Q And we also have heard that ratemaking is an art, but not a science; is that also correct?

A Yes.

Q So how do we justify the fact that including these benefits would be subjective, but ratemaking is not a science? Isn't an art, in and of itself, subjective as well?

A I think we need to make a distinction here between cost of service and rate design. Cost of service, to me, needs to avoid subjective aspects to the extent it can. And then in rate design, that's where you have more of the art. I do think that cost of service is really more of a science.

Q Thank you.

MR. LEDFORD: Madam Chair, I have no further questions.

CHAIR MITCHELL: All right. Thank you, Mr. Ledford. At this point we are with you, Mr. Neal.

MR. NEAL: Good morning. Thank you, Madam Chair. Thank you, Chair Mitchell.

CROSS EXAMINATION BY MR. NEAL:

Q Starting -- this is David Neal representing the Justice Center, et al. Starting with you, Mr. Pirro, I just want to ask a quick question first. During -- earlier this morning on cross, I believe you said that Commercial and Industrial customers are currently subsidizing the Residential class. Is that what you said?

A (Pirro) That is correct.

Q And if you would, do you have in front of you Pirro Second Settlement Exhibit 4?

A I do.

Q And if -- turning your attention to the present ROR, which is rate of return; is that right?

A That is correct.

Q So turning your attention to the Present Rate of Return column, do you agree that Pirro Second Settlement Exhibit 4 reflects a 5.3 percent present rate of return for the Residential RS?

A Yes. I agree with that.

Q And you would agree that rate OPT is not a Residential class, correct?
A That is correct.
Q And this chart shows a 4.3 percent rate of return for the rate OPT; is that right?
A Correct.
Q Thank you. Now, Mr. Pirro, you had some conversation with Mr. Page about how the cost of service study is the basis for your proposed rates. Do you recall that?
A I do.
Q And recognizing that the Company did not propose an increase in the Residential basic facilities charge in this case, you nevertheless testified that the unit cost study from the cost of service study would justify an increase to the basic facilities charge; is that right?
A Had we decided to increase the basic facilities charge, yes, the unit cost study would have shown an increase is warranted.
Q And so turning your attention -- well, let me just make sure I've got this right. You are relying on the use of the Minimum System Method in the Company's cost of service study to come to that conclusion; is that

correct?

A That is correct.

Q Okay. So turning your attention to Pirro Exhibit 8 from your direct testimony -- do you have that in front of you?

A I do.

Q So where it reads in that gray shaded area in the top near the middle Theoretical Minimum System BFC, would you agree that it's the Company's use of the Minimum System Method that results in what is listed here as a $22.56 basic facilities charge for the Residential RS tariff?

A Using the cost allocation method, that is correct. It would be $22.56.

Q And you would agree that it's -- the use of the Minimum System Method is the only support that you've offered for that theoretical basic facilities charge?

A That is correct.

MR. NEAL: At this time, Chair Mitchell, I would like to mark an exhibit, Justice Center, et al. Cross Exhibits 1 and 2, and I will -- I'll just note that this is the revised Company response to Public Staff Data Request 100-18 and an embedded spreadsheet from that same response. So Chair Mitchell, if it would simplify things, I would ask that they be marked together as Justice Center, et al. Pirro/Hager Cross Exhibit 1.

CHAIR MITCHELL: Documents will be so marked.

(Whereupon, NC Justice Center, et al. Pirro/Hager Cross Examination Exhibit Number 1 was marked for identification.)

Q Mr. Pirro, do you have -- do you have Justice Center, et al. Pirro/Hager Cross Exhibit 1 in front of you? I'm sorry. You're on mute, sir.

A Thank you. I do not, but you could explain it to me or walk me through it.

Q Are you -- so this is, Mr. Pirro, the Company's response to -- it's the revised Company response to Public Staff Data Request 100-18 which, among other things, was a request from the Public Staff to the Company to do a calculation of the Basic Customer Method of apportioning distribution system costs as customer or demand related. Do you recall this?

A Yes, I do.

Q And the -- I will represent to you that the third and final page of Justice Center, et al. Pirro/Hager Cross Exhibit 1 is the worksheet from DEC Public Staff DR 100-18 Revised which shows the unit cost study without using Minimum System. Again, do you recall seeing this before?

A Yes. I recall this. Yeah.

Q Okay. And you would agree that without using Minimum System, the unit cost for that same RS, Residential tariff, that the customer -- the costs that are allocated as customer related come down to $11.49?

A That is correct. And I would just like to add that that's because a portion of -- with Minimum System a portion of distribution lines, poles, transformers are considered to be customer related. And Ms. Hager, if you would like to add anything.

Q Mr. Pirro, if I may, I have plenty of questions for Ms. Hager on the Minimum System Method coming up.

A Okay.

Q It's like I'm almost finished with questions for you. But you would agree that this amount, this $11.49 per customer per month, is about $2.50 less than the current Residential basic facilities charge of $14.00 a month.

A The difference between the two methods, that is correct.

Q And just to be clear, you did not conduct the Company's cost of service study; is that right?

A That is correct.
Q So I think that's all the questions I have for you, Mr. Pirro. Turning to Ms. Hager, good morning.
A (Hager) Good morning, Mr. Neal.
Q So you would agree that the starting place for the Company's cost of service study is the actual costs incurred by the Utility in providing service to its customers?
A In the test period, yes, that's correct.
Q And you would agree that in the Company's cost of service study, the costs should be classified according to their cost causation characteristics?
A Yes.
Q Now, as I alluded to a moment ago, I am going to ask you some questions about the Company's use of the Minimum System Method in its cost of service study. Would you agree that the Company first identifies its actual distribution grid costs in its North Carolina service territory?
A Yes.
Q I think you previously referred to that in testimony to this Commission as the standard configuration; is that right?
A I don't recall using those words, and I'm not

sure what you mean in this context.

Q Well, there was -- in your testimony to the Commission in the last rate case about how the Minimum System Method works, I just -- I recall you using the term "standard configuration" to refer to the actual cost of the distribution grid, the poles, conduit, transformers.

A I understand what you're saying, so it's the -- it's the as-built configuration.

Q Thank you. So then the Minimum System Method is used to calculate a hypothetical minimum distribution grid, so -- and that's an estimate of what the cost would have been if the Utility had installed distribution grid units, again, transformers or poles, lines, that were each the minimum size unit of the type of equipment that would be used on the system; is that right?

A I think that's an excellent summary of it.

Q I'm not quite sure I heard your answer. Sorry, Ms. Hager.

A I said that -- I said that is an excellent summary of what Minimum System is.

Q Thank you. So just to be -- to put a finer point on it, so as an example you would take the grid as it is and then substitute the smallest size transformers

that are currently in use, right?
A Yes.
Q And is it fair to say that the reason for estimating the cost of this hypothetical minimum distribution system from the Company's point of view is then to allocate those costs as customer related?
A I'd say that the purpose is to reflect the costs that each customer caused.
Q And, again, your -- it's your belief that the customers caused this minimum distribution grid and -- but the point of doing the calculation is to then allocate those as customer related; isn't that right?
A Yes.
Q And then I guess the final step would be to subtract those minimum system costs from the standard configuration or the total actual cost of the grid, and those remaining costs are then considered demand related, correct?
A Again, a very good summary of that.
Q Okay. So -- but you would agree that Duke does not build a minimum distribution grid to connect each customer to the grid, right?
A That's correct.
Q And in that sense the Company did not incur the

cost of actually building a minimum size distribution grid?

A I wouldn't agree with that. The Company incurred a cost to build the as-built system, a portion of which was caused by the fact that the customer was being connected to the system.

Q But, again, from just a literal definition of terms, the Company did not incur cost to build a minimum distribution grid?

A I don't agree. The Company incurred that, plus additional cost to supply their demand.

Q But you would agree that -- we just went over with Mr. Pirro using a different methodology the Basic Customer Method which I know you do not agree with a Basic Customer Method, it reflects customer allocated costs in a very different way than the minimum system does, correct?

A I agree.

Q Now, put -- to maybe put this a different way, the Company's actual distribution grid is designed to serve expected and actual customer peak demand, correct?

A It's designed to serve actual and peak demand, as well as energy needs, as well as provide interconnection to the customer should they desire to use the system, all of those.

Q I guess put another way, when Duke engineers are building a grid, they're building it to serve actual and expected load, correct --

A I --

Q -- in terms of how they size equipment, for example?

A I agree.

Q And would you agree that a characteristic of the distribution grid is that it is shared between customers?

A Yes.

Q And so you can -- for example, there are times when a new home could be added to an existing distribution grid without requiring any new poles, any new conductors, or even any new transformers, correct?

A That is correct.

Q And by the same token, there might be times where a residence in the middle of a neighborhood is torn down, taken out of service, and that would not require the removal of any poles, conductors, or transformers from the grid; isn't that right?

A I am not sure, but I think that sounds correct.

Q So next I'm just going to ask you to consider kind of a hypothetical subdivision, so a new subdivision, so new service. And to keep things relatively simple, this is a new residential development that's not served by any gas utility, and it has a mixture of residential properties. Some are 3,000 square foot detached homes on large lots, some are 1,000 square foot connected townhomes, and an apartment building with small 500 square foot apartments. Are you with me so far?

A I am.

Q So you would agree that in order to serve the expected load of ten 3,000 square foot detached homes on large lots, the Company would need more poles, conductors, and really larger transformers per residence than would be required for a group of ten 1,000 square foot townhouses that were all connected?

A I believe that's correct.

Q And by the same token, you would expect fewer poles and conductors and smaller transformers needed to serve ten 500 square foot apartments per unit that was all in one building than would be required for those ten detached 3,000 square foot homes?

A Well, you're really getting beyond my expertise. I don't install distribution, but -- but I understand your examples, so if we can just move forward with it without my agreeing that -- that those dynamics work.

Q So, but under -- so you would agree, though, that under a Minimum System Method approach, a significant portion of that distribution grid, of those poles, lines, and transformers, are going to be split evenly per residential account as -- and considered customer related. Isn't that the result of using Minimum System?

A That is correct, and that is simply the nature of utility rates in terms of you bucket customers that are similarly situated. For example, on our system it's those that are served -- you know, have natural gas or have electric and those that don't have electric, and you bucket them together, and at any point one customer is probably paying more than their actual cost to be served and their next door neighbor is paying less than their actual cost to be served. So I think what you've said is true, but I don't think that's -- that means that the methodology used to develop that uniform rate is incorrect or unfair.

Q So to support the use of Minimum System, you've cited the NARUC 1992 Cost Allocation Manual; is that right?

A That is correct.
Q And have you -- you did not identify any additional support for use of Minimum System in your testimony; is that right?
A I referenced the Orders that this Commission has issued supporting Minimum System in the past, but I believe that's probably the extent.
Q And you would agree that in -- well, let me just switch gears a little bit. When you're sort of putting forward the Company's hypothetical minimum system, what do you consider to be a minimal load?
A We use -- we say something like a single light bulb. If every customer had a single light bulb behind the meter, what would that system need to look like? How would it have been built if that was what we had?
Q And you would agree that in 1992, when the NARUC Cost Allocation Manual was issued, that incandescent light bulbs were standard issue?
A Absolutely.
Q And you would agree that the light provided by a 100 watt bulb in 1992 could be replaced today with maybe a 10 watt LED bulb?
A That's correct, but it would not affect the build of the minimum system.

Q So that’s exactly what I was going to ask. With that in mind, have you ever considered what an even more minimal system to serve even more minimal usage might look like, some 10 percent less today than it might have been in 1992?

A No.

Q And so you have not attempted to measure the actual load that the Company’s hypothetical minimum system would provide to each residential customer?

A No.

Q But you would agree that this hypothetical minimum system would meet more customers -- a larger percentage of their customers’ demand than a single light bulb?

A Could you repeat that, please?

Q Yeah. I should. My apologies. Would you agree that the hypothetical minimum system would meet a significant -- a significant portion of the average residential customer’s demand requirements?

A I just don’t think I’m in a position to answer that. I don’t know how much load that minimum transformer size could serve.

Q All right. Now, we're sort of on this theme of the Company’s reasons for using Minimum System. Would you agree that a minimum size grid would not require the investments contemplated by the Company' Grid Improvement Plan?

A No. I wouldn't agree with that. I think essentially as those programs are implemented, they are essentially part of Minimum System.

Q So you think that the amount of grid distribution assets that are required to connect a customer to power a light bulb, that you would need a self-optimized grid in order to achieve that minimum size grid?

A I think the self-optimized grid would become standard -- the standard operation, and in the theoretical minimum system ideal there would be some minimum system self-optimizing grid that would be installed as well.

Q So in this way, minimum system is kind of a one-way ratchet up as the Company invests in more sophisticated distribution grid assets, what's considered a minimum grid -- a minimum distribution grid continues to increase in size and cost?

