PLACE: Held via Videoconference

DATE: Thursday, October 1, 2020

TIME: 1:40 P.M. - 4:28 P.M.

DOCKET NO.: E-2, Sub 1219

E-2, Sub 1193

BEFORE: Commissioner Daniel G. Clodfelter, Presiding

Chair Charlotte A. Mitchell

Commissioner ToNola D. Brown-Bland

Commissioner Lyons Gray

Commissioner Kimberly W. Duffley

Commissioner Jeffrey A. Hughes

Commissioner Floyd B. McKissick, Jr.

IN THE MATTER OF:

DOCKET NO. E-2, SUB 1219

Application by Duke Energy Progress, LLC,

for Adjustment of Rates and Charges Applicable to

Electric Utility Service in North Carolina

and

Noteworthy
Reporting Services, LLC

DOCKET NO. E-2, SUB 1193

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

VOLUME 16

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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 H I B I T S

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Lucas/Maness Public Staff .... Redirect Exhibit Number 2	- /19
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P R O C E E D I N G S

COMMISSIONER CLODFELTER: We are back. And I believe we are at the point of Commissioners' questions to the Lucas and Maness panel. And actually, we're not all back. Opening questioner is not here. We'll get her here. Commissioner Gray -- oh, there she is. Commissioner Brown-Bland, we'll throw you right in.

COMMISSIONER BROWN-BLAND: I have no questions. Thank you.

COMMISSIONER CLODFELTER: Okay. Commissioner Gray?

COMMISSIONER GRAY: No questions. Thank you.

COMMISSIONER CLODFELTER: All right. Chair Mitchell?

CHAIR MITCHELL: No questions.

COMMISSIONER CLODFELTER: All right. Commission Duffley?

COMMISSIONER DUFFLEY: No questions.

COMMISSIONER CLODFELTER: Commissioner Hughes? Commissioner Hughes, I couldn't hear you.

COMMISSIONER HUGHES: No questions.

COMMISSIONER CLODFELTER: Okay.

Commissioner McKissick?

COMMISSIONER McKISSICK: No questions.

COMMISSIONER CLODFELTER: And I have no questions, so I believe we will take motions at this point.

MS. LUHR: Commission Clodfelter, the Public Staff would move that the exhibits attached to the prefiled direct testimony and supplemental testimony of Mr. Lucas be entered into the record and marked for identification as premarked.

COMMISSIONER CLODFELTER: All right. Without objection, motion is allowed.

(Public Staff Lucas Exhibits 1 through 24, Corrected Public Staff Lucas Exhibit 18, and Updated Public Staff Lucas Exhibit 19, were admitted into evidence.)

MR. GRANTMYRE: Excuse me. bill Grantmyre. Commissioner Clodfelter, the Public Staff would move that the exhibits attached to the supplemental testimony of -- second supplemental testimony of Mr. Maness be entered into the record and marked for identification as premarked.

COMMISSIONER CLODFELTER: Do you mean moved into the record? They've been identified, so you're moving them into the record as evidence, correct?

MR. GRANTMYRE: Yes, please.

COMMISSIONER CLODFELTER: All right. That motion is, without objection, motion is granted.

(Public Staff Maness Second Supplemental Exhibits 1 and 2 was admitted into evidence.)

MR. GRANTMYRE: Thank you. I have another request. We would request that the Public Staff have permission to file in this Sub 1219, the Public Staff late-filed Exhibit Number 1, which was filed on September 28, 2020, in the Duke Carolinas case Sub 1214. This is the late-filed exhibit requested by Commissioner McKissick for clarity regarding the standard of culpability. And it really relates to both cases. And it was filed as a late-filed exhibit for Duke Carolinas, and we feel that it should also be a late-filed exhibit in this case.

COMMISSIONER CLODFELTER: All right.

MR. MEHTA: Commissioner Clodfelter?

COMMISSIONER CLODFELTER: Yes, Mr. Mehta.

MR. MEHTA: The Company has no objection to that. The Company is planning to file, as I believe Commissioner McKissick requested, a response to that in the DEC case, and we'll just file the same response in both cases.

COMMISSIONER CLODFELTER: That's acceptable.

Any other party have anything to say about Mr. Grantmyre's motion?

(No response.)

COMMISSIONER CLODFELTER: If not, Mr. Grantmyre, your motion is granted. And, Mr. Mehta, you need not make a motion to file a reply. You may reply as well, and that will be made part of the record here.

MR. GRANTMYRE: Thank you.

MR. MEHTA: Thank you, Commissioner Clodfelter.

COMMISSIONER CLODFELTER: Yes, indeed. Are we done with the panel?

MS. LUHR: Commissioner Clodfelter, one

more motion. I would also move that Public Staff Lucas/Maness Redirect Exhibit Number 2 be entered into the record as marked during the proceeding.

COMMISSIONER CLODFELTER: Thank you for that. I have it in my notes but had not looked at it. So without objection, that motion is also allowed.

(Lucas/Maness Public Staff Redirect Exhibit Number 2 was admitted into evidence.)

MS. LUHR: Thank you. And at this time, I would ask that Mr. Lucas be excused.

COMMISSIONER CLODFELTER: All right. Mr. Lucas -- unless there's objection, Mr. Lucas, you may be excused.

Ms. Luhr, let me also see if you want to take care of this now. Later on we have Mr. Maness reappearing as an individual witness, and you have pending -- or you had pending a motion to excuse him as an individual witness. We had held or denied that motion, I believe, at the time because a couple of the Commissioners had potential questions for Mr. Maness. I have been advised over the lunch break that none of the Commissioners have questions for Mr. Maness as an individual witness, and I believe cross examination of Mr. Maness had been waived by all other parties as recited in your original motion.

If I've gotten that correct, then we would be prepared at this time also, if you want to renew the motion, we'd be prepared to excuse Mr. Maness as an individual witness as well.

MS. HOLT: Commissioner Clodfelter.

COMMISSIONER CLODFELTER: I'm sorry, Ms. Holt, you're taking care of Mr. Maness as an individual witness.

MS. HOLT: That's right.

COMMISSIONER CLODFELTER: You were not on the screen. We were in the middle of things with Ms. Luhr and it was going good. So were you able to hear what I just recited?

MS. HOLT: Yes, I was.

COMMISSIONER CLODFELTER: Okay. Would you like to renew the motion to excuse Mr. Maness as an individual witness?

MS. HOLT: Yes, I would. I move --

COMMISSIONER CLODFELTER: Okay. The motion is -- based on the recitation I just made earlier, and unless, again, we were wrong, some party does have cross examination, speak now.

(No response.)

COMMISSIONER CLODFELTER: All right. Then the motion is allowed and, Mr. Maness, you are also excused. Thank you.

THE WITNESS: (Michael C. Maness) Thank you.

COMMISSIONER CLODFELTER: We took that a little out of order, but I thought it would be good to get that cleaned up at the same time.

MS. DOWNEY: Mr. Clodfelter, Ms. Holt might -- or somebody needs to move the rest of his testimony in, I think.

COMMISSIONER CLODFELTER: That's correct. It was -- his panel testimony only embraced part of his testimony. Let's go ahead -- since we're talking about Mr. Maness, let's just go ahead and get that done now. I know it's out of consequence, but you only got one other witness on deck, so let's go ahead and clean up Mr. Maness now too. Ms. Holt?

MS. HOLT: Thank you. At this time Public Staff moves the admission of Mr. Maness' supplemental testimony supporting his second partial settlement testimony consisting of 14 pages and two exhibits marked. Maness Second Stipulation Exhibits 1 and 2 that were filed on September 16, 2020. We move that this testimony be copied into the record as if given orally from the stand, and that his exhibits be admitted as premarked.

And also Mr. Maness filed a summary of his testimony, and I also move that his summary also be copied into the record as if given orally from the stand.

COMMISSIONER CLODFELTER: Okay. You've heard the motion. Is there any objection?

(No response.)

COMMISSIONER CLODFELTER: Hearing none, the motion is allowed.

(Maness Second Stipulation Exhibits 1 and 2 were admitted into evidence.)

(Public Staff Maness Stipulation Exhibits 1 through 3 were admitted into evidence.)

(Whereupon, the prefiled testimony in support of partial settlement, testimony supporting second partial stipulation, supplemental testimony supporting second partial settlement, and testimony summary of Michael C. Maness was 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 Utility Service in North Carolina	)))))))	TESTIMONY OF MICHAEL C. MANESS PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION IN SUPPORT OF PARTIAL SETTLEMENT

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1219

Testimony of Michael C. Maness in Support of Partial Settlement

On Behalf of the Public Staff

North Carolina Utilities Commission

June 5, 2020

Q. MR. MANESS, WHAT IS THE PURPOSE OF YOUR SETTLEMENT TESTIMONY IN THIS PROCEEDING?

A. The purpose of my settlement testimony is to (1) support the Agreement and Stipulation of Partial Settlement (Stipulation) between Duke Energy Progress, LLC (DEP or the Company), and the Public Staff (Stipulating Parties), filed on June 2, 2020; and (2) make corrections to amounts reported in Public Staff supplemental testimony.

On May 4, 2020, DEP filed rebuttal testimony and exhibits supporting a $41,699,000 decrease in its request for additional North Carolina retail revenue, for a total supported proposed increase of $544,262,000. I have included the Company's change in revenue requirement as reflected in its rebuttal filing in Maness Stipulation Exhibits 1 and 3.

Q. WHAT UPDATED REVENUE INCREASE IS THE PUBLIC STAFF RECOMMENDING?

A. Based on the level of rate base, revenue, and expenses annualized at December 31, 2018, with certain updates, the Public Staff is recommending an increase in annual base rate operating revenue of $161,082,000, reduced by rider amounts totaling $(234,434,000) during the first year after the effective date of the rate change approved in this proceeding, and $(93,565,000) in the second through fifth years.

Q. PLEASE GIVE A MORE DETAILED DESCRIPTION OF THE ORGANIZATION OF YOUR STIPULATION EXHIBITS.

A. Schedule 1 of Maness Stipulation Exhibit 1 presents a reconciliation of the difference between the Company's requested increase of $544,262,000 and the Public Staff's recommended increase of $161,082,000, including all adjustments included in the Stipulation. The schedule also presents the revenue requirement effect of the various riders recommended by the Public Staff.

Schedule 2 presents the Public Staff's adjusted North Carolina retail original cost rate base. The adjustments made to the Company's proposed level of rate base are summarized on Schedule 2-1 and are detailed on backup schedules.

Schedule 3 presents a statement of net operating income for return under present rates as adjusted by the Public Staff. Schedule 3-1 summarizes the Public Staff's adjustments, which are detailed on backup schedules.

Schedule 4 presents the calculation of required net operating income, based on the rate base and cost of capital recommended by the Public Staff.

Schedule 5 presents the calculation of the required increase in operating revenue necessary to achieve the required net operating income. This revenue increase is equal to the Public Staff's recommended increase shown on Line 44 of Schedule 1.

Maness Stipulation Exhibit 2 sets forth the calculation of the annual excess deferred income taxes (EDIT) Rider to be in effect for five years for all unprotected EDIT, the calculation of a one-year Rider to refund provisional taxes, and the calculation of a one-year Rider to refund the recent decrease in state taxes. The calculations on this Exhibit are largely unchanged from those in the previously filed Dorgan Supplemental Exhibit 2.

Maness Stipulation Exhibit 3 sets forth the calculation of the difference in allocation methodologies from the Company-filed Summer CP (SCP) study to Summer Winter Peak & Average

(SWPA) study based on the recommendation of Public Staff witness McLawhorn.

The pre-settlement adjustments set forth in these Exhibits are as recommended by Public Staff witness Dorgan. My Settlement Testimony supports the corrections described below and the agreed-upon settlement adjustments set forth in the Stipulation.

Q. WHAT ADJUSTMENTS DID THE PUBLIC STAFF MAKE TO THE EXHIBITS?

A. I have incorporated corrections to the calculations of the following adjustments:

1) The update of revenues, customer growth, and weather to reflect the correct number of bills per witness Saillor's Supplemental Testimony.

2) The adjustment to the change in depreciation rates to reflect the removal of the depreciation and amortization for costs recovered in riders to reflect DEP's supplemental adjustment.

3) The adjustment to remove storm deferral to correct the storm assets removed to reflect the DEP assets as of February 29, 2020.

4) The adjustment to the W. Asheville Vanderbilt 115kV Project to include the Company's supplemental adjustment.

Q. DID THE PUBLIC STAFF MAKE ANY OTHER ADJUSTMENTS?

A. I have aligned Maness Stipulation Exhibits 1 and 3 to reflect the Company's rebuttal testimony as a starting point for the Public Staff's adjustments.

Q. PLEASE BRIEFLY DESCRIBE THE STIPULATION.

A. The Stipulation sets forth agreement between the Stipulating Parties regarding the following revenue requirement issues:

(1) The debt cost rate
(2) Credit card fees
(3) Protected federal excess deferred income taxes (EDIT) due to the Tax Cuts and Jobs Act
(4) Aviation expenses
(5) Executive compensation
(6) Salaries and wages expense
(7) Outside services
(8) Rate case expense
(9) Storm expense
(10) Storm deferral
(11) Severance
(12) Incentives
(13) Asheville CC plant in service
(14) Asheville CC deferral
(15) W. Asheville Vanderbilt 115kV project
(16) Asheville production displacement
(17) Coal inventory
(18) End-of-life nuclear materials and supplies reserve
(19) Sponsorships and contributions

(20) Lobbying expense
(21) Board of Directors expense
(22) Inflation to February 29, 2020
(23) CertainTeed

The details of the agreements in these areas are set forth in the Stipulation.

Q. WHAT BENEFITS DOES THE STIPULATION PROVIDE FOR RATEPAYERS?

A. From the perspective of the Public Staff, the most important benefits provided by the Stipulation are as follows:

(a) An aggregate reduction in the increase of the specific expense items listed above requested in the Company's application, resulting from the adjustments agreed to by the Stipulating Parties.

(b) The avoidance of protracted litigation between the Stipulating Parties before the Commission and possibly the appellate courts.

Based on these ratepayer benefits, as well as the other provisions of the Stipulation, the Public Staff believes the Stipulation is in the public interest and should be approved.

Q. WOULD YOU BRIEFLY DESCRIBE THE PUBLIC STAFF'S PRESENTATION OF THE REVENUE REQUIREMENT ASPECTS OF THE STIPULATION?

A. Yes. The attached Maness Stipulation Exhibit 1 sets forth the accounting and ratemaking adjustments to which DEP and the Public Staff have agreed. Maness Stipulation Exhibits 1, 2, and 3 start from the Company's rebuttal position and flow the stipulated adjustments through to calculate a revenue requirement. I note that not until the Commission makes a determination regarding the yet unresolved issues (including, but not limited to, rate of return, cost of capital, allocation methodologies, revenues and customer growth, federal income taxes, and coal ash disposal costs) can the settled accounting and ratemaking adjustments be finalized, and the resulting rate base, net operating income, return, and rate increase be calculated.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

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 Utility Service in North Carolina	)))))))	TESTIMONY OF MICHAEL C. MANESS PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION SUPPORTING SECOND PARTIAL STIPULATION

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1219

Testimony of Michael C. Maness Supporting Second Partial Stipulation

On Behalf of the Public Staff

North Carolina Utilities Commission

July 31, 2020

Q. MR. MANESS, WHAT IS THE PURPOSE OF YOUR TESTIMONY IN SUPPORT OF THE SECOND PARTIAL STIPULATION IN THIS PROCEEDING?

A. The purpose of my testimony is to support the Second Agreement and Stipulation of Partial Settlement (Second Partial Stipulation) filed on July 31, 2020 between Duke Energy Progress, LLC (DEP or the Company) and the Public Staff (Stipulating Parties) regarding certain issues related to the Company's pending application for a general rate increase.

Q. PLEASE BRIEFLY DESCRIBE THE SECOND PARTIAL STIPULATION.

A. The Second Partial Stipulation sets forth agreement between the Stipulating Parties regarding the following revenue requirement and rate issues:

(1) Return on Equity, Capital Structure, and Debt Cost.
(2) Update of revenues, rate base, and expenses to May 31, 2020 (subject to further Public Staff investigation).
(3) Return of unprotected federal excess deferred income taxes (EDIT) due to the Tax Cuts and Jobs Act to customers.
(4) Return of North Carolina state EDIT due to reduction in state tax rates.
(5) Treatment of federal deferred revenue due to the Tax Cuts and Jobs Act.
(6) Amortization period for Non-Asset Retirement Obligation (ARO) coal ash costs.
(7) The Company's Grid Improvement Plan (GIP) (revenue requirement effects only in future cases).
(8) Cost of service allocation methodology.
(9) Rate design.
(10) Nuclear Decommissioning annual funding.
(11) The process to be used to determine the base fuel factor in this proceeding.

In addition to the settled issues having a revenue requirement impact in the present case, the Second Partial Stipulation also settles non-revenue requirement issues involving additional cost of service studies, a rate design study, affordability, and audit and reporting obligations.

The details of the agreements in these areas are set forth in the Second Partial Stipulation.

Q. WHAT BENEFITS DOES THE SECOND PARTIAL STIPULATION PROVIDE FOR RATEPAYERS?

A. From the perspective of the Public Staff, the most important benefits provided by the Second Partial Stipulation are as follows:

(a) A significant reduction in the Company's proposed revenue increase in this proceeding; and

(b) The avoidance of protracted litigation between the Stipulating Parties before the Commission and possibly the appellate courts.

Based on these ratepayer benefits, as well as the other provisions of the Second Partial Stipulation, the Public Staff believes the Second Partial Stipulation is in the public interest and should be approved.

Q. ARE THERE ANY AREAS ABOUT WHICH THE STIPULATING PARTIES DID NOT REACH AGREEMENT?

A. Yes. The Stipulating Parties did not reach agreement regarding recovery of ARO-related coal ash costs; depreciation rates, including the Company's proposal to shorten the lives of certain coal-fired generating facilities; and any other revenue requirement or non-revenue requirement issue not specifically addressed in the Stipulations, or agreed upon in the testimony of the Stipulating Parties. The Public Staff fully supports its filed positions on these particular issues, and intends to demonstrate the appropriateness and reasonableness of its positions through litigation in this case.

Q. WILL THE PUBLIC STAFF BE PRESENTING ITS CALCULATION OF THE REVENUE REQUIREMENT INCLUDING THE IMPACTS OF THE SECOND PARTIAL STIPULATION?

A. Yes. Once the Public Staff has completed the audit of all revenue, rate base, and expense updates through May 31, 2020, the Public Staff will file schedules supporting the Public Staff's recommended revenue requirement. I note that it is not until the Commission makes a determination regarding the yet unresolved issues, and the results of the Public Staff's audit, that the settled accounting and ratemaking adjustments can be finalized, and the resulting rate base, net operating income, return, and rate increase be calculated.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1193 In the Matter of 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	))))))	SUPPLEMENTAL TESTIMONY SUPPORTING SECOND PARTIAL SETTLEMENT OF MICHAEL C. MANESS PUBLIC STAFF – 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 Utility Service in North Carolina	))))	

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NOS. E-2, SUBS 1193 AND 1219

SUPPLEMENTAL TESTIMONY SUPPORTING SECOND PARTIAL SETTLEMENT OF MICHAEL C. MANESS ON BEHALF OF THE PUBLIC STAFF NORTH CAROLINA UTILITIES COMMISSION

September 16, 2020

Q. MR. MANESS WHAT TESTIMONY DOES THIS TESTIMONY SUPPLEMENT?

A. This Supplemental Testimony Supporting Second Partial Settlement (Supplemental Second Settlement Testimony) directly supplements my Testimony Supporting Second Partial Stipulation, filed in this proceeding on July 31, 2020. Other previous iterations of this overall revenue requirement testimony, which contain certain explanations of the Public Staff's initial adjustments and subsequent revisions, are as follows:

- Testimony of Shawn L. Dorgan, filed on April 13, 2020.
- Supplemental Testimony of Shawn L. Dorgan, filed on April 23, 2020.
- Testimony in Support of Partial Settlement of Michael C. Maness, filed on June 5, 2020.

Q. ARE YOU FILING ANY EXHIBITS WITH THIS TESTIMONY?

A. Yes. I am filing Maness Second Stipulation Exhibit 1 and Maness Second Stipulation Exhibit 2 with this testimony.

Q. WHAT EXHIBITS DO THESE EXHIBITS REVISE OR SUPPLEMENT?

A. Maness Second Stipulation Exhibits 1 and 2 are revisions of and completely replace Maness Stipulation Exhibits 1 and 2, filed on June 5, 2020, with my Testimony in Support of Partial Settlement.

Q. CAN YOU EXPLAIN THE ABSENCE OF AN EXHIBIT 3 FROM THIS FILING?

A. The Public Staff's adjustment to cost of service allocation factors previously supported by Maness Stipulation Exhibit 3, filed on June 5, 2020, and its previous iterations, is no longer being recommended by the Public Staff. Thus, the June 5 Exhibit 3 and those previous iterations are now moot for purposes of this proceeding, and should no longer be used to determine the Public Staff's recommended revenue requirement.

Q. MR. MANESS, WHAT IS THE PURPOSE OF YOUR SUPPLEMENTAL SECOND SETTLEMENT TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to provide the Public Staff's revised calculation of its recommended revenue requirement in this proceeding, including the impacts of the Second Agreement and Stipulation of Partial Settlement (Second Partial Stipulation) between Duke Energy Progress, LLC (DEP or the Company) and the Public Staff (collectively, the Stipulating Parties), dated July 31, 2020, as well as the Company's May 2020 updates and our adjustments thereto. On July 2, 2020, DEP witness Kim H. Smith filed Second Supplemental Testimony and Exhibits supporting a $147,750,000 decrease in DEP's original request for North Carolina retail revenue, for a total proposed increase of $438,211,000. On July 31, 2020, pursuant to the Second Partial Stipulation, DEP witness Smith filed Second Settlement Testimony and Exhibits (DEP's Second Settlement Testimony) supporting a $177,028,000 decrease in DEP's original request for North Carolina retail revenue, for a total supported proposed increase of $408,933,000.

Also on July 31, 2020, Public Staff witnesses J. Randall Woolridge, James S. Mclawhorn, and I each filed Testimony Supporting Second Partial Stipulation, stating that the Second Partial Stipulation is in the public interest and should be approved. I further testified that once the Public Staff had completed the audit of all revenue, rate base, and expense updates through May 31, 2020, the Public Staff would file schedules supporting the Public Staff's recommended revenue requirement.

On September 4, 2020, the Commission issued an Order (September 4 Order) granting the Public Staff leave to file testimony and exhibits regarding the Company's Second Supplemental Testimony and CCR Testimony.

In accordance with the terms of the Second Partial Stipulation and the Commission's September 4 Order, I intend to (1) present the final results of the Public Staff's evaluation of settled and non-settled accounting and ratemaking adjustments as reflected in DEP's Second Settlement Testimony; (2) recommend additional adjustments as a result of information provided by the Company during the Public Staff's investigation of that testimony; (3) reflect the impact of adjustments and corrections recommended by other Public Staff witnesses; and (4) present the Public Staff's recommended revenue requirement increase.

Q. WHAT UPDATED REVENUE INCREASE IS THE PUBLIC STAFF RECOMMENDING?

A. Based on the level of rate base, revenue, and expenses annualized at December 31, 2018, with certain updates, the Public Staff is recommending an increase in annual base rate operating revenue of $264,978,000.

Q. IS DEP'S SECOND SETTLEMENT TESTIMONY CONSISTENT WITH THE SECOND PARTIAL STIPULATION?

A. Except as described below and in the testimony filed by other Public Staff witnesses, DEP's Second Settlement Testimony is consistent with the Second Partial Stipulation, as well as with the Agreement and Stipulation of Partial Settlement (First Partial Stipulation) between the Company and the Public Staff, filed by DEP in this proceeding on June 2, 2020.

Q. HAVE THE IMPACTS OF SETTLED AND UNSETTLED ISSUES BETWEEN THE COMPANY AND THE PUBLIC STAFF BEEN SATISFACTORILY CARRIED FORWARD INTO DEP'S SECOND SETTLEMENT TESTIMONY?

A. With regard to settled issues, yes, for the most part; however, there are certain instances, as described later in my testimony, in which I have found it appropriate and reasonable to make certain adjustments to carry forward the impact of settled issues fully and accurately, including updating items of revenue and cost to May 31, 2020.

With regard to unsettled issues, while the Company has not carried forward the impact of any Public Staff positions in its filing, other Public Staff witnesses and I are recommending adjustments to do so, and those adjustments are further described herein and reflected in Maness Second Stipulation Exhibit 1.

Q. MR. MANESS, WHAT ADJUSTMENTS TO DEP'S SECOND SETTLEMENT TESTIMONY AND EXHIBITS DO YOU RECOMMEND?

A. I am recommending adjustments in the following areas:

1) Updated Net Plant, Depreciation Expense, and Accumulated Depreciation
2) Update for New Depreciation Rates
3) Update of Revenues and Related Expenses to May 31, 2020
4) Update to Benefits
5) Asheville Production Displacement
6) Operations and Maintenance (O&M) Non-Labor Expense (Inflation)
7) Cash Working Capital under Present Rates
8) Cash Working Capital Effect of Increase

Q. WHAT ADJUSTMENTS RECOMMENDED BY OTHER PUBLIC STAFF WITNESSES DO YOUR EXHIBITS INCORPORATE?

A. My exhibits reflect an adjustment recommended by Public Staff witness Metz regarding project costs included in plant in service, as well as my recommendations regarding ARO and non-ARO environmental costs and reclassification of non-ARO deferred environmental costs.

Q. WOULD YOU BRIEFLY DESCRIBE THE PUBLIC STAFF'S PRESENTATION OF THE REVENUE REQUIREMENT ASPECTS OF THE SECOND PARTIAL STIPULATION?

A. Yes. The attached Maness Second Stipulation Exhibit 1 sets forth the accounting and ratemaking adjustments that other Public Staff witnesses and I are making to the revenue, expenses, rate base, and revenue requirement set forth in DEP's Second Settlement Testimony.

Q. PLEASE GIVE A MORE DETAILED DESCRIPTION OF THE ORGANIZATION OF YOUR EXHIBITS.

A. Schedule 1 of Maness Second Stipulation Exhibit 1 presents a reconciliation of the difference between the Company's requested increase of $408,933,000 and the Public Staff's recommended increase of $264,978,000, including all adjustments included in the First and Second Partial Stipulations except for EDIT Riders.

Schedule 2 presents the Public Staff's adjusted North Carolina retail original cost rate base. The adjustments made to the Company's proposed level of rate base are summarized on Schedule 2-1 and are detailed on backup schedules.

Schedule 3 presents a statement of net operating income for return under present rates as adjusted by the Public Staff. Schedule 3-1 summarizes the Public Staff's adjustments, which are detailed on backup schedules.

Schedule 4 presents the calculation of required net operating income, based on the rate base and cost of capital recommended by the Public Staff.

Schedule 5 presents the calculation of the required decrease in operating revenue necessary to achieve the required net operating income. This revenue increase is equal to the Public Staff's recommended decrease shown at the bottom of Schedule 1.

Maness Second Stipulation Exhibit 2 sets forth the calculation of an annual excess deferred income taxes (EDIT) Rider for all unprotected taxes to be in effect for five years, the calculation of a two-year Rider to refund the provisional taxes, and the calculation of a two-year Rider to refund the recent decrease of state taxes.

Q. PLEASE DESCRIBE YOUR RECOMMENDED ADJUSTMENTS TO DEP'S POSITIONS AS SET FORTH IN ITS SECOND SETTLEMENT TESTIMONY.

A. My adjustments are described below.

UPDATE FOR PLANT AND ACCUMULATED DEPRCIATION

Q. PLEASE EXPLAIN HOW YOU HAVE COMPUTED NET PLANT.

A. My calculation begins with plant, accumulated depreciation, and the resulting net plant, based on the Company's actual per books plant in service and accumulated depreciation amounts as of the update period ending May 31, 2020, which include customer growth-related actual plant additions.

Q. PLEASE EXPLAIN THE DIFFERENCE BETWEEN YOUR AMOUNT OF NET PLANT AND THE COMPANY'S AMOUNT, LEAVING ASIDE FOR THE MOMENT THE PUBLIC STAFF'S ADJUSTMENT TO DEPRECIATION RATES.

A. Both the Company and I have reflected updated net plant for known and actual changes to depreciation expense and non-generation plant retirements that have been recorded between the end of the test year (December 31, 2018) and May 31, 2020. Furthermore, I have included one adjustment recommended by Public Staff witness Metz, which removes costs related to the Company's camera replacement project.

It is my understanding the Company agrees with the total plant in service and accumulated depreciation amounts calculated in Maness Second Stipulation Exhibit 1, Schedules 2-1(a)(1) and 2-1(a)(2), including the adjustments associated with the camera replacement project. However, the Company does not agree with the Public Staff's recommended adjustments to depreciation rates, as discussed below.

UPDATE FOR NEW DEPRECIATION RATES

Q. PLEASE DESCRIBE YOUR ADJUSTMENTS TO DEPRECIATION EXPENSE AND ACCUMULATED DEPRECIATION FOR DIFFERENCES IN RECOMMENDED DEPRECIATION RATES.

A. I have applied the depreciation rates previously recommended by Public Staff witness McCullar to the plant amounts updated through May 31, 2020, as adjusted per the recommendation of Public Staff witness Metz. I have, therefore, made adjustments to depreciation expense and accumulated depreciation to reflect witness McCullar's recommended depreciation rates.

UPDATE TO REVENUES AND RELATED EXPENSES

Q. PLEASE DESCRIBE YOUR ADJUSTMENT TO REVENUES AND RELATED EXPENSES.

A. I have updated the energy-related non-fuel variable O&M expense per KWh rate and the annual customer-related variable O&M expense per KWh rate to reflect the use of the SCP allocation methodology to calculate expense amounts used in the calculations, as well as corrected a Public Staff formula error in the schedule. I have also updated the customer growth and usage amounts per the recommendation of Public Staff witness Saillor. It is my understanding the Company agrees with these adjustments.

BENEFITS

Q. PLEASE EXPLAIN THE ADJUSTMENT TO BENEFITS.

A. I have updated the benefits related to other post-employment benefits (OPEB), pension, Statement of Financial Accounting Standards (SFAS) 112, and non-qualified pensions to reflect the updated 2020 actuarial amounts that became available after the January 31, 2020, update period. It is my understanding the Company agrees with this adjustment.

ASHEVILLE PRODUCTION DISPLACEMENT

Q. PLEASE DESCRIBE YOUR ADJUSTMENT TO THE ASHEVILLE PRODUCTION DISPLACEMENT ADJUSTMENT.

A. I have updated the Asheville production displacement calculation as updated by the Company in its May 2020 update to reflect the calculation using the SCP allocation method, as agreed to by the parties in the Second Partial Stipulation. In its calculation, the Company had based the calculation on the SWPA allocation factors.

NON-LABOR O&M EXPENSE (INFLATION)

Q. PLEASE DESCRIBE YOUR ADJUSTMENT TO NON-LABOR O&M EXPENSE FOR INFLATION.

A. I have adjusted the amount of non-labor O&M expense included in the determination of the base to which the inflation rate is applied to include the Public Staff's recommended adjustment in non-fuel variable O&M expenses due to customer growth. It is my understanding the Company agrees with this adjustment.

CASH WORKING CAPITAL UNDER PRESENT RATES

Q. PLEASE EXPLAIN THE ADJUSTMENT TO CASH WORKING CAPITAL UNDER PRESENT RATES.

A. I have incorporated the update to May 31, 2020, into the calculation of cash working capital under present rates. This cash working capital adjustment is reflected on Schedule 2-1 and incorporates the effect of the Public Staff's adjustments updated through May 31, 2020, before the rate increase, on the lead-lag study.

CASH WORKING CAPITAL EFFECT OF INCREASE

Q. PLEASE EXPLAIN THE ADJUSTMENT TO CASH WORKING CAPITAL FOR THE PROPOSED INCREASE.

A. The cash working capital lead-lag effect of the proposed revenue increase as recommended by the Public Staff has been reflected on Maness Second Stipulation Exhibit 1, Schedule 2-1.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Summary of the Testimony of Michael C. Maness Related to the Overall Public Staff Recommended Revenue Requirement, for the Remote Unconsolidated Hearing in Docket No. E-2, Subs 1193 and 1219

This summary addresses (1) my Testimony in Support of Partial Settlement (with accompanying Maness Stipulation Exhibits 1, 2, and 3), filed in Docket No. E-2, Subs 1193 and 1219 (collectively, Sub 1219), on June 5, 2020; (2) my Testimony Supporting Second Partial Stipulation, filed in Sub 1219 on July 31, 2020; and (3) my Supplemental Testimony Supporting Second Partial Stipulation (with accompanying Maness Second Stipulation Exhibits 1 and 2), filed in Sub 1219 on September 16, 2020. These sets of testimony and exhibit filings reflect the development of the Public Staff's recommended revenue requirement in this proceeding, from the first Agreement and Stipulation of Partial Settlement between Duke Energy Progress, LLC (DEP or the Company), and the Public Staff, filed on June 2, 2020 (First Partial Stipulation), through testimony supporting the Second Agreement and Stipulation of Partial Settlement between DEP and the Public Staff, filed on July 31, 2020 (Second Partial Stipulation)[1], and finally to the Second Partial Stipulation after review of items annualized by the Company through May 31, 2020. My September 16, 2020 filing reflects the Public Staff's recommended revenue requirement as of that date, which is presumably the Public Staff's final recommendation. I will briefly explain each of these filings.

[1] This testimony was filed prior to finalization of the Public Staff's review of the Company updates of certain items to May 31, 2020.

My June 5, 2020 Testimony in Support of Partial Settlement proceeded from Public Staff witness Shawn L. Dorgan's Supplemental Testimony and Exhibits, filed on April 23, 2020, to reflect certain corrections to that filing, as well as settlement of the following issues between the Company and the Public Staff, per the First Partial Stipulation:

(1) The debt cost rate.
(2) Credit card fees.
(3) Protected federal excess deferred income taxes (EDIT) due to the Tax Cuts and Jobs Act.
(4) Aviation expenses.
(5) Executive compensation.
(6) Salaries and wages expense.
(7) Outside services.
(8) Rate case expense .
(9) Storm expense.
(10) Storm deferral.
(11) Severance.
(12) Incentives.
(13) Asheville CC plant in service.
(14) Asheville CC deferral.
(15) W. Asheville Vanderbilt 115kV project.
(16) Asheville production displacement.
(17) Coal inventory.
(18) End-of-life nuclear materials and supplies reserve.
(19) Sponsorships and contributions.
(20) Lobbying expense.
(21) Board of Directors expense.
(22) Inflation to February 29, 2020.
(23) CertainTeed.

At the time of the filing of my June 5, 2020 Testimony, the Public Staff recommended a $161,082,000 increase in the Company's base rate revenue requirement.

My July 31, 2020 Testimony Supporting Second Partial Stipulation did not include any Exhibits, because the Public Staff had not completed its review of the

Company's annualization of certain items through May 31, 2020, but did reflect settlement of the following additional issues between the Company and the Public Staff, per the Second Partial Stipulation:

(1) Return on Equity, Capital Structure, and Debt Cost.
(2) Update of revenues, rate base, and expenses to May 31, 2020 (subject to further Public Staff investigation).
(3) Return of unprotected federal excess deferred income taxes (EDIT) due to the Tax Cuts and Jobs Act to customers.
(4) Return of North Carolina State EDIT due to reduction in state tax rates.
(5) Treatment of federal deferred revenue due to the Tax Cuts and Jobs Act.
(6) Amortization period for Non-Asset Retirement Obligation (ARO) coal ash costs.
(7) The Company's Grid Improvement Plan (GIP) (revenue requirement effects only in future cases).
(8) Cost of service allocation methodology.
(9) Rate design.
(10) Nuclear Decommissioning annual funding.
(11) The process to be used to determine the base fuel factor in this proceeding.

In addition to the settled issues, which had a revenue requirement impact in the present case, the Second Partial Stipulation also settles non-revenue requirement issues involving additional cost of service studies, a rate design study, affordability, and audit and reporting obligations.

My September 16, 2020 Supplemental Testimony Supporting Second Partial Stipulation (1) presents the final results of the Public Staff's evaluation of settled and non-settled accounting and ratemaking adjustments as reflected in DEP's Second Settlement Testimony; (2) recommends additional adjustments as a result of information provided by the Company during the Public Staff's investigation of that testimony; (3) reflects the impact of adjustments and corrections recommended by other Public Staff witnesses; and (4) presents the Public Staff's recommended revenue requirement increase.[2]

From the perspective of the Public Staff, the most important benefits provided by the First and Second Partial Stipulations are (a) a significant reduction in the Company's proposed revenue increase in this proceeding; and (b) the avoidance of protracted litigation between the Stipulating Parties before the Commission and possibly the appellate courts.

As a result of the First and Second Partial Stipulations, Including the updating of certain items to annualized amounts as of May 31, 2020, the Company's proposed increase in its annual base revenue requirement decreased from $544,262,000[3] to $408,933,000[4]. The Public Staff and the Company also agreed to an additional reduction of $(318,000) in the revenue requirement. The unsettled issues between the Company and the Public Staff total to $(143,637,000). As a result, the Public Staff's recommended increase in the Company's annual base revenue requirement is $264,978,000, as set forth on Maness Second Stipulation Exhibit 1, Schedule 1.

In addition to its agreements regarding base rate revenue issues, DEP and the Public Staff have agreed to the following rider decreases:

(1) A regulatory asset/liability rider decrease of $(2,091,000), for one year.
(2) An annual State EDIT rider decrease of $(12,812,000), for two years.

[2] Adjustments to DEP's Second Supplemental Testimony were recommended in the areas of plant, depreciation expense, and accumulated depreciation, revenues and related expenses, benefits, Asheville production displacement, inflation, and cash working capital.

[3] Maness Stipulation Exhibit 1, Schedule 1, Line 3.

[4] Maness Second Stipulation Exhibit 1, Schedule 1, Line 3.

(3) An annual Federal provisional EDIT rider decrease of $(58,896,000), for a two year period.

(4) An annual Federal unprotected EDIT Rider decrease of $(94,415,000), for five years (to be reduced by the amount of EDIT flowed back during the interim rate period).

This concludes my summary.

COMMISSIONER CLODFELTER: Thank you, Ms. Holt.

MS. HOLT: Thank you.

COMMISSIONER CLODFELTER: Okay. Ms. Downey, we were on a roll with Mr. Maness there, and I thought we might just go and finish him out. So thank you for reversing the order there. I don't think there was any prejudice to your case presentation, I hope.

MS. DOWNEY: No. I believe I just saw something in the chat that indicates -- there he is. Okay. It indicated he was having trouble with his video, but he's there now.

Mr. Tommy Williamson, I think he's next.

COMMISSIONER CLODFELTER: Okay.

Whereupon,

TOMMY WILLIAMSON, JR.,

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

COMMISSIONER CLODFELTER: That's great. Thank you. All right. Ms. Cummings.

DIRECT EXAMINATION BY MS. CUMMINGS:

Q. Mr. Williamson, please state your name, business address, and current position for the record.

A. My name is Tommy Williamson, Jr. My address is 430 North Salisbury Street, Raleigh, North Carolina. I'm a utilities engineering with the Public Staff.

Q. And on September 15, 2020, did you cause to be prefiled in this docket, eight pages of supplemental testimony?

A. I did.

Q. Do you have any changes or corrections to your testimony?

A. No, I do not.

Q. If I asked you the same questions today, would your answers be the same?

A. Yes, they would.

Q. Mr. Williamson, did you prepare a summary of your supplemental testimony that was sent to the parties and the Commission?

A. Yes, I did.

MS. CUMMINGS: Commissioner Clodfelter, at this time I would move that Mr. Williamson's supplemental testimony and summary that was sent to the parties be copied into the record as if it was delivered orally from the stand.

COMMISSIONER CLODFELTER: All right. You've heard the motion, any objections?

(No response.)

COMMISSIONER CLODFELTER: Hearing no objections, the motion is granted.

(Whereupon, the prefiled supplemental testimony and testimony summary of Tommy Williamson, Jr. were copied into the record as if given orally from the stand.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

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 DOCKET NO. E-2, SUB 1219 In the Matter of Application of Duke Energy Progress, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina	)))))))))))))))))	SUPPLEMENTAL TESTIMONY OF TOMMY WILLIAMSON, JR. PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUBS 1193 AND 1219

SUPPLEMENTAL TESTIMONY OF

TOMMY WILLIAMSON, JR.

ON BEHALF OF THE PUBLIC STAFF

NORTH CAROLINA UTILITIES COMMISSION

SEPTEMBER 15, 2020

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

A. My name is Tommy C. Williamson, Jr. My business address is 430 North Salisbury Street, Dobbs Building, Raleigh, North Carolina. I am an Engineer in the Energy Division of the Public Staff – North Carolina Utilities Commission.

Q. ARE YOU THE SAME TOMMY C. WILLIAMSON, JR. WHO FILED TESTIMONY IN THIS DOCKET ON APRIL 13, 2020?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR SUPPLEMENTAL TESTIMONY?

A. The purpose of my supplemental testimony is to summarize the Public Staff's investigation into the Duke Energy Progress, LLC's ("DEP") Second Supplemental Direct Testimony and Exhibits of Kim H. Smith and Second

Supplemental Direct Testimony of Michael J. Pirro, filed July 6, 2020 ("May Update"). My testimony specifically addresses the Public Staff's investigation into transmission and distribution ("T&D") assets placed in service by DEP from March 1, 2020 through May 31, 2020 ("Update Period").

Q. PLEASE SUMMARIZE THE ASSETS DEP PLACED INTO SERVICE DURING THE UPDATE PERIOD.

A. DEP placed $287.4 million of T&D investments into rate base during the Update Period. At least $52.8 million of this total was Grid Improvement Plan (GIP) related.[1]

Table 1: T&D Assets Placed in Service during the Update Period

in North and South Carolina (millions of dollars).[2]

	Transmission	Distribution	Total
DEP - Total	150.4	137.0	**287.4**
DEP - GIP Related	18.0	34.8	**52.8**

Q. WHAT ARE THE RESULTS OF YOUR INVESTIGATION?

A. Of the $34.8 million in GIP-related distribution investments in Table 1, DEP closed approximately $15.8 million of Self Optimizing Grid (SOG) Segmentation and Automation projects and $1.2 million of SOG Capacity

[1] The total T&D spend reflects all T&D spend; the GIP related spend only reflects projects above $500,000. There may be additional GIP expenses included in the total T&D spend for projects less than $500,000.

[2] DEP PSDR 79 (3rd Supplemental) and DEP PSDR 187-5.

and Connectivity projects to rate base in the May Update. The Segmentation and Automation projects consist of 135 individual distribution circuits. The Public Staff sampled ten of these circuits and discovered that only three are fully enabled with SOG functionality. The remaining seven require additional reclosers and circuit enablement, and are expected to be fully enabled in 2021.

Q. PLEASE EXPLAIN WHAT IS MEANT WHEN YOU DESCRIBE A SOG CIRCUIT AS BEING "FULLY ENABLED?"

A. "Fully enabled" refers to a set of construction and design criteria that a circuit must satisfy as follows: 1) the circuit is segmented so that any fault occurring on a particular segment can be isolated from other segments; 2) the main circuit is connected (tied) to another circuit for backfeed purposes allowing the main circuit to receive power through the backfeed during interruptions; and 3) confirm that each main and backfeed circuit, and substation transformer has sufficient capacity to supply power to the main and backfeed circuits' designed SOG load.[3]

After these three construction criteria have been satisfied, the newly configured and constructed circuits must be programmed, or enabled, into the Advanced Distribution Management System (ADMS), which enables automatic responses to faults. SOG circuits are enabled in groups of two or

[3] The Company SOG standard for a pair of circuits seeks to allow the first SOG circuit to pick up 70% of the second SOG circuit's peak load during 90% of the time.

more circuits known as "teams," which provide the segmentation and backfeed capabilities that are necessary for SOG to function.

Q. HOW DOES SOG OPERATE ON A SOG CIRCUIT TEAM ONCE IT IS FULLY ENABLED?

A. In the event of a fault occurring on a circuit segment: 1) the SOG enabled equipment first locates and isolates the fault to that particular segment; 2) the substation transformer will continue to supply power to any circuit segments that remain electrically connected to the transformer; and 3) the ADMS closes the tie connection between the teams circuits allowing the backfeed circuit to supply power to the segments between the isolated fault segment and the backfeed circuit. In a SOG enabled circuit, these steps are performed automatically in 2-3 minutes by the ADMS.

Q. CAN YOU EXPLAIN WHY SEVEN OF THE TEN SOG CIRCUITS CLOSED TO SERVICE AND SAMPLED BY THE PUBLIC STAFF ARE NOT YET FULLY ENABLED?

A. DEP has explained the concept of circuit enablement and stated that the process requires highly trained personnel who can operate the software designed to locate and isolate faults and restore service during a SOG event. Due to the specifications to which circuit devices must meet and the limited availability of and diverse workload assigned to these personnel, there is a finite number of circuits that can be programmed into ADMS over a particular time frame. Prior to this year, DEP stated that SOG investments have been proceeding at a manageable pace; however, as the number of circuits targeted for SOG has increased, the demand for the highly skilled personnel has increased. This has led to delays in enabling SOG circuits after construction is complete.

Q. IF THESE SOG CIRCUITS ARE NOT FULLY ENABLED AT THIS TIME, SHOULD THEY BE CONSIDERED USED AND USEFUL?

A. Based on a discussion with the Public Staff Accounting Division, and advice of counsel, I believe these SOG circuits meet the technical and legal definitions of plant in service. Therefore, we do not recommend any revenue adjustments. These SOG circuits are used and useful in providing utility service, even though most are not fully SOG enabled and producing the full benefits as described by DEP witness Oliver in his testimony in this proceeding.

Q. ARE THE PARTIALLY ENABLED SOG CIRCUITS PROVIDING ANY BENEFITS TO CUSTOMERS AT THIS TIME?

A. Yes. If a SOG team has completed construction and configuration but the circuits are not yet enabled, the fault isolation process described above can still be performed manually. Human operators in DEP's distribution control center can manually isolate the faulted segment and backfeed the remainder of the circuit; but this manual process is slower and produces fewer reliability benefits when compared with the automatic operation of SOG equipment through ADMS. Realizing these partial benefits is contingent upon DEP implementing a protocol to manually operate the SOG circuits prior to full enablement. The full benefits will be delayed until full completion of SOG construction, configuration, and programming criteria discussed earlier in my testimony.

Q. HAS DEP RECORDED ANY RELIABILITY BENEFITS FOR THE THREE SOG CIRCUITS THAT WERE COMPLETED?

A. Yes. Two circuits that are fully enabled with SOG functionality have each recorded one SOG activation. Combined, approximately two thousand customers avoided a sustained outage of approximately two hours. For these two circuits, the Customer Minutes Interrupted ("CMI") that were avoided exceeded the incremental CMI savings that were originally estimated in the cost benefit analyses, as submitted in DEP's witness Oliver Exhibit 7. This type of information, collected consistently, is instrumental to assessing the performance of SOG and other GIP investments relative to projections.

Q. DO YOU HAVE ANY OTHER COMMENTS BASED ON YOUR INVESTIGATION?

A. Yes. My investigation of the May Update and findings related to SOG lead me to believe that the traditional concepts of "used and useful" do not fully account for all the issues that must be considered when evaluating GIP investments and programs. The complexity with which GIP programs, software, and physical devices interact means that "full functionality" may not neatly match up with “used and useful.”[4] This is especially true given the scale and pace of T&D investments envisioned under DEP’s GIP.