A Not necessarily. I do think that all of our asset costs tend to increase over time, and minimum system would tend to increase with that.

Q But again, just so I'm clear, the theoretical justification for minimum system is what's the smallest distribution grid needed to connect each customer to power a light bulb? Integrated Volt/VAR Control is not required to connect each customer to be able to power a light bulb, correct?

A And I'm not clear if there are -- if there are any distribution assets involved in IVVC. That's the -- that's the assets that will be allocated using minimum system, is only distribution assets.

Q Fair enough. But returning back to distribution assets like self-optimized grid, you would agree that it's not really a minimal grid if it's self-optimized?

A We look -- for example -- here's an example. You could make an argument that a minimum grid is always overhead. Well, in this case in DEC, because our standard system now is overhead or underground, whichever one is most economical, we are allocating both overhead and underground conductor costs. And I would really see. If you think about the kind of assets that are going to be allocated under the GIP program, they are -- to the extent that they are in accounts that are part of what is allocated on minimum system, they become part of minimum system.

Q All right. I think we've covered that sufficiently, but I have a sort of related question that the Integrated Volt/VAR actually reminded me of, which is, you know, we've talked about this theoretical construct of what's the minimal grid needed to get power to customers to light a light bulb. Ms. Hager, does the Company use a minimum transmission system analysis in its cost of service study that would consist of the size of transmission assets that would be required to support that minimum load and allocate that hypothetical minimum transmission system as customer related?

A We don't, but I do believe there is a portion -- a minimum portion of the transmission system that is necessary. That was not included in the NARUC manual. It's just something the Company has not done. But I do think -- I do think it's there.

Q Now, turning -- I'd like to turn your attention now to Public Staff Hager/Pirro Cross Exhibit 1, the Electric Cost Allocation for a New Era from the Regulatory Assistance Project. Do you still have that in front of you?

A If you'll give me just a second, I will. So can you identify again what that is?

Q It was yesterday marked as Public Staff Hager/Pirro Cross Exhibit 1, the Regulatory Assistance Project's Electric Cost allocation for a New Era manual.

A I do have that.

Q And I think, if I heard you correctly yesterday in response to questions from Public Staff, that the Regulatory Assistance Project, in your view, comes from a specific viewpoint of favoring energy efficiency and distributed energy resources; is that right?

A That's correct.

Q And you would agree that Duke Energy has adopted corporate-wide carbon reduction goals, pledging to reduce its carbon pollution by at least 50 percent by 2030 and achieve net-zero emissions by 2050?

A That's correct.

Q And you would agree that energy efficiency and clean, renewable energy resources are going to be an important component of achieving those goals, right?

A I would agree.

Q And it's also true that within the State's declared public policy for Public Utilities regulation in General Statute 62-2(a), that the public policy of the State includes support for energy efficiency, conservation, and other demand-side options; isn't that right?

A That is correct. And I believe as those policies are enacted, including the Company's goals related to climate change, and those are accepted, we build those assets to serve to meet those public policy objectives and they become part of revenue requirement, then that's where they're captured, and then -- but cost allocation, my concern with the Regulatory Assistance Project Cost Allocation Manual is it chooses methods and policies that would -- as it says, its goal is to accelerate the adoption --

Q Uh-huh.

A -- of a -- let me see -- it's a reliable -- a clean, reliable, and efficient energy future I think that's a laudable goal, but I don't think it should be captured here in rate design. It should be captured in revenue requirements. Excuse me. It shouldn't be captured in cost of service. It should be captured in revenue requirements. And then keep the cost of service focused on cost causation and how the electrons flow.

Q And, again, as you know, there's a debate about what is the proper method to properly identify what has caused those distribution grid costs. And turning your attention to page 14 of that RAP Cost Allocation Manual, which I believe is page 985 of the Public Staff exhibits -- again, we're on Public Staff's --

A I have that.

Q -- Pirro/Hager Cross Exhibit 1. If you look at the third paragraph on that page, do you see where it says "Cost allocation has been addressed in several important books and manuals on utility regulation over the past 60 years, but much has changed since the last comprehensive publication on the topic, the 1992 Electric Utility Cost Allocation Manual from NARUC. Although these works and historic best practices are foundational, the legacy methods of cost allocation from the 20th century are no more suited to the new realities of the 21st century than the engineering of internal combustion engines is to the design of new electric motors." Did you see where it says that?

A I see that.

Q And, again, not asking whether you agree with the statement, you would agree that the electric energy sector has undergone significant changes since 1992?

A I agree.

Q Now, if you could turn to page 145 of that RAP Cost Allocation Manual. Again, we're on Public Staff Hager/Pirro Cross Exhibit 1.

A Okay.
Q Turning your attention to the last full sentence on the last page, do you see where it says "The Basic Customer Method for classification is by far the most equitable solution for the vast majority of utilities"?
A I see that.
Q And you would agree that the Basic Customer Method, that under the Basic Customer Method that only the cost of meters, service drops, and customer service are classified as customer related, and all other distribution costs are classified as demand related?
A That's correct.
Q All right. I'm almost done. I'm just going to ask you to turn to the next page, page 146 of that RAP Cost Allocation Manual.
A Okay.
Q And do you see where it says in the middle of that first column "However, more general attempts by utilities to include a far greater portion of shared distribution system cost as customer related are frequently unfair and wholly unjustified. These methods include straight fixed variable approaches" -- which -- I'm sorry -- "where all distribution costs are treated as

customer related," and just skipping past the parentheses, "and the more nuanced minimum system and zero intercept approaches included in the 1992 NARUC Cost Allocation Manual." And then just skipping down a few, do you see where it says "This minimum system analysis does not provide a reliable basis for classifying distribution investment and vastly overstates the portion of distribution that is customer related"? Have you seen that part of the manual?

A I do see that, and this is one of the reasons that I struggle with this manual. I have looked at it. I think it has -- it has a lot of good information, but I do think that the viewpoint of the authors is shared as fact as opposed to their opinion.

Q Well, and, again, I take it as a given that you don't agree with that last statement, but my question is have you read the pages that follow in which the authors of the RAP Cost Allocation Manual provide eight reasons for why the Minimum System Method is unreliable?

A I have not read it recently, but I have read it.

Q And you would agree that in your -- neither in your direct or your rebuttal testimony you have not attempted to address each of those eight points

criticizing minimum system?
A I would have to sit here and look at the -- at the eight points, and I'm not sure any of us want to do that.
Q I think the record will speak for itself. Thank you.
MR. NEAL: I have no further questions, Chair Mitchell.
CHAIR MITCHELL: All right. Thank you, Mr. Neal. Redirect for the Panel, Ms. Jagannathan?
MR. JENKINS: Madam Chair, I have a few questions if I may. Alan Jenkins.
CHAIR MITCHELL: All right. Mr. Jenkins, you may proceed.
MR. JENKINS: Thank you.
CROSS EXAMINATION BY MR. JENKINS:
Q Ms. Hager, good morning. Good to see you again.
A Good to see you.
Q You've been talking about the subjectivity of allocating cost based on perceived benefits instead of cost causation. Let's briefly explore one example. Did you hear Mr. Oliver testify that a customer requiring a 24-hour medical home ventilator device might consider the

value of outage avoidance to be priceless?
A Yes, I did.
Q Now, I understand that the Company's GIP cost-benefit analysis, a rough estimate of only five or 10 bucks was assigned to the value of each outage avoidance per residential customer. You'd agree that priceless is a much higher value than $5, right?
A Yes.
Q By simple mathematics, wouldn't adding a priceless value to the residential side of the equation necessarily dramatically shift perceived GIP benefit percentages between classes?
A It certainly would. And I think this is the challenge with trying to allocate cost on the basis of benefits. Everyone is different, and even from day to day everyone is different. It's a -- I can't envision a productive way to do that.
Q Let's assume a scenario where DEC would aggregate into a new medical device class all Residential customers employing 24-hour home medical devices. If you had to allocate GIP investment cost based on perceived benefits, couldn't this result in members of this medical device class paying significantly higher rates than similar customers who don't have such medical needs?

A Theoretically, yes.

Q I think you'd agree that not only would this be controversial and very subjective; it would also be very unfair, wouldn't it?

A It would be certainly very unfortunate if that was how those costs were allocated.

Q Okay. Thank you.

MR. JENKINS: Nothing further.

CHAIR MITCHELL: All right. Redirect?

MS. JAGANNATHAN: Thanks, Chair Mitchell.

REDIRECT EXAMINATION BY MS. JAGANNATHAN:

Q Mr. Huber, I think I'll start with you. I just have a few questions on your discussion with Mr. Barnes. Is it safe to say that -- I'm sorry -- Mr. Ledford -- given that discussion, is it safe to say that electric vehicles will be a lively discussion if it is included in an approved comprehensive rate design study?

A (Huber) Oh, most definitely.

Q And I think Mr. Pirro touched on this a bit, but if the Commission is to order a comprehensive rate design study, does the Company view this as kind of a blank slate to take a fresh look at all the rate designs?

A Yes, 100 percent. You know, this is how I view it, a data-driven collaborative process where everything is on the table, right? And when I say that, I don't want it to seem like this is going to get crushed by its own weight by any means. I think, you know, we would start out by obtaining goals from the different stakeholders, prioritization, mapping, and then diving into low-hanging fruit issues that we can, you know, work on right away. And that might be electric vehicles. It could be some other things.

And so I think I just want to strongly communicate that, that really everything is on the table, and if we find things that are low-hanging fruit that we have relative consensus around, we might -- you know, we might say, hey, let's file something right now; let's not wait till maybe even the conclusion. And you've seen that in a recent effort that I've led around a Winter Peak reduction study, where we've really leave no stone unturned and look at all the different ways that we could reduce Winter Peak through clean resources.

Well, one of the first, you know, things to pop out of that -- and, again, we didn't -- you know, this was just, you know, open it up, let's see what we find. One of the first things that popped up in that was, hey, we need to have a bring your own thermostat program for winter focused, you know, demand response. And so we actually filed that recently with this Commission, and we're not even done with that study yet and we're still working with stakeholders on it.

So, you know, that's just an example of it's a blank slate and we'll be, you know, hitting issues with a cadence that's appropriate with the data and the stakeholders.

Q Thanks, Mr. Huber. And I just have one last kind of clean-up question. Mr. Ledford was asking you some questions about access to AMI data, and I believe you said you weren't the appropriate witness for that. Is it your understanding that Mr. Schneider would be more suited to answer questions about access to AMI data?

A That's my understanding.

Q It's also my understanding that he unfortunately did not get excused this morning, so he'll have a chance to talk about it.

Okay. Thanks, Mr. Huber. Turning to Mr. Pirro, Mr. Pirro, in your discussion with Mr. Neal you mentioned that the Company elected not to seek an increase in the Residential basic facilities charge in this case; isn't that right?

A (Pirro) That is correct.

Q And I think you also mentioned that if you had

-- if you had strictly followed the unit cost study using the Minimum System Method, that would have justified an increase in the basic facilities charge for Residential customers, right?

A That is correct.

Q Okay. And can you tell me why the Company decided to leave the basic facilities charge at its current rate?

A Yes. As mentioned yesterday during Mr. De May's testimony, the Company is in full support of a low-income collaborative to address those concerns. This was a very contentious issue in the previous case, and the Company elected just to go down the path of a low-income collaborative.

Q Okay. So would it be fair to say that even if the Company were to propose the Minimum System Method in a future rate case, they wouldn’t be handcuffed from considering low income or alternatives to help low-income customers in the low-income collaborative?

A Yes. That is correct.

Q Okay. And I just wanted to ask you a quick clarifying question. You spoke about how in the Company’s last rate case in an EDIT rider the charges were spread to customer classes on a uniform sense per

kWh basis. Do you remember that discussion?
A I do.
Q And just as a point of clarification, that was a North Carolina EDIT rider that was approved by the Commission in the E-7, Sub 1146 case, right?
A Yes. That is correct.
Q Okay. Thanks. All right. My next questions are for Ms. Hager. Ms. Hager, do you recall discussing with Mr. Page EE, or energy efficiency, and DSM programs?
A (Hager) I do.
Q And is it fair to say the implementation and cost recovery for DSM and energy efficiency programs are governed by statute in North Carolina?
A That is my understanding.
Q And subject to check, would you agree that the statute governing cost recovery for energy efficiency and demand-side management programs provides that utilities are to assign cost to the class of customers that directly benefit from those programs?
A That's my understanding.
Q All right. And it gets a little chopped up when on cross, I know, but I was wondering if you'd just give us a basic explanation of what the Minimum System Method is and why the Company has proposed it for

classifying distribution cost in this case?

A Okay. The thought behind minimum system is that beyond the meter and the meter reading and the customer service and billing, those sorts of things, beyond those basic costs to connect the customer, that there are also some minimum costs that the Company incurs just to ensure that if a customer wants to flip a light -- flip on a light switch, that that power is there, you know, conductors, transformers, poles, et cetera. And it is -- the Company has used it for as long as anyone can remember. It is the method that is -- the NARUC manual is -- let me restate that. The NARUC manual states that a portion of distribution costs are -- that these costs are customer related, and it proposes methods that include minimum system.

And to me, the concept is it's -- it doesn't change as the -- as the system has evolved over time. And as we prepare for the new way that our system will be used to be, you know, dual flow sort of systems going back and forth, the concept is still solid, that there is some minimum system. And the method that the Company uses, I believe, is reasonable to develop an estimate of that. It's not -- it's -- you know, it's not something you can go out and touch that minimum system, but it is still a portion of that total distribution system.

And I understand why Intervenors, certain Intervenors would prefer not to have that in place, but it doesn't change my view that it is simply a fact that a portion of that distribution system is there to ensure that any customer who desires service can receive it.

Q Thank you. And I believe Mr. Neal alluded to this before. You were the Company's cost of service witness in Duke Energy Carolinas last rate case in E-7, Sub 1146; isn't that right?

A That's correct.

Q And is it fair to say that minimum system was a hotly contested issue in that case as well?

A It was.

Q And if I can have you -- do you have a copy of the Commission's Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction issued on June 22nd, 2018, in Docket Number E-7, Sub 1146?

A I do.

MS. JAGANNATHAN: And Chair Mitchell, I believe Ms. Force confirmed that the Commission has taken Judicial Notice of this document, but if it would be easier for me to identify it as an exhibit, I'm happy to do so.

CHAIR MITCHELL: The Commission has taken Judicial Notice of the Order.

MS. JAGANNATHAN: Okay. Thank you.

Q All right. Ms. Hager, if you could just turn to page 87 of that Order.

A Okay. I’m there.

Q Okay. And if you -- if you take a look at the last full paragraph on that page, just above the heading that says Evidence and Conclusions for Finding of Fact Number 29, the Commission, indeed, approved Duke Energy Carolinas' use of the Minimum System Methodology for cost allocation in that proceeding; isn’t that right?

A That’s correct.

Q And in so doing they note, and I quote, that “They placed significant weight on the testimony of Company witness Hager regarding the Company’s long history of employing the Minimum System Method and this method’s alignment with cost causation principles.” Is that correct?

A That’s correct.

Q Okay. And if you can go up just one paragraph from that, it’s the middle paragraph on that page. I’m not going to read through that entire paragraph, but is it your understanding that as a result of minimum system being a litigated issue in that case, and in particular in light of the Company's anticipated investments in grid modernization programs, the Commission said that -- stated that "...distribution cost allocation among customer classes will take on heightened importance in future rate cases"?

A That's what it says.

Q And as a result, the Commission directed the Public Staff to facilitate discussions with electric utilities to evaluate and document the basis for continued use of minimum system and to identify any specific changes and recommendations as appropriate?

A That's correct.

Q And I believe the Commission also directed the Public Staff if they had any alternative methods to suggest, that they should include that in their report; is that right?

A That's correct.

Q And do you know, did the Public Staff submit the report that the Commission asked it to?

A It did.

Q And are you familiar with that report?

A I am.

MS. JAGANNATHAN: All right. Chair Mitchell, I'm going to ask that DEC Exhibit 32, which is the report of the Public Staff on the minimum -- excuse me -- Minimum System Methodology of North Carolina Electric Public Utilities, Docket Number E-100, Sub 162, issued on March 28th, 2019, be identified as Hager DEC Redirect Exhibit 1.

CHAIR MITCHELL: The document will be so marked.

MS. JAGANNATHAN: Thank you, Chair Mitchell.

(Whereupon, Hager DEC Redirect Examination Exhibit Number 1 was marked for identification.)

Q And Ms. Hager, what do you understand the Public Staff's conclusion to be from this report?

A The Public Staff concluded that continued use of minimum system was justified for the electric utilities for the purposes of cost allocation, but then recommended that it did not necessarily carry over. It was sort of the beginning point for rate design.

Q Okay. And did the Public Staff in that report recommend any alternative methodologies that were a better way of allocating distribution?

A They did not.

Q Okay. If you'll turn to page 4 of that report.

A Yes, ma'am.

Q And at the top of page 4, the Public Staff lists out kind of the information they considered in forming their opinion in this report, and I just notice they list Mr. Neal as one of their sources. In the first full paragraph, the Public Staff notes that it reviewed the National Association of Regulatory Utility Commissioners Electric Utility Cost Allocation Manual. Is that what you’ve been referring to as the NARUC manual, the NARUC CAM?

A Yes.

Q Okay. And this was the version published in January 1992, and the Public Staff said that they reviewed it "...for guidance on the allocation of electric utilities costs. The NARUC manual continues to be considered an important resource for the calculation and allocation of electric utility cost of service for regulatory commissions, consumer advocates, and parties before the Commission testifying on issues of cost of service and rate design." Is that what the Public Staff said?

A Yes, it is.

Q And do you agree with that statement?

A I do.

CHAIR MITCHELL: Ms. Hager, just for purposes of clarity of the record, would you repeat your response? You trailed off there at the end.

A My apologies. I said I do.

Q All right. Ms. Hager, if I could just turn your attention to the agreement that the Company reached with CIGFUR III. I believe that was identified as Public Staff Pirro/Hager Cross Exhibit 2.

A I have that.

Q Great. And I believe yesterday with Ms. Downey you were discussing page 4, Section III.B of that Settlement Agreement; isn't that right?

A That's correct.

Q Okay. And just so that we're crystal clear, this provision, as you understand it, refers to deferred GIP costs, i.e., not the costs that are actually being sought for recovery in this proceeding, but what will be sought for recovery when those deferred costs are brought into rates if they are approved by the Commission?

A That's correct.

Q And then on that same page, if you can skip down to Section V.A, I believe Ms. Downey asked you about this section as well. And in that provision the Company agrees prior to its next rate case to discuss with CIGFUR

III potential cost of service methodologies; isn't that right?

A That's correct.

Q Okay. And in that paragraph the Company also agrees to file in its next rate case a cost of service study based on Summer/Winter Coincident Peak; is that right?

A Correct.

Q And wouldn't you agree that the Company in past rate cases and, in fact, in this case files multiple cost of service studies, but obviously only recommends one approach?

A That's correct.

Q So as you understand it, this paragraph just requires the Company to file the cost of service study, not necessarily to recommend it?

A That's certainly my understanding of the settlement.

Q And then, in fact, the Company has also agreed to perform cost of service studies under no less than six methodologies in its Second Agreement with the Public Staff; is that right?

A That's correct, too.

Q All right. Turning to next page of the CIGFUR

Settlement Agreement, page 5, and it's Section V.B, do you recall Ms. Downey asking you yesterday about the Company's agreement to adjust its peak demand to remove curtailable/non-firm load in its next general rate case?

A I do.

Q And, again, the Company is not proposing the Commission approve that approach in this rate case, are they?

A No.

Q And to your knowledge, has the Public Staff filed testimony with this Commission supporting the use of a similar adjustment for Dominion North Carolina?

A Yes. That is correct.

MS. JAGANNATHAN: And Chair Mitchell, I would just ask the Commission to take Judicial Notice of Public Staff witness Jack Floyd's testimony filed on September 24th, 2012, in Docket Number E-22, Sub 479.

CHAIR MITCHELL: Ms. Jagannathan, did you specify his direct testimony?

MS. JAGANNATHAN: Yes. I believe that's correct.

CHAIR MITCHELL: He may have only filed -- okay. All right. Hearing no objection, the Commission will take Judicial Notice of Mr. Floyd's testimony filed in Docket E-22, Sub 479.

MS. JAGANNATHAN: Thank you. And Chair Mitchell, could I just take a short break just to go through my notes? I don't think I have many more questions, but I just want to take one quick break.

CHAIR MITCHELL: Actually, we will take our morning break at this point in time. We will go off the record, and let's go back on at -- we will be back on at 10:55. I'm sorry. Not 10:55. Let's see -- 10:35.

(Recess taken from 10:19 a.m. to 10:37 a.m.)

CHAIR MITCHELL: Back on the record, please. Ms. Jagannathan, we are with you.

MS. JAGANNATHAN: Thanks, Chair Mitchell. And that's the benefit of taking a break. I went through my notes and crossed some things off, and I think I'm all done with redirect. Thank you.

CHAIR MITCHELL: All right. 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: Yes. Thank you.

Just a few.

EXAMINATION BY COMMISSIONER CLODFELTER:

Q Mr. Huber, the scope of the comprehensive study, I want to be sure I understand the contemplated scope that the Company has in mind. We've been discussing in the testimony from this panel a number of rate design issues. We've been also discussing a number of cost of service issues. Will the study encompass elements of both or just of one of those two?

A (Huber) Sorry, Commissioner. Can you repeat the last part of the question?

Q Will the study that the Company contemplates encompass elements of both aspects, both rate design and cost of service, or just one of those two?

A So it's primarily going to be focused on rate design; however, rate design in a sense translates cost of service, right? It translates, you know, marginal cost, right, embedded costs. And so there will be discussion and analytics around how well rate designs match an underlying, you know, cost -- you know, the cost of service. How efficient is that rate design in aligning with cost to serve? So to that extent they'll have some interface, but we likely wouldn't be getting into, oh, well, you know, we should change this allocator or look at that allocator. It will be more through that translation from cost to serve to rate design and pricing.

Q Thank you for that. I’m glad I asked the question. I had a somewhat different understanding from Mr. De May that perhaps it might be a little more comprehensive than that, but we’ll think about that one. I appreciate your answer. Thank you, sir.

Ms. Hager, one for you. Are you there?

A (Hager) I’m here.

Q Okay. And you can hear me okay?

A I can.

Q Great. In your rebuttal testimony, one of the things you say is that the advocates for the Summer/Winter Peak and Average Method do not follow their argument to its logical conclusion. And that’s actually what several of the expert witnesses for some of the industrial and commercial customers also say, almost in exactly the same language, is that the advocates don't follow their argument to its logical conclusion. And I’m curious, have you ever done the exercise of carrying it out to its logical conclusion?

A No, I have not.

Q Do you know if anyone has?

A I think some of the other cost of service methodologies that will be looked at, particularly with regard to the Public Staff settlement, the one that does Base Intermediate and Peaker, I think that would be probably the closest to that. I can't say for certain, but I think that's -- I think that would be the closest to what you're suggesting.

Q I ask this because I sort of feel like somebody has told me there's a Boogeyman under the bed, but nobody has looked yet, and so I don't really know until I look whether there is one and whether I should be afraid of it or not. So I'm really trying to get some assistance on seeing what would happen if we not only applied the logic of the Summer/Winter Peak and Average Method to the demand component, but also to the energy allocator for operating and variable expenses. I'm just curious to see if I can get any assistance on whether that exercise has ever been performed.

A Right. I understand.

Q Thank you. Did you listen to Mr. Jay Oliver's testimony? Were you able to listen to it?

A I was. I heard most all of it. I may have missed a little bit, but I heard most all of it.

Q Yeah. When -- well, you've read -- have you

read his prefiled testimony?
A It's been a while since I read it.
Q Okay.
A I don't -- I don't recall it specifically.
Q Is it your understanding that Mr. Oliver believes that the programs proposed in the Grid Improvement Plan are justifiable based upon measurable and quantifiable benefits?
A My understanding of his testimony is that he believes the programs are justifiable based on their overall benefits, but in request to -- by the stakeholder group to quantify benefits, they did make that effort and quantified essentially only outage cost benefits and that that provided something quantifiable for stakeholders to look at, but that in his view, you know, as I heard him say, this program, the GIP program, does a lot of things and, oh, by the way, it has some good reliability benefits that can be measured in terms of outage costs.
Q Thank you for that. He does believe, though, that with respect to those programs where a cost-benefit analysis was performed, that -- I think I heard him say he's prepared to stand behind those benefits and say they will be delivered. You heard him say that, too?
A I know I heard him say he stands behind the

analyses that were done. I'm not sure I heard the "and they will be delivered." I think one of the things I heard is they'll be constantly evaluated and reevaluated and looked at, and if they're not working, they'll stop, and if they're working better than they thought, they'll speed up and that sort of thing.

Q That's fair. You say in your rebuttal, and so I won't question you extensively about this, that you have some familiarity with the Grid Improvement Plan programs, but haven't studied them yet in depth. And so I don't want to take you too far down the road, but I do want to ask you a couple of questions about, if we can, about how some of the cost associated with those programs will be classified.

Most of them will be functionalized as distribution cost. I think that's fairly apparent from the nature of the programs and where the expenditures will be made. They'll be functionalized in the distribution system. But I really want to focus more on the classification. Are they demand related, energy related, or customer related?