This potential timing mismatch underscores the importance of completing GIP projects promptly, with as little delay as possible, so that benefits can be tracked and reported pursuant to the terms of the Settlement, if approved by the Commission. It will be more challenging to assess the cost effectiveness of GIP-related projects, and adjust the overall course of the GIP, in an ongoing manner if customers may not begin realizing the benefits of today’s rate based investments for a year or more. Nevertheless, DEP should be careful to balance the incremental costs associated with expedited project completion against the overall value to customers.

The challenges of reviewing the costs and benefits of certain GIP programs and investments also highlights the importance of detailed and transparent reporting and review of the GIP.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

[4] Advanced Metering Infrastructure (AMI) meters is a good example of this principle. While AMI meters may be used and useful in recording and transmitting electricity consumption, the lack of software or programs on the back end means ratepayers may not immediately enjoy the full benefits of a technology at the time it goes into rate base.

Tommy Williamson Supplemental Testimony Summary

Docket No. E-2, Sub 1219

The purpose of my supplemental testimony is to present the results of my investigation into Duke Energy Progress, LLC's (DEP) Second Supplemental Direct Testimony and Exhibits of Kim H. Smith and Second Supplemental Direct Testimony of Michael J. Pirro, filed on July 6, 2020 (May Update). My investigation focused on Transmission and Distribution (T&D) costs closed to plant from March 1, 2020 through May 31, 2020 (Update Period), with particular emphasis on projects related to DEP's Grid Improvement Plan (GIP). I sampled numerous projects among the approximately $287 million of T&D assets placed in service during the Update Period to determine whether these investments were reasonable and prudent.

My testimony summarizes my findings with respect to one of the largest GIP programs, Self-Optimizing Grid (SOG). While I believe that the $17 million of SOG investments included in the May Update meet the technical and legal definitions of plant in service and are currently providing some benefits to ratepayers, I do identify several concerns for the Commission's consideration. Specifically, I have concerns that ratepayers may not begin realizing benefits of today's rate based investments for a year or more due to delays in fully enabling SOG circuits to automatically locate, isolate, and restore service following distribution faults.

My testimony also highlights the potential challenges to reviewing the cost effectiveness of GIP programs in an ongoing manner. The complexity with which different GIP programs, software, and physical devices interact means that “full functionality” may not neatly match up with traditional concepts of “used and useful.” This is particularly true given the scale and scope envisioned by DEP’s GIP. The challenges of reviewing costs and benefits of GIP programs that have a cost benefit analysis, like SOG, underscore the importance of detailed and transparent reporting and review of GIP expenditures.

This concludes my summary.

MS. CUMMINGS: The witness is available for cross.

COMMISSIONER CLODFELTER: Mr. Page, you are the only party showing on my list for cross examination.

MR. PAGE: I didn't want Mr. Williamson to feel like he was lonely or rejected. So I do have some questions for him.

CROSS EXAMINATION BY MR. PAGE:

Q. Good afternoon, Mr. Williamson.

A. Good afternoon, Mr. Page.

Q. I have a few question to ask you about your testimony concerning the approximately $17 million of Duke Progress investments into SOG, or self-optimizing grid, segmentation and automation projects in this case; is that okay?

A. Yes, sir.

Q. Am I correct that the segmentation and automation SOG projects consist of some 135 individual distribution circuits?

A. Well, in our testimony we said that there were 135 distribution circuits that received some SOG work, yes.

Q. That, I'm sorry, received what?

A. That they were -- they were SOG circuits, and that they did receive some amount of SOG work.

Q. All right. And Duke requested that the full value, or investment value of all 135 being in their rate base upon which rates will be set in this case; is that correct?

A. That is correct.

Q. And the Public Staff has agreed to include all 135 circuits in the rate base in this case; is that correct?

A. Yeah. In our investigation we reviewed, and based on what we saw as internal discussions on what would be considered used and useful, and we believe at this time -- (sound failure.)

Q. All right. Thank you, sir.

(Reporter interruption due to sound failure.)

COMMISSIONER CLODFELTER: Hold on a second. Mr. Williams, your voice is bubbling or gurgling, and I think the court reporter -- Joann, do you need Mr. Williamson to repeat his answer?

COURT REPORTER: I do, I didn't catch the very end of his answer.

COMMISSIONER CLODFELTER: Okay.

Mr. Williamson, can you remember where you were?

THE WITNESS: Yes, sir. So just to go back. The Company put -- had 135 individual distribution circuits in the update period, and we reviewed those. And yes, based on the technical definition of used and useful, we believe that they made that definition for inclusion in the rates.

Q. Thank you, sir. That is a definition of about which I want to return a little bit down the road, the definition of used and useful.

The staff was actually able to perform sampling of some 10 out of those 135 circuits; is that correct?

A. Yes, sir.

Q. And you found that, out of those 10, there were three of the 10 circuits that had been fully enabled and the rest were not; is that correct?

A. That is correct.

Q. All right. What difference does is it make if a circuit is fully enabled or not fully enabled?

A. Well, let me answer that by just walking through an example. So let's just say, for instance, we have -- and just keep it very clean. For instance, let's say we have a substation, we'll call it substation 1 with one transformer getting one feeder circuit, we'll call it circuit number 1, and the -- there's a companion circuit on the other side coming out of substation 2 consisting of one transformer and one circuit, we will call it circuit number 2. All those circuits are isolated radial circuits, they're not connected, and they are designed to carry and serve the load that is currently connected to it.

So at some point, the Company decides to make circuit 1 and circuit 2 a SOG team. And through their analysis and meeting the design criteria for SOG, it's determined -- I'm just going to keep it very straightforward -- that the only work that needs to be done is on substation transformer 1 and feeder circuit 1. In that example, the transformer number 1 needs to be increased in capacity, and also the circuit number 1, the wire needs to be bigger to increase its capacity.

And along with that, there's some segmentation that you mentioned earlier, so there's automated switches that need to be put in circuit 1 to minimize and reduce the number of customers that are on each segment. So as that construction work is being completed by the Company, let's start with the transformer, the transformer is increased in capacity. And at that point, it's re-energized, and at that point is serving the load that it was originally intended.

However, that additional capacity, or SOG service, is not used at that time, it's not needed. The same thing with the feeder circuit or the distribution circuit. The wire is replaced, it's reconducted, and it has a larger capacity. That wire, as soon as it goes back in service, is serving the original load of circuit 1, but because of SOG criteria, it has to also be able to carry 70 percent of the peak load of circuit 2, 90 percent of the annual hours in a year.

So that -- that conductor in circuit 1 is serving the original load and has extra capacity for SOG service that is not used yet. The time -- or the reclosures for circuit segmentation are put in. Now we have smaller segments of the circuit so a fault can be located and isolated to minimize the customers that are affected by an outage. Those reclosures as well are performing a service, but they're not yet connected for their full SOG functionality.

And then finally, the circuits, circuit 1 and circuit 2 are tied together physically with a tie, usually that's another switch. And at that point, all of the SOG components have been physically installed. At that point, the Company would program and install all of those components and they will go into the ADMS system to allow the automatic control as envisioned by the SOG program.

So all the components, the transformers, the wire, the reclosures, the tie, they are all -- when they go back in service, they're used and useful. They are performing the tasks they were originally designed to do; but they also have capacity to serve the SOG vision. And so there's a delay in when the SOG components are installed to the point where full functionality occurs, and that is when programming and integration of those components are done in the software in the ADMS system.

So there's -- and that's where we were looking at there's a delay between when the SOG equipment is put in and when it's fully utilized for SOG service.

Q. All right. I thank you for that explanation. I also have a hypothetical situation, and mine I hope is maybe a little bit simpler because it only involves one line.

A. Okay.

Q. And I would just ask you in this hypothetical to start out the same way you did with just line number 1, and it comes out of the substation and it runs 6, 7 miles out in the country and it terminates, and it serves -- that one line services, let's just say, 100 customers. And the line is sectionalized. And I want to look at what happens before any of this SOG equipment is installed.

So let's assume in the hypothetical that it's a breezy day in March or sometime as we approach hurricane season, and down at the end of that line, in the very last segment furthest away from the substation, a tree falls on the line.

Are you with me so far?

A. Yes, sir.

Q. Would you agree that, essentially, what happens next is the line, or the existing equipment, will send a fault signal back up to the substation?

A. There would be some acknowledgement that there was a problem with the fault, yes.

Q. That would not be an unusual way to engineer a system?

A. No, sir.

Q. Or particularly a distribution line. And when it gets back to the substation, some other switches, such as reclosures, are going to have operations; is that correct?

A. If it's configured that way, yes, that can happen.

Q. All right. And in my hypothetical I would like to have it configured that way, since you're indulging me. So the reclosures try a couple of times to clear the fault and that doesn't happen; and the system is programmed at that point to just simply leave the reclosures open, the connection is not made, and that line goes dark. All 100 customers are without power.

A. Okay.

Q. And that information then comes to the attention of the utility which dispatches one man and a truck or a crew and a truck to go ride the line to see if they can locate where the problem is and what it is; is that correct?

A. Yes, that's correct.

Q. And next, once they have a diagnosis of what the problem is and what is needed to fix it, that crew out in the field is going to call back and say we need a bucket truck, we need more chainsaws, we need some more men, and that dispatch will be made, and eventually the problem is solved. But by that time, isn't it true that some two, three, four, five hours may have elapsed, depending on the seriousness of the problem?

A. That could happen, yes.

Q. And during that entire time, all of those folks, the entire 100 served on that line, are without power?

A. In your situation as you presented it, yes, that is -- that could happen.

Q. All right. Now, besides --

COMMISSIONER CLODFELTER: Mr. Page, hold just a second. Mr. Williamson, your microphone is continuing to give some problems with gargling and bubbling. Do you have any way to adjust the microphone?

THE WITNESS: I think if you'll hold on just a minute, Commissioner, I can step around and turn off some external mics and speakers that may be giving us the feedback.

COMMISSIONER CLODFELTER: I think that may be good. Let's just stand by here for a couple of seconds.

THE WITNESS: Thank you, I'll be right back.

(Pause.)

THE WITNESS: If I could do a sound check. Does that sound any better?

COMMISSIONER CLODFELTER: It does sound better. Joann, sound better to you? Okay. Mr. Page, sorry to interrupt, but I think you have an interest in getting clear answers.

MR. PAGE: Yes, sir, I do. I think we all do.

Q. So with this fairly simplistic --

A. Hold on, hold. I can't hear you now. Just a moment.

MR. PAGE: Technology is always wonderful when it works.

THE WITNESS: I apologize, I could not hear. Can you hear me now, Mr. Page?

Q. I can hear you just fine. Can you hear me?

A. Just a moment.

Q. First time I've ever been censored by the Public Staff.

A. Mr. Page, say something.

Q. Yes. Now is the time for all good men to come to the aid of their country.
A. Okay. Is this better?
Q. And women.
A. Okay.
Q. Are we communicating?
A. Yes, sir.
Q. So we no longer have, as in Cool Hand Luke, failure to communicate?
A. One of my favorite lines.
Q. Taking my little hypothetical about the one line and adding onto it, and the only change we're making is to put in the fully operational SOG equipment. Now, what happens when you make that exchange is, it really doesn't help those poor folks down at the end of the line where the tree is leaning on the line or maybe even broke through the line. They're still going to be out until the repairs are made, however long that takes.
A. Okay. Let me just expand your hypothetical just a little bit. You say down in the --
Q. Can't we just stick to my hypothetical, and I'll let your attorney ask you about variations?
A. I would say that, when you say fully all that

SOG equipment, I accept that being present on that one distribution line, and that those folks on the end are down in the last segment.

Q. Yes, sir, that's exactly right.

A. I agree with you.

Q. All right. But as to the other 95 customers -- if I didn't say, I was going to say there are 5 customers in the last segment and 95 upstream towards the substation. Those 95 customers are still going to be out for a while, but if I read your testimony correctly, if the system is fully automatically operational, they'll be out for two or three minutes, and then their power will come back on just as a function of the system operating?

A. Yes. As you -- the hypothetical as you presented, everybody from the substation down to that reclosure that's going to have to be opened to isolate those last five customers, those customers would return to service rather quickly.

Q. And that's a significant benefit when you're out two or three minutes instead of two to five hours, isn't it?

A. I think most people would say yes.

Q. But in order for the system to operate that way, all those switches have to be fully enabled or it won't operate automatically; is that correct?

A. Well, as things -- as they're currently configured, you could have reclosures in the field that do communicate back, and there could be manual operation of those switches, and that's currently done now. It's not as fast as automatic operation, but -- so there would be some difference in time between automatic return to service and manual return to service.

Q. Is the --

A. Those customers -- those 95 would still return to service quicker than those last five in that affected segment.

Q. But is the manual operation something that can be performed in a central office or a district office, or does a person in a vehicle have to go and manually change a switch out in the field?

A. The best case would be yes, we have automatic, we have reclosures on that line that you have mentioned in your hypothetical that are connected, that have communications, connections back to the control center. And after some manual calculations, those switches can be put back into service. So yes, that can be done in a central office or in the control center.

Q. Earlier in this discussion, we said that if the SOG was fully operational, the delay for the 95 customers would be two to three minutes. If those switches had to be operated manually, what time delay are we talking about? Ten minutes, 30 minutes, an hour?

A. It really comes down to the individual situation, the number of circuits affected. And if I could just put a little caveat on your hypothetical, we're talking about fully SOG enabled, and just to clarify in your hypothetical you talked about, you know, just a single circuit. A full SOG, you know, readiness, it needs two circuits at a time.

So I just want to be clear on that. So we could have the same SOG equipment that are on circuit 1, but it's not SOG ready and enabled until it's tied to a second circuit. So I just wanted to clarify that.

Q. I appreciate your doing that, Mr. Williamson. You'll have to accept that I am not my son who is an electrical engineer, but I'm a poor liberal arts lawyer, and I'm giving you my best example. I'm just trying to illustrate the difference between if you don't have any SOG circuits, if you have SOG fully enabled, and if you have SOG that would have to be manually operated.

A. Yes, sir.

Q. All right. And I think I'm understanding you to say that the time benefits for most of the customers in my hypothetical would be significant, whether it's automatic or manually operated, as opposed to having none of those circuits?

A. Yes. In your hypothetical, with five customers on that last segment the farthest from the substation, I believe with trees down, if there needs to be some reconductoring, poles break, those folks on the end are going to have a much longer outage than everybody from that point back to the substation; that is correct.

Q. All right. So would you agree with me that if the SOG equipment has to be manually operated rather than being fully automated and fully enabled, in the circumstances of the current rate case, ratepayers, customers are going to be asked to pay rates to cover rate base investment from which they are not receiving 100 percent of the design benefits; is that correct?

A. Yes. What I would say is that -- I would say they're not receiving it yet. Because as you put in the SOG equipment, whether it's upgrade of a transformer, line reclosures, or the tie, you know, the specifics of each circuit are going to be different and dictate when those investments are made. So there's not a consistent construction approach based on, you know, weather and crew demands. Some things may get put in before the other.

So -- but at the end of the day, they're all going to come together and construction will be completed, and then the enablement will be able to be done into the ADMS. So yes, there's -- customers are going to receive the benefit they originally had to serve existing load, and with the expectation that the SOG ability will come; but it will be, you know, delayed. So there is a time lag there.

And that's what we talked about in our testimony, or my testimony. We have a potential timing mismatch when something becomes used and useful and customers realizing the full benefit of the SOG program.

Q. And if I recall your testimony correctly, you seem to be pretty concerned about customers paying for something that they weren't getting the benefits out of they should get; is that correct?

A. Well, I would say it's more about the delay. We believe that, you know, the SOG fulfillment, to become fully enabled, will come. And, you know, what we're watching is to make sure that the delay does not stay a long period of time. Through conversations with the Company right now, they're longer than they want from the time construction is complete to when full enablement is completed through the ADMS integration, but they're -- due to COVID and the increase in the number of circuits being rolled out, they're looking -- you know, again, I understand from the Company to staff up that program of those folks to be able to do that work and collapse that into about a 12-week period from when construction is completed to when all the ADMS integration is completed. At that point, you'll have full ADMS -- full SOG functionality.

Q. I believe your testimony states that it is unlikely that all of these circuits will be fully enabled until sometime next year; is that correct?

A. Yeah. Through our discussions and data responses from the Company is that, you know, we're looking at 2021 for some of these circuits that are being included in rate base in this proceeding.

Q. Are you familiar with the supplemental rebuttal testimony filed by Duke witness Oliver that addresses your testimony about which we're talking now?

A. Yes, sir.

Q. And he mentions in there, does he not, that there's a process that is going to have to be gone through in order to enable all of these circuits, and that process involves assembling a team, training the team, putting the team to work, and getting the work done. And it's that last stage of getting the work done that is the 12 weeks or three-month period that you just mentioned in your testimony, correct?

A. That's right. They currently have staffing, but as the number of circuits grow, they will be increasing the staffing of that team, yes.

Q. Are you aware, either from Mr. Oliver's testimony or otherwise, when the teams will be assembled and when the actual enabling work will begin in 2021?

A. Well, it's our understanding that those teams are currently -- there is a team in place. So this modeling is taking place now. The issue is that there's not as much -- there's demand -- other demands on that team to do other work, and that they're looking at -- again, as COVID relaxes and they're able to assemble more folks on the team, that they would increase the numbers of staffing on that team, and therefore be able to do the SOG integration work.

Q. All right. But you're unable to say, based on what you know today, exactly when this actual enabling work will begin and when it will end some three months later, just that it will be sometime in 2021?

A. I want to be clear. So again, what we're saying is we know that the SOG enablement is happening today. It's just not happening as quick as the Company would like. Therefore, that's why we some delay -- longer delay than the Company has said that their goal is. That that SOG, that configuration and programming work going into the ADMS is occurring today. The goal is going forward that the time lag between that is longer than 12 weeks now to be compressed, and that's the goal for the Company that the Company has set, to be a 12-week turnaround.

So it -- it's happening now, it's just not happening as fast as they would like. And I think, you know, we would agree with that, that I believe that customers should realize the benefits of SOG and as soon as possible; but we also want the Company to balance, you know, the value of SOG and the efficiency of getting that work done. So we look at -- overstaff that team, we want it to be staffed appropriately and to maintain an efficient, you know, realization of those benefits, you know, as soon as possible.

Q. If I had one of those old figure eight future projection balls, would it translate the answer you just gave me as "situation cloudy"?

A. You know, I used to have one of those too. Let's see. Yes, we're uncertain at this point. We don't know for sure. We know where -- we hear where the Company wants to go, they will just need to, you know, stay tuned and keep an eye on it. Make sure that we do see those response times getting closer to 12 weeks, you know, in the not-too-distant future.

Q. Mr. Williamson, you and I earlier had gotten to a point where I said I wanted to revisit with you down the road the concept of used and useful, and we have now arrived at that.

Do you have a definition satisfactory to you or for the Public Staff of how you guys interpret that term "used and useful"?

A. Well, I would say I am not a lawyer and I'm not an accountant, but I will -- I'll try to summarize as best I can. I was advised by our folks in accounting that, apparently there's -- I believe it's Chapter 18 of the Uniform System of Accounts for Public Utilities, so I'm going from that. And apparently it says in there that it permits a utility to classify the operational or ready for service portions of a construction project that is not yet fully complete as alleged plant in service.

And like our earlier discussions, because those SOG components: the transformers, the lines, the reclosures, the ties, when they are installed for SOG specifically, but as soon as they go back in, they're still serving their original -- their original load. So at that point, they are serving -- providing service, and we believe that that meets the intent of used and useful.

Q. But those lines with those changes are not any more used and useful than the lines they replaced, are they? They may have slight additional capacity, but they're essentially doing the same function they were doing before?

A. They are serving the original load, and they have the capacity to serve the SOG load when called upon in the future; that's correct.

Q. Is it your testimony today that the treatment of these is yet to-be-enabled circuits does not change the traditional understanding of the term used and useful?

A. Well, in my mind -- and again, I'm -- used and useful, again, based on what we have seen -- and I'm going -- I'm looking at what we were advised by looking at the Chapter 18 there. I believe it does meet the technical definition of plant in service. So from that perspective, I would say our used and useful definition remains the same.

Q. Let me take a slightly different look at it. If we agreed earlier that, based on the random sampling that the Public Staff was able to do given the time constraints where you found three of the 10 circuits that you examined to be fully operational and the other seven remain to be enabled or fully enabled -- let's assume a slightly different situation where the utility, instead of installing SOG equipment, was conducting or constructing a fiber optic link for operational purchases -- purposes. I'll get my words straight here in a minute. The utility is constructing a fiber optic link to be used for operational purposes.

And at the close of the rate case hearings, only 30 percent of that fiber had actually been constructed, would the Public Staff include 100 percent of the cost of constructing that fiber optic link in the rate base for that case?

A. In your hypothetical, I think I heard you say that 30 percent of the line had been installed.

Q. Yeah. Ten-mile line, three miles installed.

A. Okay. I think that's a little bit different from what I put in my testimony. And I understand your hypothetical, I just want to clarify in mine, let's equate your fiber line to the actual distribution wire. When that distribution wire is put in to meet its SOG capacity, the entire line is in. The entire line is serving the original load, and the entire line will be able to serve SOG capacity in the future. So the entire line at that point is -- will -- you know, is used and useful for that original intent.

In your hypothetical where you've got only 30 percent of the line, I -- I would -- I would respectfully say I would need more information on -- or what else -- what is that other seven -- 70 percent consisting of. Do we have a complete circuit? Is that circuit just standing by itself? So I would want some more of information, Mr. Page, in order to answer your hypothetical.

Q. I understand the fiber link hypothetical is definitely different from the one involving the SOG equipment, but what I'm trying to do is simply test to the extent to which, if any, the staff is urging a different interpretation than the historical one of the concept used and useful. And I think you said you didn't think so, at least not in this case?

A. And I would -- yes, as far as that's concerned, yes, I don't believe that we are making any changes in our application of used and useful.

Q. I believe you did say in your testimony at one point that these fast-acting digital pieces of equipment put some stress on the traditional definition of used and useful?

A. I think what we've seen, due to the pace -- hang on just a minute, I'll find where we said that.

MS. CUMMINGS: Mr. Page, do you have a page number to reference Mr. Williamson's --

MR. PAGE: Yeah. I'm looking that up right now.

(Pause.)

Q. This may be in your summary, Mr. Williamson, and I'm now looking at your summary. Yeah. If you will look down at the bottom of page 1 of your summary and then over to the top of page 2, it states, does it not, quote:

My testimony also highlights the potential challenges to reviewing the cost-effectiveness of GIP, grid improvement programs, in an ongoing manner. The complexity with which current GIP program software and physical devices interact means that, quote, full functionality, unquote, may not neatly match up with traditional concepts of, quote, used and useful, period, unquote.

Is that part of your summary and thus part of your testimony?

A. Yes, sir, it is.

Q. All right. Did the Public Staff, at any point in time, consider, instead of placing 100 percent of the cost of these SOG circuits into the rate base, of only giving full rate base treatment to those that had been fully enabled as of the end of hearings and putting the rest of it in at some discounted value?

A. I don't believe in this case, Mr. Page, we actually did that analysis.

Q. That would come closer to matching up the cost with the benefits resulting; would it not?

A. I could see where you could make that argument and do the separation, but we did not do that in this case.

Q. Would it bother you, as an engineer and as a member of the Public Staff, if the Commission were, itself, to exclude some of these not-fully-enabled circuits from the rate base or to put them in at a discounted value?

A. Well, as we contemplated in the testimony, I think I did say that there is a timing mismatch between full enablement and when the SOG components are installed. So yeah, I would just say there is an argument to be made there, and we'll leave the Commission to decide if that's the proper course.

Q. Thank you, Mr. Williamson. I appreciate your taking a walk with me out in the country with me today.

MR. PAGE: And, Mr. Clodfelter, that's all I have.

COMMISSIONER CLODFELTER: Thank you, Mr. Page.

Does any other party have any cross examination for Mr. Williamson?

(No response.)

COMMISSIONER CLODFELTER: If not, Ms. Cummings, redirect.

MS. CUMMINGS: Yes, I have a few questions.

REDIRECT EXAMINATION BY MS. CUMMINGS:

Q. Mr. Williamson, for these 135 distribution circuits, all the physical components are installed and all that's left to be done is to program circuit, right?

A. I'm sorry, I just -- that feedback is hitting me again, so would you repeat your question?

Q. Sure. I think you've already testified to this, but in answering Mr. Page's question I just wanted to clarify that all the physical components have been installed on these SOG circuits, these -- the circuits you say evolved and the rest of the circuits, but you're waiting for the enablement, that's all that's left?

A. Well, just to clarify. So there -- right. There were 135 that were included in the update. We sampled 10. Three of those were fully enabled, and there were seven that still needed some additional enablement. So there are 7 of those 10 that we sampled that still needed some SOG work.

Q. Sure. And out of those 10, so for the 7 that have not been enabled, the manual operation of those circuits, it can be done from the control center, right, rather than rolling a truck?

A. Yes. If there's an outage detected and the Company wants to try to switch around it, yes, the information goes back to the distribution control center, and they do some manual calculations, determinations based on the current conditions, whether it's a storm or an accident that has caused the outage, and then they can effect those changes from the control center.

Q. So that provides some benefits over the existing -- before the SOG physical components were installed?

A. Yeah. There would be some enhancement, yes, of stability. And like we said earlier, you know, SOG enablement, that's the automatic. We should see two to three minutes on average of detection of an outage, location isolation, and then return to service of the unaffected segments. And then stepping down from that, like we said, we -- from that same -- which can be done, albeit manual.

Q. Thank you.

MS. CUMMINGS: That's all the redirect I have.

COMMISSIONER CLODFELTER: All right. Questions from Commissioners.

Commissioner Brown-Bland?

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

COMMISSIONER CLODFELTER: All right. Commissioner Gray?

COMMISSIONER GRAY: I do not have any questions.

COMMISSIONER CLODFELTER: Thank you. Chair Mitchell?

CHAIR MITCHELL: No questions.

COMMISSIONER CLODFELTER: All right. Commissioner Duffley?

COMMISSIONER DUFFLEY: No questions.

COMMISSIONER CLODFELTER: Commissioner Hughes?

COMMISSIONER HUGHES: No questions.

COMMISSIONER CLODFELTER: And Commissioner McKissick, anything from you?

COMMISSIONER McKISSICK: No. No questions.

COMMISSIONER CLODFELTER: Okay. I think we are at the point where, Ms. Cummings, any motions?

MS. CUMMINGS: There are no exhibits to the supplemental testimony, so I don't have a motion for that. But I would ask that, if we're done with Mr. Williamson, that he be excused.

COMMISSIONER CLODFELTER: Unless there is some party who has reason to hold on to Mr. Williamson, we will excuse him. Thank you, Mr. Williamson.

THE WITNESS: Yes, sir.

COMMISSIONER CLODFELTER: All right. Ms. Downey, back to you.

MS. DOWNEY: Commissioner Clodfelter, I believe that concludes the Public Staff's case.

COMMISSIONER CLODFELTER: Okay. Let me make one last check before we go back to the Company for rebuttal. Ms. Medlyn, are you with us?

MS. MEDLYN: Yes, I'm here.

COMMISSIONER CLODFELTER: I do not -- you are the only intervenor that I haven't checked with for sure. I do not have any prefiled testimony from any witnesses, and I did not have you down for any other purpose, but you are an intervenor in the case, and I wanted to check with you to see if there is any matters you wish to put into the record at this time.

MS. MEDLYN: Thank you, Commissioner. No matters for me. Thank you.

COMMISSIONER CLODFELTER: Okay. Very good. Thank you.

And with that, Mr. Robinson, we will turn the case back to the Company for its rebuttal. There you are. I found you. Okay. Mr. Robinson, you're up.

MR. ROBINSON: Yes. Thank you, Commissioner Clodfelter, I think first up we have witness Jay Oliver.

COMMISSIONER CLODFELTER: Mr. Oliver, welcome back. And I forget how many appearances you've made so for in this sequence. This is either number 2, number 3, number 4, or number however many thousand it is. Welcome back.

Whereupon,

JAY W. OLIVER,

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

COMMISSIONER CLODFELTER: Okay. Now, Mr. Jeffries, I believe we are with you.

MR. JEFFRIES: Thank you, Mr. Chairman.

DIRECT EXAMINATION BY MR. JEFFRIES:

Q. Mr. Oliver, could you state your name and business address for the record, please?

A. Yes. My name is Jay Oliver. I work at 400 South Tryon Street, Charlotte, North Carolina.

Q. And as Chairman Clodfelter alluded to just a moment ago, you're the same Jay Oliver that previously testified in the consolidated phase of these proceedings on grid improvement plan issues; is that right?

A. That is correct.

Q. Mr. Oliver, did you cause to be prefiled, supplemental rebuttal testimony in this docket consisting of four pages on September 22, 2020?

A. I did.

Q. And that testimony was filed in response to the supplemental testimony of Public Staff witness Mr. Williamson that was filed on September 15th, correct?

A. Yes.

Q. And as we just heard Mr. Williamson testify to, his supplemental testimony was focused on the issues of the SOG implementation by the Company, correct?

A. Yes.

Q. And your supplemental rebuttal testimony was addressed to those issues, correct?

A. Yes.

Q. All right. Mr. Oliver, returning to your -- the subject of your supplemental rebuttal testimony, was that testimony prepared by you or under your direction?

A. It was.

Q. Do you have any corrections to that testimony?

A. I do not.

Q. And if I asked you the same questions as are set forth in your prefiled supplemental rebuttal testimony while you were on the stand today, would your answers be the same?

A. They would.

Q. Have you also prepared a summary of your supplemental rebuttal testimony?

A. Yes.

MR. JEFFRIES: Mr. Chair, we would move

that Mr. Oliver's prefiled supplemental rebuttal testimony and summary of his supplemental rebuttal testimony be entered into the record as if given orally from the stand.

COMMISSIONER CLODFELTER: All right. You've heard Mr. Jeffries' motion. Is there any objection to the motion?

(No response.)

COMMISSIONER CLODFELTER: Hearing none, motion is granted.

(Oliver Exhibits 1 through 18, and Oliver Rebuttal Exhibit 1 was moved at the consolidated hearing and admitted into evidence.)

(Whereupon, the prefiled direct and rebuttal testimony of Jay W. Oliver were moved at the consolidated hearing and copied into the record as if given orally from the stand.)

(Whereupon, the prefiled supplemental rebuttal testimony and testimony summary of Jay W. Oliver were copied into the record as if given orally from the stand.)

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

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

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Jay W. Oliver. My business address is 400 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 General Manager, Grid Solutions Engineering and Technology. 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, GRID SOLUTIONS ENGINEERING AND TECHNOLGY FOR DUKE ENERGY.

A. My duties and responsibilities include planning for the grid and related system improvement efforts across Duke Energy.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL QUALIFICATIONS.

A. I have a Bachelor of Science degree in Electrical Engineering from the Georgia Institute of Technology and a Master's degree in Business Administration from the University of South Florida. I am a licensed Electrical Engineer and a registered Professional Engineer in Florida. From 25 years working in the electric utility business, I have experience in electric transmission, distribution, and information technology and telecommunications systems that support utility transmission and distribution networks. I began working at Duke Energy in 1996, joining one of its predecessor companies, Florida Progress. Over the past 10 years, I have held the positions of Region General Manager, Director Distribution Services, Major Projects Manager, and Director, Grid Automation. I have been in my current role since January 2017.

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

A. Yes. I testified before the North Carolina Utilities Commission ("NCUC") in DE Progress' 2013 Demand Side Management/Energy Efficiency proceeding in Docket No. E-2, Sub 1030 and in DE Progress' 2014 Fuel Charge Adjustment proceeding in Docket No. E-2, Sub 1045. I also provided direct and rebuttal testimony in DE Progress' and DE Carolinas' recent South Carolina base rate adjustment proceedings in Docket Nos. 2018-318-E and 2018-319-E. Additionally, I provided testimony in DE Carolinas' pending rate case in North Carolina in Docket No. E-7, Sub 1214.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I am testifying as an expert witness in this case in two separate capacities. In my capacity as the witness supporting ongoing operations, I describe and support the existing DE Progress transmission and distribution ("T&D") system, the operation and performance of the T&D system, and the costs necessary to operate and maintain it. In my capacity as the witness supporting DE Progress' Grid Improvement Plan for North Carolina, I describe trends affecting the electric grid and how we plan to address those growing challenges through our Grid Improvement Plan.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. Following the introduction above, my testimony is organized as follows:

I. First, I will provide a description of DE Progress' T&D system, describing notable investments made in our system since the Company's last rate case in North Carolina and an overview of the operational performance of the Company's T&D system;

II. Second, I will describe the trends affecting the electric grid in the 21st century, how we analyze those issues, and how they will impact our grid if addressed through traditional means alone;

III. Third, I will describe the tools available to address the trends, explain how programs in the Grid Improvement Plan are evaluated, and present a foundational overarching plan which addresses the issues in a stakeholder-informed manner;

IV. Finally, I will provide a three-year work plan for our 2020-2022 grid improvements with defined projects. I note we are requesting a corresponding deferral on future Grid Improvement Plan costs as further explained by Witness Smith.

Q. ARE YOU PROVIDING ANY EXHIBITS WITH YOUR TESTIMONY?

A. Yes. I have attached 18 total exhibits, described below:

Oliver Exhibit 1: Maintain Base Transmission and Distribution System Work-describing what work the Company does as base-level maintenance work;

Oliver Exhibit 2: Megatrends Impacting North Carolina - detailing key trends relevant to the Grid Improvement Plan;

Oliver Exhibit 3: North Carolina Grid Improvement Plan Implications - discussing how Megatrends are impacting operations in North Carolina;

Oliver Exhibit 4: North Carolina Grid Improvement Plan Program Summaries – describing the projects and programs in the Grid Improvement Plan;

Oliver Exhibit 5: Portfolio Prioritization Methodology – detailing how the Grid Improvement Plan is prioritized;

Oliver Exhibit 6: Cost benefit and Cost Effectiveness Evaluation Execution Protocol – showing how the Company evaluates potential grid improvement projects;

Oliver Exhibit 7: Cost Benefit Analyses

Oliver Exhibit 8: North Carolina Grid Improvement Plan Portfolio Cost Benefit Analysis Summary

Oliver Exhibit 9: Grid Improvement Plan Benefits Pyramid

Oliver Exhibit 10: North Carolina Grid Improvement Plan;

Oliver Exhibit 11: June 25, 2018 Power Forward Carolinas Technical Workshop Report - containing the results of the Company's first North Carolina stakeholder workshop;

Oliver Exhibit 12: November 2018 North Carolina Grid Improvement Plan Workshop Pre-Read - containing materials provided to stakeholders prior to the November 18, 2018 workshop;

Oliver Exhibit 13: January 9, 2019 North Carolina Grid Improvement Plan Workshop Report - containing the results of the Company's second North Carolina stakeholder workshop;

Oliver Exhibit 14: April 25, 2019 Webinar Materials

Oliver Exhibit 15: May 16, 2019 North Carolina Grid Improvement Plan Workshop Pre-Read - containing materials provided to stakeholders prior to the May 16, 2019 workshop;

Oliver Exhibit 16: July 2, 2019 North Carolina Grid Improvement Plan Workshop Report - containing the results of the Company's third North Carolina stakeholder workshop held on May 16, 2019;

Oliver Exhibit 17: March 12, 2019 Rebuttal Testimony filed in Docket No. 2018-319-E; and

Oliver Exhibit 18: June 2019 Webinar Presentations

Q. WERE OLIVER EXHIBITS 1 THROUGH 18 PREPARED OR PROVIDED HEREIN BY YOU, UNDER YOUR DIRECTION AND SUPERVISION?

A. Yes. They were.

Q. DO THESE EXHIBITS CONTAIN ONLY INFORMATION ABOUT DE PROGRESS?

A. No. Duke Energy has created a plan for the grid in North Carolina, and that includes both DE Progress and DE Carolinas. All information is shown in a utility-specific manner. I believe it is important to show these plans jointly as we think of the needs of customers in the state. Moreover, I believe it facilitates better discussions among parties and entities, who have interest in both service territories, to see the material presented together.

Q. PLEASE PROVIDE AN OVERVIEW OF YOUR OPERATIONAL TESTIMONY.

A. DE Progress reliably serves approximately 1.4 million customers in North Carolina through a multi-state electric system that includes 6,300 miles of transmission lines, approximately 76,500 miles of distribution lines, and more than 800 substations. For the DE Progress distribution system, approximately 6,900 distribution line miles were added over the last two years.

As part of the Company's commitment to reliably serve customers and continually improve operations, DE Progress has invested $1.3 billion in electric plant in service for T&D infrastructure over the last two years. Maintenance work and reliability improvements included replacement of deteriorated wooden poles, replacement of obsolete line and substation equipment, and customer-driven line and substation expansions.

DE Progress also maintains a comprehensive vegetation management program across the state that works to proactively maintain trees both within and outside the rights-of-way on regular cycles. This work seeks to improve overall reliability, harden the grid against severe weather, and reduce the impact of vegetation which currently accounts for 20 to 30 percent of outages across the system.

Overall, the DE Progress grid is reliable and well-maintained. While the Company has worked hard to maintain the system and reliably meet the needs of customers, we also understand more must be done to improve the state's energy infrastructure to meet the energy challenges and opportunities that lie ahead.

Q. PLEASE PROVIDE A SUMMARY OF THE COMPANY'S GRID IMPROVEMENT PLAN.

A. Through a comprehensive assessment of the state of the grid and influences affecting the region, the Company has identified emerging trends, which I refer to in my testimony as "Megatrends," that drive the need to make improvements now to the electric system in North Carolina.

North Carolina is a growing state, especially in urban and suburban areas, where residential and business growth is becoming concentrated. With that growth comes growing consumer expectations for more interaction with their electric company and more control over the way they use electricity. And along with that, a higher reliance on "perfect power" – power that stays on – and when an outage does occur, is restored faster than ever.

As recent events have reinforced, the Company must be ready for severe weather before it strikes and reduce the impact of storms that are worsening in frequency and intensity. The Company must be vigilant and prepare now for the very real threat of cyber and physical attacks. And as renewable energy and distributed energy technologies like solar energy, battery storage, microgrids, and electric vehicles become more affordable and accessible, it is important to take steps now to ready the grid to support the growth of these technologies that are important to the state's energy future.

These influences come at a time of increasing environmental commitments and compliance requirements that drive change for the Company and the industry. But they also come at a time when grid technology is rapidly advancing and becoming increasingly intelligent, providing new tools and new opportunities to improve the way the Company serves customers.

To deliver on customer expectations and address these trends, the Company believes that we must do more than maintain the power grid; the Company must make the appropriate investments to transform it, making strategic, data-driven improvements to power a smart-thinking grid that is more reliable, more resilient, and built to meet the energy needs of customers today and into the future.

DE Progress' Grid Improvement Plan was developed through a comprehensive analysis of the trends affecting our business in the state and the tools to best address those trends in a cost-effective and timely manner. The Grid Improvement Plan is built upon strategic, data-driven investments to: improve reliability, avoid outages, and speed restoration; harden the grid to protect against cyber and physical threats; expand solar and other innovative technologies across a two-way, smart-thinking grid; and give customers more options and control over their energy use and tools to save money. These foundational improvements will transform the grid and provide a new level of operation while providing benefits now and in the years to come.

Components of Duke Energy's Grid Improvement Plan operationally fall into one of three categories:

- Compliance-driven programs that **protect** the grid;
- Programs that leverage advanced technologies to **modernize** the grid; and
- Projects and programs that work to **optimize** the customer's experience.

1. Protect the grid

More must be done to harden and defend the grid against critical physical and cybersecurity risks. Compliance requirements in these areas are also driving improvements across the state. Examples of the company's multi-layered improvements designed to protect the grid include installing protective devices to limit access to critical systems and minimize outages from physical or cyber attack.

2. Modernize the grid

Technology is rapidly changing, and more must be done to incorporate and anticipate new technologies to better serve a growing state. Customers – more than ever – expect more options, greater reliability, and value. Self-selecting billing and payment dates, scheduling appointments, accessing real-time usage data, and information updates when outages occur are all examples of basic services consumers expect but require technology to deliver. And increasingly, consumers want access to information about how they use energy and tools to take control of that energy use and save money.

Examples of improvements designed to modernize the grid include:

- Smart meters to provide improved customer usage data, enhanced outage detection to improve customer service, and access to increased customer options to manage energy use and save money.

- Distribution automation and dispatch tools to improve power quality and reliability and support the growth of distributed energy resources and customer-owned technologies.
- Integrated system operations planning, automation, and system intelligence to prepare the grid for increased distributed resources and the dynamic power flows that these technologies bring.
- Communication improvements and expansions from high-speed, high-capacity backbone fiber optic and microwave networks to the wireless connections at the edge of the grid. These upgrades help build the secure communications required for the increasing number of smart components, sensors, and remotely activated devices on the transmission and distribution systems.

3. Optimize the customer experience

Customers want and deserve a better experience, built on the technology needed to meet their changing energy needs. To meet these expectations, we must optimize the total customer experience and transform the grid to prepare it for the energy opportunities that lie ahead.

Optimization upgrades in the grid improvement plan include:

- A self-optimizing, smart-thinking grid that anticipates outages and automatically reroutes service to keep power on for customers. Self-Optimizing Grid technology can reduce outage impacts on customers by as much as 75 percent. It will also provide the foundation for the two-way power flows needed to support more rooftop solar, battery storage, electric vehicles, and microgrids – technologies that will increasingly power the lives of customers.

- Expanded energy storage capabilities and infrastructure, which will help to power self-optimizing technologies in areas where building a redundant power line may not be feasible.
- Electric vehicle charging infrastructure improvements to expand transportation options for customers across the state. This component is filed in a separate Docket, No. E-2, Sub 1197.
- Voltage optimization and distribution of power to customers to improve reliability, increase system intelligence and support the two-way power flow needed to grow distributed resources.
- Upgrading breakers, transformers, and other grid equipment, as well as using advanced data to strategically underground the most vulnerable, outage-prone lines on the distribution system.

The Company has constructed the stakeholder-informed Grid Improvement Plan to address the risks and opportunities that the analysis revealed. The Plan seeks to balance the pace, scope, location, and timing of our work to address a diverse set of customer and stakeholder needs. As we built the Grid Improvement Plan proposed in this case, the Company has also kept the needs of our rural and low-income customers in mind and sought to develop a strategy that maximizes benefits to all customers and the state, while keeping costs as low as possible.

In developing this informed plan, the Company layered data analytics with significant input from customer and advocacy groups, and other stakeholders. Finding common ground on important topics that affect all of our customers is very important to Duke Energy. The Company realizes that plans that look good on paper may not translate the way we think they will when executed in the real world. That is why the Company has sought out customer and stakeholder perspectives, including multiple stakeholder workshops, as part of the process before presenting this plan.

Consistent with the Commission's Order in the last rate case, I describe the steps taken by the Company to collaborate with stakeholders to produce a list of projects, referred to as the North Carolina Grid Improvement Plan that I believe can effectively serve customers now and in the years ahead. Oliver Exhibit 10 shows numbers for a three-year plan for North Carolina based on budgeting methods, which differs from ratemaking allocations.

The Grid Improvement Plan is about making smart foundational choices now to make the state's energy grid more reliable, more secure, and ready for the energy opportunities that lie ahead. Just as the past decade modernized the way Duke Energy generates electricity, the years ahead will transform the way we deliver electricity and serve customers. With each improvement, we can improve the overall reliability of the grid and enhance service for every customer, regardless of the type of customer or their location.

I. DE PROGRESS' T&D SYSTEM OVERVIEW AND INVESTMENTS SINCE THE COMPANY'S LAST RATE CASE IN NORTH CAROLINA

Q. PLEASE GENERALLY DESCRIBE DE PROGRESS' T&D SYSTEM IN THE CAROLINAS.

A. DE Progress' T&D system delivers electric service to approximately 1.6 million retail customers located throughout a 32,000 square mile service area in eastern North Carolina, eastern South Carolina and western North Carolina. Approximately 1.4 million of the Company's retail customers are in North Carolina. In addition to its retail customers, DE Progress also sells electricity at wholesale rates to municipal, cooperative, and other investor-owned utilities.

DE Progress operates as a single balancing authority with two balancing authority areas to economically manage the Company's integrated electric delivery systems in both North Carolina and South Carolina, collectively. This system interconnects with other balancing authority areas[1] and includes approximately 6,300 circuit miles of transmission lines. The distribution system is comprised of approximately 46,500 miles of overhead distribution lines and 30,000 miles of underground distribution lines. DE Progress' T&D system also includes 85 transmission substations, and 724 distribution substations with a combined capacity of approximately 57 million KVA. In addition to power lines and substations, the system includes various other equipment and facilities such as control rooms, computers, poles, transformers,

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Pennsylvania-Jersey-Maryland (NC & VA), Duke Energy Carolinas, Dominion Energy South Carolina (formerly South Carolina Electric & Gas), Tennessee Valley Authority (TVA), Cube Hydro Carolinas, and South Carolina Public Service Authority (SCPSA).

regulators, capacitors, street lights, meters, and protective relays. Together, these assets provide the Company considerable operational flexibility with its T&D system and allow DE Progress to provide safe, reliable, and economical power to the Company's customers in North Carolina.

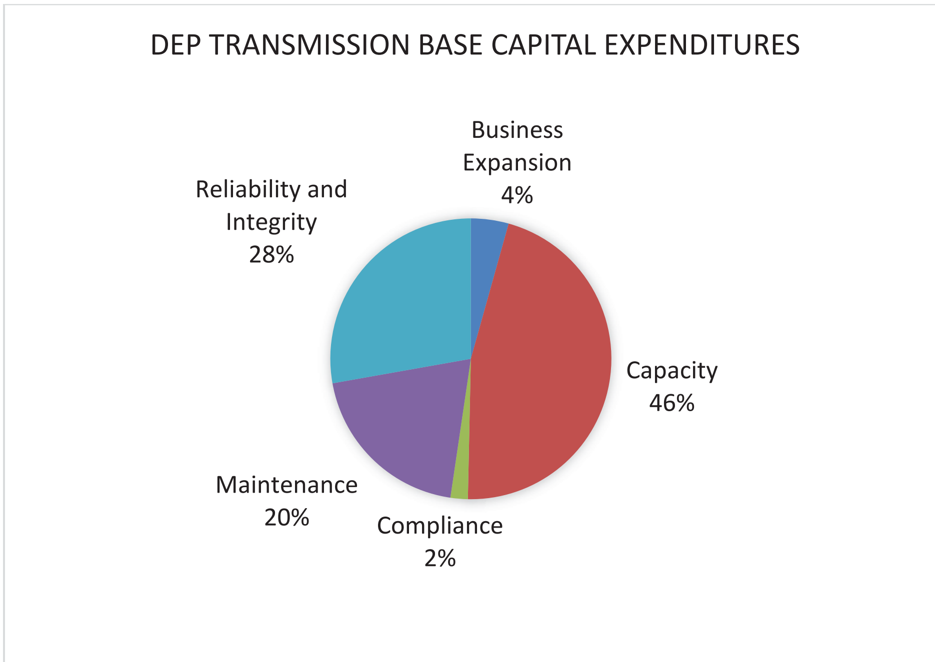
Q. HAS DE PROGRESS' T&D SYSTEM GROWN SINCE THE LAST RATE CASE?