And so one of the programs is the Integrated Volt/VAR Control program which will allow the Company to operate the grid at a lower voltage. And as I understand

Mr. Oliver, one of the results of that will be a capacity benefit for the system as a whole. Need less operating reserves. Need less capacity reserves. Would that be considered a -- for classification purposes a demand-related cost, an energy-related cost, or a customer-related cost? If what the program is delivering is capacity, functionally equivalent of additional capacity, how would you classify that?

A Commissioner Clodfelter, I don't know exactly how those -- I don't know exactly what those assets are and, therefore, I don't know what category they're going into and, therefore, I don't know how they would be classified. I'm sorry. I'm just -- I understand the concept of the system. I don't know the mechanics of what is installed to make it work.

Q Well, what would you need to know?

A What FERC account they fall into. So if they fall into generation, they're clearly -- they're clearly allocated based on Summer CP. If they fall into transmission, they're allocated on transmission demand. If they fall into distribution, then they would be allocated first with minimum system and then the remainder with demand. To the -- and that's to the extent that the things we're talking about are assets.

If they fall into the customer class, then they would -- by default -- all of these is where they would default.

Now, that doesn't mean that, for example, as we've talked, you know, by statute we pull out the EE and DSM costs and do them a little bit differently. I think that's something that can be looked at, but barring any effort or barring any, you know, deliberate attempt to adjust them, they will simply follow how the assets in that FERC account are allocated.

Q We'll follow the FERC account in order to classify whether they're energy, demand, or customer related. Do I understand you correctly?

A Yes.

Q And so even if the functionality they deliver is the equivalent of a generation asset, if for FERC accounting purposes they're placed in a non-generation account, they wouldn't be classified as demand?

A I'm saying unless we made a deliberate effort to do that. Now, I will tell you one of the things that's running through my mind right now is this is not a new system on DEP's -- in DEP's system. And I am sure someone can tell me how we do that at DEP now. And so I think -- and I would expect that if it looks like that, that it would follow -- we would propose following the same methodology. Perhaps someone can get that information pretty quickly.

Q That's fine. I'm not going to go any further with this. I really just want to introduce the point for the Company and all of us to think about, is one of the things that's happening here with the evolution of the distribution grid, and we're seeing in so many different ways, is that the distribution grid is now beginning to deliver services to the system that traditionally have only been available either from generation assets or, in some cases to a lesser extent, transmission bulk power assets, and that's happening all throughout the system, so there's been a blurring of the sharpness of those distinctions, and I'm really trying to explore to what extent we're going to be grappling with that when it's time to deal with the Grid Improvement Plan for cost recovery purposes.

I think you understand the point, and I'll leave it with that; am I correct?

A I do understand that, and just allow me one additional thought, is the things -- kind of things you're talking about I believe can be looked at because you're talking about still electrons and how they flow and how they impact the flow of electrons and those sorts of things. I still would differentiate that from benefits received. I still think you've got to stay focused on the electric system for the purpose of cost allocation.

Q I understand you, but I'm really focusing upon traditional methods of classifying cost for cost allocation purposes as energy related, demand related, or customer related.

A Yes.

Q I'm not going down -- I'm not talking now about the benefit issue. You understand that?

A I understand.

Q Okay. Thank you. Mr. Huber, back to you with a question, and I'll introduce it and others may want to take it further. In the comprehensive rate design study will the issue of rates and charges and services for -- charges for services for net metering customers be part of that equation or not?

A Yes, absolutely. That will be part of the comprehensive rate review.

COMMISSIONER CLODFELTER: Madam Chair, we could take -- I could take a lot more time this morning, but I think I'm going to stop there.

CHAIR MITCHELL: All right. Commissioner

Duffley?

COMMISSIONER DUFFLEY: No questions.

CHAIR MITCHELL: All right. Commissioner Hughes?

COMMISSIONER HUGHES: Yes. I've just got a few questions for I believe Mr. Huber, but if someone else wants to chime in, that's fine.

EXAMINATION BY COMMISSIONER HUGHES:

Q Mr. Huber, from what I understand, you will likely be very important in the Company's implementation of this rate design study if it moves forward. I don't know if you'll be the project manager, but it's fair to say that you'll be kind of one of the architects of this study?

A (Huber) That's correct.

Q So in your testimony you talked a little -- in your rebuttal you talked a little bit about some of the aspects, I guess, some of your visions and how you agreed with some other -- particularly witness Floyd's vision. I think there was at one point -- I'm reading it now; I don't think you need it in front of you -- just the six points about what would be the, you know, the driving objectives of this study, and one of them was give consumers appropriate information and the opportunity to respond to that information by adjusting the usage. Is that -- do you remember that as a bullet as one of the -- do you agree that that's one of the main goals of what the rate study would look at?

A Yes. I recall that.

Q So I'm really interested in this concept of what customers do with their rate design information because I -- you know, I think we've talked a lot about rate design being an art, and I think some of the Intervenors have talked a lot about sending pricing signals in different ways. I'm curious to just hear some really quick views of yours on what's the state of the industry related to kind of predicting behaviors. And in particular, I'm curious if you have views about some of the billing innovations and what impacts that has on rate design. I think you mentioned in your testimony AMI, but there's a number of billing -- what I would consider to be billing, not rate design, approaches that Duke is either using or rolling out that would seem to have a very big impact on the way customers get their information. So that idea of giving customers information seems in many cases to be impacted by billing practices as much as rate design.

So could you just comment on some of the billing practices that Duke is rolling out and what impact you think they will have on rate design, specifically the equal payment plan that I believe Duke has been fairly aggressive, I would say, just at least on their website and things, about pushing out AMI direct draft, some of those things? Can you just comment a little bit about that?

A Yeah. I could probably talk all day on some of these topics, so I'll try to be brief, but, you know --

Q Well, it would be fine with me, but maybe not from my colleagues, so maybe we should be briefer.

A I think in general there's a greater trend to having more customer focus and centric forms of communication, so really identify what market segment or customer segment do you need to communicate to? What are the best channels and mediums to reach those customer segments? And then what rate designs are those customer segments, you know, most apt to, you know, to join, and how can we leverage their natural inclinations in these customer segments to the benefit of not only their bill, but also to the system in general to nonparticipants?

And so, you know, you mentioned budget billing, for example. There's a good segment of the population that likes bill certainty, right? And one of the key drivers of customer dissatisfaction is higher than expected electricity bills, and this is incredibly important when we know that most, you know, Americans out there, they only have about $500 or so in savings, maybe less now because, you know, due to the pandemic, right? And so a higher than expected electricity bill can be highly detrimental to the budget of a family, right? So the question is, well, what could we provide to maybe this customer segment? I'll use them as the example just for ease. Well, you would -- you know, you would have an app that could clearly define, hey, you're on a bill certainty product. You know, your rate is fixed for this month; however, you have elected to reduce that monthly rate to be a part of our demand response program, say, and you'll get, you know, a $5 discount -- I'm just making this up -- per month to be a part of that, and we'll show you on the app, you know, how much, you know, savings maybe that thermostat can provide, but if you do something extra, we have another -- like a type of behavioral demand response, so you lower your thermostat more than, say, anticipated, they can go to their app and it can do real-time coaching.

Now, this is something we don't have yet enabled, but we're exploring, of this would save you "x" amount on your bill. So you're merging a customer's natural inclination to want certainty with them being able to respond dynamically to events, and then show them in real time what that could actually save them if they go, you know, a step beyond, for instance.

So with -- you know, and this gets into billing, you know, and some -- and prepaid as well. There's so many different things you can do to visualize it to the customer on the computer or the app so that they can see how much they have left, how their behaviors are impacting their bill, and then tips to help them along. And we're getting so sophisticated now with AMI and AI coming together, all that AMI data and advanced AI understanding, so that we can start to look -- and, again, this is a bit down the road, but we can start to look and say, hey, we think your AC is starting to go; it's using more energy than normal, and we can help with, you know, preventative maintenance on that, right, or get ahead of that.

Those are the things that I'm really excited about that we're starting to be on the cusp of with merging AMI and big data analytics. I'll pause there because I can keep going, but --

Q Yeah. And I -- again, I could keep listening, but maybe we should spare our -- the other folks on the hearing. Well, that's helpful. Do you have just a rough estimate -- I know you're not in the billing area -- but a rough estimate within 5 percent of what the current Duke budget billing subscription rate is for Residential class?

A Oh, man. Yeah. I could get that for you. I thought it was in the 15 plus percent range, but I would need to confirm that.

Q Okay. No, no. Fair enough. I'm sure we can get it. I just was --

A Yeah.

Q -- I was just curious based on the content. And everything you just said is going to -- your vision going to be part of this rate study, looking at these intersections between AI and AMI? Is that your vision, that that would occur in this comprehensive rate survey -- I mean, excuse me -- comprehensive rate study?

A Yeah. And so, you know, what I've been trying to do to prepare for this, so I haven't just been, you know, sitting around waiting for your Order, we're basically procuring a state-of-the-art analytics platform to help us with this comprehensive rate review. So we're able to take actual customer, you know, 15-minute, 30-

minute data, put it all together into the system and run what-if scenarios and run analyses, cluster analysis, load architect analysis. We're able to crunch all this data and say, all right, well, what if we segmented this class differently or what if we changed this rate design? How -- you know, what would be the impacts to the customer, to the Company, to other, you know, customers? And this is something that normally in the past you -- first, you couldn't even do it because you didn't have the AMI data, but if you did have the AMI data, it would take days to run, right, multiple days to run these scenarios of crunching just this huge amount of data. And the Company, Duke, has just been really great of starting to figure out ways to take this data and create platforms to quickly crunch, you know, a big calculation.

And so this platform that we're building for the comprehensive rate review will be able to quickly produce results and what-if scenarios and think through how does a specific approach to rate design impact customers, right? So we know there's a difference between the philosophy of rate design between DEP and DEC. Well, how will, you know, make -- you know, taking a best practice over here and putting it in over there, how will that impact, you know, the customer and revenue collection and the price signals? So those are the types of things that we're really going to tease out, and we're going to have the platform to do it, which is the most important thing.

After that, I don't want to put my hand on the scale in any direction because, frankly, I'm not in the position yet to tell folks, hey, I think we should go with this particular methodology and this segmentation of Large Industrial. I'm not there yet. I want to make sure that this is a stakeholder and data driven led collaborative and hear from actual customers, hear, you know, some of the past issues, where we see things going forward, and make some of those decisions together, and I'll just infuse it with my knowledge from, you know, the past worlds that I've lived in which has been technology, the consumer advocate world, and consulting, where I've been on the front lines of a lot of states either driving change or responding to change, and I can bring that experience, those best practices, those insights, but really I want to make sure that the outcome is custom and tailored to North Carolina on-the-ground realities and goals.

Q Great. Well, and that all leads in, so that's great to hear. And that's what I was hoping the answer was going to be, but also with analytics, it does seem to sometimes take longer than you think it will and -- so my last question was -- I think you partially answered it because you said you're already getting ready to go, but I was just -- the time frame of this study, I heard -- I think one of the other witnesses talked about it being a year-long study. In your testimony I think you said, and it just -- just seems a little bit ambitious to me, that it would be done by the second quarter of 2021. Is that still -- is that still the timeline where we can expect results for all the great things that you just said you wanted to do by 2021?

A Commissioner, I'm so glad you asked that question. So, you know, given the unprecedented, you know, issues and the delay that those issues have caused, what I'm proposing is to have a pretty comprehensive roadmap and report a year after the Final Order in this case. That means I'm obviously -- I'm preparing now to make this the most, you know, constructive and fruitful process. Of course, I haven't -- you know, we haven't started anything formal yet and we haven't, you know, reached out to stakeholders. I'm trying to get the platform to really enable this, but you're absolutely right, this is an incredibly, you know, ambitious undertaking. It's a lot of work. I want to move as quickly as possible, though, because I really feel that we can create some really, you know, quick wins, and I feel like we'll be able to get consensus from stakeholders rather quickly on a few items, you know. And I mentioned that thermostat, you know, BYOT as an example of something that just made so much sense, let's do that right away.

So I think we'll have some of those in this process that come out and we won't wait for the final report, and others that will take a little bit more time, there could be follow-up studies, but I really do want to move as quickly as possible to start modernizing some of our pricing and, you know, tackling some of these issues.

Now, when those can actually be implemented are partly a function of what type of proceeding would be needed to enable it, you know, to enable a new rate design switch or, you know, things like that. So -- but in general, it will a be a year from the Final Order in this case, but just be assured that we will be starting very, very quickly after that and it will be pretty heavy.

Q Great.

COMMISSIONER HUGHES: No further questions.

Thank you.

CHAIR MITCHELL: All right. Commissioner McKissick?

COMMISSIONER McKISSICK: Yeah. Just one or two questions. First, I'd really like to thank the attorneys who have been a part of this particular cross examination and, of course, direct examination because so many of the questions that I had in the back of my mind have been asked and answered, so it will certainly substantially reduce the time that I will need. Just a few quick follow ups.

EXAMINATION BY COMMISSIONER McKISSICK:

Q And I guess, Ms. Hager, I want to ask you this first. I mean, you're talking about developing cost of study services, studies, you know, using six different methodologies. Do you have any idea what those methodologies would be at this time? I mean, are there certain traditional methodologies that might be used or hybrid type models? What is it that is the --

A (Hager) So we have a Settlement Agreement with the Public Staff that outlines those methodologies that will be used for allocating generation related cost -- if you'll give me just a second -- and they're mostly traditional. Hold on. Hold on. Here it is. So we're going to -- we currently file a Summer Peak, a Winter Peak, and a Summer/Winter Peak and Average. That's what we filed for this case. We've agreed with -- in the CIGFUR settlement to file a Summer/Winter Peak, which will just be an average of Summer and Winter Peaks. And then we have agreed with the Public Staff to do one called Base Intermediate and Peak, and that's the one I think I was discussing maybe with Commissioner Clodfelter about that is -- it's more of an innovative -- it's a -- I don't know if it's a new approach, but it's one that's been coming -- has been coming up.

And then we're going to do a 12 Coincident Peak, so a monthly average -- an average of the 12 monthly peaks. And then we said any other identified relevant methodologies. So they are, I would say, mostly traditional with one that is more nuanced.

Q And let me ask you this. I know when you started discussing issues related to cost of service, you indicated you did not like to consider benefits. And I'm -- I guess I'm trying to drill down a little bit more and try to understand why benefits are something that you take a step away from. I mean, is it the ability to not be able to sufficiently quantify them or are -- what's the challenge, what's the difficulty in looking at benefits, because I would think that you could come up with a matrix or a way of doing it that might not be necessarily traditional, but that would take that -- take them into consideration. So maybe you can help me with why benefits are challenging or problematic from your perspective.

A Yeah. Thank you for that question. So I think several things come to mind. One is, I think -- first of all, quantifying benefits, as I've said, is very subjective, and you've heard some examples of that. They also -- if you just look at the cost-benefit analyses that were done for GIP, they only quantified one small aspect of the overall program, and there was a lot of debate about those -- the metrics that were used for that. You know, they were national, they weren't state. Should you -- you know, should you spend money to do it on a state basis? So I think there's a lot of differences of opinion of how to do that.

Essentially, how that's done is by survey and, you know, I've actually smiled and thought if industrial customers knew that if they were asked the question what's the cost of an outage and it determined how costs were allocated to them, they might have a different answer than what they've answered otherwise. As I said, everybody wants a smaller piece of the pie when it comes to cost of service.

I think additionally, you have the -- if you take it to its -- take it to kind of an extreme conclusion, which is allocate all electricity cost based on benefits, then you've completely upended the way that costs have been allocated in the past. And as has been said, any time you start changing allocation methodologies or changing even rate design structures, you create winners and losers. And so you're likely to have, you know, a lot of pushback from that, you know, from that exercise.

And so, you know, in my view, the -- you know, the place to look at benefits is in deciding what the Company should pursue. You've got to have some way to, like I say, prioritize which things that you go forward with. Well, when you carry that into cost of service, it really has the potential, I think, to create some, you know, artificial allocations based on things that are very, very difficult to quantify.

So those are some of the main reasons I -- that I would believe it's not appropriate.

Q I guess the follow up would be have you given it any great thought and reflection or ever thought about, if not in-house, a consultant being brought in to look at what it might look like if we started, you know, considering benefits as a variable and doing it discretely and identifiable and weighing it in a way that it could be insightful or helpful in terms of how to think of cost?

A I have thought about it a good bit and, you know -- and I have also discussed it with the Company's cost of service folks, and I think generally we simply believe that it's -- the place for it is not in cost of service. You know, is there a place for that in quantifying benefits to determine which GIP programs get raised to the, you know, top of the stack or other things. You know, if you look at some of the -- even the low-income collaborative, you might want to use cost-benefit analyses there to determine, you know, what actions should be taken. And that might be the proper place for those -- to do more analytics to try to get more of a quantification of benefits.

Q And I guess you mentioned the Grid Improvement program. I mean, let's say that it was determined that 98 percent of the benefits are going to commercial/industrial users. How would you -- it sounds to me, based upon the explanations I've heard previously, in terms of trying to determine how that would go back into cost of service, you'd go back to FERC and its account categories and would go back and try to establish how different components of the Grid Improvement program would fit in with traditional categories to then kind of allow it to flow back into cost of service analyses; is that correct?

A That is correct, but the thing that I would note is that I’ve heard that statement that 98 percent of the benefits are for commercial/industrial, and I think if you drill down on that some, I think what you’ve heard is that -- that that is only the reliability portion and it was -- it was that portion that was pretty easily quantified and that there would be lots of arguments that would say I understood Mr. Oliver to say that over 90 percent of the customers' impact to the residential by the self-optimizing grid, so, you know, there’s a logic there that would say they receive 90 percent of the benefit.

So it’s -- it’s -- I think we have to be careful -- it’s nice when you have something you can quantify, when you can put a number on something, but we need to be careful about not giving that more weight than -- than it should have, and particularly when it comes to cost allocation.

Q Now, let me ask you this, in terms of this exhibit of the Public Staff, I think it was originally identified as Public Staff 41, but it was introduced as a different exhibit number during the course of, I guess, your testimony, but it was the guide that was done by the Regulatory Assistance Project dealing with Electric Cost Allocation for a New Era --

A Yes.

Q -- and you indicated that, you know, it favors distributed energy resources, but I mean to what extent would you be willing to do a deep dive and look at the standards that are discussed there and the -- and the way -- and the approach and the methodologies that it articulates in terms of moving forward with the analysis that's going to be done dealing with cost of service and I guess, likewise, at some point, you know, dealing with rate design?

A Uh-huh. So to date, what the Company has committed to do is reflected in the settlements in terms of what it's willing to look at. And as not being the person who is in charge of cost of service, I am reluctant to commit the Company for what it is willing to do. I think that is something that we'd have to have someone else commit to.

COMMISSIONER McKISSICK: Well, thank you very much for your testimony. I appreciate it, and I look forward to seeing how this all evolves. And Mr. Huber, one time you mentioned to me looking at Dr. Bonbright's book. Based upon your recommendation, I did. Thank you. No further questions, Madam Chair.

EXAMINATION BY CHAIR MITCHELL:

Q All right. Mr. Huber, I have one question for you. You indicated that the rate design study that you all are going to conduct, did that include net metering? I'm getting a lot of feedback from the line here. Has the -- has the Company performed the investigation required by the net metering provision of House Bill 589 on cost and benefits associated with the technology, or will that be part of the study that you all are undertaking? Just -- can you just help me understand where things stand there?

A (Huber) Yeah. Thank you for -- for the question, Chair Mitchell. So we have -- to my knowledge, we have not conducted that study. That would fit within this comprehensive rate review as we look at partial requirement customers, the benefits, the cost, and from different temporal direction, so short term verse long term. And so this will absolutely, you know, be a part of the comprehensive rate review and making sure we -- we, you know, follow on everything we need to study and hit on per statute.

Q Okay. Thank you, Mr. Huber.

CHAIR MITCHELL: All right. Any further questions from the Commission?

(No response.)

CHAIR MITCHELL: All right. Hearing none, we will go to -- we will turn to questions on Commissioners' questions. We will start with the Public Staff.

MS. EDMONDSON: No questions.

CHAIR MITCHELL: Okay. Attorney General's Office?

MS. TOWNSEND: No questions. Thank you.

CHAIR MITCHELL: Any questions from other Intervenors?

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

CHAIR MITCHELL: All right. You may proceed, Mr. Neal.

MR. NEAL: Thank you.

EXAMINATION BY MR. NEAL:

Q First, Ms. Hager, in response to questions from Commissioner McKissick, you were talking, again, about this question of how cost allocation relates to benefits. I just have a -- it's a hypothetical question, if you will. If a grid improvement cost was allocated to one class and one class alone, and the Company's own evidence showed that all of the economic benefits from that Grid Improvement Plan cost benefitted a different rate class, would you agree that that would be an unfair allocation?

A (Hager) Not necessarily. I think if you think about how cost allocation is done, there are big buckets of costs, and inevitably you will have assets within that -- that FERC account that benefit only one group or only another group, but then they're allocated based on -- in the case of distribution cost, customer and non-coincident peak. So I don't think you can isolate -- I think you can isolate any group of assets and say isn't it unfair to allocate those costs to this group of customers, and I think that is -- is not an appropriate way to look at it because it simply is -- it's you look at it by the group -- by the total of the assets within that account.

Q So it's your testimony that if the Commission were to determine that a particular Grid Improvement Plan investment, again, based on the Company's evidence, was providing a material benefit to one group of customers, one class of customers, and then a different class of customers was the only class asked to pay for that, you're saying that that would be fair?

A Well, obviously, we would follow any Commission order that directed us differently, but barring that, we would not differentiate in that case. And I'll point out again that the cost benefit analyses only measure a very narrow aspect of the benefits of the GIP program.

Q I hear that, but to be clear about the hypothetical, I was asking a hypothetical of if the Company's evidence showed all of the benefits went in one direction and all of the cost went another direction, that doesn't change your answer?

A It does not.

Q Mr. Huber, good morning.

A (Huber) Good morning.

Q It's good to see you.

A Likewise.

Q Following up on some questions from Commissioners Clodfelter and McKissick, the -- you would -- well, actually from Commissioner Hughes first, you would agree that the conversation you had relied on the ability of customers to respond to price signals, to somewhat change their behavior or make investments that would be responsive to those price signals; is that a fair characterization?

A I think that's fair. And just, you know, it can be a wide range of definitions within price signals, so it might not be, oh, you know, you have a critical peak price of 25 cents right now. It could be if you reduce your demand, we'll give you a $3 bill credit for today, you know. It could run the whole gamut.

Q And putting that example to the side, you would agree that if a larger and larger portion of a residential customer's bill was taken up by a fixed charge, that mathematically speaking that reduces the amount of their bill that could then respond to price signals or in some way do some of the inventive things you were talking about with Mr. Hughes?

A Well, I guess it depends on the customer's goals, all right. So if the customer has a goal to electrify everything in their house, including their car, they would -- they would want a higher fixed charge as part of their bill in order to have the optimal economic benefits of electrification. So -- and that's where, you know, it really gets into what different customer segments are all about. Some may want some type of renewable energy product, right, some might want very complicated, sophisticated price signals, and others might want more bill certainty. And so they don't necessarily mind that they have some lock-in because it's actually more important to them that they can budget -- you know, they're on a fixed income, for instance -- than you know, have some impact by -- by, you know, changing how they do their lighting, for instance. So it really depends on the customer, I would say.

Q And I totally appreciate that. Did you have a chance to hear the testimony of Public Staff witness Jack Floyd during the consolidated hearing?

A Yes.

Q And so this question came up there, too, and, again, just thinking about it in terms of rate design as a tool that -- that would allow a customer to take more control over their bill and respond to price signals. Putting aside, you know, this question about an electric vehicle owner, for example, just in terms of responding to the price signals in a time of use rate or a critical peak pricing framework, the extent that a lot more of a bill comes from a fixed charge than from those volumetric rates, it reduces the incentive to respond to the signals; isn't that right?

A Well, yeah. Again, I'm just -- because it really -- I think it depends, I think, you know, on the type of pricing product. I think if -- where you're going is a pricing product that has -- you know, where the customer has full exposure to the price risk, right, and so -- you know, because, for instance, you could have a type of bill certainty product where it would be fixed, you know, each month that they could plan on, but we could have a demand response -- behavioral demand response events where we could guarantee a savings of a certain amount in exchange for sort of, you know, response from the customer.

So, for instance, in Kentucky we're running a peak time rebate pilot right now, and that's, you know, hey, if you're able to reduce your demand, you will be -- you'll save "x" amount or you'll get this type of bill credit, for instance. So their underlying bill could actually be locked and -- but at the same time they have equal to or more inclination to respond to a certain program or price signal that lies on top of it. So, you know, I guess it just really depends on exactly what type of, you know, rate design you're thinking of.

Q And Mr. Huber, if -- if the Commission ordered the Company not to use the Minimum System Method in the cost of service study and instead to use the Basic

Customer Method to allocate those distribution costs, you would agree that they could use that as a baseline in its upcoming rate design study, correct?

A Sorry. We -- what aspect would we use -- what aspect would we use? Sorry.

Q So earlier in the conversation with Commissioner Clodfelter you indicated that the focus of this upcoming process is really on rate design and not on cost of service. And I was just asking that if -- before you got underway with that stakeholder process, the Commission ordered the Company to stop using a minimum system in its cost of service study and to use the Basic Customer Method instead, that would then become the baseline for, you know, the rate design study moving forward, correct?