A. Yes. The T&D system has expanded over time to ensure adequate system voltage and capacity, based on projected system loading, and contingency requirements related to providing safe and reliable service to our customers. Transmission system growth has also occurred because of new generation and/or decommissioning of existing generation assets. For the DE Progress distribution system, approximately 6,900 distribution line miles were added over the last two years. Overall, we have added approximately $1.3 billion to electric plant in service for T&D infrastructure in the last two years.

Q. CAN YOU PROVIDE MORE DETAIL ABOUT THE ADDITIONAL INVESTMENTS THE COMPANY HAS MADE IN ITS BASE T&D SYSTEM SINCE THE LAST RATE CASE?

A. Additional investments in the Company's T&D system have been made to provide capacity to serve system growth, ensure adequate system voltage, support transmission-related infrastructure for both new generation and decommissioning of generation, and improve certain aspects of system reliability. Over the past two years, more than $0.3 billion was invested in the transmission system and approximately $1.0 billion in the distribution system inclusive of additions through the Grid Improvement Plan which I discuss in the second part of my testimony.

The chart below illustrates the major categories of the transmission base system capital investment over the last two years.[2]

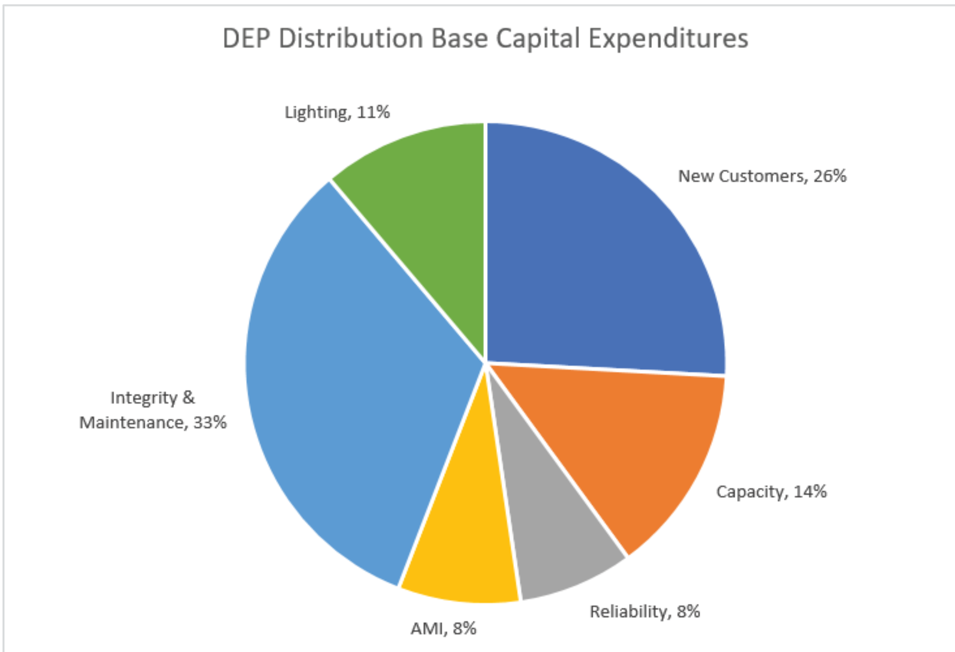


In the transmission system, approximately 46 percent of investment was driven by capacity requirements to serve load and to meet the North American Reliability Council ("NERC") Planning Standards and generation driven projects such as the Asheville Combined Cycle. Approximately 48 percent of investment was driven by reliability improvement and maintenance programs. Examples of this type of investment include the replacement of deteriorated wood poles and replacement of obsolete substation and line equipment. Approximately 4 percent of the investment was driven by business expansion

[2] 2017 and 2018 expenditures.

work which includes new customer projects as well as line and substation upgrades driven by Transmission service requests. Approximately 2 percent of the investment was driven by compliance projects.

The chart below illustrates the major categories of the distribution system base capital expenditures over the last two years.[3]



North Carolina continues to be a desirable place to live and work, as evidenced by the nearly 22,000 new retail customer meters added during the 12-month period ending December 31, 2018. Typically, new customers locate in areas where DE Progress must build new distribution facilities to serve them, including expenses for new customer connections or capacity work needed to support overall load growth. Approximately 51 percent of the Company's distribution expenditures over the last two years are for load expansion-related

[3] 2017 and 2018 expenditures.

work, including serving new customers, lighting installations, and additional capacity.

Approximately 41 percent of the investments on the Company's system relate to base-level work around standard reliability and integrity programs that address safety and environmental requirements and maintenance including service restoration. Approximately 8 percent was for the deployment of AMI.

Q. CAN YOU PROVIDE DETAIL ABOUT HOW THE COMPANY DETERMINES WHAT IS TO BE CATEGORIZED AS BASE T&D SPENDING?

A. Yes. The type and scope of transmission and distribution "Maintain Base" work that we perform on our system can generally be thought about as a product of the following equation: [Safety Requirements] + [Load Service Requirements] + [Reliability Requirements] + [Environmental Requirements] = Type and Scope of Work. What work goes into the four elements of this equation may be dictated by mandatory external requirements (such as laws, codes, and regulations), internal company standards, national industry standards, or a combination of these requirements and standards, but any base-level work done on the transmission and distribution system fits into one of these four categories. In Oliver Exhibit 1, I have provided more detail as to what general work fits into each one of the categories.

Q. IN YOUR OPINION, ARE ALL THE T&D FACILITIES INCLUDED IN DE PROGRESS' BASE RATE REQUEST USED AND USEFUL IN PROVIDING SERVICE TO DE PROGRESS' RETAIL ELECTRIC CUSTOMERS IN NORTH CAROLINA?

A. Yes. Including the projects that will be completed prior to the evidentiary hearing in this case, all of the reasonable and prudent additions to DE Progress' T&D system requested for recovery in base rates are used and useful to its 1.4 million customers in North Carolina.

Q. HAVE THE T&D INVESTMENTS THAT THE COMPANY HAS MADE ALLOWED IT TO MEET ITS OPERATIONAL PERFORMANCE GOALS?

A. Yes. They have, but as I discuss later in my testimony, we are seeing unfavorable trends that are making these goals more challenging to meet. DE Progress' principal goal is to deliver safe and reliable electric service at reasonable prices. We measure this principal goal based on customer satisfaction, safety, and reliability of the Company's T&D systems, while responsibly managing operational and capital expenditures for the benefit of our customers.

Q. PLEASE EXPLAIN THE METRICS THE COMPANY USES TO MEASURE THE EFFECTIVENESS OF ITS T&D OPERATIONS.

A. DE Progress utilizes several industry-standard metrics to assess the overall effectiveness of its T&D operations. These metrics include reliability indices to measure the performance of the T&D system and customer satisfaction scores to determine how well the Company is meeting the needs of its customers.

The Company uses several industry-accepted transmission and distribution performance metrics as defined in IEEE Standard 1366-2012:

- **System Average Interruption Frequency Index ("SAIFI")** is a ratio that indicates how often the average customer experiences a sustained interruption over a predefined period of time.
- **System Average Interruption Duration Index ("SAIDI")** is a ratio that indicates the total duration of interruption for the average customer during a predefined period of time.
- **Customers Experiencing Multiple Interruptions ("CEMI 6")** is a measure of the percentage of customers who experience six or more outages in a 12-month period.

Q. HOW HAS DE PROGRESS' TRANSMISSION AND DISTRIBUTION SYSTEM PERFORMED UNDER THESE METRICS?

A. Our system has performed well, and we have continued to provide safe, reliable, and affordable electric service to our customers. Over the past ten years however, SAIDI shows an unfavorable trend, with the duration of outages increasing across the DE Progress system despite our efforts and investments that I have discussed previously. I will discuss causes for this trend later in my testimony. Graphs displaying the trends for these metrics are set forth below:

Figure 1 – Duke Energy Progress' Historic System Average Interruption Frequency Index (SAIFI)

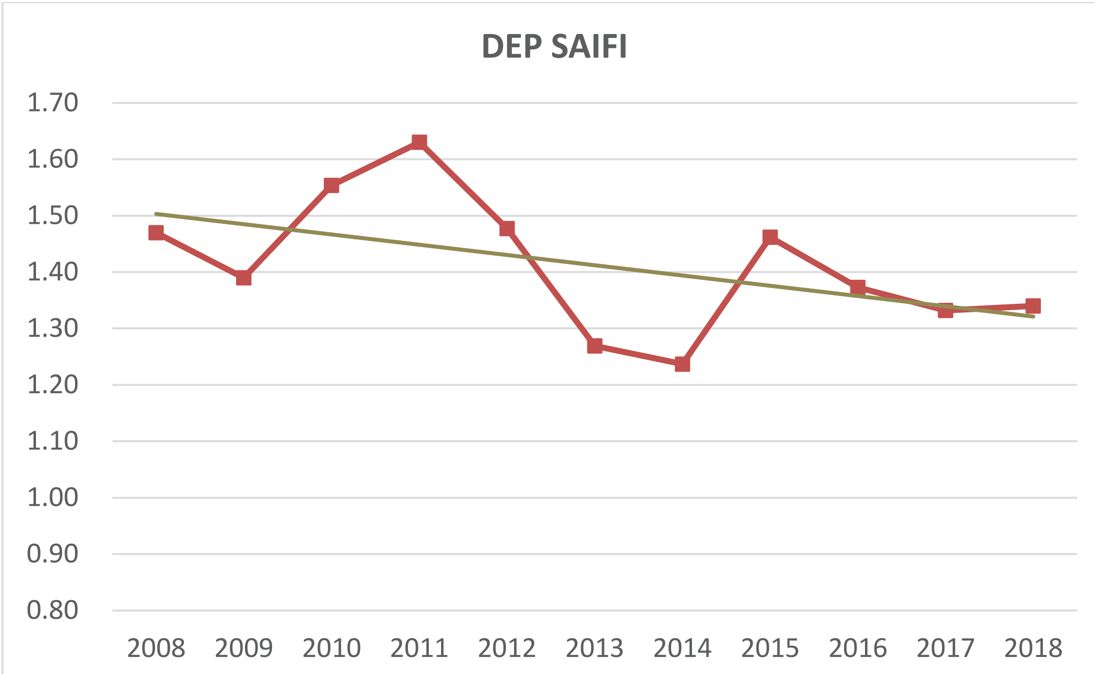
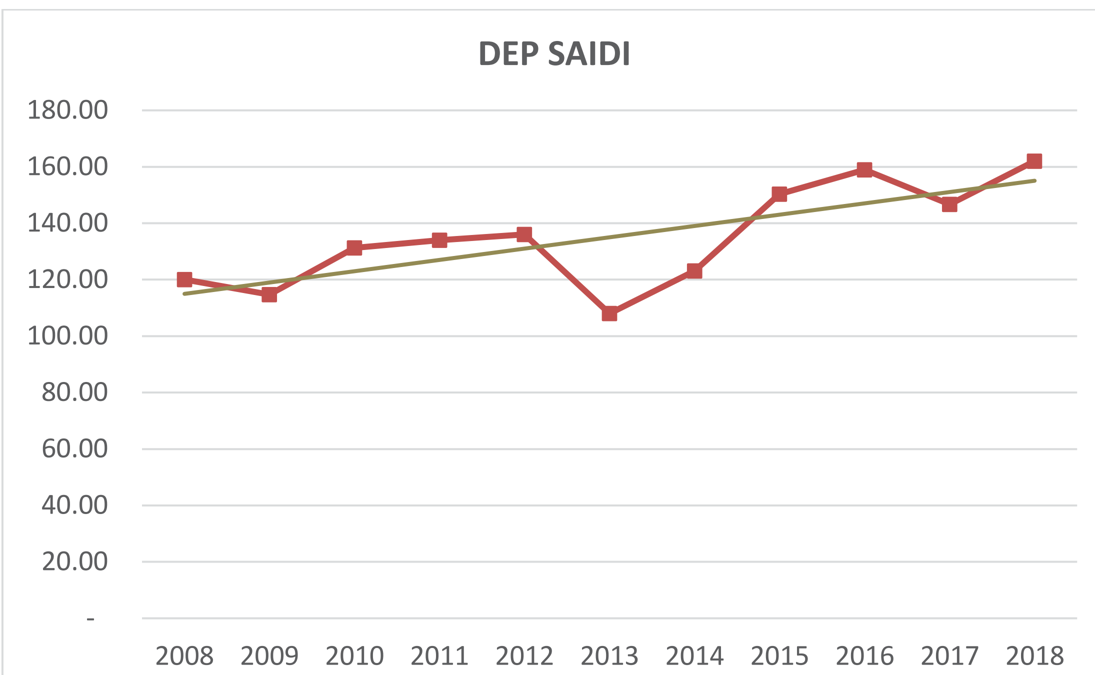


Figure 2 – Duke Energy Progress' Historic System Average Interruption Duration Index (SAIDI)



Q. PLEASE EXPLAIN HOW DE PROGRESS' APPROACH TO DISTRIBUTION VEGETATION MANAGEMENT AFFECTS OPERATIONS.

A. Vegetation management is a critical component of the Company's Customer Delivery Operation and a continued effort to drive performance for customers' benefit. DE Progress uses a combination of a reliability-based and a time-based prioritization model to drive its routine integrated vegetation management program. In addition to routine circuit maintenance, there are four other very important components to the Company's overall vegetation management approach.

(1) Herbicide spraying is planned on an annual basis to control the re-growth of incompatible vegetation along the "floor" of the right-of-way of non-landscaped areas following maintenance pruning and or on a cycle basis;

(2) Cutting down of "hazard trees" outside of the area normally maintained on a distribution line. The Company implemented this program in 2014 and has been successful in targeting removal of diseased, decayed or dying trees to preserve the integrity and safety of our lines;

(3) Unplanned work performed at the direction of reliability engineering as a result of outage follow-up investigations or by customer initiated requests; and

(4) Disciplined vegetation management outage follow-up process tied to a formal internal reliability review process.

In 2018, the Vegetation Management Plan implemented the seven-year trim cycle for non-urban miles, which had previously been set at six years. The change was based on the result of the Distribution Vegetation Management Species Frequency and Re-Growth Study completed in 2015 conducted to help determine an optimal vegetation maintenance cycle. The study did not result in a change from the three-year trim cycle set for urban miles.

Q. DOES THE COMPANY PROPOSE AN INCREASE IN FUNDING FOR VEGETATION MANAGEMENT?

A. Yes. As explained by Witness Smith, we have included a pro forma adjustment for the North Carolina retail portion of the incremental O&M for the Distribution Vegetation Management Program. The need for the increase is two-fold. First, it will cover the known contract rate increases that took effect in 2019. The increase in contract rates is driven by a tightening labor market and the ability for vegetation suppliers to acquire and retain qualified workers. Second, the increase will cover the mileage in the plan, which is higher than the mileage completed in the test year for this case due primarily to Hurricanes Florence and Michael and Winter Storm Diego.

. We have also included a pro forma adjustment for the North Carolina portion of the incremental O&M expense for the Transmission Vegetation Management Program. This increase will cover known contract rate increases in 2019 and the requirement mileage for maintenance trimming and the herbicide program.

Q. WILL THE COMPANY'S VEGETATION MANAGEMENT PLAN CURE ALL ADVERSE SYSTEM IMPACTS THAT THE COMPANY HAS SEEN DEVELOP IN THE RECENT PAST?

A. No. Vegetation events account for 20 to 30 percent of all outage events. It is important to understand that approximately 70 to 80 percent of all outages on the grid are due to other causes, such as equipment failure, public accidents, and environmental factors. In addition, for the events that are vegetation related, only approximately 50 percent of these are related to vegetation inside the right-of-way where the Company can perform vegetation management. The other 50 percent occur due to trees outside the right-of-way that will fall into or otherwise impact distribution lines, and the Company does not have the ability to perform vegetation management on these trees that are located on private property. For the outages that occur because of trees inside the right-of-way, even a perfectly executed integrated vegetation management plan will not bring this number down to zero but instead will only help minimize vegetation outages.

Keeping these facts in mind, the Company engaged in the Tree Growth Study that I previously discussed to determine the optimal right-of-way trimming cycles for our geographical areas. Trimming more often than these now pre-determined, optimal cycles will only provide diminishing returns and would not be cost effective. Drastic clear cutting and going onto customer property and cutting down live trees via condemnation or negotiating with customers for rights on their property is also impractical and not cost effective.

Instead, programs such as Targeted Undergrounding, which will be discussed in more detail later in my testimony, can be effectively used to address vegetation outages caused by trees outside of the right-of-way, where the base vegetation plan stops.

II. NEW TRENDS AFFECTING THE NORTH CAROLINA ELECTRIC GRID

Q. HAVING DESCRIBED THE EXISTING T&D SYSTEM AND HOW THE COMPANY MAINTAINS ITS BASE-LEVEL OF SYSTEM PERFORMANCE, WHAT ARE SOME SYSTEM-WIDE TRENDS YOU HAVE OBSERVED AS IMPACTING THE T&D GRID?

A. There are seven major trends that we call "Megatrends" impacting Duke Energy's grid in North Carolina. The trends are summarized below and are discussed individually in detail in Oliver Exhibit 2:

1. Population and business growth continues in North Carolina and is heavily concentrated in urban and suburban areas;
2. Technology is advancing at a rapid rate in the areas of renewables and distributed energy resources ("DERs"), which means there are new types of load and resources impacting the grid;
3. Technology is also advancing rapidly within the devices and systems that operate and manage the T&D grids, offering new capabilities and requiring new functionalities;
4. Customer expectations and use of the grid are very different from generations past;

5. There has been an increase in environmental commitments from the international to local level in DE Progress' service territory;
6. The number, severity and impact of weather events on DE Progress' customers have been increasing significantly; and
7. The threat of physical and cyber-attacks on grid infrastructure is more sophisticated and is on the rise.

These seven Megatrends are the factors that are driving the need for the Company to have a Grid Improvement Plan that goes beyond the work that the Company performs to maintain base-level operations.

Q. HOW DID THE COMPANY IDENTIFY AND VALIDATE THAT THESE MEGATRENDS EXIST?

A. Over the past several years, we have seen these Megatrends develop in the day-to-day operation of our business. Some of these Megatrends, such as the increased number and increased sophistication of attempted cyber-attacks on our system, are easily identified and are evident as they happen. Other changes, such as the way our customers are using and depending on the power we provide them, are subtler and can be harder to identify. With all these Megatrends, however, our first step was to inventory facts and information that we saw from operating our grid that appeared different than the facts and information we had seen in the previous years of operation.

Once we had conducted the aforementioned inventory, we then looked across the industry to see if other utilities and industry stakeholders were seeing the same Megatrends developing in their operations. As we suspected, the same new Megatrends that we are seeing develop in North Carolina are also being seen throughout the industry.

Q. HOW DID THE COMPANY GO ABOUT ESTABLISHING THAT THE FACTS AND INFORMATION IT WAS SEEING ROSE TO THE LEVEL OF ESTABLISHING WHAT YOU HAVE CALLED MEGATRENDS?

A. During this process of identifying and validating the Megatrends, we collected objective information from our own operations in North Carolina. We also noted commonality from other jurisdictions in the facts and information that evidenced the existence of these Megatrends. From there, we then began to look at objective national information that non-Duke companies and industry stakeholders were sharing publicly. That information also confirmed the existence and validity of the Megatrends. In Oliver Exhibit 2, I have included summary data, citations, and information that the Company collected on each Megatrend.

The 2016 South Carolina State Energy Plan also noted the existence of many of these trends, as the following passage reveals:

"In developing this State Energy Plan, it has become very evident that electric utilities are facing expanding customer expectations, increasing environmental regulation, and new technologies that have to be integrated seamlessly into the grid. The grid of the rapidly approaching future will function in ways never imagined when the original wires were installed. If South Carolina is to participate in the innovation coming to fruition in the electric sector — such as distributed energy resources like solar panels, wind turbines, electric vehicles, and microgrids — then the state will require an advanced, integrated grid to manage and optimize the increasingly dynamic flow of electricity."[4] Furthermore, reports from independent third parties as well as stakeholder interactions in North Carolina show that the Company has correctly identified the megatrends that are impacting our system.[5]

Q. WHAT WAS THE NEXT STEP IN THE DEVELOPMENT OF THE GRID IMPROVEMENT PLAN AFTER THE COMPANY IDENTIFED AND VALIDATED THE EXISTENCE OF THE MEGATRENDS?

A. Once we found that the Megatrends we were seeing in North Carolina were valid, and that those Megatrends were also impacting utilities across the nation, we then had to analyze whether the Megatrends mattered. Said another way, the Company had to evaluate whether any or all the Megatrends caused any problems or issues that warranted work in North Carolina that was above and beyond the Company's base-level T&D plan that I have previously discussed.

Q. HOW DID THE COMPANY PERFORM THIS EVALUATION?

A. To determine whether one or more of these Megatrends warranted the Company to develop an incremental Grid Improvement Plan for the state, the Company first listed out all the implications that the Megatrends would logically and objectively have on providing our customers safe, reliable, and affordable electric service. For example, one of the facts we discovered was that customers with higher usage and higher expectations for power quality and reliability were

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[4] http://www.energy.sc.gov/files/Energy%20Plan%20Appendicies%2003.02.2018.pdf
2016 South Carolina State Energy Plan, Appendices, Page 121.

[5] http://gridlab.us/wp-content/uploads/2019/04/GridLab_SC_GridMod.pdf, Page 20.

beginning to concentrate more and more in urban and suburban areas such as Charlotte and Raleigh. These customers are the most likely group to embrace technologies like roof top solar and electric vehicles. Given this seemingly undeniable fact, we had to ask the question of what this fact means to our T&D operations. What we found is that our business as usual approach to serving this new load would not address the implications created by the Megatrends. We also realized that the capital required to serve high growth areas can undermine investment in rural areas of the state, causing disparity between customer demographics and geography. In Oliver Exhibit 3, I have included our evaluations of these Megatrends and what implications they will have on the Company's grid operations.

III. GRID IMPROVEMENT PLAN

Q. ONCE THE COMPANY IDENTIFED AND VALIDATED THE MEGATRENDS AND THE IMPACTS THEY ARE HAVING ON THE GRID NOW AND IN THE FUTURE, WHAT PROCESS DID THE COMPANY USE TO PUT ALL THIS INFORMATION INTO A GRID IMPROVEMENT PLAN?

A. At this point in our evaluation, the Company took the following overall steps to develop a proactive plan that addresses impacts of the Megatrends:

1. Identified "tools" (i.e. utility projects and programs) available to address the Megatrend impacts. In Oliver Exhibit 4, I have included detailed descriptions of the programs and projects that the Company considered as "tools" to address Megatrend implications;

2. Determined constraints that impacted the creation of the plan such as equipment availability, personnel limitations, available time and schedule, any applicable prescriptive requirements, interplay with base-level work needs, and price impact;
3. Selected “tools” to use in the plan in an iterative process that built up from a foundation of protecting the grid first and foremost; establishing foundational, system-level programs that are needed for all aspects of operations and that impact all customers next; and then focusing on projects and programs that help address the most number of Megatrend implications for the best value to customers. We called this phase of the plan development “protect,” “modernize,” and “optimize,” and I have included a series of graphics that help to explain this process as Oliver Exhibit 5 to my testimony; and
4. Developed a comprehensive Grid Improvement Plan that efficiently organizes the work to be completed based on where, when, and how much is appropriate.
5. Invited stakeholder feedback to ensure the plan addressed the diverse set of customer and stakeholder needs.

Q. YOU MENTIONED THAT THE FIRST STEP IN DEVELOPING THE GRID IMPROVEMENT PLAN WAS IDENTIFYING TOOLS THE COMPANY HAS TO ADDRESS THE MEGATRENDS. CAN YOU PROVIDE MORE DETAIL ON THIS PHASE OF THE PLAN DEVELOPMENT?

A. Yes. The programs and projects that are available to the Company to help address the implications of the Megatrends in North Carolina can be grouped into three basic categories based on how the Company brings those programs into its plan. These three categories are (1) compliance-driven programs that protect the grid, (2) rapid technology advancement programs that modernize the grid, and (3) various other projects and programs that work independently or together with other programs to optimize our customers' experience. I will further describe those categorizations below.

Q. WHAT CONSTITUTES COMPLIANCE-DRIVEN WORK THAT IS DESGINED TO PROTECT THE GRID?

A. Compliance-driven programs in the Grid Improvement Plan are efforts which need to be completed to reduce physical and cyber threats to the grid. These programs may be necessitated by an external law, rule, or regulation applicable to the company that requires the work; a binding legal obligation such as a contract, agency order, or other legal document that compels the work; or Operations Council approval of the work as being critical and imperative to the Company's operations. To qualify for inclusion in the Grid Improvement Plan, work in this category is limited to rapidly evolving threats to the grid that outpace the scope and timing of standard compliance work done in our base-level operations. The type of work to address these concerns includes applying physical and cyber protections to transmission substations and distribution assets that are not yet covered under mandatory federal regulations such as special protective fencing and barricades to help minimize the threat of gunshot attacks to equipment, intruder sabotage, and vehicle attacks to critical equipment, and installing tamper alarms and protective cyber "blocking devices" on electronic distribution equipment that are susceptible to hacking by a cybercriminal on our distribution assets in the field.

Q. HOW DO YOU EVALUATE COMPLIANCE-DRIVEN PROGRAMS?

A. When evaluating compliance-driven programs as part of the Grid Improvement Plan, we first focus on work that has a prescriptive mandate that dictates how, when, or where the work must be done. For example, if a federal regulation states that we must take certain activity on a certain set of grid assets at a certain time, we necessarily put that work into our plan first given that the Company has little discretion to do otherwise. Once that work is incorporated into the plan, the Company then focuses on non-prescriptive work that poses the highest risk to the grid and then continues to incorporate grid protection work into the plan on a risk-advised basis, taking plan constraints into consideration. Since this grid protection work must be done, the Company does not evaluate these compliance-based programs with cost benefit analyses, but instead takes measures to ensure that this work is done in a cost-effective manner. In Oliver

Exhibit 6, I have included a "gating tool" that the Company uses to determine how to properly evaluate the costs and benefits of all the work in the Grid Improvement Plan. Compliance-driven programs include the following types of work and activities: electronic access blocking and gating restrictions on computerized systems and equipment; cyber defense computer programs and applications; physical access restrictions and protective devices to substations and critical equipment; and working with industry experts to determine best practices for electromagnetic pulse protections on certain critical assets.

Q. WHAT CONSTITUTES A RAPID TECHNOLOGY ADVANCEMENT PROGRAM THAT MODERNIZES THE GRID THAT YOU DESCRIBED AS THE SECOND CATEGORY OF WORK IN THE GRID IMPROVEMENT PLAN?

A. Rapid technology advancement work that is needed to modernize the grid consists of equipment, software, hardware, operating systems, or accepted system operating practices that have advanced at an atypical pace, causing the need for rapid and sometimes frequent changes within the utility at a system deployment level. Work in this category is usually related to system communication, automation, and intelligence and must be executed at a deliberate pace while ensuring not to deploy new technology before it has reached maturity. While not considered compliance activities, work in this category is essential for modern system operations. Rapid technology advancement programs include the following types of work and activities: deploying new system-wide communications devices so that the transmission and distribution system can communicate back to us and with each other, replacing pneumatic and manually actuating equipment with modern electronic and intelligent equipment that is self-actuating and self-correcting, and installing advanced system intelligence devices that will allow our underground and overhead assets to proactively report their condition status and potential problems before they manifest into equipment failures.

Q. HOW DO YOU EVALUATE RAPID TECHNOLOGY ADVANCEMENT PROGRAMS?

A. In this area of the Grid Improvement Plan, the Company looks for "Enterprise" or system-level programs that enable interoperability and functionality to grid operations and thereby impact and provide value to all our customers. A grid that can communicate and provide information to us and our customers and that can automatically react to grid events is essential to meet the demands of our customers and the implications of the Megatrends in North Carolina. Programs that help the Company meet these requirements are selected for inclusion in this part of the Grid Improvement Plan. Since these programs are essential to enabling a modern-functioning grid, the Company ensures that they are deployed and selected in a cost-effective manner.

Q. WHAT CONSTITUTES A SYSTEM OPTIMIZATION PROGRAM THAT IS PART OF THE FINAL CATEGORY OF WORK IN THE GRID IMPROVEMENT PLAN?

A. Programs and projects in this category provide customers more benefits than costs and solve for one or more of the external Megatrends that can have negative impacts to customers and grid operations. Work in this category spans a wide range of assets but primarily includes a "bundled combination" of Self-Optimizing Grid deployments and advanced power systems that, when working together, provide optimum system performance for our customers. The Self-Optimizing Grid, also known as the smart-thinking grid, redesigns key portions of the distribution system and transforms it into a dynamic self-healing network that ensures many issues on the grid can be isolated and customer impacts are limited to hundreds versus thousands. These grid capabilities are enabled by installing automated switching devices to divide circuits into switchable segments that will serve to isolate faults and automatically reroute power around trouble areas which call for expanding line and substation capacity to allow for two-way power flow and creating tie points between circuits.

Q. HOW DO YOU EVALUATE SYSTEM OPTIMIZATION PROGRAMS?

A. In selecting these programs for inclusion in the Grid Improvement Plan, the Company looks for programs that address the largest number of Megatrend implications at the lowest costs to customers. System optimization programs are justified by a qualitative and quantitative cost benefit analysis, and Oliver Exhibit 6 that I previously discussed provides more detail on how this is done at various stages of program implementation. When a system-level program like Self-Optimizing Grid[6] is deployed throughout our service territory in North

[6] Self-Optimizing Grid is an example of investments with multiple layers of benefits as it helps customers save money in avoided system costs; allows more distributed energy resources (such as rooftop solar) to be on the grid; and provides containment and mitigation of outages by reducing thousands of impacted customers in an outage down to hundreds or less.

Carolina, the Company utilizes a program-level cost benefit analysis. The Company also has a methodology for project-level cost benefit analysis, which examines the costs and benefits of deploying a specific project solution based on the nature of a specific site. For example, the Targeted Undergrounding[7] and Transmission Line Upgrade programs in the Grid Improvement Plan are evaluated on a site-by-site basis using project level cost benefit analyses. The cost benefit analyses and the underlying data sources and work sheets for all the programs and projects in the "Optimize" portion of the Company's proposed Plan, which encompasses more than seventy percent of the costs for the Plan, were placed in a virtual data room available to interested stakeholders leading up to this filing. This data room is discussed in more detail in the Stakeholder Engagement portion of my testimony. The cost benefit analyses and underlying workpapers are located in Oliver Exhibit 7.

Oliver Exhibit 8 to this testimony shows that the programs in the Company's plan designed to optimize the North Carolina grid have a positive net present value benefit to cost ratio of 4.7. This means that for every dollar spent on these programs and projects, customers should receive a payback of $4.70 in primary benefits. Also in Oliver Exhibit 8, I have included a total primary benefit analysis of the entire Grid Improvement Plan portfolio, and this document shows that all the costs in the plan (costs to protect, modernize, and optimize the North Carolina grid) have a positive total net present value benefit

[7] Target Undergrounding is the process of burying certain lines for cost saving and reliability purposes, and not for aesthetic purposes, and could yield savings for all our customers over what they would otherwise pay to maintain and repair and overhead system in addition to the improved reliability that it will provide.

ratio of 3.6. This means that for every dollar spent on the total Plan, North Carolina customers should receive a payback of $3.60 in primary benefits.

In Oliver Exhibit 8, I have also included an analysis of the secondary benefits that the Grid Improvement Plan should provide to customers and residents. If both the primary and secondary benefits of the Grid Improvement Plan are considered together, the total Grid Improvement Plan (cost to protect, modernize, and optimize the grid) should provide customers and residents a positive total net present value benefit ratio of 6.4, meaning that every dollar spent on the Plan should provide a payback of $6.40.

Q. IN YOUR DISCUSSION OF THE BENEFITS OF THE GRID IMPROVEMENT PLAN, YOU REFER TO PRIMARY (DIRECT) AND SECONDARY (INDIRECT) BENEFITS. WOULD YOU PLEASE EXPLAIN THE DISTINCTION BETWEEN THESE TWO SETS OF BENEFITS?

A. Yes. Primary benefits consist of value that is directly captured by the Company and by customers. Examples of primary benefits captured by the Company are things like avoided deployments of outage restoration crews, avoided equipment replacement costs, avoided operations and maintenance savings, and other "hard costs" that can be estimated and quantified. Examples of primary benefits captured by customers are things like avoided lost product, avoided damaged equipment costs, avoided lost wages, and other expenses that cost customers money. In Oliver Exhibit 9, I have included a graphic example of a "benefits pyramid" that shows how the benefits of electric utility projects are thought about and evaluated in the industry. As can be seen from this graphic and from the cost benefit results in Oliver Exhibit 8, the Company's proposed Grid Improvement Plan is justified in its entirety just on primary benefits alone.

However, the proposed Grid Improvement Plan for North Carolina also provides indirect, secondary benefits to customers through risk reduction; value to third parties, and value to society, which are reflected on the top three rungs of the benefits pyramid displayed on Oliver Exhibit 9. Of these indirect/secondary benefits, the Company has estimated the indirect value of the plan to third parties, and the results of this evaluation are reflected in Oliver Exhibit 8. However, the Company has not attempted to value the indirect benefits of risk reduction and the benefits to society as a whole for the Grid Improvement Plan, which means that the benefits of the plan are understated and are greater than what the Company has calculated.

Q. SHOULD THE GRID IMPROVEMENT PLAN HAVE QUANTIFIABLE TARGETS AND METRICS TO MEASURE THE PERFORMANCE AND RESULTS OF THE WORK IN THE PLAN?

A. Yes. The cost benefit analyses in Oliver Exhibit 7 provide those metrics for each of the projects and programs that are appropriate for such metrics.[8] Specifically, the cost benefit analyses performed by the Company detail, among other things, the amount of O&M savings the Company anticipates from the plan; the amount of avoided capital costs the Company anticipates from the

[8] Some programs/projects cannot be effectively measured by detailed performance metrics and targets. For example, computer hardware and software that enables grid assets to communicate with each other either works or does not work, and measures taken to prevent substations from flooding in major storms either keep water out or do not keep water out.

plan; and the amount of outages that each of the programs and projects within the plan are anticipated to avoid.

Q. HOW HAS THE COMPANY SHAPED THIS COLLECTION OF PROGRAMS INTO A HOLISTIC GRID IMPROVEMENT PLAN?

A. Once the Company had selected the programs and projects that could meet customers' needs in the manner that I have previously discussed, the Company then had to develop a formal, year-over-year work plan that can be achieved given the resource constraints that I discussed earlier in my testimony. Further, the final Grid Improvement Plan had to be developed not only in a risk-advised manner, but in a manner that is fair to all our customers. For example, a Grid Improvement Plan that was too heavily weighted to address only one of the Megatrends impacting North Carolina could be viewed as short-sighted, while a Grid Improvement Plan that was too "diluted" and lacked strategic focus would be ineffective. Similarly, a Grid Improvement Plan that focused too heavily on one type or class of customer could be viewed as unfair. The Company had to balance these and other considerations when forming the final Grid Improvement Plan work.

Q. HOW DID DUKE ENERGY BALANCE DIVERSE CUSTOMER AND STAKEHOLDER NEEDS?

A. The Grid Improvement Plan for North Carolina is designed with programs that benefit all our customers, and that is one of the primary ways that we have balanced our customers' needs and interests. Over our three-year plan, we have also balanced the pace, scope, location, and timing of our work to ensure that customer and stakeholder needs are met. Further, we have kept the needs of our rural and low-income customers in mind as we developed our plan, and programs such as IVVC in the DE Carolinas jurisdiction provide these customers both increases to reliability and resiliency while at the same time providing decreases in fuel costs, future capacity and carbon costs, and lower monthly energy usage.

Q. WHAT IS YOUR RESULTING GRID IMPROVEMENT PLAN FOR NORTH CAROLINA?

A. After completing all the steps in our plan development process, we arrived at our Grid Improvement Plan, which is presented in Oliver Exhibit 10.

Q. IS THE GRID IMPROVEMENT PLAN THAT YOU ARE PROPOSING IN THIS CASE SIMILAR TO THE GRID IMPROVEMENT PLAN THAT THE COMPANY RECENTLY INTRODUCED IN SOUTH CAROLINA?

A. Yes. By design, the Grid Improvement Plan for North Carolina is identical to the South Carolina plan in substance, so that the two plans can work together to provide benefits to DE Progress' customers.

Q. **DID STAKEHOLDERS IN SOUTH CAROLINA HAVE ANY FEEDBACK ON THE DE PROGRESS GRID IMPROVEMENT PLAN THAT YOU PROPOSED?**

A. Yes. While most of the feedback we received from South Carolina stakeholders focused on the method for cost recovery to be used for grid improvement investments, many stakeholders did provide useful substantive questions and input on the plan that I outlined and addressed in my rebuttal testimony in the South Carolina rate case dockets. For ease of reference in this testimony, I have included my rebuttal testimony from South Carolina Docket No. 2018-318-E as Oliver Exhibit 17 to this testimony rather than recounting all those questions and inputs here.

Q. WAS THE COMPANION GRID IMPROVEMENT PLAN FOR SOUTH CAROLINA APPROVED?

A. In the DE Carolinas and DE Progress rate cases for South Carolina, the parties entered a stipulation that affords deferral accounting treatment for the SC Grid Improvement Plan, and that calls for the ongoing tracking and reporting of costs and achieved benefits under the Plan as work is completed. This is the same treatment and procedure that the Company is requesting for DE Progress in this case.

IV. STAKEHOLDER ENGAGEMENT AND COST RECOVERY OF GRID IMPROVEMENT INVESTMENTS

Q. DID THE NORTH CAROLINA UTILTIES COMMISSION GIVE THE COMPANY ANY GUIDANCE ON THE RECOVERY OF FUTURE GRID IMPROVEMENT COSTS IN THE COMPANY'S LAST BASE RATE ADJUSTMENT PROCEEDING IN NORTH CAROLINA?

A. Yes. In Docket No. E-7, Sub 1146, the Commission issued an order stating:

> "With respect to deferral, the Commission acknowledges that, irrespective of its determination not to defer specific costs in this case, the Company may seek deferral at a later time outside the general rate case test year context to preserve the Company's opportunity to recover

costs, to the extent not incurred during the test period. In that regard, were the Company in the future before filing its next rate case to request a deferral outside the test year and meet the test of economic harm, the Commission is willing to entertain a requested deferral for Power Forward, as opposed to customary spend, costs. Should a collaborative undertaking with stakeholders as addressed herein produce a list of Power Forward projects, such designation would greatly assist the Commission in addressing a requested deferral. Were the Company to demonstrate that the costs can be properly classified as Power Forward and grid modernization, the Commission would seek to expeditiously address the request and to determine that the Company would meet the 'extraordinary expenditure' test and conceptually authorize deferral for subsequent consideration for recovery in a general rate case.

The Commission can authorize a test for approving a deferral within a general rate case with parameters different from those to be applied on other contexts. Consequently, with respect to demonstrated Power Forward costs incurred by DEC prior to the test year in its next case, the Commission authorizes expedited consideration, and to the extent permissible, reliance on leniency in imposing the 'extraordinary expenditure' test."

Q. WHAT STEPS HAS THE COMPANY TAKEN TO ADDRESS THE COMMISSION'S RECOMMENDATION FOR COLLABORATING WITH STAKEHOLDERS?

A. The Company has held three in-person stakeholder workshops in North Carolina and a series of webinars since the previous North Carolina rate case. The first workshop was conducted in response to the settlement agreement approved by the NCUC on February 23, 2018, in Docket No. E-2, Sub 1142 for the DE Progress general rate case, and was held on May 17, 2018. Acting as a neutral facilitator, a team from Rocky Mountain Institute ("RMI") convened 65 participants (inclusive of 18 Duke Energy and five RMI staff) for a day-long workshop. The objectives of this workshop were to develop understanding of proposed investments; hear and explore stakeholder feedback; and support a collaborative process going forward. At the conclusion of the workshop, RMI prepared a detailed, post project report which was filed with the Commission on June 26, 2018. I have included that report as Oliver Exhibit 11 to my testimony.

Q. DID THE WORKSHOP RESULT IN CHANGES TO THE COMPANY'S PLANS FOR GRID IMPROVEMENTS?

A. Yes. The feedback we received in this workshop led us to identify and validate the Megatrends as discussed earlier in my testimony. Because of the formalization of the Megatrends and stakeholder feedback, the Company made significant changes to the portfolio of investments. Most notably, the IVVC program was added in for DE Carolinas, the Targeted Undergrounding program was significantly reduced, and much of the Distribution H&R work was moved out of the plan. In November 2018, the Company sent a detailed "pre-read package" to North Carolina stakeholders describing the development and proposed Grid Improvement Plan, in advance of the second North Carolina Stakeholder Workshop held on November 18, 2018. I have included that pre-read package as Oliver Exhibit 12. In this workshop, with RMI again acting as the neutral facilitator, 78 participants (inclusive of 19 Duke Energy and four RMI staff) convened for a day-long workshop. At the conclusion of that workshop, RMI prepared a detailed, post project report which was filed with the Commission on January 9, 2019, and I have included that report as Oliver Exhibit 13 to my testimony.

Q. WHAT ACTIONS DID THE COMPANY UNDERTAKE TO RESPOND TO THE LEARNINGS FROM THE SECOND STAKEHOLDER WORKSHOP?

A. The major themes we heard in the second workshop included: Grid Improvements should be supported by cost benefit analysis; the Company should provide further details on how it conducted its cost benefit analysis; and the Company should provide how much additional distributed energy and renewable resources the grid could support with the plan's improvements. In response, the Company provided cost benefit analysis and underlying data sources and work sheets for all applicable programs and projects in a virtual data room for stakeholders to review ahead of the third stakeholder workshop held on May 16, 2019. The Company also responded to the questions regarding distributed renewable energy resources. Prior to the May 16, 2019 workshop the company conducted a webinar with stakeholders on April 25, 2019 to address questions regarding the cost benefit analysis and gather feedback regarding the agenda for the next stakeholder workshop. The webinar materials are included in Oliver Exhibit 14.

Q. CAN YOU ELABORATE ON THE FEEDBACK RECEIVED FROM STAKEHOLDERS IN THE APRIL 25, 2019 WEBINAR?

A. Yes. During the webinar, the Company conducted a poll to determine what stakeholders wanted to discuss in detail in the May 16, 2019 workshop. Seventy-six percent of the webinar participants stated that they wanted to discuss cost recovery issues regarding the Plan. Fifty-nine percent stated that they wanted more information and discussion regarding the Company's cost benefit analysis for the plan, and 41 percent stated that they wanted to further discuss plan prioritization and design. Finally, 55 percent stated that they wanted to further discuss distributed renewable energy resource enablement. Based on these responses, and with the help of RMI, the Company designed the agenda for the May 2019 workshop with these prioritized responses in mind. I have included that pre-read package as Oliver Exhibit 15.

Q. WHAT WERE THE RESULTS OF THE THIRD AND MOST RECENT STAKEHOLDER WORKSHOP?

A. In this workshop, with RMI again acting as the neutral facilitator, 52 participants (inclusive of 11 Duke Energy) convened for a day-long workshop. At the conclusion of that workshop, RMI prepared a detailed, post project report which was filed with the Commission on July 9, 2019 and I have included that report as Oliver Exhibit 16 to my testimony.

Q. WHAT ACTION HAS THE COMPANY TAKEN TO RESPOND TO STAKEHOLDERS'S FEEDBACK IN THE THIRD WORKSHOP FOR MORE INFORMATION ON THE COST BENEFIT ANALYSES?

A. A series of three webinars focused on deep dives into the analysis behind Duke Energy's Grid Improvement Plan took place in June 2019. The first webinar took place on June 13 and focused on a deep dive into the Self-Optimizing Grid cost benefit analysis. The second webinar took place on June 17 and focused on a deep dive into the Targeted Undergrounding cost benefit analysis. The third webinar took place on June 24 and focused on a deep dive into several Transmission H/R projects. Highlights of the Grid Improvement Program were presented at the beginning of each meeting. Experts were on hand to guide participants through cost benefit analysis scenarios, address questions regarding the implementation, improvements and progress of the programs. Over 40 participants attended each webinar. The materials presented in the webinars are included in Oliver Exhibit 18.

Q. WHAT CONCLUSIONS HAVE YOU DRAWN BASED ON ALL THIS STAKEHOLDER ENGAGEMENT?

A. We have drawn several conclusions. First, it appears to us that stakeholders understand and accept the Megatrends that are facing the Company and our industry. Second, the combination of the substantive changes we made to the content of the plan and the detailed cost benefit analyses that we provided seems to have helped stakeholders gain a better consensus and understanding of our proposed three-year plan. Finally, most stakeholders remain highly interested in what future phases of the plan, if any, would contain and how costs for those phases would be recovered. We will keep this last observation front and center as we continue our stakeholder engagement efforts in the Carolinas.

Q. **CAN YOU PROVIDE MORE DETAIL ON WHAT OTHER GRID IMPROVEMENT WORK THE COMPANY PLANS TO DO IN ADDITION TO THIS THREE-YEAR PLAN?**

A. Yes. Our three-year Plan is a comprehensive package of well-coordinated grid improvements. It does not need a Phase 2 to be effective, and depending on what we see in the industry and what we hear from our stakeholders in our ongoing engagement with them, there may never be a second phase to the Grid Improvement Plan. That being said, the three-year Plan does set North Carolina up for other improvements that could warrant a second phase of the Plan, and we plan to engage and work with stakeholders before deploying any future phases of the Plan. Below are potential programs for consideration and stakeholder input:

1. **Phase 2 of Self-Optimizing Grid**. The current SOG plan enables approximately 265 - 332 circuits with approximately 494,000 – 617,000 customers. A Phase 2 project could focus on the next, most cost effective, group of circuits.
2. **Increased Implementation of Power Electronics**. The current SOG and multiple "modernize" programs set up the basic capacity,

automation, and Volt/VAR control mechanisms to manage the 21st century grid. As privately owned DER grows, power electronics will be essential to managing the rapid and dynamic effects of multiple, small scale intermittent resources.

3. **Upgrade Projects that Enable Solar Capacity**. Through continuing coordination with stakeholders and regulators, these projects may afford new opportunities that provide value to customers.
4. **ISOP Optimization**. As the Company and the industry continues to develop and deploy ISOP, best practices and lessons learned can be utilized to optimize the ISOP process.
5. **Increased use of Energy Storage.** Energy Storage is part of our three-year Plan but is still in a startup/pilot phase. We believe more opportunities may exist as batteries become more cost effective and as we learn more about their capabilities on the grid.

This list is certainly not comprehensive or prescriptive. It is intended to lay out options that build off the currently proposed three-year plan. Regardless, we are committed to continued stakeholder interaction to help inform any future actions that we may, or may not, take.

Q. WHAT COST RECOVERY MECHANISM IS THE COMPANY PROPOSING FOR FUTURE GRID IMPROVEMENT PLAN WORK?

A. As discussed more fully in the testimony of Witness Smith, the Company is requesting deferral accounting treatment for the Grid Improvement Plan work as a mitigant to the debilitating effect that regulatory lag will have on the Plan absent a deferral.