A Yeah, exactly. I think, you know, what I've tried to communicate is there's a lot of different variables, right, and you want to -- especially when you have something that's as big as a comprehensive rate review, you want to try to minimize the variables and so, you know, adjusting all your different cost of service allocators and your rate design at the same time is -- is a lot, right. And I want to clarify that there would still be some cost of service studies as part of the comprehensive rate review, but they'd be more specific to, you know, individual customer cases or segments, if you will, so like net metering or, you know, large data centers, for instance, things of that nature, not getting into actual like allocators and things of that nature. You know, similar to what got established or what helped OPT-V get established, those types of cost of service studies.

So, yeah, we would take what the traditional method is, but I think what's really important is, as I've mentioned before, rate design translates cost to serve and also tries to marry it with marginal cost and so forth. And when you deal with really sticky subjects like distribution poles, right, you know, if I use less energy, does the pole shrink? If I use more, does it increase? How -- how do you send a price signal to recover that fixed infrastructure that really doesn't vary by usage?

And so, I think, you know, we're going to be looking at that and how to break down, potentially, and unbundle some of these costs. And so we'll be relying, you know, on the -- on, you know, whatever method the, you know, the Commission approves, don't get me wrong, but I think we're also going to be looking at how pricing can marry up with the realities of the system that we see out there.

Q Thank you.

MR. NEAL: Chair Mitchell, no further questions.

CHAIR MITCHELL: All right. Any additional questions?

MR. PAGE: Chair Mitchell, this is Bob Page. May I ask a few?

CHAIR MITCHELL: You may proceed, Mr. Page.

EXAMINATION BY MR. PAGE:

Q I'd like to go back to Ms. Hager, if I could, please. Good morning again. Ms. Hager, in the questions you received from -- from the Commissioners, I think I detected your saying that you just wouldn't put as much reliance on what a cost-benefit study would show versus a cost of service study. Did I correctly interpret your answers?

A (Hager) Well, I'm not sure. Let me say it this way. In my view, cost-benefit analyses have a place, but that place is determining what programs, what -- you know, what actions should be taken. Those result in revenue requirements. And once you've established revenue requirements, you don't use cost-benefit analyses to do cost of service studies. At least that's my recommendation.

Q For example, a useful place for a cost-benefit analysis would be if Duke was considering the implementation of a new program, and you wanted to find out before you spent money on it are the benefits that are going to accrue to the Company and the customers from this program greater than or less than what it's going to cost to put it in place?

A That's exactly correct. So, you know, let's talk about a couple of examples. It's nice when there are things that the Company is going to do that are sort of slam dunks, that the reductions in operating and fuel costs, you know, more than offset the incremental cost of the asset and so it's clear something should be done, but oftentimes is the case you're looking at things that will raise revenue requirements, and so you have to say, okay, how do I determine whether or not this is a good thing to do? I think, you know, an easy thing to do might be to say I'm not going to do anything that, you know, doesn't raise revenue requirements. I won't do anything that raises revenue requirements, but I don't think any of us would agree you get good results with that, so you ultimately have to do some -- some type of cost-benefit analysis.

An example would be -- and this is from more of a layperson's standpoint -- if you're looking at doing things that reduce the amount of time a customer stays on hold when they call the customer service center, that's going to raise revenue requirements to do that, but you're going to be looking at customer satisfaction, at those sorts of things, and you're going to make a -- you have five options to choose from and, you know, one reduces it five seconds, one reduces it 20 seconds, but one costs five times as much as the other. To me, that's the kind of place where cost-benefit analyses should reside. And then once they are translated into revenue requirements, then move into looking strictly at the electrons and how they flow.

Q All right. Let me just ask you about the evidence that has been offered that there's one cost-benefit analysis regarding the GIP program, grid investment, that says that the vast majority of the benefits of that program would flow to customers other than residential customers. Are you familiar with that evidence?

A Yes.

Q And I think I overheard you state that that was derived only from one function which was reliability; is that correct?

A That is my understanding.

Q All right. If -- if I'm a manufacturing customer and I have my own standby or emergency generation, then, you know, up to a point, you know, where Duke is already around 99 percent reliability, that extra one percent is probably not as important to many at the lower rate, wouldn't you think?

A Obviously, individual customers will experience these benefits differently, and that is part of the challenge in the methodology that's been used here as more of a national average. That would take into account that some customers would value outages -- would not value, but would see the cost of outages is higher than others, and that's been, you know, molded into some sort of, you know, average type of rate. But you're correct, every customer will perceive the benefits of every program, every action the Company takes, differently.

Q All right. And just one other example on that, if I'm a manufacturer and I have a process where my production is not harmed if I'm interrupted -- in other words, I am not an aluminum smelter where an interruption could ruin a whole batch -- if I have a manufacturing process like that and I volunteered for an interruptible type rate, then obviously I'm saying that cost is more important to me than reliability, am I not?

A I believe that is true. I probably should mention, Mr. Page, too, that -- just Mr. Oliver is probably kicking me under the table somewhere -- that there are a lot more benefits to the GIP than just reliability benefits, and your customers will see some of those benefits even if they won't see as much as perhaps others.

Q But those benefits, whether they be small or large, are not how you would allocate the cost of providing those benefits; am I correct?

A I certainly do not advocate allocating cost based on benefits.

Q Thank you very much.

MR. PAGE: That's all I have, Madam Chair.

CHAIR MITCHELL: All right. Any additional questions on the Commissioner's questions from the Intervenors?

MS. CRESS: Yes, Chair Mitchell. This is Christina Cress.

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

MS. CRESS: Thank you. I believe these questions are going to be directed to Ms. Hager, following up on some questions and discussion between Ms. Hager and Commissioners Clodfelter and McKissick. And I do want to apologize in advance. I am using one device for audio functionality and another device for camera functionality, so there might be some lag or issues here, but I'm just trying to make do the best I can with the situation I've got.

EXAMINATION BY MS. CRESS:

Q So that said, Ms. Hager, the interruption cost estimates for the Residential class included as part of the GIP analyses were pre-COVID, correct?

A (Hager) Yes. That would be correct.

Q And so those estimates don't reflect the fact that a significant portion of the workforce has worked from home in 2020; is that right?

A That's correct, and I think that illustrates the changing nature of benefits realized by customers.

Q I believe Mr. Jenkins asked you about the impossibility of valuing interruption cost for that residential customer who is on a 24-hour ventilator; is that right?

A Yes.

Q But in today's COVID-19 era, there's also a lot more common and perhaps less extreme examples. Just take one, for example, that all of us here today should be able to relate to, what about an expert witness testifying from home in this virtual proceeding? What value do you think that residential customer in that situation would place on avoiding a power outage?

A It would be very high.

Q So that's just one example, but with a significant portion of today's workforce continuing to work from home and perhaps continuing to work from home even beyond COVID-19, is it fair to say that a significant amount of commerce and business is being conducted from home?

A You know, anecdotally, I think that's certainly true. I don't have any documents -- oh, dear -- to -- my computer is threatening to do something -- I'm sorry. You know, I don't have any data to back that up -- I need to snooze it, I think -- I think I'm okay -- sorry, sorry -- to, you know, say specifically, but I think that's certainly a whole different paradigm than it was a year ago.

Q And so I think you've sort of made my point and jumped to my conclusion here before I had a chance to do so, so thank you for that. But it's correct, is it not, that no studies have been conducted yet to revalue the customer interruption cost in today's COVID-19 era with a significant portion of the workforce working from home?

A That is true. I'm not even sure when those estimates were made. I heard some discussion of it in talking with Mr. Oliver, but they are very much broad estimates and they were pre-pandemic.

Q Okay. Thank you.

MS. CRESS: That's all I have.

CHAIR MITCHELL: Any additional questions from Intervenors on Commissioners' questions?

(No response.)

CHAIR MITCHELL: Questions from Duke?

MS. JAGANNATHAN: Thanks, Chair Mitchell. I just have a couple of quick questions.

EXAMINATION BY MS. JAGANNATHAN:

Q Mr. Huber, you were discussing the anticipated timeline for the comprehensive rate review with Commissioner Hughes, and I was wondering if you could just let us know, kind of, how the implementation of Customer Connect fits into that timeline. I believe in your rebuttal testimony you say it's scheduled to be implemented in Duke Energy Carolinas in spring 2021; is

that right?
A (Huber) That's correct, yeah. And I think in general, though, what we want to do is get all of our ducks in a row in preparation for Customer Connect being stabilized and ready, you know, to handle new rate designs, of course. And, again, that's, you know, part of the reason why we want to get started, you know, sooner -- sooner than later on this comprehensive rate review. So in general, you know, we have that -- I have that target in mind, though, of, you know, Customer Connect has to come in, it has to be stabilized, and then, you know, depending on what the rate design is, we're off to the races and we can get -- hopefully get something implemented right away.
Q Okay. Thank you. And Ms. Hager, just one last question for you. I heard you bring up the pie again in response to Commissioner McKissick, and I just wanted to ask you, would you say that as long as all of its costs are recovered, the Company is essentially agnostic as to how the pie is sliced when it comes to cost allocation?
A (Hager) That's true.
Q So would it be fair to say the Company's primary motivation in proposing cost allocation methodologies is to allocate cost in a fair and equitable

manner, according to longstanding cost allocation principles?

A Yes. I would totally agree with that. And one of the things I had wished I had mentioned earlier was there's been some discussion about Dr. Bonbright and his book and sort of what he has to say about things. And he does -- waxes poetic somewhat about minimum system, if that's possible, but he does ultimately conclude that if you've got to do something with minimum system, he thinks it is more appropriate as a customer cost as opposed to remaining as a demand related cost. But, yes, you know, I think all things being equal, the customer -- I mean, the Company is just trying to do what it believes is fair and equitable and treats essentially all electrons equally.

Q Thank you.

MS. JAGANNATHAN: That's all I have.

CHAIR MITCHELL: All right. At this point I believe your witnesses may step down. Thank you all for the testimony today. And I will entertain motions.

MS. DOWNEY: Madam Chair, Diana Downey.

CHAIR MITCHELL: Yes, ma'am, Ms. Downey.

MS. DOWNEY: Chair Mitchell, I would move that Public Staff Pirro/Hager Cross Examination Exhibits 1 through 5 be entered into the record and into evidence.

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

(Whereupon, Public Staff Pirro/Hager Cross Examination Exhibits 1 through 5 were admitted into evidence.)

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

CHAIR MITCHELL: You may proceed, Mr. Neal.

MR. NEAL: I would also move into evidence NC Justice Center, et al. Hager/Pirro -- or maybe it was Pirro/Hager Cross Exhibit Number 1.

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

(Whereupon, NC Justice Center, et al. Pirro/Hager Cross Examination Exhibit Number 1 was admitted into evidence.)

MS. JAGANNATHAN: All right, Chair Mitchell, Molly Jagannathan. I would move that Pirro Exhibits 1 through 9 and Pirro Second Settlement Exhibits 4 and 9 be admitted into evidence, as well as Hager DEC Redirect Exhibit 1.

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

(Whereupon, Pirro Exhibits 1 through

9, Pirro Second Settlement Exhibits 4 and 9, and Hager DEC Redirect Examination Exhibit Number 1 were admitted into evidence.)

MS. JAGANNATHAN: And I would also move that Ms. Hager, Mr. Huber, and Mr. Pirro be excused.

CHAIR MITCHELL: Your witnesses may be excused.

MS. JAGANNATHAN: Thank you, Chair Mitchell.

CHAIR MITCHELL: All right. And we will -- we are still with Duke. Do you all need a brief recess to change out your witnesses?

MR. ROBINSON: Yes, Chair Mitchell. That would be nice. Thank you.

CHAIR MITCHELL: Okay.

MR. SOMERS: Chair Mitchell, if I may, this is Bo Somers. I have a procedural update that might take some of that time --

CHAIR MITCHELL: Okay.

MR. SOMERS: -- if that's okay.

CHAIR MITCHELL: You may proceed.

MR. SOMERS: Thank you. We had discussed at the beginning of the hearing today about the plan for this panel, including Mr. Schneider, and Mr. Moore on behalf of the Justice Center group of Intervenors that

MS. JAGANNATHAN: Thank you. And, finally, I would ask that the following exhibits which were accepted into evidence in Docket Number E-7, Sub 1214 be identified as designated in the DEC rate case and moved into the record in this proceeding. Those exhibits are the RAP Cost Allocation Manual which was prefiled in the DEC case as Public Staff 41 and which was introduced in the DEC case as Public Staff Pirro/Hager Cross Examination Exhibit 1. And the second exhibit is the Report of the Public Staff on the Minimum System Methodology of North Carolina Electric Public Utilities, Docket Number E-100, Sub 162 filed on March 28, 2019. This was prefiled in DEC as DEC Exhibit 32 and was introduced during the hearing as Hager DEC Redirect Exhibit 1.

COMMISSIONER CLODFELTER: All right. Any objection to the motion? If not, it will be so ordered.

(WHEREUPON, Public Staff Pirro/Hager Cross Examination Exhibit 1 and Hager DEC Redirect Exhibit 1 was marked for identification as prefiled and received into evidence.)

MS. JAGANNATHAN: Thank you, Commissioner Clodfelter. The panel is ready for cross examination.

COMMISSIONER CLODFELTER: All right. Public Staff. Ms. Edmondson.

MS. EDMONDSON: Good morning. I'm Lucy Edmondson with the Public Staff and I have a few questions for Mr. Pirro.

CROSS EXAMINATION BY MS. EDMONDSON:

Q It's good to see you again.

A (Mr. Pirro) You, too. Good morning.

Q All right. I'm still a little confused on what exhibit number I'm going to designate. But, Mr. Pirro, you're familiar with the settlement between Duke Energy Progress and CIGFUR II?

A (Mr. Pirro) I am.

MS. EDMONDSON: So I would like to mark Public Staff Exhibit 89, and it has a page number 2749 at the bottom of the first page.

COMMISSIONER CLODFELTER: All right. Ms. Edmondson, give the page number again, please.

MS. EDMONDSON: 2749.

COMMISSIONER CLODFELTER: Let me ask was this used as an exhibit in the DEC proceeding?

MS. EDMONDSON: No. This is the DEP and

CIGFUR II settlement so it's specific just to this case.

COMMISSIONER CLODFELTER: Then we will mark this Hager/Pirro/Huber Public Staff Cross Examination Exhibit 1.

(WHEREUPON, Hager/Pirro/Huber Public Staff Cross Examination Exhibit 1 is marked for identification.)

COMMISSIONER CLODFELTER: Okay. All of you hawks out there watching me, did I get that one right?

MR. NEAL: I'm sorry. I believe it would be 2.

COMMISSIONER CLODFELTER: Ms. Edmondson indicated that there was no Public Staff -- this was not used as a cross examination exhibit in the DEC case.

MR. MERTZ: Commissioner Clodfelter, this is Derrick Mertz with Commission Staff.

COMMISSIONER CLODFELTER: Correct me.

MR. MERTZ: That is true that she stated that, but previously moved in was Public Staff Pirro/Hager Cross Examination Exhibit 1 from the DEC case so this would be number 2.

COMMISSIONER CLODFELTER: That was Public Staff Exhibit Number 1 from the DEC case? All right. Then this will be Hager/Pirro/Huber Public Staff Cross Examination Exhibit Number 2.

(WHEREUPON, previously marked Hager/Pirro/Huber Public Staff Cross Examination Exhibit 1 previously identified is renamed to Hager/Pirro/Huber Public Staff Cross Examination Exhibit Number 2.)

MS. EDMONDSON: Okay. Thank you.

Q All right. Mr. Pirro, Hager/Pirro/Huber Cross Examination Exhibit -- Public Staff Exhibit Number 2 is the original Settlement Agreement between Duke Energy Progress and CIGFUR, correct?

A That is correct.

Q (Mr. Pirro) And if we could look at pages 5 and 6, and those have 2755 at the bottom and 2756?

A Yep, I'm there. Thank you.

Q In section V, or Roman Numeral V.E., the Company has agreed to explore certain rates or to file rate schedules in the next rate case, depending on whether there's a comprehensive rate design process?

A Yes, that is correct.

Q And one of these rates is an emergency demand response program similar to Southern California Edison's Time-of-Use Base Interruptible Program.

A Yes, that's what it states. Yes.

Q And another is a rate schedule similar to the Northern Indiana PSC Interruptible Industrial Service Rider?

A That is correct.

Q Are both of these rates types of demand response?

A I'm sorry. Could you repeat that again?

Q Sure. Are both of these rates types of demand response?

A Yes, they are.

Q And would they shift the timing of electricity used from peak to non-peak demand periods? I can't -- you're --

A Sorry. Ms. Edmondson, at this time the Company hasn't evaluated those specific rates that you're referring to. The Company has just agreed to have those be included as part of the overall comprehensive rate design review process. So I can't speak to shifting right now.

Q Okay. Are you going to be looking at these as part of what would be covered in base rates or would these be part of the DSM program?
A I would ask Mr. Huber to possibly provide some color to this topic. But I would say that whatever path it goes down during this review process, whether it's base rates or separate DSM-type programs.
Q If Mr. Huber wants to address that.
A (Mr. Huber) Sure. Yeah, I would agree. I don't think we want to predetermine a pathway at this point just yet.
Q So is the comprehensive rate design study going to examine DSM programs for the portfolio as well as base rate programs?
A So I think it's really the interaction between the two so I don't think we can just sort of ignore the DSM portfolio. And so I think what we'd be looking for is some synergies between the two of merging rate design with, you know, smart devices such as smart thermostats and seeing hey, is they're a 1+1=3 type of synergy between the rate design and some of these new devices that are coming out.

Q Are you familiar with the Commission's ruling in Duke Energy Carolinas Save-A-Watt Docket where the Commission kept the existing industrial interruptible programs' Riders IS and IG in base rates but closed them in the new participation and then put the new industrial interruptible program Power Share in the DSM portfolio?

A (Mr. Pirro) I mean, yeah, Ms. Edmondson, I'm familiar with that. That's correct.

Q All right. Do you know development of interruptible rates like these if they're put in the DSM portfolio could help reduce the number of industrial customers that opt-out of the DSM Rider?

A (Mr. Huber) Yes, you know, I can maybe start on that one. I'm not sure. I think that's why we need to convene stakeholders to say hey is this something that calms some of the concerns of participating and being subject to the DSM Rider.

Q All right. And this could help address the winter, the need for winter capacity?

A Yeah, that's the hope. And I think as I mentioned the last time I testified, we are undergoing a pretty in-depth study on winter peak solutions that include both DSM and rate design. Those results should be coming out very soon. I'm actually presenting I think tomorrow to the DSM collaborative on initial results. So there is hope there that we can create some innovative solutions that reduce winter peak.

MS. EDMONDSON: Okay. That's all I have. Thank you.

(Pause)

COMMISSIONER CLODFELTER: Sorry. My space bar is not working today. Mr. Jenkins, I think you're next.

MR. JENKINS: Thank you, sir.

CROSS EXAMINATION BY MR. JENKINS:

Q Good morning, panel. Alan Jenkins for the Commercial Group.

Mr. Pirro, I think these questions might be for you. I'll direct you to page 5 of the joint supplemental rebuttal testimony. And if you can look at your first Q and A where you address SGS TOU rate design. Let me know when you're there.

A (Mr. Pirro) Mr. Jenkins, you said second agreement and stipulation of partial settlement?

Q That's -- no, your joint supplemental rebuttal testimony?
A Okay. I have that in front of me.
Q Page 5 at the first Q and A where you address SGS TOU rate design.
A Yes, sir.
Q Now, you state there that SGS TOU energy charges at cost would be about 3.8 cents per kWh; is that right?
A That is correct.
Q And you compare that then with higher current SGS TOU energy charges of about 5.9 cents per kWh on peak and 4.6 cents per kWh off peak. Now my question is isn't it true that under the Commercial Group settlement with DEP that SGS TOU energy charges would still be increased further?
A Yes, there would be a slight movement upward. That is correct.
Q The energy charge increase would simply be limited to half the overall percentage increase that SGS TOU overall is allocated, correct?
A That is correct.
Q And would you agree then that this is gradual move toward cost?

A Yes, absolutely. You know, looking at the unit cost and balancing the components of customer demand and energy, this would fall in a small gradual movement toward costs.

Q Thank you. And such a gradual move could remove -- could reduce subsidies by one set of SGS TOU ratepayers to another?

A Sure. With any movement, you know, you would either eliminate or create subsidies, but that is correct.

Q Now, I notice in the settlement DEP made with Staff, the second settlement, that there's a whole section on rate design. Wouldn't you agree that this settlement with Staff would move class rates over a turn toward parity?

A Yes. You know, over the past several years we've taken a gradual approach moving rate classes closer to retail average rate parity. We're very sensitive to those movements and this would be a step towards that.

Q And at the stated goal in this settlement for this provision was to minimize subsidization among customer classes, right?

A Yes. We always consider subsidization and we try to eliminate that or mitigate that as much as possible.

Q Would you agree that neither the modest move toward cost DEP agreed to in its second Staff settlement or its Commercial Group settlement would constrain the ability to conduct future comprehensive rate design?

A That is correct. The rates that the Company are proposing in this case are just for this case only until the Company files another rate case. You know, the Company considers this comprehensive rate study as a clean slate to look at not only current rate offerings and, you know, the intricacies within the schedules but also at new product offerings.

Q Thank you. Nothing further.

COMMISSIONER CLODFELTER: Thank you, Mr. Jenkins. Ms. Cress, I have you next.

MS. CRESS: Commissioner Clodfelter, I don't believe that I had reserved cross for this panel. I may have some questions on Commission questions, but I don't have any cross at this time.

COMMISSIONER CLODFELTER: Then we'll move next to Mr. Page.

MR. PAGE: Thank you.

COMMISSIONER CLODFELTER: Mr. Page, you're on mute.

(Pause)

You're on now.

MR. PAGE: All right, good.

CROSS EXAMINATION BY MR. PAGE:

Q By my clock on the wall it's a minute past noon so I'll bid you a good afternoon. No response so I --

A (Mr. Pirro) Good afternoon.

Q I do want to say the questions I have are primarily for Ms. Hager. But I want to assure Mr. Pirro and Mr. Huber that if they have anything to add to the responses please feel free to do so.

So with that, good afternoon, Ms. Hager.

A (Ms. Hager) Good afternoon, Mr. Page.

Q You will recall when you and I were last exchanging questions and answers that I asked you a variety of questions involving cost-of-service studies which is your area of expertise, is it not?

A That's correct.
Q And among other things that we talked about, we discussed the fundamental engineering, accounting, and economic principles that are involved in performing a proper cost-of-service study, did we not?
A That's correct.
Q In your opinion, is it proper to structure a cost-of-service study where the parameters given in advance for the study will essentially drive and determine the outcome of the study?
A You may have to repeat that question. I'm not sure exactly where you were from.
Q I'll try to simplify it because I do get tied up in my legalese from time to time, most of the time. Is it a proper use of the cost-of-service study, in your opinion, to engage in a study where the outcome is essentially predetermined by the parameters that you put on the study?
A By the parameters that you put where?
Q On the study.
A Let me answer it this way. I don't think it should ever be predetermined what the outcome is. I do believe you do cost of service within

certain parameters. But it basically is about determining what customers caused what costs and -- on the electric system and make that free of biases, you're not trying to implement public policy, you're just trying to get down to the nuts and bolts of what costs were caused by what group of customers.

Q So you would agree with me that it would not be a proper use of a cost-of-service study to embark on an exercise whose purpose is simply to reallocate costs from one class of customers to another class of customers; is that correct?

A I would agree with you on that.

Q So in essence you would say you would take the cost-of-service study and you'd start with either the revenue requirement or the costs and then you'd follow those engineering, accounting, and economic principles to derive a result and the result indicates where the cost causation lies; is that correct?

A That's correct.

Q Mr. Pirro and Mr. Huber, do you have anything to add or do you disagree with the answers I have just gotten from Ms. Hager?

A (Mr. Pirro) I concur with Ms. Hager.
A (Mr. Huber) Nothing to add at this time.
Q Thank you, panel.
And, Commissioner Clodfelter, that's all the questions I have of this panel.

COMMISSIONER CLODFELTER: Thank you, Mr. Page. Again, the list I have, Ms. Goldstein, are you with us? I have you up next.

MS. GOLDSTEIN: Yes, sir. Thank you, Commissioner Clodfelter. The majority of my questions are going to be for Mr. Pirro.

CROSS EXAMINATION BY MS. GOLDSTEIN:

Q Good afternoon, Mr. Pirro. How are you?
A (Mr. Pirro) Good afternoon. How are you?
Q Doing well, thanks. To start, have you read or familiarized yourself with Hornwood, Inc's prefiled testimony from April 13th, 2020?
A Yes, I have read it. I haven't looked at it recently, but I'm familiar with that.
Q Okay. And you're aware of the relief that Hornwood, Inc., is requesting in this rate case is it regards -- as it's related to the large general service real-time pricing rate?
A Yes, I am familiar with that.

Q Okay. Thank you.

COMMISSIONER CLODFELTER: Ms. Goldstein, my apologies for interrupting you but I don't have your video showing on my screen. Do you have your video turned off?

MS. GOLDSTEIN: Apologies. Yes, sir. I'm sorry.

COMMISSIONER CLODFELTER: Thank you.