Q. PLEASE EXPLAIN THE IMPACT THAT REGULATORY LAG WILL HAVE ON THE GRID IMPROVEMENT PLAN WORK ABSENT A DEFERRAL.

A. It is important for stakeholders to recognize that just like any other company that must manage a monthly budget and pay bills, a regulated utility has a limited amount of funds to pay a given amount of expenses. Unlike unregulated companies that can raise the price of their products as they see fit to cover incremental expenses, the Company's income stream to pay for projects needed to maintain a base level of service to customers in North Carolina is set by the Commission in base rate proceedings like this one and once that revenue stream is set, the Company cannot increase it without filing another base rate case. This means that every day, the Company must decide what projects and programs it will deploy and which ones that it will not, which, in turn, means that programs and projects must compete against each other for funding priority. Thus, to fund incremental work like the Grid Improvement Plan, the Company must obtain money between its rate cases to pay for new work, and obtaining money naturally comes with a cost.

In instances where the Company has large, centralized projects that take longer to complete (such as building a new power plant), I understand that regulatory rules allow the utility to apply a carrying charge to the funds that the Company must borrow and pay interest on to complete this work as a principle of fundamental fairness. In other words, one cannot reasonably expect the Company to borrow money and pay interest on that money on behalf of customers to build a power plant that will serve those customers and then not pay the Company back for the money it borrowed plus the interest it had to pay on it. However, I understand that smaller and more quickly-installed programs and projects like many of those included in the Grid Improvement Plan, do not receive those same benefits for accumulating a carrying charge as apply to the large, time-intensive projects. To ensure that utilities are not discouraged from these smaller programs that deliver benefits more quickly to customers, I have seen regulators enact measures to avoid the problem of regulatory lag such as rider recovery, rate adjustment step ups, or deferral accounting treatment with returns for such projects.

Q. ARE YOU SUGGESTING THAT THE COMPANY WILL NOT PERFORM ANY OF THE WORK IN THE GRID IMPROVEMENT PLAN IF THE COMMISSION DOES NOT APPROVE SOME METHOD TO AVOID REGULATORY LAG ON THOSE PROJECTS?

A. No. However, without a reasonable means of mitigating the negative impacts of regulatory lag associated with significant ongoing and incremental spending under the Grid Improvement Plan the Company would be required to reassess its ability to commit to the planned level of investment in this program given that the level of investment anticipated under the plan simply cannot be reasonably sustained in the absence of mitigation measures such as the deferral requested herein. As such, if the Commission determines not to grant the regulatory asset treatment for the Company's Grid Improvement Plan investment sought in this proceeding, the Company will be required to reassess its ability to implement that plan. In such a situation, the Company would have to try and perform small pieces of the Grid Improvement Plan over a much longer period with its existing revenues, which will delay important benefits and potentially essential improvements for customers.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

BEFORE THE NORTH CAROLINA UTILITY COMMISSSION

DOCKET NO. E-2, SUB 1219

In the Matter of:	)	
	)	**REBUTTAL TESTIMONY OF**
Application of Duke Energy Progress, LLC	)	**JAY W. OLIVER**
for Adjustments in Electric Rate Schedules	)	**FOR DUKE ENERGY**
and Tariffs and Request for Accounting Order	)	**PROGRESS, LLC**

I. INTRODUCTION

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

A. My name is Jay W. Oliver. My business address is 400 South Tryon Street, Charlotte, North Carolina. I am employed by Duke Energy Business Services, LLC ("DEBS") as General Manager, Grid Strategy and Asset Management Governance. 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 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. I respond to testimony from the Public Staff and Intervenors in this case regarding the Grid Improvement Plan ("GIP"). For organizational purposes, my rebuttal testimony is divided as follows:

- Agreed programs for deferral: Public Staff witnesses and some other intervenors recognize several of the GIP programs and projects as "extraordinary type of activity" that should be considered eligible for the deferral treatment sought by DE Progress in this case. The Company agrees with those determinations. Further, notwithstanding the Company's position that all of the programs and projects in the GIP should be eligible for deferral treatment, the Company believes that additional GIP programs and projects should also qualify for deferral treatment as "extraordinary in type," using the Public Staff's own criteria.

- Cost benefit analysis concerns: Public Staff Witness Jeff Thomas cited some concerns with the GIP cost benefit analyses ("CBAs") that DE Progress presented in this case. I will address his concerns, as well as concerns from witnesses representing other intervening parties.
- Performance measurement: DE Progress believes it would be appropriate to conform to the reporting measurements proposed by the Public Staff for programs deemed eligible for deferral treatment, and I will explain how we propose to do so.
- Projects/Programs that the Public Staff and intervenors did not find to be "extraordinary": I will address why programs that the Public Staff and intervenors found not to be "extraordinary" were included in the GIP in the first place and why the Company believes that those projects and programs should still be included in the GIP.
- Stakeholder engagement has been productive: Finally, I will respond to complaints from some intervenors regarding the stakeholder process used to form the Company's GIP. While the Public Staff recommends a productive next step in consideration of the GIP, other intervenors recommend inaction or misguided action without recognition that the

Company's GIP is a step down the path to a reasonable objective that is shared by many stakeholders.

I also respond to Public Staff's recommendation that the Company file an annual report of its vegetation management performance similar to the DE Carolinas report.

Q. DO YOU HAVE ANY EXHIBITS TO YOUR REBUTTAL TESTIMONY?

A. Yes. Oliver DEP Rebuttal Exhibit 1 is attached hereto and incorporated herein by reference.

Q. WAS THAT EXHIBIT PREPARED BY YOU OR UNDER YOUR DIRECTION?

A. Yes.

III. AGREED PROGRAMS FOR DEFERRAL

Q. AS AN INITIAL MATTER, DID ANY INTERVENOR OBJECT TO OR CONTEST THE MEGATRENDS THAT THE COMPANY IDENTIFIED AS THE DRIVERS OF THE GIP?

A. No. While some intervenors suggested that the Megatrends that are driving the need for the GIP have existed longer than the Company suggests, no intervenor credibly disputed that the Megatrends are real or that they are having an impact on the Company.

Q. WHY IS THIS FACT IMPORTANT?

A. I mention this general consensus regarding the Megatrends to show that there is no serious dispute that these forces exist and that they must be addressed. With this backdrop, I am pleased that the Public Staff and other intervenors did recognize that some of the programs and projects in the GIP are reasonable and prudent ways to address these Megatrends.

Q. THE PUBLIC STAFF CREATED A MATRIX FOR REVIEWING THE GIP TO DETERMINE IF PROJECTS/PROGRAMS SHOULD BE RECOGNIZED AS GRID MODERNIZATION. WHAT ARE YOUR THOUGHTS ON THIS MATRIX?

A. I applaud the Public Staff for deploying an objective approach to evaluating the various components of the GIP. I do, however, have some additional thoughts as to some of their methods and conclusions. First, the Public Staff sought to identify those programs that would "bring the current grid up to new standards of operation and reliability" and that would be transformative. I note that in Exhibit 3 of my direct testimony I highlight the implications of a "business as usual" approach to grid investments, and in Exhibit 4 of my direct testimony I review each program and highlight new or transformative grid capabilities and value to our customers. Each program within the GIP seeks to bring the current grid up to new standards of operation or reliability. Leveraging new equipment and analytics along with traditional equipment and work practices will transform the grid to a new level of operation. The equipment being installed in the GIP is not a like-for-like exchange that brings no other value other than being new, rather the new equipment often comes with advanced monitoring and control features not present on the grid today which will incrementally expand our ability to control the grid and provide more flexibility and reliability going forward.

Q. WHICH GIP PROGRAMS WERE RECOGNIZED AS "EXTRAORDINARY" AND DESERVING OF DEFERRAL TREATMENT IN PUBLIC STAFF TESTIMONY PER THEIR EVALUATION?

A. Public Staff Witnesses Williamson recognized the following programs as extraordinary: ISOP, SOG Segmentation and Automation, Transmission System Intelligence, SOG ADMS and Underground System Automation.

Q. DO YOU AGREE WITH THE PUBLIC STAFF'S ASSESSMENT OF THE PROGRAMS RECOGNIZED AS "EXTRAORDINARY" AND DESERVING OF DEFERRAL TREATMENT AS A REASONABLE STANDARD?

A. Yes. However, using Public Staff's evaluation methodology, the Company believes that several other GIP programs should also qualify for deferral treatment.

Q. WHAT OTHER GIP PROGRAMS SHOULD BE CONSIDERED EXTRAORDINARY AND DESERVING OF DEFERRAL TREATMENT, USING THE ANALYSES PROPOSED BY PUBLIC STAFF?

A. The following programs were analyzed further using the Public Staff's matrix and methodology, and the Company believes that they should be added to the "extraordinary" list using the Public Staff's methodology. Please see Oliver DEP Rebuttal Exhibit 1 where I have prepared an analysis of these additional programs using the Public Staff's evaluation matrix.

- SOG Capacity and SOG Connectivity

- DSDR Conversion to Conservation Voltage Reduction (CVR)
- Distribution Automation (note the Underground System Automation sub program is already included on Public Staff's list)
- Power Electronics
- DER Dispatch Tool
- Cyber Security

Q. WHY DOES SOG CAPACITY AND SOG CONNECTIVITY MEET THE PUBLIC STAFF'S CRITERIA AS EXTRAORDINARY?

A. Fundamentally, the distribution system was built for one-way power flow and not designed to accommodate the 2-way power flow needs generated by increased utilization of distributed energy resources ("DER"). Additional circuit capacity and connectivity are needed to begin to network and transform the current grid which has only limited ability to reroute or rapidly restore power and limited ability to optimize for the growing penetrations of DER. All of the major components of SOG work together to fundamentally redesign key portions of the distribution system and transform it into a dynamic, smart-thinking, self-healing grid. The benefits outlined in the SOG cost-benefit analysis cannot be achieved by leaving out capacity and connectivity. Therefore, using the Public Staff's methodology, I have normalized Witnesses Williamson's matrix to score capacity and connectivity as a 3 for transformative and 2 for timing. This aligns with the Public Staff's view of the other components for SOG. SOG with all of its components is by far the cornerstone program to transform the distribution grid to better accommodate DER and it cannot achieve these goals if only partially implemented.

Q. WHY DOES DSDR CONVERSION TO CONSERVATION VOLTAGE REDUCTION (CVR) MEET THE PUBLIC STAFF'S CRITERIA AS EXTRAORDINARY?

A. The Company agrees with Witness Thomas that the amount of peak reduction lost by the conversion from DSDR to CVR has not yet been estimated, as Duke Energy will require further analysis to more accurately quantify the impacts on DSDR and net benefits. The Company agrees that proceeding in a manner that ensures customer value is paramount. However, advancing the current DSDR capabilities beyond its current state to CVR operational mode is critical now to enable the greater application of Distributed Energy Resources (DER) on the grid and result in greater fuel savings to customers. The DE Progress DSDR CBA evaluation shows the estimated incremental cost/benefits of transitioning to CVR operational mode results in greater fuel savings to customers than the current DSDR operational mode alone. A delayed deployment (transition) of CVR operation in DE Progress beyond the next 3 years will reduce the grid's ability to respond to the growing penetration of solar and other intermittent DER. Operating in CVR mode year-round is a key dependency for DER integration and enablement in North Carolina. Distributed solar PV installations are projected to increase in North Carolina for the foreseeable future. Solar generation and other forms of DER operate year-round, not just during the approximate 80 hours per year that DSDR currently operates during peak conditions. Operating in CVR mode on a near continuous basis provides increased visibility into the status and condition of substation and field devices in near real-time, year-round on a daily basis. Having visibility and optimized voltage and var control on a year-round basis helps manage the integration of distributed energy resources (i.e. solar) by improving the grid's ability to respond to intermittency.

For those reasons I recommend that the Public Staff's scoring system for DSDR conversion be adjusted to a three for transformative and two for timing and remain the same on grid architecture.

Q. WHY SHOULD DISTRIBUTION AUTOMATION MEET THE PUBLIC STAFF'S PROPOSAL FOR EXTRAORDINARY?

A. There are three core subprograms that the Public Staff deemed not extraordinary; 1) hydraulic to electronic recloser replacement, 2) system intelligence and monitoring and 3) replacement of standard tap line fuses with automatic reclosing devices known as ALDs (automatic lateral device).

First, with hydraulic to electronic recloser replacement, the Company shifts from old oil-filled reclosers to new industry standard electronic reclosers. Aside from the environmental benefit of replacing oil-filled equipment, and as the Public Staff notes, these new devices can allow for remote operation and provide ongoing and continuous monitoring of the distribution systems health. This transformative capability is not available today utilizing the current equipment. Those new reclosers enabled with monitoring capability will feed data into the new ADMS system and will allow for more direct dispatch of crews while furthering the remote command and control capability available to the distribution grid operators that is needed in the dynamic energy future that lies ahead. For those reasons, I recommend that the Public Staff's scoring of hydraulic to electronic recloser replacement be adjusted to a three for transformative, two for timing and remain the same on the grid architecture.

Second, system intelligence and monitoring add significant new digital and analytical capabilities for devices on the grid. The work in this category is focused on advanced devices and tools that provide enhanced detection of events and remote monitoring of events for proactive maintenance, such as: enhanced asset grid intelligence, where small sensors are placed in hard to reach locations; in vaults to monitor major equipment; and transformers to detect oil level or moisture ingression. Additionally, systems will help enable distributed intelligence, where high speed/low latency decisions need to be made that allow the grid's mechanical and electronic devices to optimize their operation due to intermittency from DER. These and other efforts result in greater transformative grid intelligence capabilities that leverage enhanced sensors and control capabilities that allow the Company to proactively understand grid events. For those reasons I recommend that the Public Staff's scoring system intelligence and monitoring be adjusted to a three for transformative, two for timing and remain the same on grid architecture.

Third, as the Public Staff notes, the fuse replacement component will replace single-use fuses with an Automatic Lateral Device (ALD). The use of an

ALD is truly a leap forward in capability not previously available to the electric industry. Due to advancements in technology, ALD's are now compact enough to fit in a standard fuse cut-out and will save momentary interruptions from reaching customers on the main feeder. Additionally, when an ALD does trip, the restore time is much faster as line technicians no longer have to change a blown fuse. Bringing this new capability to the grid has the ability to further increase reliability from day one of install. For those reasons, I recommend that the Public Staff's scoring of the fuse replacement be adjusted to a two for timing and remain the same for transformative and grid architecture.

Q. SHOULD POWER ELECTRONICS MEET THE PUBLIC STAFF'S PROPOSAL FOR EXTRAORDINARY?

A. Yes. As the adoption of DER continues to increase, protective device technology is also advancing so that we can appropriately detect and respond to rapid voltage and power fluctuations that often accompany non-dispatchable resources, such as solar. These intermittent power impacts occur and then change at rapid rates (in some cases sub-second) and frequently faster than the legacy electro-mechanical voltage management equipment, like regulators and capacitors, can handle. Integrating advanced solid-state technologies like power electronics, enhances the transformative capability of the distribution system to manage power quality issues associated with increasing DER penetration. The Company's Power Electronics for Volt/Var pilot project will pilot the use of this new modern technology to determine its potential use to combat Volt/Var issues caused by intermittent solar.

Due to the significant possibilities of this technology compared to what is and has been available to the electric industry, I recommend that the Public Staff's scoring for this program be adjusted to a three for transformative and remain the same for time and grid architecture.

Q. WHY SHOULD THE DER DISPATCH TOOL MEET THE PUBLIC STAFF'S CRITERION AS EXTRAORDINARY?

A. The Distributed Energy Resources (DER) Dispatch Enterprise tool will coordinate with the Distribution Management System (DMS) and Energy Management System (EMS) to improve the way DERs are integrated into the energy supply mix, both at the Distribution and the bulk power level. Today, due to the explosive growth in DER on the North Carolina system, the Company only has a rudimentary ability to quickly shed large blocks of solar generation in emergency conditions to meet standards for real power control. The DER Dispatch tool will provide operators with a more automated and refined toolset to optimize management of both utility and customer owned DERs to meet system stability requirements. For these reasons, I recommend that the Public Staff's scoring remain the same for their transformative rating but adjust their ranking to a two for timing and a three for grid architecture.

Q. WHY SHOULD CYBER SECURITY MEET THE PUBLIC STAFF'S STANDARD FOR EXTRAORDINARY?

A. As the Public Staff notes, security is a major concern for all utilities across the country. Grid modernization and optimization efforts are deploying connected/networked intelligent electronic devices (IEDs) to the field enabling new capabilities for optimization, modernization, and automation. These devices increase the complexity, connectivity, and potential points of entry to our system. Purposeful threats to the electric grid are on the rise worldwide and as the grid transforms the threat landscape changes and we must adapt with it. Additionally, the threat landscape focusing on electric utilities in North America is expansive and increasing, led by numerous intrusions into industrial control system (ICS) networks for reconnaissance and research purposes and ICS activity groups demonstrating new interest in the electric sector. Attacks on electric utilities can have significant geopolitical, humanitarian, and economic impact. Thus, state-associated actors will increasingly target power and related industries like natural gas to further their goals.[1]

The historic approach to defending our assets (including but not limited to physical barriers, firewalls, manual configurations, and manual work procedures) are appropriate and must be maintained; however, additional transformative and architectural measures must be taken to address new risks and the changing landscape. To mitigate the potential risks related to intelligent field equipment, the Company is focusing on three major efforts to ensure system security and reliability: 1) Device Entry Alert System: Physical Access Management – deploying a platform and organization to enhance physical access

[1] North American Electric Cyber Threat Perspective, January 2020, https://dragos.com/wp-content/uploads/NA-EL-Threat-Perspective-2019.pdf

control/monitoring and response capabilities for field control devices; 2) Secure Access Device Management: User Access Management – deploying a platform to perform automated and remote Password Management, Access Logging, and Device/Event information retrieval for field devices; and 3) Distribution Line Device Cyber Protection and Windows-based Change Outs: Equipment Management – replacing vulnerable legacy equipment with new devices capable of supporting Cybersecurity best practices. The utility industry is highly regulated, and the Company is subject to many compliance requirements (CIP, etc.). From a physical/cyber security perspective we are not falling into the trap of thinking that being compliant means we are adequately protected. Our cyber-related investments within the GIP are addressing real risks to the grid. Accordingly, I recommend that the Public Staff's scoring of all of the cyber related investments be adjusted to a two for transformative, two for timing, and a three for grid architecture.

Q. BASED UPON YOUR EVALUATION USING THE PUBLIC STAFF'S MATRIX WHAT IS THE SUMMARY OF THE INVESTMENTS THAT SHOULD BE DESIGNATED AS EXTRAORDINARY?

A. Below I have included all programs that scored a nine or higher utilizing the updated scoring matrix. The total investment in GIP programs deemed extraordinary under my revised application of the Public Staff analysis is $434 million.

	DEP (millions)
Public Staff - Programs deemed "Extraordinary"	
SOG Automation and Control	$130
SOG: ADMS	$19
Transmission System Intelligence	$24
UG System Automation	$11
ISOP	$2
	$186
Duke Energy - Additional programs for consideration as "Extraordinary"	
SOG: Capacity and Connectivity	$154
DSDR Conversion to CVR	$10
Distribution Automation (less UG System Intelligence)	$68
Power Electronics	$1
DER Dispatch Tool	$3
Cyber Security (SADM, DEAS, Line Device Protection)	$12
	$248
Public Staff + Duke Energy Additional Programs	$434

[2]

Q. **WHAT OTHER PROGRAMS IN THE GIP DID THE PUBLIC STAFF NOT QUALIFY AS EXTRAORDINARY USING ITS SCORING METHODOLOGY?**

A. Using its methodology, the Public Staff determined that the following programs did not "score as extraordinary":

[2] The figures above represent the three-year plan for North Carolina based on budgeting methodology, which may differ from ratemaking allocations.

	DEP (millions)
Additional Programs in GIP	
Targeted Undergrounding	$55
Distribution Transformer Retrofit	$110
Long Duration Int/High Impact Sites	$16
T-Transformer Bank Replacements	$83
Oil Breaker Replacements	$84
Transmission H&R	$32
Physical Security	$56
Enterprise Communications	$108
Enterprise Applications	$10
	$554

Q. DOES THIS MEAN THAT THE PROGRAMS ABOVE SHOULD NOT HAVE BEEN INCLUDED IN THE GIP?

A. No. I discuss why those programs are appropriate for the GIP in Section VI of my testimony. And to be clear, the Public Staff rating methodology is a rational way to approach the evaluation of our GIP programs, but it is also somewhat subjective (as the Public Staff acknowledges) and it is also not the only way to evaluate those programs.

Q. WHAT DOES THE PUBLIC STAFF RECOMMEND THE COMMISSION DO ABOUT GIP PROGRAMS NOT DESIGNATED AS EXTRAORDINARY?

A. The Public Staff is not recommending any of the GIP not be implemented. They only take issue with the requested deferral accounting for programs and projects that did not meet their standard of “extraordinary.”

Q. APART FROM PUBLIC STAFF, DID ANY OF THE INTERVENOR WITNESSES SUPPORT ANY OF THE WORK PROPOSED IN THE GIP?

A. Yes, to some degree. In an alternative recommendation, NCJC et al. Witnesses Alvarez and Stephens suggest that the Commission approve the following programs/projects should the Commission support the GIP.

Program/Subcomponent	Capital $ per Oliver Exh. 10 (in millions)	Suggested Adjustments	Capital $ per NCJC/NCSEA If GIP Not Rejected
Merits Approval w/Conditions	$ 374.16	$ -	$ 374.16
Integrated Volt/VAr Control	$ 216.66	$ -	$ 216.66
Transmission H&R -- Flood & Animal Mitigation Components	$ 13.18	$ -	$ 13.18
Long Duration Interruption/High Impact Sites	$ 27.10	$ -	$ 27.10
Enterprise Applications/ISOP Software/DER Software	$ 41.94	$ -	$ 41.94
Cyber and Physical Security, excluding substation physical	$ 23.04	$ -	$ 23.04
Enterprise Comm's excluding new data and voice networks	$ 52.24	$ -	$ 52.24
Merits Approval w/Material Modifications & Conditions	$ 843.05	$ (336.80)	$ 506.25
Self-Optimizing Grid/Advanced Dist Mgmt System	$ 722.48	$ (336.80)	$ 385.67
Transmission H&R (DER Capacity Upgrades ONLY)	$ 120.57	$ -	$ 120.57
Merits Rejection	$ 659.95	$ (659.95)	$ -
Targeted Undergrounding	$ 114.54	$ (114.54)	$ -
Distribution Transformer Retrofit	$ 118.02	$ (118.02)	$ -
Transfomer Bank Replacement	$ 116.39	$ (116.39)	$ -
Oil-Filled Breaker Replacement	$ 200.29	$ (200.29)	$ -
Substation Perimeter Security	$ 110.71	$ (110.71)	$ -
Merits Rejection Pending Further Evaluation	$ 440.27	$ (440.27)	$ -
Enterprise Comm's, new data & voice (tech/econ make/buy analyses)	$ 159.58	$ (159.58)	$ -
Distribution Automation (benefit-cost analysis)	$ 194.29	$ (194.29)	$ -
Transmission System Intelligence (benefit-cost analysis)	$ 86.41	$ (86.41)	$ -
GIP Components Being Considered in Other Dockets	$ 192.48	$ (192.48)	$ -
Energy Storage (NCUC #E-100, Sub 164)	$ 129.00	$ (129.00)	$ -
Electric Transportation (NCUC #E-2 Sub 1197 & E-7 Sub 1195)	$ 63.48	$ (63.48)	$ -
TOTALS	$ 2,509.92	$ (1,629.51)	$ 880.41

IV. COST BENEFIT ANALYSIS CONCERNS

Q. WHAT CONCERNS DID PUBLIC STAFF AND INTERVENORS RAISE REGARDING THE COST BENEFIT ANALYSES THAT SUPPORT THE GIP?

A. The Public Staff raised the following concerns regarding the CBAs prepared for the GIP: additional CBAs should be performed for certain programs; there should be sensitivity analyses for the cost benefit analyses; DE Progress should develop new resiliency cost survey data; and the Company should revise its cost benefit analyses for programs such as SOG, TUG, and other programs with benefit estimates that could be affected by long-term outage values or vegetation management impacts. Other intervenors raised these additional concerns: the Company underestimated costs and overestimated benefits for its GIP; the Company should have conducted CBAs for programs such as those in Enterprise Communications; and the Company should have conducted sensitivity analyses on its cost benefit analyses. I will first respond to the issues that the Public Staff raised and then will address the concerns from other intervenors.

Q. WHAT WERE PUBLIC STAFF WITNESS THOMAS' RECOMMENDATIONS REGARDING THE GIP COST BENEFIT ANALYSES?

A. On pages 85-87 of his testimony, Witness Thomas recommends that DE Progress should:

- Perform CBAs for the Distribution Automation and DER Dispatch programs;
- Perform and file sensitivity analyses of its cost benefit analyses;
- Conduct an interruption cost study in the Carolinas or otherwise update interruption costs used in the Interruption Cost Estimate tool;
- Remove or modify certain benefits, including long duration reliability benefits over 24 hours, asset management benefits, and CO2 emission savings;
- Revise the SOG cost benefit analyses to include the effect of momentary outages;
- Revise the SOG cost benefit analysis to account for increased vegetation management activity; and
- Revise the TUG cost benefit analysis to include the cost of repairing faults on underground lines.

I will address each of Witness Thomas's recommendations regarding the GIP cost benefit analyses below. However, I first want to note that in Table 8 on page 88 of Witness Thomas's testimony, he includes a matrix showing how the GIP

CBA results could be impacted under certain sensitivity scenarios that account for issues that he raises in his testimony. I observe that even under scenarios that have sensitivities that cut against the GIP, the projects and programs that were evaluated are still cost beneficial in some instances and are at or near break-even in others. Given the conservative assumptions that the Company included in the GIP CBAs, this reassures me that the work in question will positively benefit customers.

Q. WHY DID DUKE ENERGY NOT PERFORM A CBA FOR THE DER DISPATCH TOOL AND DISTRIBUTION AUTOMATION PROGRAMS?

A. The DER Dispatch Tool and Distribution Automation programs are part of the "modernize" portion of the protect/modernize/optimize framework used by the Company to evaluate the programs that were included in the Grid Improvement Plan. On pages 31-34 of my direct testimony on this matter, I describe the nature of the work we considered "modernize" as well as "protect" and why a cost benefit analysis is not the proper measure for approving this work.

Q. SHOULD DUKE ENERGY HAVE PERFORMED SENSITIVITY ANALYSES AROUND ITS CBAS?

A. A sensitivity analysis was not contemplated as a required function of the CBA process. For the CBA process, the concept of the AACE estimate classes associated with a project or program provide a reasonable measure of the expected cost estimate accuracy. Regarding the benefit component, the amount of combined operational and customer benefits for most projects and programs provided assurance the project or program was a positive benefit to our customers.

Q. PRIOR TO PROVIDING HIS OWN SENSITIVITY ANALYSES FOR THE SOG AND DISTRIBUTION TRANSFORMER RETROFIT PROGRAMS, WITNESS THOMAS NOTES SOME DIFFERENCES BETWEEN COST ESTIMATE FIGURES SHOWN IN OLIVER EXHIBITS 7 AND 10. WOULD YOU EXPLAIN THOSE DIFFERENCES?

A. These figures quoted by Witness Thomas do not reflect the same timeframe of GIP costs and would not be expected to align. Exhibit 10 identifies the budgeted GIP capital costs only for the three subject years of 2020-2022. The figure noted from Exhibit 7 ($1.90 billion) represents capital costs for all years evaluated within the CBA lifecycle period (2019-2052).

Q. SHOULD RELIABILITY BENEFITS BE EXCLUDED FROM CONSIDERATION OF THE GIP CBAS?

A. No. Provision of safe and reliable electricity is a foundational responsibility of the Company to its customers. As Witness Alvarez notes, the need for electricity is universal and ubiquitous. The issue is not that such a product has value, it is how to adequately quantify the benefit from providing greater reliability to our customers. The use of the ICE model data allows a utility to assign a projected value to that benefit from measurable improvements in reliability metrics.

Q. WHY IS IT APPROPRIATE FOR THE COMPANY TO HAVE USED THE ICE MODEL DATA TO ESTIMATE THE BENEFIT OF ITS GIP PROGRAMS?

A. The ICE model was designed for electric reliability planners at utilities and government organizations to estimate interruption costs. The underlying data supporting the model is based on extensive utility customer surveys and has been validated multiple times through on-going updates by LBNL/Nexant. This data analysis was judged by Duke Energy to be the best available means to assist in quantifying customer benefits related to reliability improvements. The Company was able to pair detailed project related outage and customer data with the published ICE survey data to calculate customized individual project and program estimated customer savings. It is important to note that all economic benefits calculated are estimates. These estimates should be considered statistically valid having been generated through the use of well-established and well-respected industry modeling techniques.

Q. HOW CAN CUSTOMER RELIABILITY BENEFITS BE VERIFIED?

A. The Company intends to track the actual customer reliability benefits by measuring the Customer Interruptions ("CI") and Customer Minute Interruptions ("CMI") saved for each of the respective programs compared to the expected CI and CMI saving represented in the CBAs for each of the respective programs supported by a CBA. The Company has already been tracking the CI and CMI savings from SOG segmentation and automation. Performance tracking is discussed further in Section V. of this testimony.

Q. IS IT APPROPRIATE TO COMPARE THE COMPANY'S GIP RELIABILITY BENEFITS AGAINST THE GDP OF NORTH CAROLINA?

A. While we acknowledge that from a pure math perspective the figure of $6 billion is approximately 1% of the 2018 NC GDP amount of $566 billion, any correlation of these two figures beyond that math exercise is pure speculation. For starters, the $6 billion figure is the NPV of 25-30 years of annual benefit streams. It would seem more appropriate to speculate on the impact each annual period could have on the state GDP, which is a much smaller portion.

Further, the economic impact to the state of North Carolina resulting from increases (or decreases) in reliability benefits cannot be measured by simply examining changes in state-level GDP growth over time. For example, if GDP growth were to improve over a twelve-month period during which time reliability benefits simultaneously decreased, this would not constitute evidence that worsening reliability had no adverse impact on economic growth. One could just as easily make the case that GDP growth would have been higher if not for worsening reliability benefits. More generally, because GDP growth is affected by many variables, the correlation between changes in reliability benefits and changes in GDP growth cannot point to evidence of a relationship between these two specific variables unless all other variables are held constant. This is one of the principal features of the methodology used in the CBAs to estimate primary and secondary economic benefits. This methodology is specifically designed to estimate the benefits of improved reliability holding all other economic factors constant. The primary and secondary economic benefits resulting from improvements in reliability represents the marginal increase in economic activity that one would expect regardless of the current total GDP value for the state of North Carolina.

Q. WHY IS IT UNNECESSARY FOR DUKE ENERGY TO CONDUCT DIRECT CUSTOMER SURVEYS TO REVISE ITS RELIABILITY BENEFIT ESTIMATES?

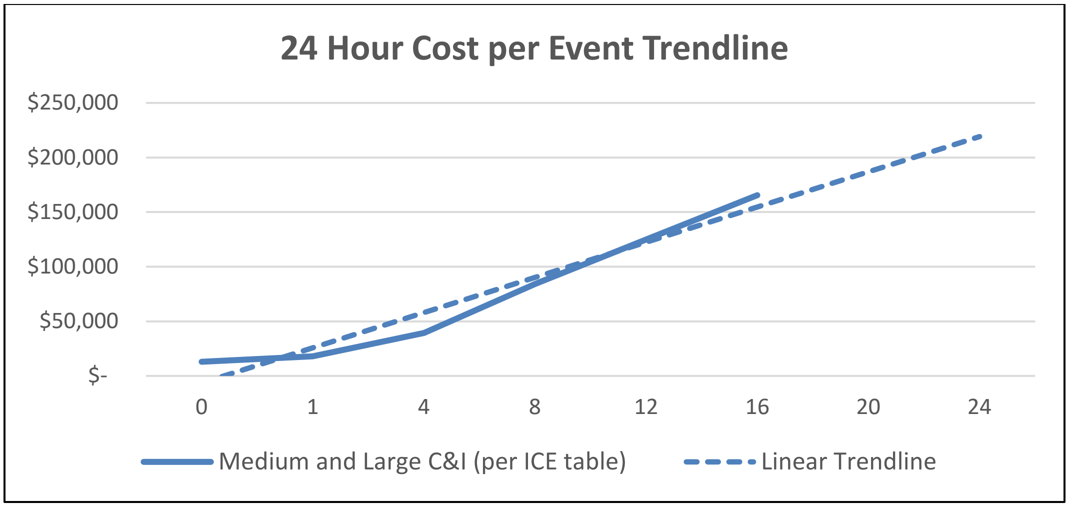
A. There would likely be only marginal value in conducting an independent survey of customers in North Carolina for the purposes of evaluating customer savings associated with GIP reliability improvements. Specifically, the law of large numbers suggests that the statistical validity of estimates obtained using the relatively large sample size of customer data that is part of the ICE model is far greater than that of a small sample size of customer data in North Carolina. The significant cost, resource, and time requirements of conducting such a study without a guarantee of greater statistical value seems unwarranted at this time. Duke Energy representatives, along with our economic consultant, reviewed the ICE model process in late 2018 with representatives of Nexant and concurred that the data as provided would be satisfactory to use for reliability valuations.

Q. HOW DO YOU RESPOND TO THE RECOMMENDATIONS FROM WITNESS THOMAS THAT DE PROGRESS SHOULD REMOVE OR MODIFY CERTAIN BENEFITS FROM ITS CBAS, INCLUDING LONG DURATION RELIABILITY BENEFITS OVER 24 HOURS, ASSET MANAGEMENT BENEFITS, AND CO2 EMISSION SAVINGS?

A. I will provide specific responses to those individual examples below, but generally I do not agree that it is necessary to remove or modify those benefits in the CBAs.

Q. WHY DID DUKE ENERGY INCLUDE LONG-TERM RELIABILITY BENEFITS IN ITS CBAS (GREATER THAN 24-HOUR VALUES FROM ICE)?

A. Duke Energy recognizes the limitation applied in the LBNL document referenced by Witness Thomas. However, we also assert there is continued value to be gained from elimination of those longer-term outages and that the value does not significantly decrease after the initial 24-hour period. Our assumption of a continued linear progression to use for estimates was based upon a trendline imposed upon the Table ES-1 ($2013) referenced from the same LBNL report.



Estimated Customer Interruption Costs (2013$) by Duration Source: Table ES-1 from LBNL Report

Witness Thomas provides a similar graphical view of a cost profile; however, this view used a summer weekday version to represent a typical Major Event Day ("MED") outage profile. The Company's 10-year outage data represents a number of potential MED outage sources. In addition to summer thunderstorms during this time period, we would have likely experienced ice storms, hurricanes, tornadoes, and straight-line wind events which could result in various MEDs. Taking into consideration the caveat from LBNL around the 24-hour limitation, the Company utilized the best information available to provide an estimate of that benefit value. Reviewing the filed CBAs, a subjective capping of the ICE survey values at a 24-hour maximum as suggested would appear to have a minor impact on the overall reliability benefit totals. While LDI items would have the most potential variance, the others noted by Witness Thomas should have virtually no impact. Exceeding the 24-hour threshold are five TUG projects, one transmission H&R project (Whiteville substation replacement), and no distribution transformer retrofit items.

Q. WHY IS IT UNNECESSARY FOR DE PROGRESS TO MODIFY ITS TUG PROGRAM CBA FOR THE COST OF REPARING UNDERGROUND LINES?

A. An estimate of underground cable repair costs has been included in the TUG CBAs. Underground restoration costs, the component of Total On-Going O&M, represents the incremental cost of potential underground outages based on a minimum events per mile. Therefore, it is not necessary to update the TUG CBAs.

Q. WHY IS IT APPROPRIATE FOR DUKE ENERGY TO INCLUDE A CO_2 EMISSION SAVINGS BENEFIT IN ITS DSDR CBA?

A. It is undeniable that DSDR operating in a continuous conservation voltage reduction (CVR) provides the benefit of voltage reduction and therefore load reduction. That load reduction benefit results in lower CO_2 emissions. DE Progress has simply presented a valuation of that CO_2 reduction for consideration. If the Company had excluded a benefit for CO_2 reductions from its DSDR CBA, other stakeholders may be concerned that the Company is not properly valuing the CO_2 reduction benefits of DSDR.

Q. WHY IS IT UNNECESSARY FOR DE PROGRESS TO MODIFY ITS SOG CBA?

A. Witness Thomas cites some concerns around the Company's SOG CBA and makes some recommendations to modify the CBA. The following questions and answers will address those concerns and explain why revising the SOG CBA is unnecessary.

Q. HOW DO YOU RESPOND TO THE STATEMENT ON PAGE 10 OF WITNESS THOMAS'S TESTIMONY THAT IT IS POSSIBLE THAT MORE COST-EFFECTIVE SOLUTIONS EXIST THAT WOULD PROVIDE SIMILAR RELIABILITY BENEFITS TO SOG?

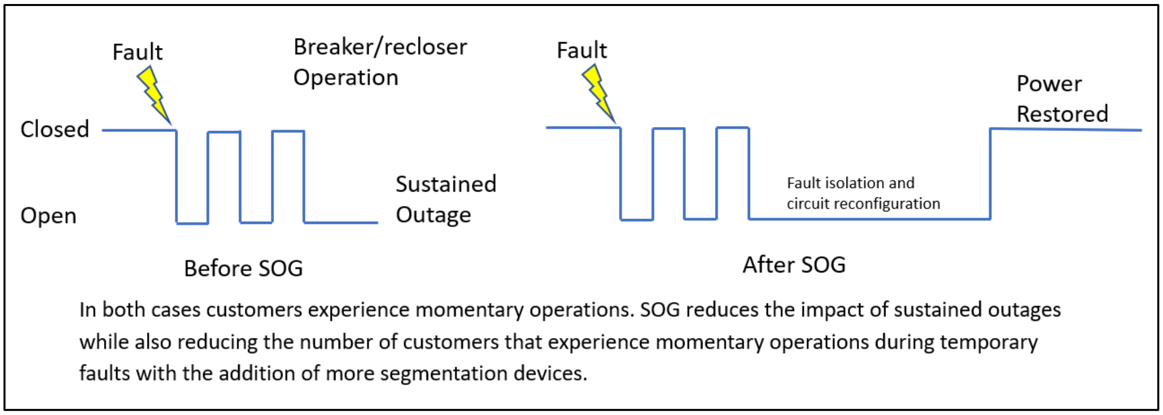
A. The driver for many of the GIP projects is the full portfolio of Megatrends and not just reliability. The SOG example cited presents an excellent opportunity to illustrate. In Exhibit 5 to my direct testimony, proposed GIP programs and investments are shown compared against the matrix of the Megatrends to illustrate beneficial impact, but also the driver behind why programs were included. SOG checks the box across all the Megatrends. When wide-spread, privately owned roof-top solar begins to be adopted in scale, a dynamic, automated, capacity-enabled two-way power flow grid is an essential component to be in place. During lightly loaded shoulder seasons (spring and fall) excess locally produced DER energy can be quickly re-routed to adjacent neighborhoods for local consumption, maximizing its value by reducing line losses.

Q. HOW DOES THE COMPANY ASSESS THE VALIDITY OF THE LBNL FLISR DOCUMENT?

A. As shown in additional details in a question below, we believe that Witness Thomas's analysis of momentary outages is incorrect. Witness Thomas states that additional momentaries are experienced by customers due to SOG implementation. This is not correct. All customers experience momentaries while protective devices attempt to clear faults on the system. If a permanent fault occurs in a segment, then all customers past the protective device will experience momentaries until the device locks out. This process occurs whether SOG is implemented on a circuit or not. The difference is that on a SOG circuit the customers on un-faulted line sections are automatically restored post lock out. For the majority of customers this represents a shortening of a sustained outages into a momentary outage.

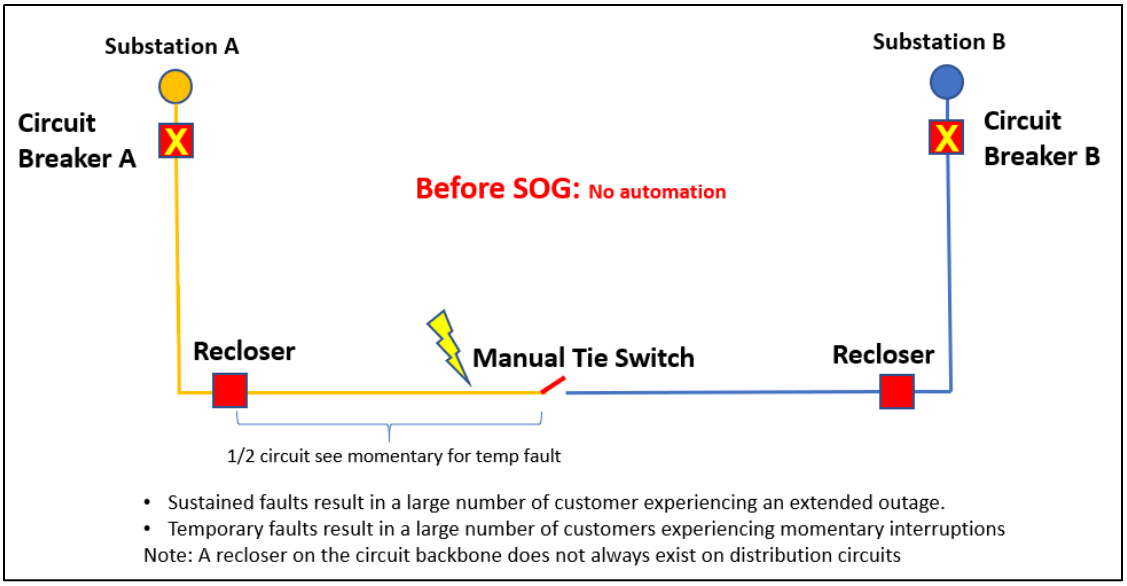
Q. WITNESS THOMAS DESCRIBES HOW SOG OPERATES ON PAGES 31-33 OF HIS TESTIMONY. DO YOU AGREE THAT CUSTOMERS EXPERIENCE A "NEW" MOMENTARY OUTAGE AS DESCRIBED?

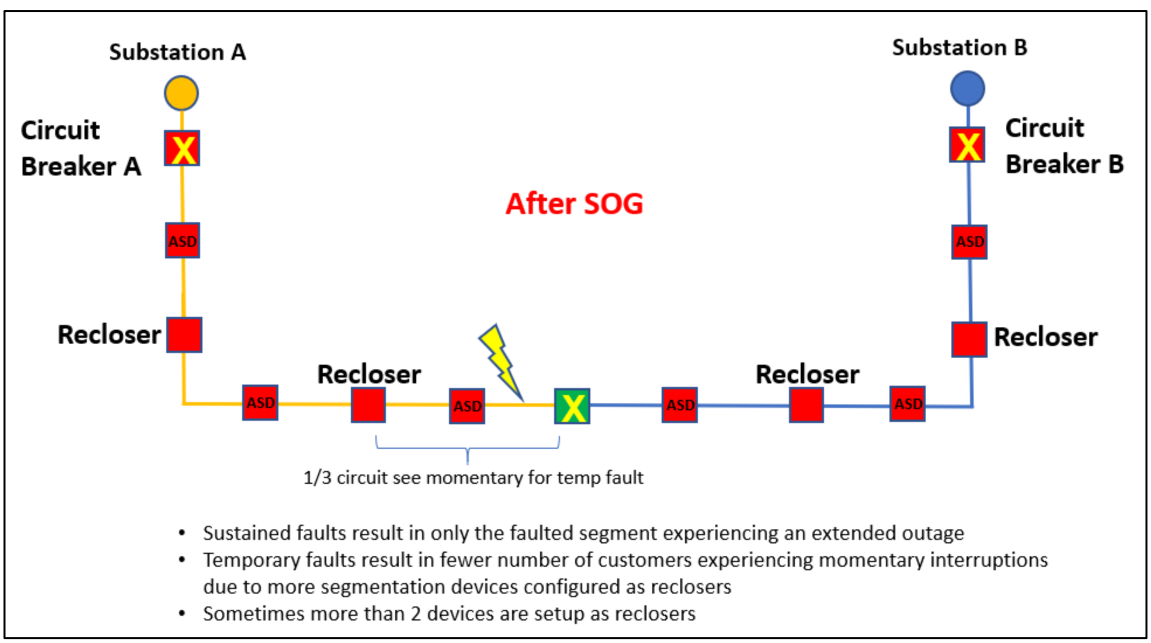
A. The addition of SOG does not increase momentary outages. Let me explain. System faults on the typical distribution circuit backbone result in either an upstream breaker or recloser opening, then reclosing in attempt to clear the fault without a sustained outage. All customers down stream of this protective device reclosing experience "momentaries". If the fault remains, these upstream devices continue to operate up to three or four times before eventually locking out, resulting in a sustained outage. These faults start as momentary blinks that can culminate to a sustained outage if the fault remains. Self-Optimizing Grid isolates faults after a lockout and restores all un-faulted line segments. Because of SOG, many customers will experience just the momentaries instead of momentaries followed by a sustained outage. The addition of SOG adds the faster restoration of un-faulted sections and does not increase momentary outages.



Q. DOES THAT MEAN THAT THE IMPLEMENTATION OF SOG ACTUALLY RESULTS IN A DECREASE OF MOMENTARY INTERRUPTION INSTEAD OF AN INCREASE?

A. Yes. Faults on the circuit backbone usually result in breaker and recloser operations that can lead to sustained outages. However, the majority of faults are temporary in nature and are cleared resulting in a momentary outage instead of as sustained outage. On average, for every sustained outage there are approximately two to three faults that are cleared without a sustained outage. As a circuit is added to SOG, segmentation devices are added in accordance with SOG segment targets. These devices can be setup in different operational modes depending on protection needs and device protection coordination. As more devices are setup as reclosers, fewer customers are affected by temporary faults. Our protection engineers will cascade devices in recloser mode as coordination allows, which can be up to three or four. Consider the example below. Before SOG there is one downstream recloser, but after there are multiple. Now, when temporary faults occur fewer customers are affected, thus a reduction in number of customers experiencing momentary operations than before SOG. Thomas appears not to take into account this reduction in the number of customers experiencing the momentaries due to the increased number of reclosers added to the grid. Therefore it is unnecessary to update the SOG CBA.





Q. DOES SOG ONLY BENEFIT CUSTOMERS ON SELECTED CIRCUITS?

A. While SOG is deployed on the circuits which have been identified as the most cost beneficial, there are benefits to all customers. The deployment of SOG will increase the efficiency of Company resources during outages, minor storms and also during MED events. Efficient deployment to circuits with SOG deployed will increase the availability of resources for assignment to non-SOG circuits and therefore benefit those customers also. Witness Thomas seemed to concur with that assessment, as his DE Progress testimony provided the caveat on page 53 that "Company resources have the potential to be more efficiently deployed on non-SOG circuits as a result of SOG".

Q. WHY IS IT UNNECESSARY FOR DE PROGRESS TO REVISE ITS SOG CBA DUE TO THE INCREASED PACE OF VEGETATION MANAGEMENT PROPOSED IN THIS PROCEEDING?

A. Witness Thomas retained this recommendation from his DE Carolinas testimony. However, he notes on page 30 of his DE Progress testimony, "I do not believe the impact in DEP will be as pronounced as the impact in DEC". As stated in my own DE Carolinas testimony, the difference for DE Carolinas would have been small, just 2% meaning DE Progress would be even less relevant.

Q. IF DUKE ENERGY WERE TO CONDUCT A SENSITIVITY ANALYSIS OF ITS SOG CBA, ARE THERE ANY ADDITIONAL BENEFITS DUKE ENERGY WOULD PROPOSE EVALUATING?

A. If Duke Energy were to perform a sensitivity analysis for its SOG CBA, it could include a benefit for Major Event Day (MED) reliability that was not included in the filed CBA. Given that SOG is a system level program, and storms are variable, we took a conservative approach at the time the CBAs were developed. However, in retrospect, we left out an important benefit that our customers enjoy. In looking at actual results for DEC and DEP from 2016 through 2019, MED Customer Minutes Interrupted (CMI) savings in total are 33% greater than non-MED savings for the existing Self-Healing Network installations. A recent example would be the tornadoes that occurred on 2/6/20 and 2/7/20. These were MEDs for both DEC and DEP. The SOG CMI saved during these events in DEC was approximately 5 Million and DEP was 5.3 Million. These savings would not show up in the conservative CBA methodology we used to justify the program but were invaluable for our customers. When viewed in its entirety, SOG is a "no regrets" investment that provides significant value for customers in multiple ways.

Q. WRAPPING UP RESPONSES TO WITNESS THOMAS'S TESTIMONY REGARDING SOG, DID YOUR SOG CBA APPROPRIATELY VALUE THE DER ENABLEMENT BENEFIT?

A. Yes. Witness Thomas points out that as of 2019, DEP has connected less than 50 MW of net metered projects onto the distribution system and questions whether the

DER benefit will be realized considering that it is contingent upon significant growth in the DER market in DEP's service territory.

No one seems to argue that growth of private DER will only continue to grow in the Carolinas in the foreseeable future. The GIP begins to prepare the distribution grid to integrate and manage widespread distributed solar installations across the Carolinas.

Q. DID ANY OTHER WITNESSES PROVIDE THEIR EVALUATION OF DUKE ENERGY'S GIP COST BENEFIT ANALYSES?

A. As mentioned previously, other intervenors made the following allegations regarding Duke Energy's GIP cost benefit analyses:

- Duke Energy underestimated costs for its GIP
  - GIP will cost ratepayers $8.6 billion over 30 years, compared to $2.3 billion presented by Duke Energy in Ex. 10 pg. 3 (Alvarez)
  - $424.5 million capital in Duke Energy's cost benefit analyses was not included in its 2020-2022 capital schedule (Alvarez)
  - $192.5 million for Energy Storage and Transportation Electrification are not included in the 2020-2022 capital schedule (Alvarez)
  - $1.1 billion in software and communications network replacement costs should have been included in the GIP (Alvarez)
  - $4.5 billion in estimated carrying charges should have been included in the GIP (Alvarez)

  - Costs for individual programs were not correctly evaluated (Alvarez)
- Duke Energy should have conducted cost benefit analyses for other programs such as those in Enterprise Communications (O'Donnell)
- Duke Energy should have conducted sensitivity analyses on its cost benefit analyses (O'Donnell, addressed above in Thomas' section)
- Duke Energy overestimated benefits for its GIP
  - Duke Energy's projected reliability improvement estimates are unsupported and the results from the ICE calculator are flawed (Alvarez)
  - Results from the IMPLAN secondary benefits analysis are flawed (Alvarez)
  - Duke Energy did not estimate the detrimental impact to GIP benefits that would come from GIP-related rate increases (Alvarez, and O'Donnell)

The concerns above come from the testimony of Witnesses Alvarez, and O'Donnell, and some were previously covered in my reactions to the Testimony of Public Staff Witness Thomas. These intervenors recommended that the Commission reject the proposed GIP program, as opposed to Public Staff's recommendation that the GIP work is reasonable and certain programs could be considered eligible for deferral treatment. Some intervenors recommended, as an alternative, that the Commission could approve certain GIP programs, despite their concerns regarding the Company's cost benefit analysis process. I will address these intervenors' concerns regarding the GIP cost benefit analyses and explain why those concerns should not prevent the Commission from approving deferral treatment of certain GIP programs.

Q. HOW DO YOU RESPOND TO THE ALLEGATION OF WITNESS ALVAREZ THAT THE GIP WILL COST RATEPAYERS $8.6 BILLION OVER 30 YEARS, COMPARED TO $2.3 BILLION PRESENTED BY DUKE ENERGY IN EXHIBIT 10 PAGE 3?

A. Witness Alvarez conflates Duke Energy's three-year (2020-2022) capital budget for GIP in North Carolina (both DEC and DEP) with his unsubstantiated $8.6 billion 30-year cost estimate. I will explain below how the cost estimate is unsubstantiated and not useful for the Commission's determination of GIP deferral eligibility, but I must first point out that the comparison itself is not a valid starting point for serious consideration.

Q. CAN YOU EXPLAIN THE $424.5 MILLION IN CAPITAL IDENTIFIED IN THE TESTIMONY OF PAUL ALVAREZ AS SHOWING UP IN THE GIP CBAS BUT NOT IN THE GIP CAPITAL SCHEDULE?

A. Attempting to reconcile the values from the CBAs to the values from Exhibit 10 relative to the 2020-2022 period is not an accurate comparison. Each set of values serves a valid but different purpose. The collection of CBAs assists in validating the benefit-to-cost ratio for selected projects and programs. The Exhibit 10 amounts are budgetary in nature. Differences can evolve from: 1) some CBAs start in 2019 therefore their 2019 capital is not included in Exhibit 10, 2) other CBA's were intended to demonstrate the project or program value proposition, their 2020-2022 values did not always align with the 2020-2022 budget due to project timing and other budgetary variances, 3) a number of CBAs are for projects or programs that may have started in the 2020-2022 period but continue deployment into 2023 and beyond. For example, a TUG neighborhood project may be a four-year deployment starting in 2021. The 2020-2022 budget amount would have two years of costs while the CBA would have four years of costs (2021-2024).

Q. CAN YOU EXPLAIN WHY THE $192.5 MILLION IN CAPITAL IDENTIFIED IN THE TESTIMONY OF PAUL ALVAREZ IS NOT INCLUDED IN THE GIP CAPITAL SCHEDULE?

A. As noted at Oliver Exhibit 10, Energy Storage Projects and Electric Transportation have been excluded from the GIP totals as they are being reviewed and evaluated in separate forums, and Duke Energy is not seeking to include them in the GIP deferral request.

Q. WHY WOULD IT BE UNREASONABLE FOR DUKE ENERGY TO HAVE PROJECTED THE $1.1 BILLION IN SOFTWARE AND COMMUNICATIONS NETWORK REPLACEMENT COSTS IDENTIFIED IN THE TESTIMONY OF PAUL ALVAREZ?

A. The majority of the line items Witness Alvarez noted in his Table 1 are categorized as Modernize, which are justified under cost-effective guidelines instead of a CBA. As such, there are only costs for the three-year GIP period of 2020-2022. There is no intention nor need to evaluate all programs over the same lifecycle. The replacement of those Modernize assets will be evaluated appropriately in the timeframe required.

Q. DID DUKE ENERGY CONSIDER ALTERNATIVES FOR ITS $160 MILLION IN COMMUNICATIONS NETWORK INVESTMENTS?

A. Witness Alvarez' generalized assertions and assumptions have taken specific detailed information related to a given component of Duke Energy's Communications Network and applied it to the broader, Enterprise-wide communications network. For example:

- Duke Energy has not stated that we did not perform any "technical or economic" analyses on the $160 million in communications network investment. Communications network investments made by Duke Energy follow documented enterprise supply chain processes including RFIs and RFPs to evaluate the available alternatives in the marketplace.
- Duke Energy's Core Data Network supports many applications. Where appropriate, considering the cost, security, speed to deploy and level of service required, external carriers are leveraged to provide services to the edge of Duke Energy's networks. Core Data Network requirements exceed the current capabilities that third-party cellular providers can provide given the 4G LTE and CatM1 typical bandwidth limitations.
- For the Land Mobile Radio program alternative services were included during the RFP process. Bidders were eliminated based on their inability to meet RFP

requirements as noted in Alvarez Exhibit 9. Commercial cellular carriers noted that they could not meet mission critical requirements of the program.

Q. HOW DO YOU RESPOND TO WITNESS O'DONNELL'S SUGGESTION THAT DUKE ENERGY SHOULD HAVE PERFORMED CBAS FOR ADDITIONAL PROGRAMS?

A. Witness O'Donnell recommended that Duke Energy should have performed CBAs for its proposed Enterprise Communications programs. While Public Staff Witness Thomas recommended that Duke Energy perform CBAs for a few additional programs, he did not find it necessary to do so for Enterprise Communications. As explained in response to Witness Thomas, the Enterprise Communications programs are evaluated on a cost effectiveness basis. Furthermore, as noted in response to the allegations from Witness Alvarez regarding Enterprise Communications programs, the analysis for those programs involves considering alternative options for addressing the communications needs of the Company, not determining if those needs actually exist.

Q. ARE THE ENTERPRISE COMMUNICATIONS PROJECTS NECESSARY TO ACCOMPLISH ANY OTHER PROGRAMS IDENTIFIED IN GIP?

A. Duke Energy included the costs for communications in its CBAs for programs like SOG and IVVC, since incremental communications infrastructure will be needed to implement those functionalities. The Enterprise Communications programs are necessary to upgrade and secure the foundational telecom infrastructure needed to operate Duke Energy's grid as a whole. While the Company's telecom infrastructure is foundational for programs like SOG it would be unreasonable and inefficient from a cost perspective to pursue those grid-wide telecom upgrades as an ad hoc subproject of projects that are more limited in scope.

Q. HOW DO YOU RESPOND TO WITNESS O'DONNELL'S SUGGESTION THAT DUKE ENERGY SHOULD HAVE PERFORMED SENSITIVITY ANALYES FOR ITS CBAS?

A. As stated in response to a similar suggestion from Public Staff Witness Thomas, a sensitivity analysis was not contemplated as a required function of the CBA process for Duke Energy's GIP.

Q. CAN YOU EXPLAIN WHY WITNESS ALVAREZ CONTENDS THAT DUKE ENERGY'S AGGREGATION OF INDIVIDUAL SERVICE OUTAGE IMPACTS DOES NOT RECONCILE WITH HIS CALCULATED OVERALL OUTAGE VALUES?

A. There are a number of reasons comparing an overall jurisdictional ICE model analysis by Witness Alvarez to the multitude of individual project analyses conducted by Duke Energy using consistent ICE model data is not a valid assessment. Even though Witness Alvarez's testimony notes a present value reliability benefit to customers of $4.8 billion, which is still substantially higher than the total 2020-2023 GIP request, there are still key differences that omit additional benefit value from his assertion. His calculation:

- Excludes the impact of a significant amount of individual project and program assumptions, including customized customer counts, customer mix, actual outage history, etc.
- Excludes the impact of MEDs
- Excludes several projects and programs included in the complete GIP summary as the SAIDI/SAIFI figures used are derived from only the most significant Distribution items
- Excludes the impact of Transmission projects completely

Q. IS WITNESS ALVAREZ'S REFERENCE TO BACKUP GENERATION AND UNINTERRUPTIBLE POWER SUPPLIES (UPS) A RELEVANT CRITICISM OF DUKE ENERGY'S CBA'S?

A. No. The study cited by Witness Alvarez is a review of critical infrastructure facilities in the United States as defined by the Department of Homeland Security. This includes facilities such as hydroelectric dams, electric generation facilities, hospitals, water treatment facilities, wastewater treatment facilities, communications facilities, emergency services and others. The assertion that C&I benefits are in any way meaningfully overstated within the Company's CBA's is misleading.

Q. WHAT IS THE RELATIONSHIP BETWEEN DUKE ENERGY'S IMPLAN BENEFITS AND ITS CALCULATED ICE BENEFITS?

A. The secondary estimates of the calculated IMPLAN benefits are largely dependent upon the primary customer reliability benefits estimated using the ICE model. As such, changes in the ICE model parameters (either in a positive or negative direction) would affect the associated IMPLAN benefits. The main purpose of estimating both the primary and secondary economic benefits, however, is to provide perspective on the overarching significance and magnitude of these results.

Q. HOW DO YOU RESPOND TO WITNESS ALVAREZ'S CONCERN THAT THE COPPERLEAF MODEL IS DRAMATICALLY OVERSTATING TRANMSISSION H&R BENEFITS?

A. The specific Transmission Line Assets represented in the three-year Grid Improvement Plan are not representative of the general population of Transmission Line Assets as Witness Alvarez alludes. The projects being pursued are specifically selected based on condition (probability of failure) and potential customer impact (consequence of failure) accumulating to a level of risk deemed unacceptable by the Company to tolerate.

I would also like to address the Alverez Testimony on Transmission Line failure rates. He states, "For example, Witness Stephens believes strongly that asset degradation curves should be based solely on Duke Energy's historical asset failure rates. In discovery, DEP stated that in the last five years it had only 10 static line failures out of 6,244 transmission line miles, a failure rate of just 0.03% per line mile per year (3 in 10,000 likelihood). DEP also provided zero instances of pole failures in the last five years, the result of its highly effective, existing pole inspection program. Assuming historical failure rates continue into the future – and DEP has provided no evidence as to why they should not – there is no possibility that the reliability benefits associated with just 2 static line failures every year for all of DEP, and zero pole failures every year for all of DEP, will provide the approximately $200 million in average annual primary reliability benefits required for a $1.899 billion present-value primary benefit estimate from the TH&R program."

Alvarez, quoting Stephens, appears to be confusing data provided in support of the DE Carolinas rate case with data provided for the DE Progress rate case. For DE Progress, the Transmission Hardening & Resiliency Projects provide approximately $10 million in average annual primary reliability benefits (customer benefits) required for a $89 million present-value primary benefit estimate. These customer benefits are approximately 1/20th of the values quoted, although despite this, they still represent significant reliability improvements for customers. As the Cost Benefit Analysis shows, proactively rebuilding these transmission line assets will prevent customer outages and deliver an NPV benefit to cost ratio of 3.3. In the last 5 years alone, DE Progress line equipment failures have resulted in over 155,000 customer outages, totaling nearly 11 million customer minutes interrupted. These figures demonstrate the risk presented by transmission circuit assets and the true benefit of the Transmission H&R program; failures are low frequency, but consequences are high.

Q. WHY DID DUKE ENERGY EXCLUDE THE IMPACT OF POTENTIAL RATE CHANGES IN ITS IMPLAN ANALYSIS?

A. The purpose of calculating both the primary economic benefits and the secondary economic benefits (via the IMPLAN analysis) was to estimate the aggregate benefit stream from the GIP that will accrue to the Duke Energy customer base as a whole. Or put another way, these estimated benefits provide a means to assign a value to the Duke customer base that would likely result from all GIP reliability improvements. This allows these estimates then to serve as a resource for others to do additional comparative analyses to evaluate various costs and benefits as part of the GIP evaluation process. As such, incorporating additional factors into these estimates such as the impact of rate increases, or the economic benefits of GIP-related construction activity falls outside of the scope of this analysis.

V. PERFORMANCE MEASUREMENTS

Q. WHAT IS YOUR RESPONSE TO INTERVENORS ASSERTION THAT THE GRID IMPROVEMENT PLAN SHOULD HAVE QUANTIFIABLE TARGETS AND METRICS TO MEASURE PERFORMANCE AND THE COMPANY SHOULD BE REQUIRED TO REPORT ON THE RESULTS OF THE WORK IN THE PLAN?

A. I agree with this contention and the cost/benefit analyses included in my direct testimony provide metrics for the projects and programs, as appropriate. Specifically, the cost/benefit analyses performed by the Company detail, among other things, the amount of O&M savings the Company anticipates from the Plan;

the amount of avoided capital costs the Company anticipates from the Plan; and the amount of outages that each of the programs and projects within the Plan are anticipated to avoid. Additionally, the Company can track the voltage reduction from the DSDR CVR conversion project and sees this as a good metric that demonstrates the value of adding CVR capabilities.

Q. DOES THE COMPANY PLAN TO TRACK DEPLOYMENT METRICS FOR THE GIP?

A. Yes. The Company intends to track project/program scope, schedule, cost and benefits as appropriate during implementation. Additionally, the Company does not oppose the recommendations by Witnesses Thomas and Metz to collaborate on GIP reporting.

Q. SINCE THE COMPANY DOES HAVE QUANTIFIABLE METRICS AND TARGETS BUILT INTO ITS GIP, HOW DO YOU RESPOND TO WITNESS STEPHENS SUGGESTION THAT THE COMMISSION IMPLEMENT COST CAPS AND AUDITS?

A. I believe that the Company's performance is subject to prudence reviews that are already inherent in the regulatory process. To explain, unlike unregulated companies, a regulated utility must always prove to regulators that the work it performs delivers customers the value that they pay for. For example, if the Company builds a generation facility that is supposed to deliver 100 megawatts of power to customers, that unit must deliver 100 megawatts of power to customers unless the Company has a reasonable and prudent reason why it is not doing so. If the Company does not have a reasonable and prudent reason for work not delivering the value it is supposed to, the Company is subject to a disallowance for the cost of that work. The work to be performed in the GIP is no different. If customers do not get the value they pay for under the Plan, the Company remains at risk for a prudence disallowance unless the company can provide reasonable and prudent reasons as to why they did not.

Q. HOW DO YOU RESPOND TO WITNESS STEPHENS CONCLUSION THAT DEC & DEP GRID INVESTMENTS IN RECENT YEARS DO NOT APPEAR TO BE ACHIEVING THE INTENDED RESULTS?

A. The referenced growth in distribution base was largely driven by customer load growth in our DEC and DEP service territories. The portion of the distribution investment spent on maintaining service quality has remained constant relative to the total spend in the past 5 years. While the previous level of expenditures has maintained system performance, since 2013 we have seen a worsening trend in reliability indices such as SAIDI due to an increase in number of outage events, and several other factors such as megatrends as discussed in my direct testimony. The analysis and Megatrends utilized to inform our GIP resulted in programs (i.e.- SOG, TUG) that were designed specifically to address these worsening trends (i.e. – weather). However, in 2019 the Company saw SAIDI and SAIFI improvements: DEC 171 & DEP 150 (SAIDI) and DEC 1.05 & DEP 1.31 (SAIFI) respectively.

VI. <u>ADDITIONAL PROGRAMS IN GIP</u>

Q. WHAT ARE THE OTHER PROGRAMS IN YOUR GIP THAT PARTIES GENERALLY AGREED WERE NOT EXTRAORDINARY IN NATURE?

A. See the table in Section III of this testimony.

Q. DO YOU AGREE WITH SEVERAL INTERVENORS WHO CLAIM THAT TRANSFORMER RETROFIT, BANK REPLACEMENTS, BREAKER REPLACEMENTS, TRANSMISSION H&R, AND UNDERGOUNDING ARE ALL BASE MAINENTANCE WORK THAT SHOULD NOT BE INCLUDED IN THE GIP?

A. All but targeted undergrounding have been performed in base work in the past, but a point is being missed. What is different is the pace of change required by the changing landscape of our industry. This changing landscape is a result of the Megatrends. Transformer retrofit took over twenty years to implement in DEC. We are seeking to accelerate it in DE Progress to better manage changing customer expectations and deal with the increase in extreme weather events. Bank replacements, breaker replacements, and transmission line rebuilds are similar. The GIP accelerates the historical pace to better position the Company to deal with the future requirements. Targeted UG is not a historical base program. Targeted UG projects are specifically aimed to improve reliability and harden the system against increasing storm frequency and cost in the areas that are in fact the most prone to damage.

Q. WHY DID THE COMPANY BELIEVE IT WAS IMPORTANT TO INCLUDE TARGETED UNDERGROUNDING IN ITS GIP?

A. The scope of the targeted undergrounding program was scaled back by approximately 90 percent to balance stakeholder priorities. The portion that remains is highly cost beneficial, and in fact uses a refreshed targeting approach. It now focuses on laterals that experience the highest outage events per year in a sustained pattern (ten years of history), correlated with significant age, high percentages of facilities inaccessible to trucks, and high vegetation management expenses. The high age and outage experience correlates to line section where the conductor is likely annealed and weakened from heavy fault duty exposure. It also means that a rebuild of these facilities (analogous to deteriorated conductor work) is imminent. Using a CBA comparison to evaluate between replacing these facilities with a brand-new antiquated design basis (rear lot overhead) from decades ago versus rebuilding with modern, updated and standard underground design represents modernization of antiquated infrastructure. This approach greatly increases the benefit to cost ratio from the statistics cited by Witness Stephens.

Further, this is the one program that has a very immediate and direct positive impact on customer satisfaction and for these reasons we felt it was important to keep some level of this work in the plan. We do not agree with those that say targeted undergrounding programs are not standard industry practice. Both Dominion in Virginia and Florida Power & Light in Florida have active targeted undergrounding programs. Dominion's program is branded "Strategic

Undergrounding Program and has been active for multiple years, and FPL's program is known as "Storm Secure Underground Program." Both programmatic approaches have been further encouraged by legislation within each state SB 1473 in Virginia and SB 796 (Storm Protection Plan) in Florida. Further, we also do not agree with Witness Stephens depiction of DE Progress system protection scheme and viable alternative actions to address the issue of upstream momentaries associated with faults in TUG areas. His recommendation would in fact increase sustained outages for our customers and accelerate damage to transmission and distribution equipment from fault current.

Q. WITNESS STEPHENS SUGGESTS THAT THE COSTS PER MILE IS DOUBLE FOR TUG DUE TO LOOPING. IS THIS CORRECT?

A. No. Looping is a standard practice for undergrounding services and is included in the current CBA costs for targeted undergrounding.

Q. WHY DID THE COMPANY BELIEVE IT WAS IMPORTANT TO INCLUDE LONG DURATION INT/HIGH IMPACT SITES IN ITS GIP?

A. Extreme weather events and concentrated population growth are Megatrends that the LDI/HIS program is designed to address. This program is designed to improve reliability in parts of the grid where duration of outages is much higher than average due to their accessibility. This program is also designed to improve the reliability of high-impact customers like airports and hospitals, and high-density areas that require a variety of solutions to improve power quality and reliability.

Q. WHY DID THE COMPANY BELIEVE IT WAS IMPORTANT TO INCLUDE TRANSMISSION TRANSFORMER BANK REPLACEMENTS IN ITS GIP?

A. GIP accelerates the historical pace of replacements to better position the Company to deal with for the future requirements. Witness Stephens asserts that Duke Energy is proposing replacing substation transformers in the absence of oil testing results. In fact, it is this oil testing along with other condition-based assessment triggers such as electrical testing and physical inspections that are the basis for which transformers are to be included in the Transformer Bank Replacement Program. Dissolved Gas Analysis (DGA) oil testing is the primary means relied upon by Duke Energy to determine substation transformer health and subsequent maintenance and replacement priority. Witness Stephens also discussed transformer failure rates calculated by Witness Alvarez. The calculation completed by Witness Alvarez is flawed and inaccurate. He states, "DEP reliability benefits are based on an estimate that 45 of the 101 transformer banks to be replaced would fail between now and 2036". The CBA for DEP substation bank replacement indeed accounts for 45 potential bank failures, but this is out of a population of approximately 700 banks. These 45 represent the highest risk population out of that 700 banks, so the failure rate would be 45/700 not 45/101.

Q. WHY DID THE COMPANY BELIEVE IT WAS IMPORTANT TO INCLUDE OIL BREAKER REPLACEMENTS IN ITS GIP?

A. GIP accelerates the historical pace of replacements to better position the Company to deal with future requirements. Witness Stephens asserts that circuit breakers should be identified for replacement based on test results and operating counts; Duke Energy agrees. Duke Energy does inspect and test substation circuit breakers to determine their health and maintenance needs. This program is the primary feeder into the prioritization and sequencing of oil breaker replacements. All oil circuit breakers proposed for replacement in the GIP have been selected based on these criteria, and each represent a potential reliability threat to our customers. As laid out in the CBA, the majority benefit delivered through replacing these assets is reduced customer outage impacts. Witness Stephens also discusses breaker failure rates calculated by Witness Alvarez. The calculation completed by Witness Alvarez is flawed and inaccurate. He states, "Duke Energy estimates that of the 370 DEP oil-filled circuit breakers proposed for prospective replacement, 456, or 123%, would have failed by 2032." The CBA for DEP oil breaker replacement does account for 370 potential breaker failures through 2032, but this is out of a population of approximately 2700 oil circuit breakers in the DEP territory. This equates to an annual failure rate of approximately 1%.

Q. HOW DO YOU RESPOND TO WITNESS THOMAS'S PROPOSAL FOR A REDUCED WORK SCOPE ON THE TRANSFORMER BANK REPLACEMENT AND OIL FILLED BREAKER REPLACEMENT PROGRAMS?

A. Witness Thomas testifies that the Company's CBA's have appropriately captured the additional cost of early retirement against the benefit to customers, by preventing customer outages, when compared to a condition where these assets fail while in-service. Nonetheless, Witness Thomas alleges that the assets being replaced in these programs often have many years of remaining life when they are replaced as part of GIP and may represent unnecessary early asset replacements. I do not agree with the characterization of these proactive asset replacement programs as unnecessary early asset retirements. We are targeting the riskiest assets on our system prior to catastrophic failure where long outages could occur. It is well understood that the financial depreciation life does not always align to the targeted replacements of these assets due to inherent operational variabilities that necessitate Duke Energy to replace some assets while there is existing financial depreciation life remaining. The remaining life values used in the CBAs are themselves an estimation based on an extremely wide and diverse population of assets. As Witness Thomas testified, the Health and Risk Management program under the GIP for Transformer Banks and Circuit Breakers is a software platform and management program that allows for more real time asset health data to inform a quantitative risk ranking methodology in order to better optimize and target assets requiring replacement.

Q. WHY DID THE COMPANY BELIEVE IT WAS IMPORTANT TO INCLUDE SUBSTATON PHYSICAL SECURITY IN IT'S GIP?

A. Threats to grid infrastructure is one of the top megatrends that has shaped the Grid Improvement Plan. This threat is widely accepted as valid throughout the utility industry. Duke Energy is committed and obligated to protect critical grid assets from external threats. Duke Energy has determined the top priority physical security improvement needs based on a threat and vulnerability assessment informed from the National Electric Reliability Council (NERC) Critical Infrastructure Protection (CIP) criteria for defining critical substations, which was reviewed by an independent industry third party. A graded approach is used with regard to physical security at substations not covered by NERC CIP-014 physical security requirements; the majority of substations will not necessitate security improvement projects. The ultimate goal of the Company is to provide our customers with reasonable assurance of reliable electric service through minimizing the risks of grid impacts associated with physical threats. Duke Energy is proud of the existing record of not having any instances of successful intrusions into our substations and intends to maintain this record.

Q. WHY DID THE COMPANY BELIEVE IT WAS IMPORTANT TO INCLUDE ENTERPRISE COMMUNICATIONS IN ITS GIP?

A. The Enterprise Communications program focuses on modernizing and securing the critical communications networks between intelligent grid management systems located at grid operation centers, data and controls systems located at substations, and sensing and control devices across the entire electric power network. As the Company places more and more intelligent two-way communicating devices on the grid, having a robust communications platform is a requirement of the modern grid. Some in the industry consider the expanding high-speed communications networks the third grid. I agree. A strong, secure, updated and robust communications system is a foundational pillar to any advanced grid needed to address the issues of today and the challenges of tomorrow. All the programs within the enterprise communications will work together to increase data capacity and/or bring new communications capability to areas of our system previously unserved. As noted by the Public Staff the Company is working diligently to replace all 2G/3G modems before cellular providers sunset those technologies.

Q. WHY DID THE COMPANY BELIEVE IT WAS IMPORTANT TO INCLUDE ENTERPRISE APPLICATIONS IN ITS GIP?

A. The Enterprise Systems focuses on delivering transformative, cross-functional solutions to the enterprise in non-disruptive ways. As an example, grid analytics can optimize the electric system health and performance through the deployment of the Health Risk Management (HRM) tool thereby helping to prevent equipment failures and improve asset performance on our transmission systems.

VII. STAKEHOLDER ENGAGEMENT

Q. HOW DO YOU RESPOND TO ALLEGATIONS FROM INTERVENORS THAT THE COMPANY'S STAKEHOLDER ENGAGEMENT EFFORTS WERE SOMEHOW "SUPERFICIAL" AND /OR "INADEQUATE"? PLEASE ALSO ADDRESS WITNESS WILLIAMSON'S CONCERN REGARDING "GLOBAL CONSENSUS."

A. During the last rate case (Docket No. E-7, Sub 1146), the Company uniformly heard that stakeholders wanted to be engaged and have their input heard in developing and deploying a grid improvement plan for the State. The Company accommodated this request in multiple ways prior to filing the GIP in this proceeding. As noted in my direct testimony, prior to submitting this plan to the Commission, the Company sought out customer and stakeholder perspectives, including holding multiple in-person stakeholder workshops and conducting deep dive webinars on topics specifically requested by stakeholders, as part of the engagement process. These efforts not only allowed for increased collaboration with stakeholders but also enhanced the transparency of the development of the GIP. During these workshops, the Company invited stakeholder feedback to ensure the plan addressed the diverse set of customer and stakeholder needs. While "global consensus" was not reached on all topics addressed during the stakeholder engagement process, as accurately noted by Witness Williamson, the feedback received in the workshops was used by the Company to validate the Megatrends, conduct additional analysis to support the programs in the GIP, drive future workshop discussions and make significant changes to the portfolio of investments. Further, the additional analyses (CBAs) conducted by the Company along with other meeting materials were published in a virtual on-line data room for stakeholder review during the stakeholder process, prior to the Company filing its GIP with the Commission.

Q. HOW DO YOU RESPOND TO INTERVENOR'S CRITIQUES THAT THE GIP IS IN MANY WAYS A SUBSET OF THE 10-YEAR, $13 BILLION POWERFORWARD PLAN?

A. No, this is not true. There are clear differences in the purpose, scope, and level of stakeholder engagement between Power Forward and the three-year GIP. Let me highlight a few key differences:

1. The GIP is a three-year plan while Power Forward was a 10-year plan. There is currently no "Phase 2" of the plan and any future plan would be built based on collaboration with stakeholders.
2. The scope of the two plans is dramatically different.
    a. Distribution Hardening & Resiliency and Targeted Undergrounding made up 64% of the Power Forward scope. These programs make up 11% of the three-year GIP.
    b. Large new programs exist in the three-year GIP. Significant examples are the DEC IVVC program at 10% of the total and Physical & Cyber Security at 6%.
    c. Self-Optimizing Grid, a program generally supported by all stakeholders, made up less than 10% of Power Forward. It is the largest program in the three-year GIP making up over 31% of the total.

CURRENT

Grid Improvement Plan Carolinas (NC)

dollars in (000's)	NC 2020-2022
Compliance: Cost Effectiveness Justified	**$134**
Physical Security	$111
Cyber Security	$23
Cost Benefit & Cost Effectiveness Justified	**$1,649**
SOG	$722
Incremental Distribution H&R	$145
IVVC	$217
Incremental Transmission H&R	$134
TUG	$115
Energy Storage	$129
Transmission Bank Replacement	$116
OIL Breaker Replacements	$200
Rapid Technology Advancement: Cost-Effectivenes	**$536**
T&D Communications	$212
Distribution System Automation	$194
Transmission System Intelligence	$86
T&D Enterprise Systems	$28
ISOP	$7
DER Dispatch Tool	$7
Electric Vehicle Charging	$63
Power Electronics for volt/var control	$2
Total	**$2.3 billion**

PREVIOUS

Power/Forward (NC)

dollars in (000's)	NC 2018-2027	
Compliance: Cost Effectiveness Justified		
Physical Security	$0	*new program*
Cyber Security	$0	*new program*
Cost Benefit & Cost Effectiveness Justified	**$11,804**	
SOG	$1,267	
Incremental Distribution H&R	$3,379	↓ 96%
IVVC DEC	$0	*new program*
Transmission	$2,195	
TUG	$4,962	↓ 98%
Energy Storage	$0	*new program*
Transmission Bank Replacement		
OIL Breaker Replacements		
Rapid Technology Advancement: Cost-Effectivene	**$926**	
T&D Communications	$447	
Distribution System Automation	$140	
Transmission System Intelligence		
T&D Enterprise Systems	$339	
ISOP	$0	*new program*
DER Dispatch Tool	$0	*new program*
Electric Vehicle Charging	$0	*new program*
Power Electronics for volt/var control	$0	*new program*
Total NC	**$13 billion**	

Megatrends

	GIP PROGRAMS	I - Phys & Cyber Threats	II - Adv Tech (Solar/Battery)	III - Environmental Policy	IV - Weather	V - Grid Improvement Techn.	VI - Concentrated Growth	VII - Customer Expectation	NC - DEC Total ($M)	NC - DEP Total ($M)	NC TOTAL ($M)	
Protect	Physical Security	x	x			x		x	$58.0	$64.7	$122.7	
	Cyber Security	x	x			x		x	$7.0	$4.0	$11.0	
Optimize	Self-Optimizing Grid	x	x	x	x	x	x	x	$420.0	$302.0	$722.5	1st
	Integrated Volt/VAR Control	x	x	x	x	x	x	x	$207.0	$10.0	$217.0	2nd
	Harden &Resiliency [T]		x	x	x			x	$102.4	$31.3	$133.7	
	Targeted Underground				x			x	$59.8	$54.7	$114.5	
	Energy Storage*		x	x	x		x	x	$56.5	$72.5	$129.0	
	Transformer Retrofit [D]				x			x	$8.3	$109.7	$118.0	
	Long Duration Interruptions				x			x	$11.3	$15.8	$27.1	
	Transformer Bank Repl [T]		x	x				x	$33.6	$82.7	$116.3	
	Oil Breaker Rpl [T]			x		x		x	$101.6	$42.8	$144.4	
	Oil Breaker Rpl [D]			x		x		x	$13.9	$42.0	$55.9	
Modernize	Enterprise Communications	x	x	x	x	x	x	x	$103.8	$108.0	$211.8	3rd
	Distribution Automation		x	x	x	x		x	$118.4	$70.9	$189.3	4th
	System Intelligence [T]		x	x		x		x	$62.7	$23.7	$86.4	
	Enterprise Applications		x	x		x		x	$17.0	$10.8	$27.8	
	ISOP		x	x		x	x	x	$4.1	$2.5	$6.6	
	DER Dispatch		x	x		x		x	$4.5	$2.9	$7.4	
	Electic Transportation*		x	x					$38.2	$25.2	$63.4	
	Power Electronics		x	x		x		x	$0.7	$1.1	$1.8	
											$2,314.2	

***Note:** *Energy Storage Projects and Electric Transportation have been excluded from these totals. These programs are important components of grid improvement but not included in the costs for the GIP given that they are being reviewed and evaluated in separate forums.*

(Oliver Direct Testimony - Exhibit 5)

The three-year GIP plan is the result of our compliance with Commission directives in the last rate case as to how to develop grid improvement initiatives. It is mainly in that regard it is related to Power Forward. The current three-year plan is a "no regrets" package of well-coordinated grid improvements. The plan begins preparing the North Carolina grid for the implications resulting from the megatrends highlighted in my testimony. Also, the current stakeholder informed three-year plan begins to prepare the North Carolina grid for growth in privately owned DER and electric vehicles, but even if this growth does not occur, the plan still is cost effective and warranted. This is proven in our CBAs.

Q. WHAT IS YOUR RESPONSE TO CONCERNS THAT THE PROPOSED GRID IMPROVEMENT PLAN DOES NOT ADDRESS DER ACCOMMODATION AS DISCUSSED DURING THE STAKEHOLDER ENGAGEMENT PROCESS?

A. I completely agree that the GIP does not address third party owned DER accommodation in North Carolina because that is not what the plan is designed to do, nor should it be. I understand that state and federal rules and policies dictate how these interconnection issues are addressed, and I further understand that vibrant discussions regarding these issues are ongoing in North and South Carolina in other forums. While there are some programs and projects in the plan that may provide ancillary benefits to interconnection issues, they are secondary to their primary purposes (such as voltage management, more capacity for distributed energy resources on the distribution system via aspects of the Self-Optimizing Grid program, and upgrades to certain transmission line structures and power transformation assets), the Company cannot and should not attempt to get ahead of federal and state rules and evolving policy issues regarding interconnection in the Grid Improvement Plan.

Q. WERE WITNESSES ALVAREZ AND POWERS ACTIVE PARTICIPANTS IN DUKE ENERGY'S GIP STAKEHOLDER ENGAGEMENT PROCESS?

A. I do not recall Witnesses Alvarez and Powers being active participants in any of the GIP stakeholder proceedings. Therefore, I am confused as to their critique of a process in which they had virtually no involvement.

Q. WHY SHOULD THE COMMISSION IGNORE WITNESS ALVAREZ'S PRIMARY RECOMMENDATION TO "REJECT" DUKE ENERGY'S GIP AND INSTEAD "ESTABLISH A PROCEEDING TO DEVELOP A TRANSPARENT, STAKEHOLDER-ENGAGED DISTRIBUTION PLANNING AND CAPITAL BUDGETING PROCESS FOR FUTURE USE IN NORTH CAROLINA?"

A. The Commission should ignore Witness Alvarez's primary recommendation for several reasons. First, if the Commission were to reject the GIP it could result in negative impacts as outlined in Exhibit 3 in my direct testimony. Second, contrary to Witness Alvarez's allegation and as discussed earlier in my testimony, the Company undertook an extensive and transparent stakeholder engaged planning process when it was deciding on which programs to include in its GIP and the associated budgets. A rejection of the stakeholder informed GIP would undermine not only the efforts of the Company but also each stakeholder involved in the stakeholder engagement process. Finally, if the Commission were to reject the Company's proposal, the work in the GIP would have to be sub-optimized, delayed, diminished in scope and effectiveness, and potentially not done at all. In such a situation, the Company would have to try and perform small pieces of the GIP over a much longer period of time within its existing revenues, delaying important benefits and potentially essential improvements for customers.

Q. HOW DO YOU RESPOND TO ARGUMENTS THAT THE GRID IMPROVEMENT PLAN SHOULD BE DELAYED UNTIL AN INTEGRATED DISTRIBUTION PLAN (IDP) OR INTEGRATED SYSTEMS PLANNING & OPERATIONS (ISOP) PROCESS IS DEVELOPED AND CONDUCTED?

A. I disagree. In fact, GIP programs such as Self-Optimizing Grid, IVVC, 44 KV Uplift, Transmission System Intelligence, and Distribution Automation will only improve the success of ISOP once implemented. These programs are foundational to the concept of two-way power flow and intelligent system control. Delaying them could in fact hinder the ability of ISOP to deliver its intended benefits. As discussed in my direct testimony, the Company is already engaging stakeholders in the development of our ISOP process. The Company has already completed/scheduled the following stakeholder engagement events:

<u>ISOP</u>

- ISOP Workshop # 1 - December 10, 2019 – Raleigh, NC
- ISOP Webinar #1 - January 30, 2020
- ISOP Webinar # 2 - March 3, 2020
- ISOP Workshop #2 - August 4, 2020 10am – 3pm in Columbia, SC

<u>IRP</u>

- IRP 101 Webinar - March 10, 2020
- IRP SC Virtual Workshop – March 17, 2020
- IRP NC Virtual Workshop – April 16, 2020

When complete, ISOP will focus on the integration of the Company's planning disciplines for generation, transmission, distribution and customer programs in order to improve the valuation and optimization of energy resources across all segments to best serve our customers. The ISOP process will addresses key operational and economic considerations across all segments of the system through integration and refinement of existing system planning tools and, in some cases, development of new analytical tools to assess characteristics that have not historically been captured or considered in long-term planning. Some examples include locational values for distributed resources, system ancillaries and reserves needed to support future operations, and energy resource flexibility to support new dynamic operational demands on the system. As the ISOP process is currently being developed, the Company cannot reasonably be criticized for not having this tool in place now.

VIII. VEGETATION MANAGEMENT

Q. **IN THE PUBLIC STAFF JOINT TESTIMONY OF D. WILLIAMSON AND T. WILLIAMSON THEY RECOMMEND THE COMPANY FILE AN ANNUAL REPORT OF ITS VEGETATION MANAGEMENT PERFORMANCE SIMILAR TO THE DE CAROLINAS REPORT. HOW DOES THE COMPANY RESPOND?**

A. The Company is not opposed to submitting an annual report for DE Progress on its distribution vegetation management performance. The Company recommends the

DE Progress annual report be due at the end of February for performance in the previous year.

IX. CONCLUSION

Q. MR. OLIVER, YOUR REBUTTAL COVERS A LOT OF GROUND BUT DID YOU RESPOND TO EVERY CONTENTION REGARDING THE COMPANY'S PROPOSED GIP PROGRAM IN YOUR REBUTTAL?

A. No. Intervenor testimony on the GIP involved hundreds of pages of testimony and I could not reasonably respond to every single statement or assertion and, therefore, I focused on the issues that I thought were most important in my rebuttal testimony. As a result, my silence on any particular assertion in the intervenor testimony should not be read as agreement with or consent to that assertion.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

BEFORE
THE PUBLIC SERVICE COMMISSION OF
NORTH CAROLINA

DOCKET NO. E-2 SUB 1219

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

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

A. My name is Jay W. Oliver. My business address is 400 South Tryon Street, Charlotte, North Carolina. I am employed by Duke Energy Business Services, LLC ("DEBS") as General Manager, Grid Strategy and Asset Management Governance for Duke Energy Corporation ("Duke Energy"), the parent holding company for Duke Energy Progress, LLC ("DE Progress" or the "Company").

Q. WHAT IS THE PURPOSE OF YOUR SUPPLEMENTAL REBUTTAL TESTIMONY?

A. I am responding to the Supplemental Testimony of Tommy Williamson, Jr. filed on behalf of the Public Staff regarding transmission and distribution ("T&D") assets placed in service from March 1, 2020 through May 31, 2020 for DEP ("Update Period").

Q. WITNESS WILLIAMSON NOTED IN HIS TESTIMONY THAT DE PROGRESS HAD COMPLETED CONSTRUCTION ON SOME CIRCUITS THAT WERE PENDING SOG "ENABLEMENT." WHAT IS THE COMPANY'S TARGETED TIMEFRAME FOR COMPLETING THE SOG "ENABLEMENT" WORKSCOPE?

A. Currently, the timeframe is longer than we would like between construction completion and SOG enablement. As noted in witness Williamson's testimony, prior to this year the Company had been proceeding at a slower pace; however, as the number of circuits targeted for SOG has increased, the demand for more highly skilled personnel to perform the enablement work has increased. Once fully staffed we anticipate it will take approximately 12 weeks between the point construction work is complete and full SOG enablement. This 12-week timeframe is needed for scheduling multiple interdependencies between the reliability engineers who create the device settings; the ADMS Model Builders who will program the devices into the software and facilitate testing and validation; and coordination with the with the Grid Management technicians to ensure devices are showing up correctly in the Distribution Control Center (DCC).

Q. WHAT ARE THE COMPANY'S PLANS FOR ACHIEVING THE TARGETED TWELVE WEEK SOG ENABLEMENT TIMEFRAME?

A. As COVID restrictions ease, we intend to begin building the staff required to reach the targeted 12-week timeframe. Modelling resources are a highly specialized skill set, but we are confident in our ability to find those resources with the additions likely being a combination of company and contract personnel. Training the resources will include sitting with our experienced team, reviewing the work of others and being productive along the way as they complete the needed training which we anticipate will take approximately four months.

Q. WILL SOG ENABLEMENT BE INCLUDED AMONG THE KEY METRICS FOR GIP REPORTING?

A. Yes. As noted in the Second Agreement and Stipulation of Partial Settlement in this case, DE Progress, in conjunction with the concurrent commitment of DE Carolinas, and the Public Staff will work together to develop biannual reporting on scope, schedule, costs, and benefits on the programs agreed upon for GIP deferral. Today the company's project management team is already tracking on a circuit by circuit basis the 1) Capacity and tie work completed; 2) Reclosers installed; 3) Reclosers commissioned (programmed and verified the recloser can safely operate in switch mode; and 4) Enablement of the self-healing team. The timeframe for how long it is taking from construction complete to SOG enablement can be an additional metric.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes.

Duke Energy Progress, LLC
Summary of Supplemental Rebuttal Testimony of Jay Oliver
Docket No. E-2, Sub 1219

I am employed by Duke Energy Business Services, LLC as General Manager, Grid Strategy and Asset Management Governance for Duke Energy Corporation, the parent holding company for Duke Energy Progress, LLC/Duke Energy Carolinas, LLC. The purpose of my supplemental rebuttal testimony is to respond to the Supplemental Testimony of Public Staff witness, Tommy Williamson, Jr. regarding transmission and distribution assets placed in service from March 1, 2020 through May 31, 2020.

The timeframe between construction completion and SOG enablement is currently longer than we would prefer. Prior to this year the Company had been proceeding at a slower pace; however, as the number of circuits targeted for SOG has increased, the demand for more highly skilled personnel to perform the enablement work has increased. Our target is approximately 12 weeks between the point construction work is complete and full SOG enablement. This timeframe is needed for system modeling, coordination, and scheduling..

We acknowledge we are not currently meeting the 12 week target. COVID restrictions have added to this challenge. However, we are in the process of adding the appropriate resources in order to achieve the targeted 12-week timeframe. Modelling resources are a highly specialized skill set, thus the hiring and training the process will take some time. Training the new resources will include sitting with our experienced team, reviewing the work of others and being productive along the way.

DE Progress, DE Carolinas, and the Public Staff will work together to develop biannual reporting on scope, schedule, costs, and benefits on the programs agreed upon for GIP deferral. The company's project management team is already tracking on a circuit by circuit basis the 1) Capacity and tie work completed; 2) Reclosers installed; and 3) Reclosers commissioned (programmed and verified the recloser can safely operate in switch mode). The timeframe for how long it is taking from construction complete to SOG enablement can be an additional metric. This concludes my summary of my rebuttal testimony.

MR. JEFFRIES: Thank you, Mr. Chairman. Mr. Oliver -- I will note for the record that Mr. Oliver's prior testimonies have already been admitted into the record in both rate case dockets, so that concludes moving his testimony into the record, and he's available for cross examination and questions by the Commission.

COMMISSIONER CLODFELTER: According to my notes, Mr. Page, we're back with you.

MR. PAGE: Thank you, Commissioner Clodfelter.

CROSS EXAMINATION BY MR. PAGE:

Q. Mr. Oliver, were you able to listen to the Cross examination that I had and the conversation with Mr. Williamson of the Public Staff?

A. I was, Mr. Page, yes.

Q. I think the good news is -- good afternoon. I should have said that to start with.

Good news is, I think that conversation is going to limit the questions I have for you to maybe one or two. We were talking about the enablement of these circuits, and from I understood from Mr. Williamson, your team is in place. You may have to add a few members because the number of circuits is large.

But my real question -- I'll just skip all the intermediate steps and get to the bottom line, if that's all right with you. Is there a drop-dead date you can give us today for when all of this enabling work will be done and all of these circuits will be fully automatic?

A. Well, our goal is to get to a 12-week time frame from the time that all the work in the field is complete, the SCADA control, which is the remote control that goes back to the control center, is enabled, and we have the capacity and connectivity complete. So when that happens, it's ready for the modeling exercise to happen, which is the resources we're talking about, and we're working to get that to 12 weeks.

We're averaging right now in Duke Energy Progress about three to four months before that enablement of these teams, so we got to get that down about a month or two. We are in the process of adding those resources. I don't have an exact date for when each of these current networks will be enabled, but I feel very confident we'll get to that 12 weeks in relatively short order.

Q. But would you agree with Mr. Williamson it's likely to be sometime in 2021, at least not by the end of the hearings in this case?

A. I would say it's possible some of those may go to '21, but others will be done in 2020. I don't know which. I don't know an exact date. I had a conversation with the leader of that organization last week just to make sure I was familiar with where they were at, and understood that they were already making progress on this backlog with the current staff and are getting ready to bring on additional staff to move this process forward.