Q So, Mr. Pirro, is it correct that Hornwood, Inc., as you understand it, is requesting to eliminate the cap of 85 customers that can participate on RTP and reduce the kW requirement from 1000 to 75?

A Yes, I am familiar with that request.

Q Okay. Thank you. And can describe your understanding of the RTP rate as it's administered in DEP?

A Sure. Good question. And, more importantly, I think in order to provide a little color on the history of LGS RTP, in Docket E-2, Sub 704, this was back in December of '96, the Company offered an experimental LGS, large general service, that's with demands greater than 1000 kW to see how customers would respond to day-ahead hourly pricing. Would customers be able to shift their operations and take advantage of, say, lower cost power during certain hours or also perhaps not run when prices are high.

The Commission approved this first tariff back in 1997. Again, it had 25 customers. The RTP is managed by an EPO software. It's called Energy Profiler Online. Customers have to be sophisticated to be able to plan their operations and respond to price signals. In December of 1998, the Commission approved an increase to 85 customers.

Q Okay. Thank you. Do you know, Mr. Pirro, at this time why RTP is still limited to 85 customers?

A Sure. I mean, RTP is a very complex rate. It's -- to me, it's for large users who have, first of all, the ability to respond to price signals. It takes, you know, Company personnel to manage this program. And, you know, with the onset of customer connect coming, we just don't see a need to increase that.

Q Okay. Thank you. You mentioned that this rate was approved in '97, I believe, and then

increased to from a participant cap of 25 - 85 in 1998. As you are aware, this is not an experimental rate at this time, correct?
A That's correct. It was a standard offering back in 1997. It was Commission approved in 1997.
Q Okay. And it would appear that it's still a standard approved rate at this time as well, nonexperimental?
A That is correct.
Q Okay. Is it common to have a participant cap on an experimental rate to your knowledge?
A Well, I --
Q A nonexperimental rate, excuse me.
A Yep. This is nonexperimental. And we have a similar cap in the DEC North Carolina on the hourly pricing program. And we still have a lot of open spots per se on the DEC North Carolina site.
There's risk that comes with early pricing. You know, prices aren't always level. There's hours throughout the day that prices spike. And this type of rate is not for every one. Especially in my view, in being in the industry for 30 years, especially not for small

general service-type customers.
Q Okay. The customers in our -- they have the ability to shift their load and respond to price signals, are they receiving preferential pricing then?
A No. I wouldn't classify it as preferential pricing at all. They're responding to price signals. That's -- like I mentioned, there's risks with that. If they don't respond, they will be paying more during certain hours.
Q Okay. So they are -- customers who are able to shift, they're rewarded financially?
A Customers who are able to respond to price signals, day-ahead price signals, are able to reduce exposure to higher prices and modify their operations accordingly.
Q Okay. And, conversely, the customers who are not able to shift are not going to receive those financial benefits, correct?
A Customers that are not on LGS or the general service RTP are not receiving day-ahead prices; that is correct.
Q Okay. And do you agree that DEP as well is receiving a benefit when customers are able to

shift their load during those high-price times?
A I'm sorry. Could you repeat that question?
Q Would you agree that DEP is receiving a benefit when these customers are able to shift their load during the high-price times?
A If customers are responding to price signals then that is a benefit to the system.
Q Okay. Thank you. So going back to the administration of the rate. It's been as we discussed in use for 23 years. In this -- do you know what kind of a meter is required to take service on RTP?
A The Company's transitioning as we all know the smart meter technology and I believe the plan is to include these in that functionality, but they use an EPO software process. The specific meter that the customers have, currently I don't know offhand.
Q Okay. The meter that's being used, it's safe to assume though it was around 23 years ago, it's been able to be administered for that amount of time with the metering technology that's in place, correct?
A Yeah, the part about managing this program really

doesn't -- I'm not referring to the meter, I'm referring more to the creation of a customer base line load, calendar mapping that would reflect the customers' operation. These participants require much more attention than a standard tariff customer. And it would be extremely difficult to manage a large population of greater than 85 at this time.

Q Okay, sir. Is DEP charging an administrative fee to administer the RTP rate specific to customers who are participating on that?

A That is correct.

Q And what do the administrative fees -- what exactly does that cover?

A The items that I just mentioned.

Q Okay. So would you agree then that if the participation cap was eliminated and more customers went on that DEP would receive the administrative fee to cover their cost for the added customers?

A The administrative fee is part of the rate schedule, LGS RTP; however, that's not the issue. The issue is that LGS is for large general service just like DEC's hourly pricing program is for large general service customers. In my opinion, again being in this industry for 30 years, small general and medium service customers would not respond to day-ahead hourly prices. It just doesn't fit into their type of large commercial industrial operations. It's not similar business operations.

Q Okay. Let's say, for example, that is the case and we're only talking about customers that are 1000 kW. One, just eliminating the cap of 85 for everybody a 1000 and above work?

A I think, Ms. Goldstein, that this could be a topic that could be discussed in a comprehensive rate review. You know, customers on this rate, currently, their general service category falls into the revenue requirement that is allocated to that class. To expand that would just further increase their standard tariff rates across the whole --

Q Okay. This -- staying along the lines of if we just eliminated the cap and kept the kW requirement a 1000 and above, wouldn't -- if the customers are only receiving a financial benefit for electricity used above or below the CBO, correct?

A Yeah, Ms. Goldstein, we don't have customers more than 85 of that greater than a 1000 kW requesting service on the LGS RTP. One or two customers maybe are in the pipeline to receive that. Some customers come, some customers don't. You -- Hornwood is referring to customers in the small/medium general service category.

Q Yes, sir. And I'd like to point out that Hornwood has an account above a 1000. They've got another one lower. But the -- you mentioned before the comprehensive rate study. This rate being administered now for 23 years. What would be further required to study this rate?

A 1996 is well before my time at Duke Energy. But, you know, for my research of the design of this rate, and to, how do I say it, to prompt customer response and participation of that original 25, the design itself may not be appropriate on a grand scale. So that is what I think needs to be reviewed further. And Mr. Huber may have more to add to this topic.

Q Okay. In your testimony, Mr. Pirro, there's discussion of -- there's no dynamic or hourly rates being offered right now and the reason is is that you guys are -- or the Company is studying the DEC pilot rates; is that correct?

A That is correct. Just like DEC North Carolina's current rate case, the Company has kept things for the most part status quo. We did initiate nine pilots approximately close to one year ago. There's a team that's evaluating those pilots and compiling the results and those results will be shared probably early January I believe, if I recall correctly. Those results would transfer and be applicable to the DEP territory but they may require changes. So the Company does not feel that rolling out the same pilots in DEP is prudent or makes sense at this time.

Q Understood. And those DEC rates, they do not go above 75-kW, correct? So they wouldn't translate anyway to the relief that Hornwood is requesting; is that correct?

A I'm not familiar with all of Hornwood's demand levels, but the current pilot, that is correct, and that's why per the evaluation and discussion and within the comprehensive rate review study is appropriate.

Q Okay. Mr. Pirro, you mentioned you don't have a long -- I don't remember the exact wording, but there's not a long line of customers. How do you notify your customers when a RTP spot is available? Do you maintain a queue of these waiting customers?

A Yes. The large general service customers are assigned accounts or they have account managers assigned to them and they're in constant communication of those types of issues.

Q And is that large account manager instructed to advise customers that are waiting on the RTP queue list that there is a spot available?

A Not only does the Company do an annual rate review for all of its customers, because I know there's rate consultants out there that also go and try to secure customers and find rate relief and share that savings 50/50, the Company does that proactively. They on an annual basis review customer bills, what rates they're on, and if there's a more attractive or cheaper, quote, rate schedule to be on, they notify the customers. As far as the account managers, I don't want to speak directly for that team but that is my

understanding.
Q Okay. So, Mr. Pirro, there is a queue that is kept, a list of customers that are waiting to go on the RTP rate; is that correct?
A Again, I don't specifically have a list but I know in speaking to the large account management team that they're aware of customers that have expressed interest.
Q Okay. And just a couple more questions, Mr. Pirro. There's been some discussion about various industry loss in North Carolina. Are you familiar with the JRR, the Job Retention Rider, or the Industrial Economic Rider, those types of rates -- riders, rather?
A I was very familiar with the Job Retention Rider.
Q Okay. And the purpose would you say of these types of rates and riders is to retain businesses, incent businesses and -- to stay in North Carolina?
A Yes, Ms. Goldstein, that is the intent. That was the intent of the Job Retention Rider. And, you know, looking at the results of the participation levels, customers did not take advantage of the Job Retention Rider.

Q Okay. The RTP rate, would you agree, opening that up to or just eliminating the cap of 85 would incent businesses, the businesses at least that can shift load and curtail during the high-price signals?

A The current LGS RTP rate, no. I think there would be bigger issues opening that up. We're talking about population within the small/medium general service of 45,000 customers, and that would -- the way the rate is designed currently would not be applicable to that mass scale.

Q Okay. For a 1000 kW and above, would it, the same question apply?

A For a 1000 kW -- I'm not sure I recall what the question was. But if you're just asking to expand that cap, I would say that if the Commission ordered us to expand the cap then obviously we would agree to that. But at the current state, I'm going to go back to what I mentioned earlier, there is a lot of front-end work that goes with administering our program. And if you're not on an LGS RTP rate, you can't understand the work that goes into that.

Q Isn't the administrative fee there to cover that extra work that goes into it for DEP to offer this rate?

A There is a fee that's part of the rate schedule. We're talking about full-time employees. If this went to mass scale there would be -- I haven't even looked at that, but there would obviously be more full-time employees that would be required to administer that type of program.

Q Okay. And we're kind of back to my original question just a few minutes ago. I don't think it was entirely clear. If the cap was eliminated for just a 1000 kW and above, do you agree that would help industry, the large general service RTP customers stay, or would it help North Carolina retain these businesses, the ones that at least can curtail during those high-price signals?

A They're -- if more customers were on LGS RTP and they were able to respond to day-ahead price signals and reduce their electric power costs, that would be one component of their operations to stay in business. And the utility -- the only pricing they have as part of their rate.

Q And then the customers who are not able to --

(Interruption by the court reporter)

COMMISSIONER CLODFELTER: Ms. Goldstein, hold a second. Ms. Mitchell.

COURT REPORTER: I would like for Mr. Pirro to at least repeat the end of his answer. There's a lot of static going on when, I think, Ms. Goldstein is not muted.

COMMISSIONER CLODFELTER: Mr. Pirro, can you remember the question and repeat your answer.

A Sure. I think I was at the part when I said if customers are able to respond to price signals, day-ahead price signals and shift their operations to reduce their exposure to electric power cost, that would only be one part of a business expenses that they have and would not necessarily mean that they would remain in business just being on RTP rate.

Q Okay. Understood. And the customers, Mr. Pirro, who are not able to shift and say they are taking service on RTP, isn't DEP recovering their costs because these customers are taking service on much higher rates when they're not able to shift the load?

A When customers do not respond to price signals, and prices are high, customers are paying that price in that actual hour.
Q Okay. Thank you.
A And with that said that's where the risk lies. And, for me, the non-large customers really do not have that ability to fluctuate their business operations like a large general service customers do. Again, that's --
Q Well, in that case wouldn't it be up to the customer to decide if they want to take service on LGS RTP, or RTP?
A Yes, absolutely.
Q Okay. Just a few more questions. I don't want to belabor the point. As it stands now without the metering technology that's being deployed, RTP is able to be administered with the current technology by DEP, correct?
A RTP is currently administered with its current technology and manpower to administer the program.
Q Okay. Thank you, Mr. Pirro. That ends my questioning.
A Thank you, Ms. Goldstein.

COMMISSIONER CLODFELTER: Mr. Neal, we normally break at about 12:30 for lunch. Could you, if we went a little bit, could we get us done or should be go ahead and break.

MR. NEAL: I'd hate to make a promise, Commissioner Clodfelter. Maybe we should go ahead and break for lunch.

COMMISSIONER CLODFELTER: I don't want you to break a promise. So we will go ahead and break for lunch. And we will resume back on the record at 12:30.

Mr. Pirro, we were getting some low grade echoing throughout your testimony. Most of it was intelligible but we were tending to get some fuzz around you. I'm not sure whether that was interaction with Ms. Goldstein or if there was some other cause, but if you could check on that during the lunch break that would help us when we come back. And we will be back on the -- we will be back on the record at 1:30.

(The proceedings were adjourned at 12:30 p.m. and set to convene at 1:30 p.m. on September 29, 2020.)

C E R T I F I C A T E

I, KIM T. MITCHELL, DO HEREBY CERTIFY that the Proceedings in the above-captioned matter were taken before me, that I did report in stenographic shorthand the Proceedings set forth herein, and the foregoing pages are a true and correct transcription to the best of my ability.

Kim T. Mitchell

Kim T. Mitchell
Court Reporter