Q. Thank you very much, Mr. Oliver. Good to see you again. That's all the questions I have for you.

A. Good to see you, sir.

COMMISSIONER CLODFELTER: All right. Is there any other party who wishes cross examination of Mr. Oliver?

(No response.)

COMMISSIONER CLODFELTER: If not, Mr. Jeffries, is there any redirect?

MR. JEFFRIES: Just two quick questions, Mr. Chairman.

REDIRECT EXAMINATION BY MR. JEFFRIES:

Q. Mr. Oliver, you could briefly explain the modeling exercise you referenced that the Company will have to go through after the physical components of SOG are installed for any particular circuit segment?

A. Yes, certainly. So I think to do that, it's best to explain all the work that takes place up front before we get to that stage. So let's take a typical circuit that we have today, maybe it's 5 or 6 miles long and serves 2,000 or so customers. We would first install the segmentation devices. These are protective devices and also switches. We put about -- we put a segmentation device about every 400 customers or so, or every 2 miles, depending -- depending on the circuit. So you're going to segment that circuit into individual sections of about 400 customers.

That work takes place first. If there is any capacity work that needs to be done at the substation, that will happen. We'll then install the ties to the adjacent circuit and also segment that adjacent circuit. As we segment that adjacent circuit, we now have what was two individual circuits that were not necessarily connected, they are now connected via automatic controllable devices, and the circuits are segmented to about 400 customers or so.

That is the point at which it moves to the modeling exercise where the restoration activities become automatic. Now, when all that work is done, we have created -- and that's the work we're talking about going into service -- we have, in fact, created reliability benefits for customers that are out there today. Because, in Mr. Page's example earlier where it was a radial circuit, if we installed one of those segmentation devices, which we are, it would, in fact, operate in about two to three seconds and save all the customers upstream, and isolate that out as to just the customers downstream. In that example, though, there was no backfeed capability.

So we do have all of that. We would isolate and less customers would be affected in that state, and we could actually backfeed because we've installed the capacity and connectivity to do so, it just doesn't happen automatically. So depending on the situation, because each situation is different, we may send a crew out to take a look, or the control center may look at it and manually -- because they can do it -- when I say manually, envision clicking a mouse. That's what manually means in this case. Click the mouse a couple of times and reconfigure the circuit manually via their commuter screen.

What's missing is the automatic control, and that's the part that takes a little bit of time. So envision all these segments -- I might have 10 to 100 segments that have to be enabled. Each of those -- for each of those segments we need to think about an if-then statement, that's probably the best way to put it. If a fault happens here, then this is how we configure; if the fault is here, then this is how we configure. And we also do some checks to ensure that we have enough load to backfeed.

That's the modeling exercise. It takes quite a bit of time to do that to get it right. We need to run it through testing scenarios. And it takes some specialized resources to do that. So that's that 12-week time frame that we're working on. We're not there yet, but we're closing that gap.

Q. And thank you, Mr. Oliver, for that explanation. Mr. Page asked you about when you thought the work might be done to close that gap, and specifically in reference to the SOG equipment that's been included in rate base in the DEP case.

When would you anticipate having most of that fully functional?

A. So the equipment that's in the field now is fully functional. That equipment is operated -- can be operated by SCADA, it has been enabled with protection and control to limit the number of customers affected. The only thing that's missing is the automated control, and that is the final piece that takes a little bit of time. We are working on that. It's going to take us -- I would estimate we will have all the resources in place before the end of the year, and we'll be training those resources as they come along. And, in fact, using them as they come along. But it will take a little bit of time to get that done, and then we got to make sure they get trained.

So we're looking to get the resources in place by the end of this year. We've had to slow down because of COVID. There are some important restrictions we need to follow, obviously, during this time. As those restrictions ease, it will be a little bit easier to bring resources on and get them trained.

Q. So I realize you're an engineer and not a rates guy, but do you have an understanding about when rates might be effective or this rate case -- when new rates might go into effect?

A. Unfortunately, Mr. Jeffries, I do not.

Q. Okay. That's fine.

MR. JEFFRIES: That's all the questions I have, Mr. Chair.

COMMISSIONER CLODFELTER: All right. Thank you, Mr. Jeffries. Let's see if we have questions from Commissioners.

Commissioner Brown-Bland?

COMMISSIONER BROWN-BLAND: No, I do not have any questions. Thank you.

COMMISSIONER CLODFELTER: Commissioner Gray?

COMMISSIONER GRAY: No questions.

COMMISSIONER CLODFELTER: Chair Mitchell?

CHAIR MITCHELL: No questions.

COMMISSIONER CLODFELTER: Commissioner Duffley?

COMMISSIONER DUFFLEY: No questions.

COMMISSIONER CLODFELTER: Commissioner Hughes?

COMMISSIONER HUGHES: No questions.

COMMISSIONER CLODFELTER: Okay. Commissioner McKissick?

COMMISSIONER McKISSICK: No questions.

COMMISSIONER CLODFELTER: All right.

Mr. Oliver, I have one question for you, and it's just really a matter of curiosity.

EXAMINATION BY COMMISSIONER CLODFELTER:

Q. I'm not an engineer, so I'm going to ask you a question in layman's terms so you can back -- answer back in layman's terms. The DSDR system that Duke Progress currently operates, as I understand it from your testimony in the consolidated case, is going to be reprogrammed or repurposed. I'm not sure whether you got to add software or whether you just turn some switches or what, but it's going to be repurposed, as it were, so it operates in the volt/VAR control mode, if I'm expressing it right. I hope I am.

I'm really curious about, will you lose or will you retain the ability to reconvert, if you saw any benefit or reason to do so and operated in what I think is the peaking mode now where you're using the DSDR system for management of peak loads; will you be able to go backwards if you want to?

A. Yes. That is the intention.

Q. Okay.

A. And we feel would provide the most benefit that way. So we'll look to what we call conservation voltage reduction mode, or CVR, and we'll operate the vast majority of the hours of the year in that mode. We'll still have the ability to do peak-shaving mode on top of that to get that benefit. Now, what we need to do is do some testing to see what that benefit would be compared to what we currently get in DSDR peak-shaving mode and do some discussion about that, work with the Public Staff and others so we come to an understanding of what the right mode of operation is. But we do feel that the CVR mode with the ability to implement peak shaving when needed is the most beneficial for our customers.

Q. That answers my question. You will not lose any existing functionality you have in the existing system?

A. Yes, Commissioner Clodfelter, that is true. The one thing I want to make sure we do, though, is take a look at the difference in peak-shaving value that we're going to get because we're starting at a different voltage point. We've already lowered voltage and it's staying there. This will be in the conservation voltage reduction mode. And then now when we do peak shaving, we'll lower it a little more. So may not get as much, and we need to take a look and see what that looks like and make sure that it makes sense for all parties.

Q. Thank you. Helpful to my education, I appreciate it. That's all I have.

COMMISSIONER CLODFELTER: Questions on the Commission's questions? Ms. Cummings, Mr. Jeffries?

MR. JEFFRIES: Nothing for the Company, Mr. Chairman.

COMMISSIONER CLODFELTER: Okay. Fine. I don't know that we have any exhibits we need to deal with, do we, Mr. Jeffries? I don't think so.

MR. JEFFRIES: No exhibits for Mr. Oliver's supplemental rebuttal.

COMMISSIONER CLODFELTER: Okay. Would you like for Mr. Jeffries to be -- Mr. Oliver to be excused?

MR. JEFFRIES: I'm sure Mr. Oliver would like for Mr. Oliver to be excused, so yes, Mr. Chairman.

COMMISSIONER CLODFELTER: Very good. Mr. Oliver, thank you for being with us, and unless there's an objection, you may be excused.

THE WITNESS: Thank you.

COMMISSIONER CLODFELTER: Thank you. Okay. Let's see where we are now. Who have we got next? Mr. Jeffries, do you -- are you captaining this panel?

MR. JEFFRIES: I will start. I won't claim the captain's seat, but Mr. Marzo and I will handle this panel. So we would call -- Duke would call Mr. Spanos, Mr. Doss, and Mr. Riley to the stand, Your Honor.

COMMISSIONER CLODFELTER: Okay. I have Mr. Spanos up, and I now have Mr. Doss up. And looking -- now I have Mr. Riley. So that's great.

Whereupon,

JOHN J. SPANOS, DAVID L. DOSS, AND SEAN P. RILEY,
having first been duly affirmed, were examined
and testified as follows:

COMMISSIONER CLODFELTER: Great. Mr. Jeffries, you have the witnesses.

MR. JEFFRIES: Thank you, Mr. Chair. I will start with Mr. Spanos, and then Mr. Marzo will introduce Mr. Riley and Mr. Doss.

DIRECT EXAMINATION BY MR. JEFFRIES:

Q. So, Mr. Spanos, could you state your name and business address for the record, please.

A. (John J. Spanos) John J. Spanos. 207 Senate Avenue, Camp Hill, Pennsylvania 17011.

Q. And where do you work, Mr. Spanos?

A. I work for Gannett Fleming Valuation and Rate Consultants, LLC.

Q. And what's your position with Gannett Fleming?

A. I'm the president.

Q. All right. Thank you. Now, Mr. Spanos, you prefiled direct testimony in this docket on October 30, 2019, consisting of 18 pages, Appendix A, and Spanos Exhibit 1; is that right?

A. That is correct.

Q. Okay.

MR. JEFFRIES: Mr. Chair, I would simply note for the record that Mr. Spanos' prefiled direct testimony, Appendix A, and Exhibit 1 were admitted into evidence at the beginning of the DEP proceedings, so I won't be moving those in.

Q. Mr. Spanos, you also prefiled rebuttal testimony on May 4, 2020, consisting of 41 pages, correct?

A. That's correct.

Q. And was your rebuttal testimony prepared by you or under your direction?

A. Yes, it was.

Q. All right.

MR. JEFFRIES: And, Mr. Chairman, we filed an errata earlier this week for Mr. Spanos' rebuttal testimony that simply we had some errors, some formatting errors and some content errors in the table of contents for his testimony. So that's been provided to the other parties and submitted already.

Q. Mr. Spanos, if I asked you the same questions that were set forth in your prefiled rebuttal testimony while you on the stand today, would your answers be the same?

A. Yes, they would.

Q. And, Mr. Spanos, you also prepared a summary of your rebuttal testimony; is that correct?

A. That is correct.

Q. All right.

MR. JEFFRIES: Mr. Chairman, we would move that Mr. Spanos' rebuttal testimony and the summary of his rebuttal testimony be entered into the record as if given orally from the stand.

COMMISSIONER CLODFELTER: Thank you,

Mr. Jeffries. You've heard the motion. Unless there's objection?

(No response.)

COMMISSIONER CLODFELTER: Hearing none, it will be so ordered.

(Spanos Exhibit 1 was moved at the consolidated hearing and admitted into evidence.)

(Whereupon, the prefiled direct testimony with Appendix A and testimony summary of John J. Spanos was moved at the consolidated hearing and copied into the record as if given orally from the stand.)

(Whereupon, the prefiled rebuttal testimony, errata, and testimony summary of John J. Spanos were copied into the record as if given orally from the stand.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1219

In the Matter of:	)	
	)	**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	ISO82, 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

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

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	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

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

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	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

Duke Energy Progress, LLC
Summary of Direct Testimony of John Spanos
Docket No. E-2, Sub 1219

My name is John Spanos and I am President of Gannett Fleming Valuation and Rate Consultants, LLC, an international energy and regulatory consulting firm. I am an expert in depreciation and have more than 34 years of experience in conducting depreciation studies for the various clients of my firm, including in this docket Duke Energy Progress, LLC. I have testified before this Commission on multiple prior occasions and have prepared depreciation studies for and on behalf of regulated utilities on depreciation related issues hundreds of times. The purpose of my Direct Testimony in this docket is to present the Depreciation Study I conducted for DEP for purposes of this rate case, which is attached to my testimony as Spanos Exhibit 1.

In calculating depreciation expense for DEP, along with the subcomponent calculations and analyses that support such depreciation expense (such as probable retirement dates, service life, survivor curves, accrued depreciation, and net salvage), I used widely accepted depreciation methodologies adopted to the specific circumstances of DEP. These methodologies have been previously accepted by this Commission in prior cases and are the prevailing methods accepted by the majority of Public Service Commissions that engage in evaluating depreciation expense for regulated utilities.

The precise methodologies used to calculate depreciation rates and depreciation expense for DEP is set forth in my Direct Testimony and in the Depreciation Study attached to my testimony.

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	)	**JOHN J. SPANOS**
For Adjustment of Rates and Charges	)	**FOR DUKE ENERGY**
Applicable to Electric Service in North Carolina	)	**PROGRESS, LLC**

I. WITNESS IDENTIFICATION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

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

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

A. I am employed by Gannett Fleming Valuation and Rate Consultants, LLC as President.

Q. ARE YOU THE SAME JOHN J. SPANOS THAT PREVIOUSLY PROVIDED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes.

II. PURPOSE AND OVERVIEW OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My rebuttal testimony addresses the testimonies of Commission Public Staff witnesses Roxie McCullar, Shawn L. Dorgan and Michael C. Maness and Fayetteville Public Works District ("FPWC") witness Gary D. Brunault regarding Public Staff's proposed adjustments to the depreciation rates submitted by Duke Energy Progress, LLC ("DE Progress" or the "Company") in this case. I also respond to Public Staff witness Maness' testimony around the issue of whether prior depreciation studies included costs for the closure of coal ash facilities in net salvage percentages.

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

A. My testimony responds to the depreciation related proposals of the Public Staff and FPWC witnesses mentioned above. I will explain that my proposals are consistent with current expectations for the Company's assets and with concepts that are either incorporated in the Company's current depreciation rates or have been previously decided by the Commission.[1] To the extent the depreciation study differs from prior studies or decisions, such as the need to change retirement dates for generating units at the Mayo and Roxboro facilities, there are sufficient reasons to do so. In contrast, Public Staff and FPWC's proposals are not consistent with either the current outlook for the Company's assets, prior decisions, or reasonable estimates of the future. This is particularly true when considered in the context of other proposals in this case. For example, Ms. McCullar's mass property net salvage proposals are not consistent with the concepts decided by the Commission in DE Carolinas' most recent case, Docket No. E-7, Sub 1146. Specifically, Ms. McCullar's proposals for net salvage are not established in a manner that will recover the full amount of future net salvage costs. Additionally, Ms. McCullar proposed to extend the life of AMI Meters, despite the fact that none of the factors affecting the life of these assets have changed since the Company's last study or

[1] The current depreciation rates for DE Progress were based on a settlement agreement. However, the depreciation issues for the Company's affiliate, DE Carolinas, were decided in a Commission order in Docket No. E-7, Sub 1146. As a result, I reference the Sub 1146 Order in multiple instances in my rebuttal testimony.

from DE Carolina's last study in which the Commission accepted a 15-year average service life in Docket No. E-7, Sub 1146.

There are also issues that affect depreciation that will be addressed by other DE Progress witnesses. DE Progress witness Stephen De May will address the retirement dates for Mayo and Roxboro Units 3 and 4. Additionally, while I discuss the level of contingency included in the terminal net salvage estimates, the issue has been addressed in the decommissioning study and in DE Progress witness Kopp's testimony in DE Progress's previous rate case.

Q. DO YOU HAVE ANY GENERAL COMMENTS ON THE PROPOSALS OF OTHER PARTIES?

A. Yes. As I will discuss in detail, I believe the recommendations I have made in the depreciation study are appropriate on the merits. However, I think the Commission should also consider the depreciation recommendations in the context of proposals made by Public Staff and other parties related to coal ash costs. Coal ash costs are part of the capital cost of operating coal-fired generation. As with any costs experienced at or near the end of the life of a given facility, there are challenges to estimating the costs that should be recovered prior to when they are incurred. As we now know, the end of life costs for coal-fired generation are higher than was originally anticipated and many coal-fired power plants across the country have been or will be retired earlier than originally anticipated. I note that, at least as it relates to the retirement of coal-fired facilities and the cost of remediating ash ponds, the over-estimation of service lives and under-estimation of retirement costs is an industry-wide issue and not specific to DE Progress.

I believe these facts should inform how the depreciation proposals are considered in this case. Staff and FPWC propose longer life spans for the Company's power plants and propose a reduced contingency for the decommissioning costs of the Company's plants. Public Staff also proposes longer lives for AMI meters and reduced removal costs for other types of property. Each of these proposals risk a recurrence of the same challenges posed by earlier retirements of coal-fired generation and the level of coal-ash costs that need to be incurred. Specifically, the other parties' proposals for both the retirements of power plants and coal-ash costs increase the risk that a portion of the costs of coal-fired generation will have to be paid by customers (or shareholders if Staff's proposal is adopted) who did not receive electric service from the retired plants. Adoption of Public Staff and FPWC's proposals for life spans and contingency would mean failing to learn the lessons of the past about the risks of failing to fully recover the costs of the Company's assets over their service lives.

This context also highlights the inequity of Public Staff's proposals when considered together. Staff proposes that the Company not be able to recover the full costs of coal ash in a timely manner (with the intended consequence that these costs be shared with shareholders). However, Staff also proposes reducing the estimates of future retirement costs and longer lives for coal-fired power plants. I am concerned that this means that in the future Staff could again propose that the

Company not be afforded the opportunity to recover its costs in a timely manner – even if at that time those costs had not yet been recovered because of Staff's proposals. This is also a larger risk if the precedent is established of not allowing the Company full or timely recovery of its coal-ash costs.

It is important to recognize that these risks are not symmetric. If power plants last longer than expected or if retirement costs are lower than expected, I have no doubt that the difference in costs will be trued-up, either through the use of the remaining life technique or another method. In other words, I can say with confidence that if depreciation is estimated to be too high for these facilities the recovered costs will not be retained by shareholders. However, if depreciation is estimated to be too low, the likelihood of which is increased by Staff and FWPC's proposals, there is a real risk that the Company will not be afforded the opportunity for the full recovery of (i.e., a return of and on) its costs.

In light of these considerations, I believe it is most appropriate to adopt the Company's proposals. However, it would be particularly inequitable and unfair to both the Company and to future customers to adopt all of Staff's proposals – both increasing lives and reducing net salvage while not allowing the Company to recover the costs of its plants that have retired.

Q. DO YOU HAVE ANY OTHER GENERAL COMMENTS REGARDING PUBLIC STAFF'S DEPRECIATION PROPOSALS?

A Yes. In addition to the conceptual disagreements that I have with Public Staff's proposals, I also do not agree with the calculations that Staff witness, McCullar presented. Ms. McCullar's workpapers and resulting expense have some incorrect assumptions. First, Ms. McCullar has not properly calculated the weighted net salvage percentage to incorporate her changes to the life span date of Mayo and Roxboro as well as the total recovery due to the longer life span dates. Second, for Hydro and Other Production Plant, Ms. McCullar does not recalculate the remaining lives to reflect her adjustments. Third, the distribution plant adjustments by Ms. McCullar does not reflect the update remaining lives with her parameter changes. Fourth, Ms. McCullar did not properly calculate expense on the appropriate vintages for the accounts that she proposed different amortization periods. Also, she did not properly segregate the reserve between amortized plant and the unrecovered reserve component for each account. Finally, Ms. McCullar did not revise the life span for land rights related to Mayo and Roxboro. All of these items affect the depreciation expense recommended by Public Staff.

III. NET SALVAGE

Q. WHAT IS NET SALVAGE?

A. Net salvage, as used in depreciation, is defined as gross salvage less cost of removal. When an asset is retired it may have scrap or reuse value, which is gross salvage. There is also a cost to retire the asset. For example, the retirement of a distribution pole typically requires a multiple person crew and heavy equipment to remove the pole from the ground and cut the pole for disposal. There also may be disposal costs for the pole. If the costs to remove the equipment from service are greater than the salvage value of the asset, then the net salvage is referred to as negative net salvage.

Q. DO ANY PARTIES RECOMMEND CHANGES TO THE NET SALVAGE ESTIMATES IN THE DEPRECIATION STUDY?

A. Yes. Public Staff witness McCullar proposes different net salvage estimates for three distribution plant accounts. I will address these estimates in my rebuttal testimony and explain the issues with Ms. McCullar's overall approach to estimating net salvage, which is inconsistent with the Commission's order in DE Carolina's most recent rate case.

Additionally, both Public Staff and FPWC propose the use of a 10 percent contingency instead of a 20 percent contingency. I will briefly address these proposals. The 20 percent contingency was also addressed in the decommissioning study and in the testimony of DE Progress witness Kopp in the Company's previous rate case.

Q. SHOULD NET SALVAGE BE DETERMINED AS AN ESTIMATE OF THE COST TO RETIRE AN ASSET TODAY OR AS THE FUTURE COST TO RETIRE AN ASSET AT THE TIME OF ITS EXPECTED RETIREMENT?

A. Net salvage is estimated as the cost to retire an asset, net of any gross salvage, at the time the asset is expected to be retired. Net salvage is not estimated as today's cost to retire an asset. The reason for this is that if today's costs were estimated, then the application of straight-line depreciation would typically fail to recover the full cost to retire the asset because costs tend to increase over time.

Q. HAS THE COMMISSION PREVIOUSLY RULED ON THIS CONCEPT?

A. Yes. Ms. McCullar challenged this concept in both DE Progress's most recent rate case and in Docket No. E-7, Sub 1146 for DE Carolinas. While DE Progress's case was settled, the Commission ruled on this concept in the Sub 1146 Order. In that docket, Ms. McCullar challenged the inclusion of the full future net salvage cost in depreciation and instead proposed to only include estimates of net salvage costs at current cost levels. The Commission determined that the full future net salvage cost should be included, stating that:

> Considering all the evidence, the Commission finds and concludes that the escalation of terminal net salvage cost and the use of the straight-line method of depreciation in determining escalation as performed in the DEC Decommissioning Study is just and reasonable, appropriate for use in this case, and is adopted.[2]

The Commission also concluded that estimating net salvage as the future costs to retire an asset is consistent with authoritative texts and depreciation practices:

> The testimony and evidence presented in this case demonstrates that authoritative texts and sound depreciation practices support escalating terminal net salvage costs to the date that the costs are expected to be incurred.[3]

As an example, the Commission cited to the National Association of Regulatory Utility Commissioners' ("NARUC") *Public Utility Depreciation Practices:*

> Under presently accepted concepts, the amount of depreciation to be accrued over the life of an asset is its original cost less net salvage. <u>Net salvage is the difference between gross salvage that</u>

[2] Sub 1146 Order at p. 175.
[3] Sub 1146 Order at p. 174

<u>will be realized when the asset is disposed of and the costs of retiring it.</u>[4]

Q. ARE STAFF'S NET SALVAGE PROPOSALS IN THE INSTANT CASE CONSISTENT WITH THE COMMISSION'S ORDER IN DOCKET NO. E-7, SUB 1146?

A. No, at least not for all accounts. For production plant accounts, Public Staff's proposed net salvage estimates for decommissioning the Company's power plants are escalated to the date of retirement, consistent with Commission order.[5] However, while Ms. McCullar's actual proposed depreciation rates for production plant accounts incorporate the escalation concept consistent with the Commission's Decision, she makes proposals for distribution plant that are not consistent with the Commission's decision in Docket No. E.7 Sub 1146. Ms. McCullar proposes a less negative net salvage estimate for Account 364, Poles, Towers and Fixtures, Account 366, Underground Conduit and Account 369, Services. She does not provide any statistical basis for her proposal other than to compare her results to the Company's recently recorded costs. Additionally, she supports her proposal in testimony by arguing against including future inflation in net salvage estimates. As I have discussed, the Commission has already decided against Ms. McCullar's opinion on this concept and has found that the Company's approach is widely supported.

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[4] Sub 1146 Order at p. 174, citing NARUC at p. 18. (Emphasis added in Commission order)
[5] McCullar at 15:1-7.

Q. HAS THE COMMISSION PREVIOUSLY RECOGNIZED PROBLEMS WITH MS. MCCULLAR'S APPROACH TO ESTIMATING NET SALVAGE?

A. Yes. In addition to recognizing that the Company's approach is widely accepted and consistent with authoritative texts and depreciation practices, the Commission observed that Ms. McCullar's approach has been previously found to be deficient:

> [O]ther state utility commissions have rejected witness McCullar's alternative approach as unsupported. For example, in a recent case before the Washington Utilities and Transportation Commission (WTC), witness McCullar advanced similar arguments against the escalation of terminal net salvage costs along with other recommendation related to depreciation. In rejecting the recommendation, the WTC noted that Public Counsel and witness McCullar provided no response to the critique that witness McCullar's approaches were not supported by authoritative accounting literature. The WTC found witness McCullar's net salvage proposal "[v]ague in its methodology, not supported by authoritative accounting literature, and supported by unwarranted assumptions."[6]

The quote above from the WTC is related to the same net salvage methodology advanced by Ms. McCullar in the instant case for Accounts 364, 366 and 369.

Q. HOW IS NET SALVAGE ESTIMATED IN A DEPRECIATION STUDY?

A. Net salvage estimates are expressed as a percentage of the original cost retired. For example, if an account has a net salvage estimate of negative 50%, then a $1,000 asset would be expected to, on average, cost $500 to retire, net of any gross salvage. The method of determining the estimated net salvage percent depends on the type of property. For power plants, the estimate is typically based on a

[6] Order at 175. Footnotes omitted.

decommissioning study, with additional net salvage incorporated for interim retirements (i.e., those that occur prior to the final retirement of the plant). These costs are typically estimates of the cost to retire a facility today, and, as the Commission affirmed in the Sub 1146 Order, need to be adjusted to estimate the cost that will be incurred in the future when the plant is actually retired.

For mass property accounts such as those for transmission and distribution plant, net salvage estimates are based in part on statistical analyses of historical net salvage data. In this analysis, net salvage (as well as its components of gross salvage and cost of removal) are expressed as a percentage of retirements. This approach, which is widely accepted in the industry and supported by depreciation textbooks, is referred to as the traditional method.

Q. ON PAGES 20 THROUGH 22 OF HER TESTIMONY MS. MCCULLAR CITES TO DECISIONS FROM FIVE STATE COMMISSIONS AND THE DISTRICT OF COLUMBIA THAT SHE CLAIMS "ADOPTED FUTURE NET SALVAGE PERCENT THAT RECOGNIZES THE TIME VALUE OF COST OF REMOVAL DUE TO INFLATION." DO THE ORDERS CITED BY MS. MCCULLAR SUPPORT THAT HER PROPOSED APPROACH IS WIDELY ACCEPTED?

A. No. The existence of a handful of instances in which different approaches were used does not disprove that the Company's approach for net salvage is used by the vast majority of jurisdictions. Additionally, at least two of the state jurisdictions cited by Ms. McCullar do not use the type of approach claimed by Ms. McCullar.

Rather than adopting future net salvage estimates that "recognize the time value of cost of removal due to inflation," New Jersey and Pennsylvania do not include future net salvage estimates in depreciation.[7] Instead, in these jurisdictions net salvage is recovered either as it is incurred or after the costs are incurred.

Additionally, none of these cases change the fact that, as discussed above, the Commission has already concluded that net salvage should be escalated to the date of retirement. It follows that Ms. McCullar's preferred approach of adopting "future net salvage percents that [recognize] the inflated dollars included in the historic net salvage ratio" and adopting "future net salvage percent[s] that [recognize] the time value of the cost of removal due to inflation"[8] is not consistent with the Commission's established practice.

Q. HAS THE COMMISSION ALSO FOUND THAT THE COMPANY'S APPROACH TO NET SALVAGE IS USED BY THE VAST MAJORITY OF REGULATORY JURISDICTIONS?

A. Yes. In the Decision in Docket No. E-7 Sub 1146, which was issued in June of 2018, the Commission recognized that:

> The fact is the vast majority of jurisdictions use a method for net salvage in which future net salvage is estimated at its future cost and recovered through straight-line depreciation (also known as the traditional method). Approximately 46 out of 50 jurisdictions recover future costs using the straight-line depreciation method.[9]

[7] That this is the case can be seen in the plain language of the citations to New Jersey and Pennsylvania on pages 21 and 22 of Ms. McCullar's testimony.
[8] McCullar at 19:22-20:2
[9] Order at 175

While Ms. McCullar cites a handful of cases she claims support her approach to net salvage, these are in the minority. As the Commission has previously recognized, the vast majority of jurisdictions use the Company's approach.

Q. IS RECOVERING THE FUTURE COST OF NET SALVAGE CONSISTENT WITH THE UNIFORM SYSTEM OF ACCOUNTS?

A. Yes. The Uniform System of Accounts ("USOA") specifically defines net salvage as follows:

> 19. Net salvage value means the salvage value of property retired less the cost of removal.

Cost of removal is defined as:

> 10. Cost of removal means the cost of demolishing, dismantling, tearing down or otherwise removing electric plant, including the cost of transportation and handling incidental thereto. It does not include the cost of removal activities associated with asset retirement obligations that are capitalized as part of the tangible long-lived assets that give rise to the obligation. (See General Instruction 25).

Finally, cost is defined as (emphasis added):

> 9. Cost means the <u>amount of money actually paid</u> for property or services. When the consideration given is other than cash in a purchase and sale transaction, as distinguished from a transaction involving the issuance of common stock in a merger or a pooling of interest, the value of such consideration shall be determined on a cash basis.

Read together, these definitions make clear that the USOA specifies that cost of removal, which as part of net salvage must be recovered through depreciation expense, is the actual amount that is paid at the time of the transaction. Because net salvage will occur in the future, it is an estimate of the future cost that must be included in depreciation rates.

Q. HAS FERC CONFIRMED THAT THE ESTIMATED FUTURE NET SALVAGE COST SHOULD BE INCLUDED IN DEPRECIATION?

A. Yes. FERC has clarified that not only should future net salvage estimates include future inflation (which are recovered on a straight-line basis rather than a present value basis), but that failing to include future inflation results in intergenerational inequity:

> We affirm the Presiding Judge's finding that Entergy has demonstrated that the decommissioning cost estimate should be escalated three percent annually to the retirement dates estimated for Entergy Arkansas' steam production units. Based on the record before us, we agree with the Presiding Judge that it is reasonable for the current decommissioning costs to be inflated to reflect future costs of decommissioning at the time of retirement in order to avoid intergenerational inequities between current and future ratepayers.[10]

Q. ON PAGES 18 AND 19 OF HER TESTIMONY, MS. MCCULLAR CITES TO NARUC's *PUBLIC UTILITY DEPRECIATION PRACTICES* AND WOLF AND FITCH'S *DEPRECIATION SYSTEMS*. DO THESE TEXTS SUPPORT HER APPROACH FOR NET SALVAGE?

A. No. As discussed previously, the Commission found in DE Carolina's previous rate case that NARUC supported the Company's approach for net salvage. Ms. McCullar's citations do not dispute this point and a more comprehensive review

[10] 142 FERC ¶ 61,022 at P 175. (Emphasis added)

demonstrates that neither text supports the type of analysis she performed. Further, her discussion of these texts does not put the quotes that she cites in the proper context. For example, Ms. McCullar presents a quote from page 19 of NARUC that, without context, may give the appearance that NARUC believes the inclusion of future net salvage costs is problematic due to the impact of inflation. The portion she cites reads:

> The sensitivity of salvage and cost of retirement to the age of the property retired is also troublesome. Due to inflation and other factors, there is a tendency for costs of retirement, typically labor, to increase more rapidly than material prices.[11]

However, the very next sentences on page 19 of NARUC make clear that the future costs, including the impact of inflation, should be included in depreciation:

> In an increasing number of instances, the average net salvage is estimated to be a large negative number when expressed as a percentage of original cost, sometimes in excess of negative 100%. This may look unrealistic but is appropriate and necessary so that the required cost allocation occurs.[12]

Q. PLEASE EXPLAIN FURTHER THAT NARUC AND WOLF AND FITCH SUPPORT THAT THE NET SALVAGE INCLUDED IN DEPRECIATION SHOULD REPRESENT FUTURE, NOT CURRENT, COSTS.

A. In the passage cited by the Commission in Docket No. E-7, Sub 1146, NARUC explains the following:

> [U]nder presently accepted concepts, the amount of depreciation to be accrued over the life of an asset is its original cost less net salvage. <u>Net salvage is difference</u>

[11] McCullar at 19:8-12, citing *Public Utility Depreciation Practices* at 19.
[12] *Public Utility Depreciation Practices* at 19.

> between the gross salvage that will be realized when the asset is disposed of and the cost of retiring it.[13] (Emphasis added in Commission order)

Wolf and Fitch also explain that net salvage should be included in depreciation and that it should be recognized as a future cost:

> The matching principle specifies that all cost incurred to produce a service should be matched against the revenue produced. Estimated future costs of retiring an asset currently in service must be accrued and allocated as part of the current expenses.[14]

In the same paragraph, the authors are clear that inflation is part of the future cost of net salvage, stating that:

> Negative salvage is a common occurrence. With inflation, the cost of retiring long-lived property, such as a water main, may exceed the original installed cost.[15]

Wolf and Fitch then address intergenerational equity, stating:

> The accounting treatment of these future costs is clear. They are part of the current cost of using the asset and must be matched against revenue. While the current consumers would say they should not pay for future costs, it would be unfair to the future users if these costs were postponed.[16]

Finally, Wolf and Fitch argue against a present value or current value concept. The authors note that:

> Some say that although the current consumers should pay for the future costs, the future value of the payments, calculated at some reasonable interest rate, should equal the retirement

[13] NARUC Manual, p. 18.
[14] Wolf and Fitch, p. 7.
[15] Ibid, p. 7.
[16] Ibid, p. 8.

> cost. Studies show that the salvage is often "more negative" than forecasters had predicted.[17]

They also state that:

> In the accounting framework, depreciation is defined as an allocation process, *not* a valuation process.[18] (Emphasis in original)

Q. DO NARUC AND WOLF AND FITCH EXPLAIN HOW NET SALVAGE IS ESTIMATED FOR MASS PROPERTY ACCOUNTS?

A. Yes. NARUC states that "net salvage is expressed as a percentage of plant retired by dividing the dollars of net salvage by the dollars of original cost of plant retired."[19] This is the method of analysis used in the Company's depreciation study.

Wolf and Fitch also explain that net salvage is expressed as a percentage of the original cost of plant retired, noting "the SR [Salvage Ratio] is the salvage divided by the original cost of the retirements and usually is expressed as a percentage."[20]

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[17] Ibid, p. 8.

[18] Ibid, p. 4.

[9] NARUC Manual, p. 18.

[10] Wolf and Fitch, p. 261. Note that, in this context, Wolf and Fitch use the term "salvage" to mean "net salvage." In addition to describing the traditional method, Wolf and Fitch also present more detailed analysis of net salvage by age. The intent of this more detailed analysis is to recognize the impact of age and inflation on the traditional method of net salvage analysis. In the aged net salvage analysis described by Wolf and Fitch, net salvage is first converted to constant dollars. Then, the level of inflation that will occur over the full service life of each asset is calculated (which is often longer than the age of retirements in the historical net salvage data). The result of this more detailed analysis is typically more negative net salvage estimates than would occur from the traditional method.

Q. WHAT ANALYTICAL METHOD DOES MS. MCCULLAR PROVIDE TO SUPPORT HER NET SALVAGE ESTIMATES?

A. The only analysis Ms. McCullar provides in support of her proposals is a comparison of the net salvage costs included in the proposed depreciation rates to the amount of net salvage the Company has incurred, on average, over the past five years.[21]

Q. DOES THE TYPE OF ANALYSIS PROVIDED BY MS. MCCULLAR PROVIDE A REASONABLE BASIS TO ESTIMATE FUTURE NET SALVAGE?

A. No. The premise of the type of analysis performed by Ms. McCullar is that depreciation accruals for net salvage should be similar to, if not the same as, the net salvage incurred each year. This premise is inconsistent with the goal of depreciation of recovering capital costs, including net salvage, over the service life of the related assets. Because net salvage costs are future costs, the recovery of these costs through depreciation will occur prior to net salvage costs being incurred and, as a result, depreciation accruals for net salvage will often exceed incurred net salvage.

It is also important to understand that net salvage recorded in a given year is a function of the amount of property retired. For example, it would cost more to retire 1,000 poles in a given year than to retire 100 poles. By expressing historical net salvage as a percentage of historical retirements, the method of net

[21] McCullar at 24.

salvage analysis I have used to estimate net salvage in the depreciation study, which is the industry standard method for estimating future net salvage, recognizes this relationship between net salvage and retirements. Ms. McCullar's analysis does not recognize this important relationship.

Q. DO ANY AUTHORITATIVE DEPRECIATION TEXTS SUPPORT MS. MCCULLAR'S ANALYSIS?

A. No. I am not familiar with any, and Ms. McCullar has not provided any citations that support comparing the dollar level of net salvage included in depreciation rates to the dollar level of net salvage incurred. As noted above, the texts cited by Ms. McCullar support the methodology I have used in the Company's depreciation study.

Q. PUBLIC STAFF AND FPWC ALSO PROPOSE A 10 PERCENT CONTINGENCY INSTEAD OF THE 20 PERCENT CONTINGENCY USED IN THE COMPANY'S DECOMMISSIONING STUDIES. DO YOU AGREE WITH THEIR PROPOSALS?

A. No. The terminal net salvage estimates I have used in the calculation of depreciation rates are based on a comprehensive decommissioning study performed by Burns and McDonnell. The decommissioning study incorporates a 20 percent contingency and this study, as well as DE Progress Witness Kopp's testimony in DE Progress's previous case, provide the justification for this contingency factor. Additionally, as discussed previously in my rebuttal testimony, the context of other proposals in this case and the fact that coal ash costs show that end of life costs can be higher than originally anticipated provide additional support for the need for contingency.

IV. SERVICE LIFE OF AMI METERS

Q. HAVE ANY PARTIES MADE ANY RECOMMENDATIONS RELATED TO THE COMPANY'S AMI METER DEPLOYMENT?

A. Yes. Ms. McCullar recommends a different average service life for the new AMI meters than the 15-year average service life proposed for DE Progress and approved by the Commission for DE Carolinas in Docket No. E-7, Sub 1146.

Q. WHAT AVERAGE SERVICE LIFE WAS USED FOR METERS IN THE COMPANY'S PREVIOUS DEPRECIATION STUDY?

A. A 15-year average service life was used in the Company's previous depreciation study, which is the same as used in the depreciation study filed in the instant case. However, as part of the settlement agreement in the Company's previous case, a 17-year average service life for AMI meters was adopted.

Q. WHILE A 17-YEAR AVERAGE SERVICE LIFE WAS ADOPTED AS PART OF DE PROGRESS' SETTLEMENT AGREEMENT, HAS THE COMMISSION ADOPTED A 15-YEAR AVERAGE SERVICE LIFE FOR AMI METERS IN A LITIGATED CASE?

A. Yes. Although DE Progress' most recent case resulted in a settlement that included the life of AMI meters, this issue was fully litigated in DE Carolinas' most recent case (which was decided subsequent to DE Progress' settlement agreement). In that case, Docket No. E-7, Sub 1146, a 15-year average service life was adopted by the Commission. Similar to the instant case, Ms. McCullar proposed a 17-year average service life in Docket No. E-7, Sub 1146. However, the Commission adopted the 15-year average service life proposed by the Company. On page 178 of the order in that docket, the Commission stated that the depreciation rates proposed by the Company were adopted, with the exception of certain depreciation rates discussed in the decision. Because the 15-year average service life for AMI meters was not specifically identified and modified in the Commission's decision, the 15-year average service life for AMI meters was adopted by the Commission. Additionally, the Company's cost-benefit analysis in that case for AMI meters was based on a 15-year life and the Commission had specifically requested that such analysis included the "cost of replacing AMI meters at the end of their 15-year useful life."[22]

Q. WHAT HAVE YOU RECOMMENDED FOR AMI METERS IN THE INSTANT CASE?

A. I have recommended to use the 15-S2.5 survivor curve for DE Progress and currently approved for DE Carolinas. This estimate is consistent with the manufacturer recommendation for the physical life of AMI meters, but also considers that meters are retired for other reasons, such as damage or obsolescence. It is also consistent with the service life adopted by the Commission for DE Carolinas.

[22] Sub 1146 Order at p. 117.

Q. IS THERE ANY REASON TO EXPECT A LONGER SERVICE LIFE FOR DE PROGRESS' AMI METERS THAN THOSE OF DE CAROLINAS?

A. No. The AMI meters for both companies should be expected to have similar service lives. Because the Commission adopted the 15-year average service life for DE Carolinas, it is reasonable to use the same for DE Progress.

Q. WHAT HAS PUBLIC STAFF PROPOSED?

A. Public Staff has proposed an average service life of 17 years. Public Staff references that in discovery that DE Carolinas stated that the manufacturers of the meters estimate a life of 15 to 20 years and Ms. McCullar recommends an estimate in the middle of this range. However, Ms. McCullar does not provide any reason to expect a longer service life for DE Progress' AMI meters than those of DE Carolinas.

Q. DO YOU AGREE WITH PUBLIC STAFF'S ESTIMATE?

A. No. Ms. McCullar has not provided any new information in the instant case that supports changing the Commission-approved 15-year life. Indeed, Ms. McCullar's arguments are substantially similar to those she presented in DE Carolinas' previous case that were not adopted by the Commission. Manufacturers' estimates are typically based only on the possible physical life of the assets. However, other factors can cause meters to retire. For example, meters can retire due to obsolescence. The 15-year life continues to be most appropriate for AMI meters.

V. LIFE SPANS OF MAYO UNIT 1 AND ROXBORO UNITS 3 AND 4

Q. WHAT HAS THE COMPANY PROPOSED FOR THE MAYO AND ROXBORO UNITS 3 AND 4 GENERATING UNITS?

A. The current expectation is a retirement date of 2029 for both facilities. For both facilities, these are earlier dates than was anticipated in the previous depreciation study. I have incorporated these expectations into the depreciation study and have recommended depreciation rates using these retirement dates.

Q. WILL YOU ADDRESS THE JUSTIFICATION FOR A 2029 RETIREMENT DATE?

A. No. The reason for the 2029 retirement date will be addressed by DE Progress witness Stephen De May. However, I will address certain conceptual issues in the testimony of other parties.

Q. IN YOUR EXPERIENCE, HAS THERE BEEN A TREND IN THE INDUSTRY TOWARDS SHORTER LIFE SPANS FOR COAL-FIRED POWER PLANTS?

A. Yes. Across the country a number of coal-fired power plants either have been or are planned to be retired earlier than had been expected in the past. A combination of factors, including higher costs of operating coal plants (due in part to environmental regulations) and lower costs of different generating technologies (due factors such as lower natural gas prices and more competitive costs for renewables), has led to the retirements of many coal plants. As a result, shorter life spans for coal-fired power plants has been a common occurrence in depreciation studies.

Q. IS THERE A REQUIREMENT THAT ASSETS BE DEPRECIATED OVER THEIR SERVICE LIVES, RATHER THAN OVER A LONGER PERIOD OF TIME?

A. Yes. General Instruction 22A of the electric USOA states that:

> Utilities must use a method of depreciation that allocates in a systematic and rational manner the service value of depreciable property over the service life of the property.

Thus, the USOA requires that depreciation recover the costs of an asset (including net salvage) over its service life. Failing to recover costs over an asset's life will result in intergenerational inequity because it will result in costs for the asset to be recovered after the asset is retired. The result would be that future customers, who will not receive service from the retired asset, will have to pay the costs for an asset that is already retired. As a result, if the current expectation is that these plants will be retired in 2029, then the depreciation rates should be adjusted to incorporate this expectation.

Q. WHAT DO STAFF AND FPWC PROPOSE?

A. Both propose to use the estimated retirement dates from the previous depreciation study for these units.

Q. WILL THESE PROPOSALS RESULT IN INTERGENERATIONAL EQUITY?

A. No. Based on the expectations of a 2029 retirement date, Staff and FPWC's proposals will result in recovering a portion of the costs of these plants after they are retired, which will result in intergenerational inequity. Importantly, while there is the potential for disagreement on the outlook of each facility, Staff's testimony provides the impression that intergenerational equity is not a concern. I will address this and other conceptual issues in my testimony.

Q. WHAT JUSTIFICATION DOES STAFF PROVIDE FOR ITS PROPOSAL TO NOT RECOVER THE FULL COSTS OF THESE FACILITIES OVER THEIR SERVICE LIVES?

A. Public Staff witness Dorgan provides three reasons for Public Staff's proposal. The first is related to technical details discussed by Public Staff witness Metz. I will not address those. Second, he claims that "although the Company has stated in its testimony that it intends to retire these plants, it has not presently done so."[23] Leaving aside the technical details, this statement is conceptually incorrect and inconsistent with the goal of depreciating an asset over its service life. For the purposes of determining depreciation, one cannot wait until an asset is retired to determine its service life, because the costs need to be recovered over the asset's life (*i.e.*, before the asset is retired). As a matter of principle, the concept Mr.

[23] Dorgan at 16:18-19.

Dorgan sets forth does not comport with the USOA or with generally accepted depreciation principles.

The third reason set forth by Mr. Dorgan is that "the Public Staff has consistently recommended leaving the depreciation rates set at the original retirement date of the plant, and, at the date of actual physical retirement, any remaining net book value be placed in a regulatory asset account and amortized over an appropriate period, to be determined in a future general rate case."[24] While Public Staff may have taken this position in the past, it is by definition inequitable. Any of the costs that Public Staff would have placed in a regulatory asset account and amortized over a given period will be recovered after a facility is retired. Staff's proposal will, by design, result in intergenerational inequity.

I do recognize that there are some instances in which the date of retirement of a power plant is close to the date of a filed rate case (and that there can even be instances in which a plant is retired before a depreciation study is performed), which may necessitate the use of a regulatory asset. However, the expected retirement dates of Mayo and Roxboro Units 3 and 4 are ten years or more from the test year in the depreciation study. As a result, there is still time to recover the costs of these plants over their service lives and the use of a longer period, as proposed by Staff, is unnecessary and will result in intergenerational inequity.

[24] Boswell at 14:18-23.

Q. DO THE SAME CONCEPTS APPLY TO FPWC WITNESS BRUNAULT'S TESTIMONY?

A. Yes. The same concepts apply to Mr. Brunault's testimony. Specifically, on pages 22 and 23, he argues that the costs of these plants be treated similar to plants that were retired early in the past, for which the unrecovered costs were amortized over a longer period of time. However, a difference between the current situation and those plants (the most recent of which was Asheville) is that for plants such as Asheville there was limited time prior to retirement over which the unrecovered costs could be recovered. That is, because the plants had either short remaining lives or were already retired, there may have been a need to recover their costs over a longer period of time. In contrast, the 2029 retirement date estimated for Mayo and Roxboro Units 3 and 4 is a sufficient length of time to recover the costs of these facilities. Indeed, failing to update the estimated retirement dates will increase the likelihood of the intergenerational inequity of recovering their costs after they are retired from customers who did not receive service from these plants.

VI. GENERAL PLANT AMORTIZATION

Q. WHAT IS GENERAL PLANT AMORTIZATION?

A. General plant amortization accounting is used for general plant accounts that include a large number of units with a relatively low unit cost. Because the cost of tracking retirements for every single asset (e.g., every computer or chair the company owns) typically exceeds the benefit of doing so, most companies use (and most commissions have approved) general plant amortization for these accounts.

When using general plant amortization, an amortization period is established based on the expected average life of assets in the account. When an asset reaches the end of the amortization period, it is retired from the books. DE Progress began to use amortization accounting at the conclusion of its previous rate case. I have continued to propose amortization accounting in the depreciation study.

Q. HAVE ANY PARTIES OPPOSED THE USE OF GENERAL PLANT AMORTIZATION?

A. No. However, Public Staff has proposed different amortization periods for two accounts.

Q. YOU INDICATED THAT DE PROGRESS BEGAN USING AMORTIZATION ACCOUNTING IN THE PREVIOUS RATE CASE. PRIOR TO THAT CASE, HAD THE COMMISSION PREVIOUSLY APPROVED AMORTIZATION ACCOUNTING?

A. Yes. The Company's affiliate, Duke Energy Carolinas ("DE Carolinas"), had used amortization accounting for the same accounts for which I have proposed general plant amortization for DE Progress. The Commission had previously approved the use of amortization accounting and the amortization periods used by DE Carolinas.

Q. HAVE YOU RECOMMENDED THE SAME AMORTIZATION PERIODS FOR DE PROGRESS THAT THE COMMISSION APPROVED FOR DE CAROLINAS?

A. Yes. I believe it is reasonable to have consistency between the two companies for these types of assets. For this reason, I think it is most appropriate for DE Progress to use the amortization periods the Commission has previously approved for DE Carolinas.

Q. WHAT HAS MS. MCCULLAR PROPOSED FOR THESE ACCOUNTS?

A. Ms. McCullar has proposed longer amortization periods for Account 391 Office Furniture and Equipment and Account 397 Communication Equipment.

Q. DO YOU AGREE WITH HER RECOMMENDATIONS?

A. No. Again, I think it is most reasonable to use the same amortization periods as are currently approved for DE Carolinas. I note that Ms. McCullar is a witness in a current case for DE Carolinas and did not challenge the amortization periods in that case. There is no compelling reason to use a different amortization period for these accounts for DE Progress than is approved and undisputed for DE Carolinas.

Further, Ms. McCullar's only support provided in this case to use longer amortization periods is that the current depreciation rates for DE Progress use longer amortization periods for two accounts. However, the current depreciation rates for DE Progress are the result of a settlement agreement. Ms. McCullar has not provided any analysis in the instant case to support why the assets in these accounts for DE Progress should be expected to have longer lives than similar assets for DE Carolinas. Instead, she states that "[b]ased on the analysis I provided in the Sub 1142 Proceeding and since DEP did not provide any information supporting the change in the current approved amortization periods for these accounts. I recommend the continued use of the currently approved 20-year amortization period for these accounts."[25]

Q. DID THE ANALYSIS PROVIDED BY MS. MCCULLAR IN THE SUB 1142 PROCEEDING PROVIDE A REASONABLE BASIS TO ASSUME LONGER LIVES FOR THE ASSETS OF DE PROGRESS THAN THOSE OF DE CAROLINAS?

A. No. First, much of her analysis was based on historical life analysis. However, relying on the historical analysis for amortization accounts is often unreliable. Due to the nature of the assets in these accounts (in which there are many units with small dollar values), historically many companies had difficulty in tracking retirements. Because retirements were not always recorded, the statistical life analyses often produce indications of too long of lives. Thus, Ms. McCullar's references to the statistical analyses in a previous depreciation study is not a reasonable basis to incorporate longer lives for DE Progress than is appropriate.

Additionally, for Account 391, she referenced a data request response from the Sub 1142 proceeding that explained for assets "such as chairs, desks and tables…most are expected to be in service for 20 years on average."[26] However,

[25] McCullar at 30:6-10.
[26] Testimony of Roxie McCullar In Docket No. E-2, Sub 1214 at 37 citing DE Progress response to FPWC-2-27(a).

this is just the furniture in the account. There is also equipment such as faxes and printers, which have shorter average lives of 10 years or less. For this reason, an overall average service life of 15 years – which is the same as is approved for DE Carolinas – is most appropriate.

For Account 397, Ms. McCullar references a range of estimates for this account. However, estimates for communication equipment can vary depending on the assets in the account. As noted above, the Commission has approved a 10-year life for DE Carolinas for this account, and the same is reasonable for DE Progress.

Q. ARE THERE ANY ERRORS IN MS. MCCULLAR'S PROPOSALS FOR ACCOUNTS 391 AND 397?

A. Yes. Ms. McCullar has excluded millions of dollars of investment from her calculations of depreciation expense for these accounts. The result is that she understates the depreciation expense that results from her proposal. Ms. McCullar also overstates the remaining life for each account and has not updated the reserve adjustment for amortization to reflect her proposed changes to the amortization period, which overstates the reserve adjustment shown in her proposal.

Q. PLEASE EXPLAIN.

A. As discussed above, when amortization accounting is used, assets are retired once they reach the end of the amortization period. It follows that if a shorter amortization period is used, then older assets will need to be retired. In the depreciation study, these assets are reflected as "Fully Accrued" and no depreciation expense is calculated because the assets will be retired. For example, on page VI-9 of the depreciation study, the fully accrued amount for Account 391 of $10.2 million is expected to be retired and no depreciation is calculated for this amount.

Ms. McCullar proposes longer lives for each of these accounts. The result of her proposal would be that the amounts shown on page VI-9 of the study as Fully Accrued should be included in her depreciation calculations, since they are within her proposed amortization periods. However, as can be seen on page 12 of Exhibit RMM-1, Ms. McCullar incorrectly calculates no depreciation expense for these amounts. By excluding the older vintages from her calculations, Ms. McCullar also overstates the average remaining lives she calculates for each account. Additionally, in order to be consistent with the other amortization accounts, Ms. McCullar should also have adjusted the amounts shown as “Reserve Adjustment for Amortization” on page 14 of Exhibit RMM-1. Thus, there are multiple issues with the recommended depreciation rates and accruals proposed by Ms. McCullar for these accounts.

VII. ASH POND COSTS

Q. HAVE YOU REVIEWED THE TESTIMONY OF PUBLIC STAFF WITNESS MANESS REGARDING DEPRECIATION AND DECOMMISSIONING OF COAL PLANTS?

A. Yes.

Q. PLEASE COMMENT ON WITNESS MANESS' TESTIMONY.

A. Witness Maness refers in his testimony to an investigation performed by the Public Staff in response to an Order issued by the Commission in this Docket on January 22, 2020 and alludes to the Company's responses to a data request (DR 147) served by the Public Staff. In order to provide the Commission with the full context of the results of the Public Staff's investigation, some additional details regarding these responses would be helpful.

The Company's responses to DR 147-1 indicate that since 2000 three depreciation studies and three decommissioning studies were conducted by or on behalf of the Company. The earliest depreciation study, dated as of December 31, 2002 (E-2, Sub 828) reflects a calculated net salvage percentage for the equipment and facilities subject to the study, which would include coal ash basins as part of the plant facilities, although not in any specific dollar amount. None of those net salvage percentages include or account for anticipated costs of coal ash removal or remediation, or retirement/decommissioning of coal ash impoundments or storage facilities. The second depreciation study, dated as of December 31, 2010 (E-2, Sub 1023), included net salvage estimates that incorporated decommissioning estimates based on two Burns & McDonnell decommissioning studies each dated January 27, 2012 (one study for near-term units and one study for future units). These decommissioning studies included costs related to closure of ash ponds. The response to the data request further indicates that the most recent depreciation study, dated as of December 31, 2016 (E-2, Sub 1142), does not include such costs, nor does the Burns & McDonnell decommissioning study, dated as of April 19, 2017, upon which it was based, inasmuch as DE Progress had by the time of those studies established asset retirement obligations in connection with anticipated coal ash basin closure costs. Company witnesses Doss and Riley discuss the accounting rules regarding AROs in their testimony.

Witness Maness' testimony quotes from the Company's response to DR 147-3, as follows:

> Prior to approximately the mid-2010s, and particularly in connection with the promulgation of the US Environmental Protection Agency's final rule on coal combustion residuals ("CCR Rule"), it was not standard industry practice to include anticipated costs of coal ash impoundment closure in net salvage portion of depreciation expense for several reasons. In the early part of the period specified in DR [147-1], it was not common to have decommissioning studies performed that included coal burning facilities because the prevailing presumption by electric companies at that time was that such facilities would continue to provide power in same fashion well into the future. Moreover, ash basins would continue serving their function of holding CCRs and would in that connection continue to be managed and permitted. Without a definite plan to decommission these plants, or the specific manner at which the facility will be decommissioned, it was not common to include decommissioning costs related to coal ash basin closures in the calculation of depreciation rates. Further, as a general matter, pre-CCR Rule coal ash basin closures ordinarily were planned and carried out in conjunction with the relevant environmental authorities.

This response squares with my own experience with and understanding of industry practice.

I understand further from the testimony of Company witness Wells that DE Progress and its environmental regulator began in 2009 to consider potential closure of coal ash basins, in connection with the Company's potential retirement of certain of its coal-fired plants. In that timeframe, many electric utilities with coal-fired plants were undergoing evaluations of those plants due to the combination of tighter environmental regulation coupled with the falling price of natural gas. I was not involved in the DE Progress depreciation studies apart from its most recent study (dated as of December 31, 2016 (E-2, Sub 1142)), but in light of these discussions with its environmental regulator, it would not have been unusual for DE Progress to retain Burns & McDonnell to prepare the decommissioning studies that I reference above in connection with the second of the three depreciation studies (dated as of December 31, 2010 (E-2, Sub 1023)).

Q HAVE YOU ALSO REVIEWED THE COMMISSION'S ORDER IN DOCKET NO. E-22, SUB 562, ISSUED ON FEBRUARY 24, 2020, AS IT RELATES TO ASH POND COSTS AND THE DECOMMISSIONING OF COAL PLANTS?

A. Yes. I am also aware that the Commission cited to my testimony in a case in South Dakota for Black Hills Power Company, which discussed the inclusion of terminal net salvage in depreciation.

Q. TO PROVIDE CONTEXT FOR THE RECOVERY OF DE PROGRESS' COSTS AND YOUR TESTIMONY IN THE BLACK HILLS POWER CASE, PLEASE DISCUSS HOW DECOMMISSIONING COSTS HAVE BEEN ADDRESSED BY UTILITIES.

A. In the context of DE Progress' filing and the Commission's Order in Docket No. E-22, Sub 562, I think it is important to understand the background of the recovery of terminal net salvage costs in general – and coal ash costs in particular – throughout the utility industry. In discussing this history, it is important to recognize that there have been two distinct, though related issues with this concept. The first is the conceptual issue as to whether net salvage, and especially terminal net salvage, should be included in depreciation rates at all. The second is the issue of how to estimate these future costs. It is important to recognize that, historically, utilities have faced resistance – at times strong resistance – on both of these issues. Thus, not only has there been the challenge of estimating future net salvage costs, including the uncertainty what would be included for these future costs, but there has also been resistance to the basic concept of recovering terminal net salvage through depreciation.

I also want to make clear that throughout my career I have supported the idea that terminal net salvage should be included in depreciation rates. As I discuss in more detail below, this has been true for many years in previous studies, including studies in North Carolina for DE Carolinas. I have tried to consistently apply these concepts, both for Duke companies and other utilities both with respect to the potential retirements of coal plant facilities and generally. However, what has changed in the recent past is the degree of precision of estimating terminal net salvage for coal-fired generation facilities, which has improved as more information has become available and as the types of required decommissioning activities have become more certain.

Q. PLEASE EXPLAIN IN MORE DETAIL THE BACKGROUND OF THE RECOVERY OF TERMINAL NET SALVAGE COSTS IN THE INDUSTRY.

A. Throughout my career, the inclusion and estimation of terminal net salvage has been one of the more contentious issues in rate cases (as has the somewhat related issue of estimating the life spans of power plants). It is only relatively recently that a wider consensus has emerged on required decommissioning activities. Prior to recent years, many intervenors, commission staffs and commission orders had argued that terminal net salvage costs were not likely to be incurred. The arguments why this would be the case and the proposals varied, but generally many argued that companies' coal-fired power plants were likely to operate indefinitely, that decommissioning costs were unlikely because the site could be reused, that decommissioning costs were too speculative, or that these costs should simply be recovered once they were incurred. Even to the extent that decommissioning costs were included in depreciation studies, the costs were often challenged and reduced.

Indeed, this was the context of the testimony I provided in South Dakota that the Commission cited in its recent order. A consultant hired by an industrial intervenor group in that case had proposed that terminal net salvage be excluded from depreciation altogether. To be clear, this consultant's proposal was not just to exclude ash pond costs, but to exclude all terminal net salvage costs. As a result, my rebuttal testimony not only had to support the estimated terminal net salvage, but also had to explain why terminal net salvage should be included in depreciation at all.

Unfortunately, the view of the consultant in that case had been more pervasive in the past than I would hope. While a stronger consensus has now emerged for the inclusion of terminal net salvage in depreciation, it is unfortunately not universally agreed upon. Indeed, the Public Staff's consultant in this case not only indicates a preference to reduce terminal net salvage below the expected future costs, in a current case for DE Carolinas she cites to two commissions (Missouri and West Virginia) that have not included terminal net salvage in depreciation at all in order to support a position she has taken in that case. This appears to be a continuation of the argument that has been espoused by some that terminal net salvage costs may not be incurred and therefore should be excluded from depreciation. I have also attended a presentation made by Staff's consultant in which she argued that removal costs for power plants (i.e., terminal net salvage) may not be incurred, which was at a minimum an implicit argument against recovering terminal net salvage in depreciation. I also note that in the instant case, as discussed in Section V of my rebuttal, Public Staff has not espoused the matching principle the Commission discusses in the order in Docket No. E-22, Sub 562. In Public Staff's arguments to depreciate Mayo and Roxboro Units 3 and 4 over a period longer than they will be in service, Public Staff's proposal will fail to match the costs of these plants with revenues and defer recovery to future ratepayers.

I believe that it is against this overall context that the Commission should judge past recoveries of coal ash costs. One must keep in mind that, at least with regard to coal-fired power plants, it is a very different world today than it was in the first decade of the 2000s. Over the last ten years or so, the combination of cheap natural gas and environmental regulations has resulted in significant retirements of coal-fired generation across the industry. However, in the earlier period, gas was more expensive, there were fewer regulations on coal-fired generation, and the newer technologies that have replaced them were less developed. The outlook for these types of assets was very different than it is today. With the benefit of hindsight, many of the arguments made in the earlier period for long life spans for coal plants and excluding decommissioning costs have proven to be incorrect. However, in the context of that period they were more convincing to many people. Again, at the time I argued for shorter life spans and the inclusion of decommissioning, but in the context of the times these were more difficult arguments to make and they were not readily accepted.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Duke Energy Progress, LLC
Summary of Rebuttal Testimony of John Spanos
Docket No. E-2, Sub 1219

My rebuttal testimony addresses two primary topics. The first is a response to criticisms or proposed changes to my depreciation study performed for DEP in this proceeding. The second is to address certain net salvage related testimony of Public Staff witness Maness concerning CCR impoundment facility closure costs.

On the first topic, my rebuttal testimony rejects several proposals by Public Staff witness McCullar and Fayetteville Public Works Commission witness Brunault to modify my net salvage calculations and addresses the proper service life for AMI meters. In general, each of my net salvage calculations and the use of a 15-year service life for AMI meter depreciation are consistent with accepted depreciation practices and the prior decisions of this Commission. This includes my use of a 20% contingency factor for calculating net salvage based on the decommissioning study performed for DEP by Burns and McDonnell. In my direct testimony, I also identify a number of errors in Ms. McCullar's depreciation calculations.

On the second topic, I begin my discussion of the issue of including terminal net salvage costs in depreciation studies by noting that including such costs in depreciation expense for state regulatory ratemaking purposes has been controversial and there is little consensus as to how to calculate terminal net salvage costs for coal ash impoundment facilities. While I have been a consistent advocate for including terminal net salvage in depreciation expense in the studies I have performed, it is only very recently that a prevailing consensus has emerged supporting this approach on an industry-wide basis.

DEP has included some terminal net salvage costs for all plant in service in its depreciation studies since at least 2000. Several of these studies included some level of costs for anticipated coal ash basin closures consistent with the multiple decommissioning studies performed for DEP during this period. The most recent depreciation study for DEP, in Docket No. E-2, Sub 1142, did

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not include expense for ash basin closure because DEP, by that point in time, had established AROs for such anticipated expenses.

At the time CAMA was enacted and the federal CCR Rule was promulgated, DEP determined to establish AROs to address requirements associated with the retirement and remediation of coal ash impoundment facilities. That decision, along with the establishment of the corresponding AROs, removed CCR impoundment closure costs from consideration in calculating DEP's depreciation rates. Based on my experience, DEP was somewhat ahead of the curve in addressing coal ash impoundment closure costs compared to other electric generation utilities in the United States but certainly not dramatically out of step with the industry as a whole of DEC in particular.

This concludes the summary of my rebuttal testimony.

MR. JEFFRIES: And there were no exhibits to Mr. Spanos' rebuttal testimony, so there's no need to identify any of those. And at this point I'll turn it over to Mr. Marzo to handle Mr. Riley and Mr. Doss.

COMMISSIONER CLODFELTER: Thank you. Mr. Marzo?

MR. MARZO: Thank you, Commissioner Clodfelter.

DIRECT EXAMINATION BY MR. MARZO:

Q. Mr. Doss, would you please state your name and business address for the record.

A. (David L. Doss, Jr.) Yes. My name is David Doss. My business address is 550 South Tryon Street, Charlotte, North Carolina 28202.

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

A. I'm employed by Duke Energy Business Services. I'm the director of asset accounting.

Q. And did you cause to be prefiled in this docket, rebuttal testimony consisting of 35 pages?

A. Yes, I did.

Q. And do you have any changes or corrections to your prefiled rebuttal testimony?

A. Yes, I do have a change. My rebuttal testimony mentions two prefiled exhibits. There's only one exhibit, and that exhibit was inadvertently omitted from the May 4, 2020, filing of my rebuttal testimony. Doss Rebuttal Exhibit 1 was subsequently filed on August 13, 2020.

Q. Thank you, Mr. Doss. And with that change, if I asked you the same questions today, would your answers be the same?

A. Yes.

Q. Do you have any changes or corrections to your rebuttal exhibit that was filed on August 13th?

A. No.

Q. Mr. Doss, did you also cause to be prefiled in this docket, supplemental testimony consisting of eight pages?

A. Yes.

Q. And do you have any changes or corrections to your supplemental testimony?

A. No, I do not.

Q. If I asked you the same questions today, would your answers be the same?

A. Yes.

Q. And did you also cause to be prefiled, Doss

Supplemental Exhibit 1 to your supplemental testimony?

A. Yes.

Q. And do you have any changes or corrections to your prefiled supplemental exhibit?

A. No, no changes.

Q. And did you prepare a summary of your testimony as well?

A. I did.

Q. Thank you, Mr. Doss.

MR. MARZO: Commissioner Clodfelter, at this time, I would move that Mr. Doss' prefiled rebuttal testimony as well as his prefiled supplemental testimony be entered into the record as if given orally from the stand; and that -- I can move the exhibits too if you want to at the same time.

COMMISSIONER CLODFELTER: If you want to just go ahead and designate the exhibits, we'll take it all in one motion.

MR. MARZO: And Doss Rebuttal Exhibit 1 and Doss Supplemental Exhibit 1 be marked for identification.

COMMISSIONER CLODFELTER: All right. You've heard the motion. Without objection, it is so ordered.

(Doss Rebuttal Exhibit 1 and Doss Supplemental Exhibit 1, were identified as they were marked when prefiled.)

(Whereupon, the prefiled rebuttal and supplemental testimony and errata of David L. Doss were copied into the record as if given orally from the stand.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1219

In the Matter of:	)	
	)	**REBUTTAL TESTIMONY OF**
Application of Duke Energy Progress, LLC	)	**DAVID L. DOSS JR.**
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 David L. Doss Jr., 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, a service company affiliate of Duke Energy Progress, LLC ("DE Progress" or the "Company"), as Director of Asset Accounting. DE Progress is a subsidiary of Duke Energy Corporation (together with its subsidiaries "Duke Energy").

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

A. No.

II. PURPOSE AND OVERVIEW OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony will address certain comments and recommendations submitted by Public Staff witness Michael C. Maness regarding the Company's Asset Retirement Obligation ("ARO") accounting for coal ash basin closure cost. I also address Witness John R. Hinton's recommendation regarding the rate of return to be utilized for the qualified trust for the Nuclear Decommissioning Trust Fund ("NDTF"). Specifically, I will explain how the NDTF is structured and how it relies upon several reliable sources for the rates of return. Importantly, the Commission requires the Company to go through the exercise of developing a cost and funding model, which is an important and iterative process that is currently underway but will not be completed until early 2021. As I will explain in more detail below, it is not appropriate for the Public Staff to make a recommendation that essentially undermines this process. In addition, DE Progress rebuttal witnesses Hevert will respond to witness Hinton's specific challenges to the reasonableness of the rate of return utilized by the Company for the NDTF.

Q. ARE YOU SPONSORING ANY EXHIBITS WITH YOUR REBUTTAL TESTIMONY?

A. Yes. I am sponsoring two exhibits, which were prepared at my direction and under my supervision.

III. ARO ACCOUNTING FOR COAL ASH BASIN CLOSURE COSTS

Q. DO YOU AGREE WITH PUBLIC STAFF WITNESS MANESS'S CONCLUSION THAT DEFERRED COAL ASH BASIN CLOSURE COSTS PROPOSED BY DE PROGRESS IN THIS CASE FALL INTO THE CATEGORY OF A DEFERRED EXPENSE?

A. I do not. I believe Mr. Maness incorrectly characterizes the facts upon which the Company's ARO accounting is based. On page 32 of his testimony, Mr. Maness, as he did in Duke Energy Carolinas ("DE Carolinas") Docket No E-7, Sub 1214, asserts once again that "The Company has itself chosen to request a regulatory accounting and ratemaking method that does not explicitly account for any coal ash compliance costs, either in the past or in the future, as the capitalized costs of property, but instead accounts for them as ongoing expenses, with a proposed regulatory asset intended to provide for the recovery of expenses incurred in the past, expenses that but for the Commission's approval of the deferral request, would be immediately written off." This is simply incorrect. Rather than "choosing" a particular path, the Company was required to (and did) adhere to and apply the accounting guidance under GAAP and Federal Energy Regulatory Commission ("FERC") Code of Federal Regulations ("CFR"), as well as Orders of this Commission.

Q. PLEASE EXPLAIN WHAT TRIGGERED THE GAAP AND FERC GUIDANCE THAT THE COMPANY IS REQUIRED TO FOLLOW WITH RESPECT TO ITS COAL ASH BASINS.

A. The Company evaluated GAAP and FERC guidance in light of the legal obligations imposed upon it by North Carolina's Coal Ash Management Act ("CAMA"), which was originally enacted in 2014, and the Environmental Protection Agency's ("EPA") Coal Combustion Residuals Rule ("CCR Rule"), which was promulgated in 2015. The Company determined that the coal ash basins it operated at its coal-fired generating facilities needed to be closed as a result of the passage of CAMA and/or the CCR Rule. The closure obligation triggered ARO accounting requirements.

Q. WHAT GAAP REQUIREMENTS MUST DE PROGRESS FOLLOW IN CONNECTION WITH COAL ASH BASIN CLOSURE?

A. Statement of Financial Accounting Standard ("SFAS") No. 143 (now codified as ASC 410) was effective for and implemented by the Company in 2003 for financial reporting purposes. This guidance requires recognition of liabilities for the expected cost of retiring tangible long-lived assets for which a legal retirement obligation exists. GAAP (in ASC 410-20-20) refers to these costs as an "Asset Retirement Obligation" or an ARO, and defines a "legal obligation" as an "obligation that a party is required to settle as a result of an existing *or enacted* law …." (Emphasis added). Each of CAMA and the CCR Rule qualify as an "enacted law" under this guidance.

A copy of the relevant GAAP guidance is attached to my testimony as Doss Rebuttal Exhibit 1. Based on the guidance in my Rebuttal Exhibit 1, DE Progress evaluated the retirement requirements of CAMA and the CCR Rule and concluded that DE Progress should record an ARO for the closure of its coal ash basins. The key concepts and their related GAAP provisions are as follows.

First, it is important to understand the scope of the ARO guidance. This is the subject of ASC 410-20-15. Subtopic 15-2 indicates that the guidance applies to the following transactions and activities:

a) Legal obligations associated with the retirement of a tangible long-lived asset that result from the acquisition, construction, or development and (or) the normal operation of a long-lived asset, including any legal obligations that require disposal of a replaced part that is a component of a tangible long-lived asset.

b) An environmental remediation liability that results from the normal operation of a long-lived asset and that is associated with the retirement of that asset. The fact that partial settlement of an obligation is required or performed before full retirement of an asset does not remove that obligation from the scope of this Subtopic. If environmental contamination is incurred in the normal operation of a long-lived asset and is associated with the retirement of that asset, then this Subtopic will apply (and Subtopic 410-30 will not apply) if the entity is legally obligated to treat the contamination.

c) A conditional obligation to perform a retirement activity. Uncertainty about the timing of settlement of the asset retirement obligation does not remove that obligation from the scope of this Subtopic but will affect the measurement of a liability for that obligation (see paragraph 410-20-25-10).

Here, the coal ash basins being retired are tangible long-lived assets, and so Subtopic 15-2(a) applies. In addition, to the extent that retirement involves any environmental remediation, that remediation is the result of the normal operation of the basins, which is the subject of Subtopic 15-2(b). As noted in Company witness Kerin's testimony in Docket No. E-2, Sub 1142 and witness

Bednarcik in this case, the use of ash impoundments as a storage location for coal ash and other CCRs was in accordance with industry standards and then-applicable regulations. Finally, under Subtopic 15-2(c), the retirement requirements are a conditional obligation to perform a retirement activity as the nature, timing and extent of the closure depends on various determinations. In CAMA, those determinations revolve around the legislative or the North Carolina Department of Environmental Quality assessed risk rankings. Under the CCR rule, those determinations revolve around the evaluation of certain criteria by specific deadlines.

Second, it is important to distinguish the activities captured in the coal ash basin closure ARO with other environmental remediation activities. Subtopic 15-3 indicates that certain transactions and activities are not permitted to be included in the ARO. Specifically, as set out in Subtopic 15-3(b):

b) An environmental remediation liability that results from the improper operation of a long-lived asset (see Subtopic 410-30). Obligations resulting from improper operations do not represent costs that are an integral part of the tangible long-lived asset and therefore should not be accounted for as part of the cost basis of the asset. For example, a certain amount of spillage may be inherent in the normal operations of a fuel storage facility, but a catastrophic accident caused by noncompliance with an entity's safety procedures is not. The obligation to clean up the spillage resulting from the normal operation of the fuel storage facility is within the scope of this Subtopic. The obligation to clean up after the catastrophic accident results from the improper use of the facility and is not within the scope of this Subtopic.

DE Progress concluded that based on the guidance noted above that the retirement requirements relating to the closure of the ash impoundments under CAMA and the CCR Rule were Asset Retirement Obligations. Therefore, the accounting for costs as it relates to the retirement of the coal ash impoundments must follow ARO accounting under GAAP.

Q. DOES DE PROGRESS HAVE INTERNAL CONTROLS TO DETERMINE WHAT TYPES OF COSTS ARE CONSIDERED ARO?

A. Yes. DE Progress has internal controls to ensure transactions related to these costs are properly evaluated for accounting treatment. As I explained for DE Carolinas in Docket No E-7, Sub 1146 and Docket No E-7, Sub 1214, DE Progress has also implemented a Coal Ash ARO Charging Committee whose purpose is to evaluate costs to be incurred for determination as to whether they qualify for ARO accounting treatment. The Committee utilizes the guidance in ASC 410, other GAAP, FERC and Commission guidance and Duke Energy Corporation accounting policies to make these determinations. Specifically, for example, the Committee utilizes ASC 410-20-55-13 to determine the extent of costs to include in the ARO. Decisions of the Coal Ash ARO Charging Committee are summarized in a charging guidelines document.

Q. ARE THE DECISIONS OF THE COMMITTEE REVIEWED?

A. Yes. The Committee's decisions are reported back to the Coal Combustion Products ("CCP") group to ensure that 1) all relevant facts were appropriately communicated by CCP and understood by the Committee, and 2) that the CCP group understands the decisions to properly categorize actual project costs.

Q. ARE THERE AUDITS PERFORMED ON THE ACCOUNTING AND FINANCIAL REPORTING IN CONNECTION WITH THE COAL ASH ARO?

A. Yes. The Company's auditors, Deloitte & Touche LLP, perform the annual audit of the Company's financial statements. Deloitte & Touche has issued its opinion that the financial statements are presented fairly, in all material respects, in conformity with U.S. GAAP standards. Deloitte & Touche also performs a review of the FERC Form 1 and issues its opinion that the Regulatory Basis Financial Statements are presented fairly, in all material respects, in conformity with the FERC Uniform System of Accounts. Finally, Deloitte & Touche also issues an opinion on internal controls that states that Duke Energy Corporation maintained, in all material respects, effective internal control over financial reporting.

Q. IN ADDITION TO THE ACCOUNTING REQUIREMENTS UNDER GAAP, ARE THERE FERC ACCOUNTING REQUIREMENTS THAT DE PROGRESS MUST FOLLOW?

A. Yes. In addition to being required to follow GAAP, DE Progress is regulated by FERC, which requires the use of the FERC Uniform System of Accounts, which states:

> (A) An asset retirement obligation represents a liability for the legal obligation associated with the retirement of a tangible long-lived asset that a company is required to settle as a result of an existing or enacted law, statute, ordinance, or written or oral contract or by legal construction of a contract under the doctrine of promissory estoppel. An asset retirement cost represents the amount capitalized when the liability is recognized for the long-lived asset that gives rise to the legal obligation. The amount recognized for the liability and an associated asset retirement cost shall be stated at the fair value of the asset retirement obligation in the period in which the obligation is incurred.

The FERC Uniform System of Accounts General Instruction No. 25 also requires that "a utility initially record a liability for an ARO in Account 230 — Asset Retirement Obligations, and charge the associated asset retirement costs to the electric utility plant that gave rise to the legal obligation in Account 101-Electric Plant in Service. The asset retirement cost is to be depreciated over the useful life of the related asset that gives rise to the obligation by recording a debit to Account 403.1- Depreciation Expense for Asset Retirement Costs and a credit to Account 108 Accumulated Provision for Depreciation of Electric Utility Plant. In periods subsequent to the initial recording of the ARO, the utility shall recognize the period-to-period changes of the ARO that result from the passage of time due to the accretion of the liability by recording a debit to Account 411.10 — Accretion Expense, and a credit to Account 230."

Q. **DOES WITNESS MANESS APPEAR TO ACKNOWLEGE THAT DE PROGRESS WAS REQUIRED TO FOLLOW GAAP AND FERC ACCOUNTING REQUIREMENTS?**

A. In footnote 8 on page 32, witness Maness appears to acknowledge that DE Progress has no choice but to adhere to GAAP and FERC requirements. However, in the same footnote, he refers to the deferral of coal ash costs to a regulatory asset for North Carolina ratemaking purposes as a choice.

Q. PLEASE EXPLAIN WHAT LED TO THE DEFERRAL OF COAL ASH COMPLIANCE COSTS TO A REGULATORY ASSET.

A. While both GAAP and the FERC Uniform System of Accounts require the recognition in the income statement of depreciation expense and accretion expense, the Commission has required these amounts to be deferred into regulatory assets. In 2003, after the ARO accounting guidance was required to be implemented by the Financial Accounting Standards Board, the Commission ruled in Docket No. E-2, Sub 826 "That the implementation of SFAS 143 for financial reporting purposes and the deferrals allowed in this docket shall have no impact on the ultimate amount of costs recovered from the North Carolina retail ratepayers for nuclear decommissioning or other AROs, subject to future orders of the Commission." Those deferrals allowed in the docket related to the depreciation and accretion expenses required by GAAP and FERC noted in my testimony. The Company's deferral request of costs incurred and the recovery request in this rate case are in accordance with the deferral Order the Commission issued in Docket No. E-2, Sub 826. Furthermore, as noted by DE Progress witness Sean Riley, it is common for a regulated entity to rely upon an accounting order to support regulatory asset treatment as DE Progress did in this case.

Q. HAVE YOU PROVIDED TESTIMONY PREVIOUSLY ON THE GAAP, FERC, AND DEFERRAL DIRECTIVES THAT GOVERN THE MANNER IN WHICH THE COMPANY ESTABLISHED THE ARO FOR COAL ASH BASINS?

A. Yes. I provided testimony in Docket E-7, Sub 1146 fully explaining the GAAP, FERC and deferral requirements that governed DE Carolinas' establishment of the ARO for its coal ash basin closure costs, and the explanation I provided in that testimony applies to DE Progress' ARO for coal ash basin closure costs, as well. In the Commission's *Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction* in that case, the Commission expressly credited my explanation and testimony regarding GAAP, FERC and deferral directives and found my testimony to be un-contradicted in that case.

(E-7, Sub 1146 Rate Order, p. 148.) I also provided similar testimony in DE Carolinas Docket E-7, Sub 1214.

Q. DO YOU AGREE WITH WITNESS MANESS'S ASSERTION THAT "THE COMPANY HAS USED AN ACCOUNTING AND RATEMAKING MODEL THAT ACCOUNTS FOR AND RECOVERS THE ARO-RELATED COAL ASH CLEANUP COSTS AS EXPENSES ON AN 'AS-SPENT' OR 'AS-ACCRUED'" BASIS?

A. No. I believe that Mr. Maness has mischaracterized the accounting treatment the Company is applying to the coal ash related costs. The cash outflows to which he refers are not recorded as an expense on the books of DE Progress. In accordance with GAAP and FERC rules, these costs were accrued previously as a capital cost in electric utility plant as part of the Asset Retirement Cost (ARC) related to the ARO, and the Company has already recognized depreciation expense through the life of the ARC and accretion expense over the period of expected settlement of the ARO. *See* ASC 410-20-25-5. However, in the case of DE Progress and pursuant to the Commission's Orders in Docket No. E-2, Sub 826, the depreciation and accretion expenses were deferred. The amount spent related to the coal ash basin closure ARO is effectively the portion of the depreciation and accretion expenses that were previously deferred in accordance with Commission orders and which has now been incurred as the Company has expended cash to settle its ARO. Although for ratemaking purposes the Company is seeking recovery of these cash costs on an "as-spent" or "as-incurred" basis, Mr. Maness's claim that the Company has used an accounting model that accounts for these cash outflows as expenses is incorrect. In the Company's financial statements, these cash outflows are reflected as a reduction to cash and a reduction to the ARO; an ARO which, when it was established, was charged as an ARC to the electric utility plant that gave rise to the legal obligation, in accordance with GAAP and FERC rules.

Q. DO YOU AGREE WITH WITNESS MANESS'S ASSERTION THAT THE COMPANY IS NOT UTILIZING ARO ACCOUNTING AS PRESCRIBED BY FASB?

A. No, I do not. Mr. Maness seems to imply that the Company's accounting related to its coal ash AROs is not in compliance with Generally Accepted Accounting Principles ("GAAP") as promulgated by FASB. This simply is not true. As explained earlier in my testimony, the Company has accounted for its coal ash AROs in accordance with the GAAP requirements that govern ARO accounting as found in ASC 410-20. In addition, as a regulated utility, DE Progress must comply with FASB ASC 980 "Regulated Operations," which requires cost-based, rate-regulated enterprises such as DE Progress to reflect the impacts of decisions of its regulators in their financial statements. Pursuant to this requirement and as noted earlier in my testimony, DE Progress has reflected in its financial statements the impacts of the Commission's directives regarding the deferral of coal ash ARO related costs.

Q. COULD THE COMPANY HAVE CHOSEN TO FOLLOW THE GAAP METHODOLOGY FOR NONREGULATED COMPANIES AS SUGGESTED BY WITNESS MANESS?

A. No. Although it is not clear, Mr. Maness seems to suggest on page 32-33 of his testimony that the Company could have chosen not to apply the GAAP provisions of ASC 980, and instead accounted for its ARO-related coal ash compliance costs as if it were an enterprise that is not subject to regulation for rates and other matters by the Commission. However, DE Progress is subject to regulation by the Commission, and therefore it meets the definition of a rate-regulated enterprise under ASC 980 and must comply with the requirements of ASC 980; it is not a choice as Mr. Maness seems to suggest. As explained further in Mr. Riley's testimony, the economic effects of regulation were considered unique by FASB, which ultimately resulted in ASC 980. It is incorrect to suggest that the Company could have chosen to not apply ASC 980 consistent with GAAP.

Q. **HAS THE COMPANY "CHOSEN" A TOTALLY DIFFERENT APPROACH THAN THE ONE TYPICALLY FOLLOWED FOR UTILITY PROPERTY AS WITNESS MANESS SUGGESTS?**

A. No. The Company has simply accounted for these costs as required under GAAP and the FERC Uniform System of Accounts. Further, as it was authorized to do by the Commission, the Company deferred the impacts of ARO accounting, and now seeks an order from the Commission with regards to recovery.

In Docket No. E-2, Sub 1142, which was the Company's last rate case, Witness Maness made similar arguments that the Company had "chosen" a method to account for CCR compliance costs ("DE Progress 2018 Rate Order").[1] In the Commission's Order in that case the Commission explained that "once it became clear that new laws and regulations governing coal ash would require closure of the Company's existing coal ash basins, GAAP required the ARO be established, and the Company had no choice in the matter."[2]

Q. **WHAT OTHER ARGUMENT DOES WITNESS MANESS MAKE TO SUPPORT HIS CLAIM THAT THE COAL ASH RELATED ARO COST SHOULD BE TREATED AS AN EXPENSE?**

A. Witness Maness also states that "the ARO related cost proposed for deferral and amortization themselves are not in any manner costs related to present or future operations; instead they are costs that but for Commission approval of the deferral and amortization will be immediately written off as expenses related to the past." Once again, Witness Maness ignores the fundamental nature of ARO accounting and the requirements adhered to by the Company to reach a

[1] *See Order Accepting Stipulation, Deciding Contested Issues, and Granting Partial Rate Increase*, Docket No E-2, Sub 1142 (February 23, 2018) ("DE Progress 2018 Rate Order").
[2] *Id.* at 194.

conclusion that the Commission should classify these costs as "deferred expenses."

As I previously testified, the Company is required to account for Asset Retirement Obligations in accordance with GAAP and FERC guidance. Under both GAAP and FERC guidance, the asset created when a Company initially recognizes an ARO is considered part of the property, plant and equipment for the assets which must be eventually retired. GAAP states, in ASC 410-20-25-5, with regards to recognition of the asset related to the recognition of the ARO that:

> Upon initial recognition of a liability for an asset retirement obligation, an entity shall capitalize an asset retirement cost by increasing the carrying amount of the related long-lived asset by the same amount as the liability.

Similarly, the FERC guidance regarding Asset Retirement Costs in General Instruction Number 25 for asset retirement obligations states that: "The utility shall initially record a liability for an asset retirement obligation in account 230, Asset retirement obligations, and charge the associated asset retirement costs to electric utility plant and nonutility plant, as appropriate, related to the plant that gives rise to the legal obligation."

By characterizing coal ash ARO related costs as expenses, witness Maness ignores the fact that both the FASB and FERC have ruled that asset retirement costs are an integral part of the plant asset that gives rise to the ARO, and therefore must be capitalized as part of such asset. Although plant assets are eventually expensed over time through charges to depreciation expense, it does not change the fact that the FASB and FERC have ruled that ARO related costs are capital in nature and in origin.

Q. HAS THE COMMISSION PREVIOUSLY CONSIDERED AND REJECTED THE ARGUMENT THAT THE COAL ASH ARO COST SHOULD BE CLASSIFIED AS DEFERRED EXPENSES?

A. Yes. In Docket No. E-7, Sub 1146, which was DE Carolinas' 2017 rate case, Witness Maness made similar arguments for the classification of coal ash ARO related cost as "deferred expenses". In the Order in that case *Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction* ("DE Carolinas' 2018 Rate Order")[3] , the Commission acknowledged that DE Carolinas has accounted for these costs as required under GAAP and FERC Uniform System of Accounts. The Commission further found that, under GAAP, the costs (no matter what their classification), are capitalized pursuant to ASC 410-20-25-5. Under FERC accounting, they are capitalized as well. Accordingly, when properly accounted for in an ARO, the specific classification of costs is not determinative because, under GAAP and FERC guidance, ARO costs are capitalized. Thus, as the Commission concluded in its Order in DE Carolinas' last rate case, "witness Maness' classification of these costs as "deferred expenses" is not persuasive, not supported by authority and not determinative, given the nature of deferral," and "it is also incorrect as a matter

[3] *See Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction*, Docket No E-27, Sub 1146 (June 22, 2018) ("DE Carolinas 2018 Rate Order").

of accounting."[4] The Commission further concluded that "The nomenclature relied upon in GAAP and FERC is costs, assets, and liabilities, not expenses."[5]

Q. WAS THE ACCOUNTING FOR THE COAL ASH BASIN CLOSURE COSTS FULLY UNDERSTOOD BY PUBLIC STAFF AND OTHER INTERESTED PARTIES?

A. Yes. As early as December 21, 2015, the Company, through its then Chief Accounting Officer, notified the Commission through a letter of the manner in which it was required to account for coal ash basin closure costs. The letter explained GAAP and FERC accounting requirements regarding AROs. The letter described the triggering events for creation of the ARO, noting the promulgation of the CCR Rule and the passage of CAMA; it indicated that an ARO related to the closure of coal ash basins was recorded on the Company's balance sheet; it indicated further that a corresponding asset was recorded "as part of the associated coal plant in the property, plant and equipment (PP&E) accounts, or if associated with a retired coal plant, recorded in regulatory assets." Finally, the letter noted that "[c]onsistent with the requirements of the Commission's Order dated August 8, 2003 in Docket No. E-7, Sub 723 and Order dated August 12, 2003 in Docket No. E-2, Sub 826, all income statement impacts related to the AROs ultimately reside in regulatory asset accounts." As noted by witness Riley, the recognition of a regulatory asset as was described

[4] *Id*. at 289.
[5] *Id.* at 290.

by the Company in the letter is consistent with how ASC 410 acknowledges that regulated entities recover asset retirement costs.

Q. WHAT ACTIONS WERE TAKEN IN RESPONSE TO THE LETTER?

A. The Commission established Docket No. E-2, Sub 1103 for DE Progress and Docket No. E-7, Sub 1110 for DE Carolinas[6] on March 28, 2016 and placed the Letter, referred to as the Savoy Letter, in those dockets. In its Order in Docket No. E-7, Sub 1146, the Commission explains that Docket No. E-7, Sub 1110 was opened "so as to acknowledge the letter and allow parties with interest to be made aware of it." The Commission went on to explain that "no filings were made in response to the letter as of the time the Docket was established, and indeed, no substantive filings were made thereafter until the Company filed its petition for Accounting Order on December 30, 2016, formally seeking deferral of coal ash basin closure costs." This all supports the conclusion that the Company's required treatment of these costs was well understood from the outset. Specifically, the Commission stated in its Order the following:

> No party takes issue with the Company's accounting of coal ash basin closure costs in an ARO, as detailed in the Savoy Letter. Certainly, the Public Staff does not – witness Maness' testimony does not challenge the basis for or the propriety of the accounting treatment, he comes to a different conclusion regarding the effect of such treatment upon the Company's entitlement versus its eligibility to earn a return on the unamortized balance of those costs. As noted previously, Interveners have a burden of production when challenging the Company's costs. This principle equally applies to the accounting costs. The Commission determines that the

[6] *In re: Joint Petition* of Duke Energy Progress LLC, and Duke Energy Carolinas, LLC for Accounting Order to Defer Environmental Compliance *Costs*, Docket Nos E-2 Sub 1103 & E-7, Sub 1110 (December 21, 2015).

Company has met this burden. The Public Staff challenge makes the issue ripe for the Commission to address the issue on the merits. The Company has met its burden of showing that the costs it seeks to recover are not only reasonably and prudently incurred, but also appropriately accounted for in ARO accounting, and the Commission agrees that based on its determinations on the merits that recovery is appropriate except as addressed below.

Several consequences flow from this determination. First, deferred costs are costs "that have been paid for by the …[utility] but have yet to be included for ratemaking purposes …"Lesser & Giacchino, p 52. Through the Savoy Letter, the Company told the Commission and the Public Staff, and the Commission told all interested parties, exactly how the Company's coal ash basin closure costs were being accounted for, and explicitly indicated that the costs were being deferred pursuant to the Commission's orders in Docket No. E-7, Sub 723. Neither the Public Staff nor anyone else, including the AGO, raised objection.

Nor did the Public Staff or AGO raise any objection when the Company made its formal deferral request in 2016. TR. Vol. 9, p.126. The Public Staff however asserts that deferral for regulatory accounting purposes is appropriate, given the magnitude of the costs and their potential impact upon the authorized rate of return. The nature of the deferral is such that all costs, no matter how classified, related to the Company's coal ash basin closure obligations are accounted for in the ARO. Id. P.125. The ARO was established for this purpose, as the Savoy Letter makes clear. As such, the Commission determines that even were it necessary to resolve this issue, witness Maness' classification of these costs as "deferred expenses" is not persuasive, not supported by authority and not determinative, given the nature of deferral.[7]

[7] *See DE Carolinas 2018 Rate Order* at 289.

Q. DO YOU AGREE WITH MR. MANESS'S CONCLUSION THAT THE COAL ASH DISPOSAL COSTS THAT DE PROGRESS IS SEEKING TO RECOVER IN THIS CASE ARE NOT CHARACTERISTIC OF ASSETS RECORDED AS USED AND USEFUL PROPERTY?

A. No, I do not. I believe the costs incurred (relating to the deferred depreciation and accretion) are used and useful as those costs are reasonable and prudently incurred and are intended to provide utility service in the present or in the future through achieving their intended purpose: environmental compliance, the retirement of the ash impoundments and the final storage location for the residuals from the generation of electricity. The achievement of those three purposes is used and useful as the utility has the obligation to comply with CAMA and the CCR Rule. This point was driven home by the Commission in the DE Progress 2018 Rate Order through the following illustration:

> A concrete illustration highlights this issue more clearly. Take, for example, the new coal ash landfill that the Company constructed at the Sutton plant. The landfill "went into service in July ..[2017], and .. [the Company is] placing ash in the landfill today." (Tr. Vol. 20, p.65.) The Public Staff, through its consultants Garrett and Moore, has no quarrel with the construction of the landfill or its cost, except for the liner chosen, and agrees that the funds expended in constructing this landfill were reasonable and prudent. The Public Staff maintains however that the landfill should have been constructed sooner and so has proposed a disallowance of the cost of off-site transportation and disposal of coal ash from the Sutton plant. The landfill is "used and useful." It consist of liners, for example, that are capital items with service lives in excess of one year. It stores coal ash which is itself is a byproduct of electricity generation and is required to be stored in a landfill by the CCR Rule and/or CAMA. Yet the Public Staff is also saying that because the costs of construction are accounted for in an

> ARO – as required by GAAP, to which the Company is subject – they are somehow not "used and useful." The Commission rejects this label-driven classification.[8]

In addition to my testimony, DE Progress Witness Kim Smith further discusses in her rebuttal testimony that the deferred coal ash costs were funded with investor supplied funds which entitles the Company to earn a return on these funds over the period the costs are amortized as the Commission previously found in the 2018 Rate Order[9].

IV. NUCLEAR DECOMMISSIONING TRUST FUND

Q. WHAT IS THE PURPOSE OF THE NUCLEAR DECOMMISSIONING TRUST FUND?

A. The NDTF was established to pay for the decommissioning costs of DE Progress's nuclear power plants. The NDTF investments are managed and invested in accordance with applicable requirements of various regulatory bodies, including the Nuclear Regulatory Commission, Federal Energy Regulatory Commission, North Carolina Utilities Commission, and the Internal Revenue Service. Use of the NDTF investments is restricted to nuclear decommissioning activities, which include license termination, spent fuel, and site restoration.

[8] *See DE Progress 2018 Rate Order* at 195-196.
[9] *Id.* at 195.

Q. PLEASE DESCRIBE THE COMMISSION'S GUIDELINES FOR DETERMINING AND REPORTING NUCLEAR DECOMMISSIONING COSTS.

A. Pursuant to Commission-approved guidelines for determining and reporting nuclear decommissioning costs,[10] electric utilities are required to update site-specific decommissioning cost studies ("Cost Studies") for their nuclear generating stations every five years. Within 90 days of completion, the updated Cost Studies must be filed with the Commission.

The utilities are then required to translate the cost estimates included in the Cost Studies into an annual revenue requirement/expense calculation required to provide the total amount of decommissioning revenue needed to decommission each unit at the end of its license life. Within 210 days of completion of the Cost Studies, the companies are required to file a Decommissioning Cost and Funding Report ("Funding Report"), which includes this annual revenue requirement/expense calculation. The Public Staff, Attorney General, and other interested parties then have a 90-day period in which to conduct discovery concerning the details of the new decommissioning studies and the related revenue requirement/expense calculations.

If the total annual expense level calculation (on a North Carolina retail basis) contained in the Funding Report varies by more than 15% from the total

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

North Carolina retail annual expense level being recorded on the Company's books or there are other disagreements regarding the calculations of the expense/revenue requirements after completion of discovery, the parties have the opportunity to submit comments to the Commission setting forth their respective positions and recommendations within 180 days of the filing of the Funding Report.

Q. PLEASE DESCRIBE THE PROCESS FOR DETERMINING THE AMOUNT OF NUCLEAR DECOMMISSIONING COSTS INCLUDED IN THE COMPANY'S REVENUE REQUIREMENT.

A. In 2014, DE Progress retained TLG Services, Inc. ("TLG") to perform updated, site-specific decommissioning cost studies for DE Progress's four nuclear units – Brunswick Unit 1, Brunswick Unit 2, Shearon Harris, and Robinson. TLG completed its updated cost analysis for DE Progress's nuclear generating units in December 2014.

DE Progress filed the updated cost studies with the Commission on April 13, 2015. As a result of receiving the updated TLG cost studies, the new estimates, along with other financial data and assumptions such as fund balances, earnings rates and escalation factors, were entered into an internal nuclear decommissioning revenue requirement model that showed a North Carolina retail annuity required for sufficient funding for decommissioning of the four nuclear units. An explanation of the calculation, and the various inputs to the model, are discussed later in this testimony.

On September 11, 2015, DE Progress filed its Funding Report with the Commission, providing updated decommissioning cost estimates, fund balances as of June 30, 2015 adjusted for the receipt of funds from North Carolina Eastern Municipal Power Agency on July 31, 2015, projected investment earnings rates, and the annual system nuclear decommissioning expense needed on a going forward basis. The Commission approved the Public Staff's recommendation and DE Progress' request on April 15, 2016, in Docket Nos. E-100, Sub 56 and E-2, Sub 1088, which proposed to update the portion of decommissioning costs recovered through the Joint Agency Asset Rider ("JAAR") to reflect the 2014 Decommissioning Cost Analyses.

Q. DID DE PROGRESS SEEK ANY UPDATES TO THE ANNUAL NUCLEAR DECOMMISSIONING EXPENSE IN ITS LAST RATE CASE?

A. Yes. In its last rate case in Docket No. E-2, Sub 1142 ("2017 Rate Case"), the Company requested additional funding as a result of an update to the North Carolina retail nuclear decommissioning revenue requirement model. Among other things, this update reflected changes in forecasted escalation and earnings rates. As I noted in that case, adjustments to escalation and earnings rates can lead to significant variances in projected funding requirements. DE Progress requested to increase the North Carolina retail share of annual decommissioning expense currently collected through base rates and the JAAR from $8,762,878 to $19,590,285 (with $3,007,593 in North Carolina retail decommissioning costs recovered through JAAR and the remaining $16,582,692 in NC retail costs recovered through base rates).

Certain inputs into the DE Progress model, such as North Carolina Retail allocation factor, tax rates, portfolio turnover/ realized portion of portfolio turnover and current income percentage remained largely unchanged from the 2015 model. Any revisions to those assumptions resulted in immaterial changes in the projected annual funding requirement. The largest contributor to the increase in projected annual funding was revised earnings assumptions. Lowered earnings expectations resulted in an increased annuity of approximately $7 million (of the $10 million total increase). DE Progress used projected investment rates of return that were developed by averaging rates of return from several different sources, including Willis Towers Watson, JPMorgan, BlackRock, and StateStreet Global Advisors. The assumptions regarding projected investment rates of return on DE Progress' nuclear decommissioning trust funds for qualified and non-qualified trust funds are shown below.

Unit	Pre-tax ROR Qualified Growth Fund	Pre-tax ROR Qualified De-risked Fund[11]	After-tax ROR Non Qualified Growth Fund	After-tax ROR Non Qualified De-risked
Brunswick Unit 1	5.61%	2.30%	4.01%	1.44%
Brunswick Unit 2	5.72%	2.30%	4.03%	1.44%
Shearon Harris	5.84%	2.30%	2.71%	1.44%
Robinson	5.62%	2.30%	2.71%	1.44%

[7] For purposes of ensuring adequate funds are available when needed, amounts from the external decommissioning funds will be "de-risked" (i.e., a portion of the portfolio will be

For comparison purposes, below are assumptions regarding projected investment rates of return, as used in the 2015 model.

Unit	Pre-tax ROR Qualified	Pre-tax ROR Qualified	After-tax ROR Non Qualified	After-tax ROR Non Qualified
Brunswick Unit 1	6.39%	2.31%	2.71%	1.42%
Brunswick Unit 2	6.32%	2.31%	2.71%	1.42%
Shearon Harris	6.18%	2.31%	2.71%	1.42%
Robinson	5.81%	2.31%	2.71%	1.42%

In addition to the revised earnings assumptions, DE Progress thought it was also necessary to calculate an updated escalation rate to incorporate inflationary changes from the time the last North Carolina retail analysis was performed. The initial cost escalation factors applied were obtained from the unit-specific March 2015 Escalation Analyses prepared by TLG, as filed with the Commission under Docket Nos. E-100, Sub 56 and E-2, Sub 1088. In order to calculate revised escalation assumptions, DE Progress adjusted the escalation rates from the previous filing by the rate of change in the long-term inflation assumption as provided by Willis Towers Watson, Duke Energy's consultant for the Nuclear Decommissioning Trust Funds. This rate of change reflects the increased inflation expectations currently in the economy. Specifically, the escalation factors for the four DE Progress units are as follows:

moved from traditional growth investments to more secure investments) such that the de-risked amount in the fund will always be equal to the decommissioning costs that are expected to be incurred within five years.

Unit	Cost Escalation Rate
Brunswick Unit 1	2.82%
Brunswick Unit 2	2.80%
Shearon Harris	2.61%
Robinson	2.73%

For comparison purposes, below are assumptions regarding projected cost escalation rates, as used in the 2015 model.

Unit	Cost Escalation Rate
Brunswick Unit 1	2.70%
Brunswick Unit 2	2.68%
Shearon Harris	2.50%
Robinson	2.61%

The cost escalation factors are slightly different among the four units primarily as a result of the different time horizons the nuclear units will be retired, coupled with the fact that the units have different mixes of costs (e.g., labor vs. materials), which escalate at different rates. Increased escalation assumptions used in the analysis resulted in an increase of approximately $3 million in annual funding requirement (of the $10 million total increase). Please see the below table for a summary of the nuclear decommissioning revenue requirement results by unit.

Unit	2015 Calculated	2017 Calculated
Brunswick Unit 1	5,316,687	8,276,237
Brunswick Unit 2	527,539	2,497,488
Shearon Harris	3,085,956	6,386,945
Robinson	260,101	2,429,615
Total	9,190,283	19,590,285

Q. PLEASE EXPLAIN HOW DE PROGRESS CALCULATED THE ANNUAL DECOMMISSIONING EXPENSE FOR ONE OF THE NUCLEAR UNITS.

A. I will use the calculation for the Company's Robinson Nuclear Station as an example. Robinson is scheduled to commence decommissioning in 2030 when its current operating license expires. The estimated decommissioning costs of $745.9 million (in 2014 dollars) represent costs from the site-specific decommissioning cost analysis performed by TLG.

Applying the North Carolina historical/projected average retail jurisdictional allocation factor of 63.795 percent, the NC retail customers' share of projected decommissioning costs is $475.9 million. Using the updated escalation rate of 2.73 percent results in a total estimated decommissioning cost of $896.8 million in future dollars.

As of December 31, 2016, the amount in the North Carolina retail qualified and non-qualified trust funds for the Robinson Nuclear Station is $397.2 million (i.e., $377.8 million in the qualified trust fund and $19.4 million in the non-qualified trust fund). Based upon these amounts, DE Progress calculated the expected future trust fund balances by applying certain financial assumptions as to the performance of the trust funds, including the rates of return on the qualified and non-qualified trust funds (as set forth in the table in my above testimony) and the tax effects on the earnings. Note at this point, the analysis assumes no additional contributions from North Carolina retail customers beyond those made through December 31, 2016. The purposes of the analysis is to determine whether, given the existing fund balance plus future after-tax earnings less withdrawals for decommissioning costs, a shortfall or surplus exists.

At the end of the decommissioning period in 2058, the decommissioning expenditures and trust fund balances were compared to determine whether sufficient funds will be available. In this case, there was a shortfall as there were insufficient future funds to pay for future decommissioning costs. To cover the shortfall, DE Progress calculated the annuity which would eliminate this expected shortfall. Based on the result, DE Progress would need to contribute $2,429,615 annually, on behalf of the North Carolina retail customers, up until the Robinson Nuclear Plant license termination date of 2030. The calculation for the remaining units used this same methodology

Q. WHAT AMOUNT OF NUCLEAR DECOMMISSIONING EXPENSE IS INCLUDED IN THE REVENUE REQUIREMENT REQUESTED IN THIS RATE CASE?

A. As noted in the Direct Testimony of DE Progress witness Shana Angers, 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 the 2017 Rate Case. Of this amount, $16,536,686 will be collected in base rates and $3,053,599 will be recovered through the JAAR.

Q. IS DE PROGRESS SEEKING ANY UPDATES TO THE ANNUAL NUCLEAR DECOMMISSIONING EXPENSE IN THIS RATE CASE?

A. No. The Company filed its Application in this rate case on October 30, 2019. We opted to keep the revenue requirement the same as the amount that was approved in the 2017 Rate Case given that a new TLG Cost Study was expected by the end of 2019, and we would be going through the lengthy process of updating the cost and funding model in 2020. At the time of filing our direct case, we did not expect to complete that process prior to the close of this rate case. That is still true today. Even taking into account the unanticipated delays in the procedural schedule resulting from the COVID-19 pandemic, we do not expect the process to be complete prior to the conclusion of this rate case. As outlined in the table below, pursuant to the Commission's guidelines described above, the Company's Funding Report is not due to be filed until July 2020, and the Public Staff and other parties have until January 2021 to vet the Funding Report and submit comments and recommendations.

Action	Deadline	Actual
Cost Study Completion	December 2019	December 21, 2019
Cost Study Filing	March 20, 2020	March 12, 2020
Funding Report Filing	July 18, 2020	TBD
Discovery Period Ends	October 16, 2020	TBD
Comment Period Ends	January 14, 2021	TBD

Q. PLEASE SUMMARIZE THE PUBLIC STAFF'S POSITION ON THE AMOUNT OF NUCLEAR DECOMMISSIONING EXPENSE THAT SHOULD BE INCLUDED IN DE PROGRESS' REVENUE REQUIREMENT IN THIS CASE.

A. Public Staff witness Hinton argues that DE Progress' proposed rates of return for its qualified trust fund are unreasonable and overly conservative. He references analyses performed by the Public Staff's ROE expert to support his argument that a 9.50% rate of return on the market is reasonable and uses that number to extrapolate an overall expected return for the qualified trust fund. He also states the Company's projected long-run rate of return of 4.56% is overly conservative based on his review of past performance of annual rates of return for this fund. He also analogizes to earned rates of return for the Company's pension plan funds. His conclusion is that a 6.00% expected rate of return for the cost and funding model is reasonable.

Based on the Company's recently filed cost estimates to decommission its four nuclear plants, the December 31, 2019 qualified and non-qualified trust fund balances, current state and federal tax rates, and the use of a 6.00% rate of return for DE Progress' qualified trust fund, Public Staff witness Hinton recommends that Commission reduce the Company's decommissioning expense to $0.

Q. DO YOU AGREE WITH WITNESS HINTON?

A. No. While the Company's cost of equity expert, Robert Hevert, will address why it is inappropriate for Mr. Hinton to base his recommended return for the NDTF on analyses of market returns relating to ROE, I will address witness Hinton's recommendation that this Commission update the Company's decommissioning expense outside of the typical process. As outlined above, the process of developing a cost and funding model is complicated and includes many inputs and assumptions. DE Progress relies on a number of independent third parties to provide asset class return forecasts and to run portfolio-specific simulations to generate long-term portfolio return assumptions to calculate projected funding requirements to ensure funding is adequate to meet future decommissioning obligations. This analysis is necessary to determine the appropriate level of decommissioning expense, and Witness Hinton acknowledges that the Public Staff has not performed these various simulations in coming up with its recommendation.

Simply put, there is a reason the Commission requires the Company to go through the exercise of developing a cost and funding model and a reason that the Commission allows 210 days from the receipt of cost estimates for the Company to complete the funding report. That process is currently underway and should not be allowed to be short-circuited by the Public Staff. The Public Staff will have the opportunity to fully vet the Company's Funding Report once it has been filed in Docket No. E-100, Sub 56. Until that process has been completed and any updates are made as a result of that process, it is reasonable to hold DE Progress' nuclear decommissioning expense at the same level that was previously approved by this Commission in the 2017 Rate Case.

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:	)	
	)	**SUPPLEMENTAL TESTIMONY**
Application of Duke Energy Progress, LLC	)	**OF DAVID L. DOSS JR.**
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 David L. Doss Jr., 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, a service company affiliate of Duke Energy Progress, LLC ("DE Progress" or the "Company"), as Director of Asset Accounting. DE Progress is a subsidiary of Duke Energy Corporation (together with its subsidiaries "Duke Energy").

Q. DID YOU PREVIOUSLY FILE TESTIMONY IN THIS PROCEEDING?

A. Yes. I filed rebuttal testimony and one exhibit on May 4, 2020.

II. PURPOSE AND OVERVIEW OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony is in response to the July 23, 2020 order issued by the Commission requiring that DE Progress and Duke Energy Carolinas, LLC ("DE Carolinas") file additional testimony in their currently pending rate cases responding to the Commission's request for information on coal combustion residual costs. *See Order Requiring Duke Energy Carolinas, LLC and Duke Energy Progresss, LLC to File Additional Testimony on Grid Improvement Plans and Coal Combustion Residual Costs* ((the "Order"). My testimony provides the Commission with information concerning the manner in which the Company classifies costs incurred or to be incurred in connection with the Company's ongoing legal obligations, imposed by federal and North Carolina law, to close ash basins at its coal-fired generating plants. Among other uses, these basins either are (in the case of currently operating plants) or were (in the case of recently closed plants) used to store coal ash generated as a byproduct of the combustion of coal. Coal combustion was (or, in the case of currently operating plants, is) the process used at these plants to generate electricity for the Company's customers.

Q. ARE YOU SPONSORING ANY EXHIBITS WITH YOUR REBUTTAL TESTIMONY?

A. Yes. I am sponsoring one exhibit, which was prepared at my direction and under my supervision.

III. RESPONSE TO THE ORDER

Q. PLEASE PROVIDE AN OVERVIEW OF YOUR TESTIMONY.

A. As I describe in detail in my Rebuttal Testimony, the costs incurred in connection with coal ash basin closure activities undergo rigorous evaluation to ensure they are properly classified under accounting rules. Specifically, my Rebuttal Testimony notes:

> DE Progress has … implemented a Coal Ash ARO charging commitee whose purpose is to evaluate costs to be incurred for determination as to whether they qualify for ARO accounting treatment. The commitee utilizes the guidance in ASC 410, other GAAP, FERC and Commission guidance and Duke Energy Corporation accounting policies to make these determinations. Specifically, for example, the

> commitee utilizes ASC 410-20-55-13 to determine the extent of costs to include in the ARO. Decisions of the Coal Ash ARO Charging commitee are summarized in a charging guidelines document.

(Rebuttal p. 8, lines 13-21). I have reviewed the Supplemental Testimony of Jessica Bednarcik, including Supplemental Exhibit 1 to that testimony. Witness Bednarcik's Supplemental Testimony notes that the activities identified in Supplemental Exhibit 1 were charged to "ARO," meaning that under the charging guidelines they were classified as Asset Retirement Obligations ("ARO"). As such, the costs incurred in connection with the activities I reviewed would properly be capitalized costs. As I explained in my Rebuttal Testimony, under Financial Accounting Standards Board ("FASB") and Federal Energy Regulatory Commission ("FERC") guidance, ARO costs are an integral part of the plant asset that gives rise to the ARO, and therefore must be capitalized as part of such asset when the ARO liability is recognized.

Q. HAS THE COMMISSION SPOKEN TO THIS ISSUE AS WELL?

A. Yes. In the *Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction* entered on June 22, 2018 in Docket No. E-7, Sub 1146, which was DE Carolinas' 2017 rate case ("DE Carolinas 2018 Rate Order"), the Commission acknowledged that both GAAP and FERC accounting guidance required the Company to recognize an ARO upon becoming subject to the legal obligation to retire its ash basins. *Id.* at 288. The Commission further acknowledged that "recognition of the liability carries with it recognition of a corresponding asset – the capitalized cost of settling the liability, which under both GAAP and FERC rules is considered part of the property, plant and equipment for the assets that must be retired." *Id.* at 288.

Q. ARE THERE SOME ACTIVITIES THAT ARE UNDERTAKEN TO SUPPORT COAL ASH BASIN CLOSURE THAT ARE NOT CAPITALIZED AS PART OF THE ARO?

A. Yes. The charging guidelines provide a list of the activities undertaken to close DE Carolinas' ash basins along with the designated charging categories determined by the ARO charging commitee. The guidelines identify, for charging purposes, activities as ARO, Non-ARO capital, operations and maintenance ("O&M") costs or some combination. Doss DEP Supplemental Exhibit 1 provides an example of costs evaluated by the Coal Ash charging commitee and the associated accounting determination. This information was also provided as an attachment in response to Public Staff data request No. 135-2.

Q. PLEASE EXPLAIN MORE ABOUT THE CHARGING COMMITTEE'S ROLE IN DESIGNATING THE APPRORIATE CATEGORY FOR COAL ASH REMEDIATION ACTIVITIES.

A. As I discuss in my rebuttal, the Coal Ash ARO charging commitee's purpose is to evaluate costs to be incurred to determine whether they qualify for ARO accounting treatment. The charging commitee utilizes the guidance in ASC

410, other GAAP, FERC and Commission guidance and Duke Energy Corporation accounting policies to make these determinations. In the *DE Carolinas 2018 Rate Order*, the Commission discussed these processes as follows:

> DEC has implemented a Coal Ash ARO charging commitee whose purpose is to evaluate costs to be incurred for determination as to whether they qualify for ARO accounting treatment..[and that decisions] of the Coal Ash ARO charging commitee are summarized in a charging guidelines document document. *Id.* at 66-67. These decisions are reviewed internally by the Company's Coal Combustion Products (CCP) group to ensure that 1) all relevant facts were appropriately communicated by CCP and understood by the commitee, and 2) that the CCP group understands the decisions to properly categorize actual project costs." *Id.* at 286.

Q. FOR ACTIVITES THAT ARE DESIGNATED AS AROs IS THERE ANY SUBDESIGNATION OF THOSE ACTIVITIES AS CAPITAL OR O&M?

A. No. The charging commitee evaluates expenditures based on the current accounting guidance and policies in place, and under current GAAP and FERC ARO accounting guidance the costs associated with activities that are designated as AROs are capitalized as part of the property, plant, and equipment for the assets which must be eventually retired. As with any other costs that are capitalized as part of property, plant, and equipment, there is no GAAP or FERC requirement to subdesignate the ARO costs to reflect how they would have been accounted for had they not been capitalized. Therefore, the Company's accounting systems and processes are not designed to facilitate such subdesignations or produce financial statement data under an alternative accounting model that is not reflective of current GAAP and FERC rules. As I discuss in my rebuttal testimony, in *DE Carolinas 2018 Rate Order*, the Commission addressed this issue and found that, under GAAP, the costs (no matter what their classification), are capitalized pursuant to ASC 410-20-25-5. Under FERC accounting, they are capitalized as well. Accordingly, when properly accounted for in an ARO, the specific classification of costs is not determinative because, under GAAP and FERC guidance, ARO costs are capitalized. The Commission further concluded that "The nomenclature relied upon in GAAP and FERC is costs, assets, and liabilities, not expenses."

Q. **CAN YOU ELABORATE ON HOW CATEGORIZING THE NATURE OF THE ACTIVITY CANNOT BE SEPARATED FROM GUIDANCE UNDER GAAP, FERC, COMMISSION REQUIREMENTS AND DE PROGRESS'S OWN ACCOUNTING POLICIES?**

A. Yes. The classification of an expenditure is explicitly dependent upon the purpose of the activity, the existing GAAP and FERC guidance and existing Commission rulings at the time that determination is being made. For example, current GAAP and FERC ARO guidance recognizes that a legal obligation was created and that an ARO liability and offsetting ARO asset needed to be recorded to the Company's books when the CCR Rule and CAMA went into effect. In the absence of GAAP and FERC ARO accounting requirements, there would have been no legal obligation to record when these regulations were enacted. Instead, the costs would have been recorded as they were incurred, and assessed for the proper accounting classification based on the particular activity and the accounting guidance and Commission rulings that would have been in place at the time, in the absence of ARO accounting rules. It is difficult to speculate how accounting rules and Commission guidance may have evolved in the absence of the ARO accounting model. Thus, not only is DE Progress' accounting system incapable of facilitating a retroactive removal of accounting guidance a retroactive assessment of what designation other than ARO might be appropriate for a particular activity would be pure speculation.

Q. DOES THIS CONCLUDE YOUR 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	))))))))	**DUKE ENERGY PROGRESS, LLC'S CORRECTIONS TO THE REBUTTAL TESTIMONY OF DAVID DOSS**

CORRECTION TO REBUTTAL TESTIMONY OF DAVID DOSS

PAGE 3, LINES 10-11 SHOULD READ:	REASON FOR CHANGE:
Yes. I am sponsoring ~~two~~ one exhibit~~s~~, which was ~~were~~ prepared at my direction and under my supervision.	There is only one exhibit and that exhibit was inadvertently omitted from the May 4, 2020 filing of my rebuttal testimony. Doss Rebuttal Exhibit 1 was subsequently filed on August 13, 2020.

MR. MARZO: I'd also ask, Commissioner Clodfelter, that Mr. Doss' summary be copied into the record as if given orally.

COMMISSIONER CLODFELTER: Without objection, it will be so ordered.

(Whereupon, the prefiled summary of testimony of David L. Doss was copied into the record as if given orally from the stand.)

Duke Energy Progress, LLC
Summary of Rebuttal Testimony of David Doss
Docket No. E-2, Sub 1219

My rebuttal testimony will respond to the testimony of Public Staff witnesses Michael C. Maness on coal ash ARO accounting. As it pertains to Mr. Maness, he asserts that the Company has "chosen" to request a regulatory accounting and ratemaking method that accounts for coal ash compliance costs as ongoing expenses, with a proposed regulatory asset intended to provide for the recovery of expenses incurred in the past that would ordinarily be immediately written off. Mr. Maness incorrectly characterizes the facts upon which the Company's Asset Retirement Obligation ("ARO") accounting is based.

As I explain in my rebuttal, the Company was required to adhere to and apply the accounting guidance under the Financial Accounting Standards Board's ("FASB"), Generally Accepted Accounting Principles ("GAAP"), and the Federal Energy Regulatory Commission's ("FERC") Uniform System of Accounts, as well as Orders of this Commission. The Company evaluated GAAP and FERC guidance in light of the legal obligations imposed upon it by North Carolina's Coal Ash Management Act ("CAMA"), and the Environmental Protection Agency's ("EPA") Coal Combustion Residuals Rule ("CCR Rule"), which was promulgated in 2015. At that time, the Company determined that the coal ash basins it operated at its coal-fired generating facilities needed to be closed as a result of the passage of CAMA and the CCR Rule. The closure obligation triggered ARO accounting requirements. In addition, the Commission's Order entered in the Company's E-2, Sub 826 Docket required that ARO accounting impacts be deferred into regulatory assets.

By characterizing coal ash ARO related costs as expenses, witness Maness ignores the fact that both the FASB and FERC have ruled that asset retirement costs are an integral part of the plant asset that gives rise to the ARO, and therefore must be capitalized as part of such asset. Mr. Maness made similar arguments in the Company's last rate case and the Commission found that under GAAP, the costs (no matter what their classification), are capitalized pursuant to ASC 410-20-25-5. Under FERC accounting, they are capitalized as well. Accordingly, when properly accounted for in an ARO, the specific classification of costs is not determinative because under GAAP and FERC guidance ARO costs are capitalized. Thus, as the Commission concluded in its Order in DE Progress' last rate case, "witness Maness' classification of these costs as "deferred expenses" is not persuasive, not supported by authority and not determinative, given the nature of deferral," and "[i]t is also incorrect as a matter of accounting."

Additionally, I explain that the deferral of coal ash ARO related costs was not a choice. The Company simply accounted for these costs as required under GAAP and FERC Uniform System of Accounts. Further, as it was authorized to do by the Commission, the Company deferred the impacts of ARO accounting, and now seeks an order from the Commission with regards to recovery.

Finally Commissioners, I respond to Mr. Maness's assertion that coal ash ARO costs are not characteristic of assets recorded as used and useful property. I explain in my rebuttal that the costs incurred (relating to the deferred depreciation and accretion) are used and useful as those costs are reasonable and prudently incurred and are intended to provide utility service in the present or in the future through achieving their intended purpose: environmental compliance, the retirement of the ash impoundments and the final storage location for the residuals from the generation of electricity.

This concludes my testimony summary.

MR. MARZO: Thank you, Commissioner Clodfelter. Commissioner Clodfelter, Mr. Riley's testimony has already been entered into the record, he was -- the only issue remaining with him was whether or not he'd be called, and obviously he's being called today, you've just swore him in. Do need me to do any other steps with him?

COMMISSIONER CLODFELTER: Unless you have any additional prefiled evidence or premarked exhibits that you need to move in or identify, there's nothing else that we need to do at this point.

MR. MARZO: Okay. Thank you, Commissioner Clodfelter. In that case, the witnesses are available for cross.

COMMISSIONER CLODFELTER: All right. Mr. Dodge, Mr. Grantmyre, we -- let me ask you how you want to proceed. We are moving toward the time of our afternoon break. I have one of my colleagues who needs to leave us just a little bit before 3:00 and has another matter that has to be attended to. We were going to take probably a 20-minute break anyway to allow that commissioner to take care of some other necessary business. That's going to disrupt your cross examination. So how do you want to -- how do you think is most efficient for you two to proceed? Do you have some lines of questioning you think we could get through in the next five minutes or so?

MR. DODGE: Thank you, Commissioner Clodfelter. I have a couple. Mine's kind of three subjects, each are about 10 minutes. I could probably get through one of those before the break if that would be helpful, if that works for the parties.

COMMISSIONER CLODFELTER: Let's use the time. If you've got a subject -- discrete subject that you can get in the next five to eight minutes or so, let's do that. Go ahead. Please proceed.

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

CROSS EXAMINATION BY MR. DODGE:

Q. I'll start off with the panel followed by Mr. Grantmyre, as you just discussed, and I believe all my questions are related to Mr. Spanos' rebuttal testimony.

Good afternoon, Mr. Spanos. Mr. Spanos, can you hear me?

A. (John J. Spanos) Yes. Good afternoon, sorry.

Q. No worries. So I'd like to discuss a bit more with you the difference between terminal net salvage estimates for a production plant and mass property accounts. Can you turn to page 11 of your rebuttal testimony, if you have it with you? Just let me know when you're there.

A. Yes, I'm on page 11.

Q. Okay. So on lines line 9 through 12 of your rebuttal, you're referring to Public Staff witness McCullar's testimony, and you state that:

"However, while Ms. McCullar's actual proposed depreciation rates for production plant accounts incorporate the escalation concept consistent with the Commission's decision, she makes proposals for distribution plant that are not consistent with the Commission's decision in Docket Number E-7, Sub 1146."

And then you also, on page 10, the prior page, you include a quote from the Commission's order to support your point. Do you see that quote?

A. (Witness peruses document.)

Yes, I do.

Q. Okay.

MR. DODGE: Commissioner Clodfelter, I'd like to introduce Public Staff Potential Cross Exhibit Number 78, which is Duke Energy Progress' response to Public Staff Data Request 179-1, and ask that it be marked as Public Staff Doss/Spanos -- are we including Riley? I'm sorry, it will be the Doss/Spanos/Riley panel for the exhibits as well?

COMMISSIONER CLODFELTER: Let's do it that way since the panel is appearing together, yes.

MR. DODGE: Okay. So I'd ask that it be marked as Public Staff Doss/Spanos/Riley Rebuttal Cross Exhibit Number 1 [sic].

COMMISSIONER CLODFELTER: It will be so marked.

(Doss/Spanos/Riley Rebuttal Public Staff Cross Exhibit Number 1 was marked for identification.)

Q. Mr. Spanos, this is, again, Potential Cross Exhibit Number 78, which was the response to Public Staff Data Request 179-1.

A. Yes, I believe I have it.

Q. Okay. And have you reviewed this response previously?

A. Yes, I have.

Q. All right. Now, looking at the first line of that response, does it not indicate that the quote from the Commission's Sub 1146 order that you included is referring to production plant accounts and not mass property salvage accounts?

A. It's -- the discussion is talking about production accounts, and I think what I was trying to explain is, for production accounts, you have two components, an interim net salvage component, which is similar to a mass property account, and then the terminal net salvage component, which would only be related to decommissioning costs that would be for production accounts.

Q. Okay. Thank you. And now let's go to page 14 of your rebuttal testimony. I am looking at lines 5 through 7 on that page.

A. I am there.

Q. All right. And on those lines you state that:

"Additionally, none of these cases change the fact that, as discussed above, the Commission has already concluded the net salvage should be escalated to the date of retirement."

So is it your position that the Commission has previously or had previously concluded that mass property net salvage should be escalated to the date of retirement?

A. The concept of the Uniform System of Accounts, which describes the net salvage component and how it is to be recovered, includes the fact that you need to incorporate costs when they're going to be retired. So that's the concept for mass property. The escalation component that I'm talking about in this particular component is the terminal set salvage related to production accounts where you do escalate to the date of retirement.

So there is a relationship between the two, and the discussions in that -- under the Uniform System of Accounts, you must estimate the cost up to the date of retirement because that is into the future. So in both instances, you need to incorporate that; but as far as escalation is concerned, that is a production component of net salvage for terminal purposes.

Q. Okay. Thank you. Now, turning to page 16 of your testimony, lines 9 through 18, you have a quote from a FERC order regarding an Entergy Arkansas proceeding?

A. Yes, I see that. Nine -- excuse me, lines 9 through 18; is that what you said?

Q. Correct, yes.

A. Thank you. Okay.

Q. So is that quote discussing the terminal net salvage for power plants or mass property net salvage?

A. The specific quote that is here is relating to the decommissioning component, which would only apply to production accounts. So -- and then that's what's referenced there, as far as steam production units. So again, the concept applies to mass property, but the specific quote is related to production and terminal net salvage.

Q. Okay. Thank you. I just wanted to ensure it was clear what type of net salvage costs that order was referring to. Okay.

MR. DODGE: Commissioner Clodfelter, I'm at a -- switching subjects, if this is an appropriate time to break.

COMMISSIONER CLODFELTER: Yes. This is an excellent time to break. And again, to accommodate Commissioner McKissick, let's -- we're going to lengthen the break a little bit here. So let's take our afternoon break, and we will recess and resume again at 3:20 p.m. 3:20 p.m. Please go off video.

(At this time, a recess was taken from 2:59 p.m. to 3:29 p.m.)

COMMISSIONER CLODFELTER: Apologies for the late resumption, but, Mr. Dodge, we're still with you.

MR. DODGE: Thank you, Commissioner Clodfelter.

Q. Mr. Spanos, can we -- let's go ahead and turn to pages 29 and 30 of your rebuttal testimony, please. We're going to switch subjects a little bit from net salvage to general plant amortization issues. Let me know when you're there.

A. Okay. I am now on page 29.

Q. All right. So looking at line 20 -- or line 18, excuse me, on page 29, you briefly describe general amortization accounting for accounts that include a large number of units at a very low unit cost. And indicate -- and I'm paraphrasing a bit here, but the use of general plant amortization reduces the accounting expenses associated with those accounts since the retirements of every single asset don't have to be tracked.

Do you agree with that characterization?

A. Yes. There are other benefits to that, but those are the primary ones, as far as why general plant amortization has been utilized for many utilities since the '90s. This is not something that's new. So yes, that's the basic overlaying benefit of general plant amortization.

Q. All right. And would you agree that -- and I think you state this at the top of page 30 -- that when using general plant amortization, an amortization period is established based on the expected average life of assets in that account?

A. That's the general concept. You have to understand what assets are in the account, and then coming up with the most appropriate life that would represent recovery of those assets.

Q. All right. And then on lines 3 and 4 at the top of page 30, you note that Duke Energy Progress began to use amortization accounting at the conclusion of the 2018 rate case for -- for two accounts that we're discussing here today: accounts 391, office furniture and equipment; and account 397, communication equipment; is that correct?

A. Those are two of the accounts that amortization accounting is being applied to. They happen to be the two that there was a disagreement on. All the others, amortization accounting was not being challenged. It was just the period of time for these two. The other ones were accepted as the same process. And then the use of amortization accounting was acceptable.

Q. All right. You kind of led to my next question. So on lines 8 and 9, you note that the Public Staff -- or you testified that the Public Staff has proposed different amortization periods for two accounts, the two we were just referring to, correct?

A. Yes. I emphasize that they're different than what I propose in this case for Duke Progress, and they're also -- you know, my estimates are the same as what have been utilized and accepted for Duke Carolinas. So that's why, you know, I thought it was important to be talking about these, because we're trying to be consistent between the two companies, given they're the same types of assets.

Q. And I appreciate the consistency reference there. But to be clear, your testimony recommends a change in the amortization period for these two accounts from what the Commission approved in its last Duke Energy Progress rate case?

A. In the last case, there was a settlement that the agreement was to use different estimates for these accounts. The overall implementation is the same as what was proposed in the last case, and that was what I was trying to clarify.

Q. Okay. And so it's not Public Staff witness McCullar who's recommending a change, but she is recommending that we keep the current approved amortization periods for those two accounts; is that correct?

A. She is requesting to maintain what was settled on in the last case. There was no discussion as to the nature of the accounts as to why we should develop different amortization periods than what's proposed here. And in the litigated case for Duke Carolina, we have the same amortization periods here that we have there.

So I think that's an important clarification to understand what's going on with the general plant amortization accounts between the two companies and particularly in this case.

Q. All right. And now turning to page 33 of your rebuttal testimony.

A. I'm there.

Q. On lines 12 and 13, you state that Ms. McCullar has excluded millions of dollars in investment from her calculations of depreciation expense for these accounts.

Are you indicating here that the original costs for the accounts in question used by Ms. McCullar differed from those you used in your depreciation calculations?

A. No. I think this is very important to understand the calculation, how it works, and the fact that Ms. McCullar, in her adjustments, from my schedules, has not applied the appropriate amortization period and its rate to those assets. And what I'm trying to explain is, we segregate assets -- and when I say "we," that's my study or Duke Progress -- segregate the assets by the amortization period.

So if you have a 10-year amortization period, assets that are older than 10 years are fully accrued and have a zero rate. However, if you're going to change the amortization period, like Ms. McCullar is recommending, and going to apply a 20-year amortization period, then you need to apply the rate that she has come up with to all of the dollars that are within that amortization period.

And that means 20 years of vintages. So she would have to apply her rate -- in the case for 391, the 5 percent rate -- to all of the vintages that are listed in the account for 391. She only applies her rate to the 10-year amortization assets that I had done. So because of that, she has excluded millions of dollars that need to be applied to depreciation or amortization expense based on her estimates, and that's what's being discussed here.

If you're going to use amortization and change the period, you have to apply it to the right vintage base, and that has not been done in Ms. McCullar's calculations.

MR. DODGE: Okay. Commissioner Clodfelter, I'd like to introduce Public Staff Potential Cross Exhibit 83 at this time, which is Duke Energy Progress' response to Public Staff Data Request 179-7.

COMMISSIONER CLODFELTER: All right. And how do you wish that to be marked in the record?

MR. DODGE: Thank you. I would ask that it be marked Public Staff Doss/Spanos/Riley Rebuttal Cross Exhibit Number 2 [sic].

COMMISSIONER CLODFELTER: All right. It will be so marked.

(Doss/Spanos/Riley Rebuttal Public Staff Cross Exhibit Number 2 was marked for identification.)

Q. All right. Mr. Spanos, are you familiar with this data response; have you reviewed this data response?

A. Yes, I have.

Q. And so in the first part of the question, part A, you -- the question asked if you were claiming that Ms. McCullar was not using the same investment amount shown in Mr. Spanos' calculations from the depreciation study that was included in your -- with your direct testimony. And you respond, again, I think as we just discussed, that no, she -- that is -- that's not what you were claiming. That it's not that there's a difference in those initial investment amounts; is that correct?

A. That is my response. And I explain pretty thoroughly in that response similar to what I just explained, that if you don't apply the amortization period to the proper vintages, you are excluding the depreciation expense that's being applied. And I go through quite a bit of discussion in my rebuttal testimony explaining the error that she made. And so she lists all of the dollars that are there, but she does not apply the rate for her amortization period to those dollars.

So as I discuss in the response, the fully accrued section, when you use a 10-year amortization period, which would then have a zero rate, is not appropriate if you use a 20-year amortization period, which is what she is using. So you have to apply her amortization rate to all of the investment, so that's the exclusion that she's done in her calculations.

Q. So just to be clear, it's -- you're indicating that it's not just based on the change in the amortization schedule and the segregation of those costs into amortization period as a result in this -- you referred to it, the exclusion of millions of dollars in investments, it's the application of a different rate to those different buckets, basically?

A. That is the concept. I think maybe it would be helpful if I could turn you to my study that properly show what I'm trying to explain. Because I want to make sure that it's very clear as to why I'm making this statement, because it's not something that should be just, you know, taken lightly as an exclusion issue versus an application concept. It applies to both.

So if I was to go to my study Roman numeral IX, page 185, you will see in that particular account there are two categories. One is called fully accrued, which is vintages 1999 to 2003; and one is amortized, which is 2004 to 2018. So, in my study, the vintages when you have a 15-year amortization period for account 391, you only apply a rate to the assets that are within that amortization period. So that would be vintages 2004 to 2018.

However, if you're going to apply a 20-year amortization period like Ms. McCullar has requested, then you must apply the 5 percent rate to all vintages, which is 1999 to 2018. So Ms. McCullar, in her calculation, has excluded the $10,200,000 worth of plant that should have an amortization period and rate assigned to it.

On top of that, what I've explained further in my discussion is, the assignment of the book reserve by vintage has to be redistributed as well as with the unrecovered reserve which she has also not correctly done, which then causes the second component to be left out. And that's why both of these areas, it's very important to understand the proper application of amortization accounting to the proper vintages and the assignment of the unrecovered reserve that we've assigned that is a separate calculation.

Both of those things are affected by the manner in which she has applied her calculation with a different amortization period. And that's why the reference to that in my response, she shows the dollars, but she doesn't apply the appropriate dollars and then doesn't make the proper adjustments to the accumulated depreciation level to present the overall expense that's necessary for full recovery and utilization of amortization accounting.

Q. All right. Thank you for that explanation. I think that goes a bit beyond where I was going with this question, but I think it is helpful information. Just wanted to emphasize again the recommendation that Ms. McCullar made in her testimony was to maintain the same amortization period for these accounts that was previously approved in the last DEP rate case.

Let's go on to one other topic here. This is -- we're going to touch base on the Atmos case.

Mr. Spanos, do you have Public Staff Potential Cross Exhibit 87 available?

A. I do, yes.

MR. DODGE: Commissioner Clodfelter, I'd like to introduce Public Staff Potential Cross Exhibit 87, which is the Kansas State Corporation Commission's February 4, 2020, order in the Atmos Energy rate case that we discussed in the DEP -- excuse me, in the DEC proceeding. I'd ask that that be marked as Public Staff Doss/Spanos/Riley Rebuttal Cross Exhibit Number 3.

COMMISSIONER CLODFELTER: Okay. We'll mark it as Spanos/Doss/Riley Public Staff Cross Examination Exhibit Number 3 [sic].

(Doss/Spanos/Riley Public Staff Cross Exhibit Number 3 was marked for identification.)

Q. So, Mr. Spanos, during the DEC proceeding, we talked about paragraphs 52 and 54 in this order. But at the end of that discussion, there was still some confusion, I think, about the positions of the parties and how much the Kansas State Commission's relied on the historic expense levels in that proceeding. So I just wanted -- I think at this point I'd like to turn to page -- excuse me, paragraph 53 in that order. Let me know when you're there.

MR. JEFFRIES: I'm sorry, what paragraph was that, Mr. Dodge?

MR. DODGE: Paragraph 53.

MR. JEFFRIES: Thank you.

THE WITNESS: Is that on page 20, I believe? Does that seem right to you?

Q. Let me see here. I believe that's correct. My electronic version, unfortunately, is --

A. Okay. Maybe I could ask, the paragraph starts "as the applicant"?

Q. Correct, yes.

A. Okay. All right. Thank you.

Q. About -- thank you. At about midway down through that paragraph, the order describes the position of the three parties in -- three of the parties in that case: Atmos, the Commission staff, and the Citizens Utility Review Board, or CURB, related to their reliance on statistical analysis and informed judgment and the question of net salvage here.

And it states that Atmos' witness Alice

(phonetic spelling) states that the net salvage percentages that they propose were based on a combination of statistical analysis and informed judgment; does it not? Do you see that statement?

A. I do see that, yes.

Q. All right. And then it says Commission staff witness McCullar, her testimony proposed future net salvage accrual amounts that considered Atmos' historic practices, the impact of inflation, built a reserve for reasonable estimated future net salvage removal -- excuse me, future net removal costs based on the type of investments in the account, and Ms. McCullar's previous experience; does it not?

A. That's what it says, yes.

Q. All right. And the CURB witness Garrin (phonetic spelling) was the only witness in that proceeding that made a recommendation based strictly on the most recent five-year average, which the Commission rejected; is that correct?

A. That is correct, yes.

Q. All right. And would you agree that, subject to check, Ms. McCullar in the Atmos proceeding on behalf of the Kansas Commission staff conducted a similar comparison of the historic ratios and net salvage comparison that she conducted in this proceeding?

A. There were similarities to that. I don't specifically know that she presented all of the different comparisons of current expense to future expense, which is the concepts that the uniform system of accounts applies. So I can't confirm that. I can tell you that, based on the words that are here, that is what she says; however, that methodology is counter to what all authoritative texts say to utilize for determining a net salvage percent.

So you need to be very clear that, when looking at the information, and particularly the last five years, which is what Ms. McCullar's doing in this case, that she makes sure that she understands how retirements are recorded and the cost of removal that's in place. And authoritative texts make it clear, and I think that's what is described by CURB's process, that you don't just utilize the most five years of historical information, you need to understand the entire cycle of net salvage and the age of the retirements.

And in this case, Ms. McCullar explains that she's focusing on the last five years. So I don't know that they are exactly the same between the Kansas case for Atmos and this case. I will say that the language that you read is what is on the information here. But I don't think that, on an account-by-account basis, you should be doing things differently. And the methodologies in this particular Commission, as well as many others, continually use the traditional method, which is what I use, and that is a combination of historical indications and informed judgment, meaning you have to understand the data to be able to utilize the statistical information properly.

Q. All right. And would you agree that, in this -- in the DEP proceeding -- and I'm going to read from Ms. McCullar's testimony, but if you want to turn there, I'm happy to refer you to the page and line numbers. This is page 24 -- bottom of page 24 and the top of page 25, following where she has completed the analysis of these future net salvage percentages.

A. I see that.

Q. And she again refers to the table as providing a reasonableness check, and then indicates that, similar to the Kansas Commission, her proposed future net salvage accrual amounts consider those historic practices, but also include the impact of inflation, federal reserve for estimated future, net removal costs associated with future retirements based on the type of those investments in the account, and her previous experience.

A. I see that. And again, I -- what was done here and is referenced on page 16 of her testimony is that she has selected a few accounts that randomly need to be treated differently and produces a net salvage percent from that, and does not -- it's all based on a five-year comparison and does not necessarily stay consistent from account to account. So that's kind of been the challenge.

So I don't know, in her discussion here, how she can justify following each of those steps when for three accounts she randomly changes an expense because she doesn't like the fact that the most recent five years incurred is different than what's accrued.

So that's kind of why, in the same issue with the Kansas case, I'm not sure how that fits in, because it's not exactly following those guidelines.

Q. Right. And now turning back to the Kansas case just briefly in the last question here.

Paragraph 54, the Commission -- you agree the Commission, in that paragraph, indicates that they accept the staff's position, finding that the net salvage analysis used by Ms. McCullar represented the best balance -- the best balance of the interest of Atmos' current versus future ratepayers?

A. It does. It also adds that they -- the findings is not based on adopting any particular methodology in this docket. So that's kind of the discussion within that paragraph. And again, the best balance between current and future ratepayers, this methodology will not necessarily get full recovery of the investment. So I'm not sure that I agree with that statement. Obviously, that was what was written in the docket, but that's not necessarily true.

Q. Thank you, Mr. Spanos, and Mr. Doss, and Mr. Riley. Mr. Grantmyre will pick up from here.

A. Thank you.

CROSS EXAMINATION BY MR. GRANTMYRE:

Q. This is Bill Grantmyre. All my questions are going to be for Mr. Doss. And I would first ask that we go to Public Staff Potential Cross Examination Exhibit 97, which is on page 3112. And it is the Progress Energy's E-1, Item 34-A.

Do you have that available, Mr. Doss?

A. (David L. Doss, Jr.) I do have that

available, yes.

Q. And you would agree that this is the E-1 --

MR. GRANTMYRE: Or I would ask that this be identified as Public Staff Doss/Spanos/Riley Rebuttal Cross Examination Exhibit 4 [sic].

COMMISSIONER CLODFELTER: It will be so marked. Mr. Grantmyre, I actually think the E-1 may be in the record already, but it's probably useful to go ahead and mark this separately just so it can be located readily and more quickly, so we'll mark it accordingly.

(Doss/Spanos/Riley Rebuttal Public Staff Cross Exhibit Number 4 was marked for identification.)

Q. Now, you agree that this is listed as an updated as of February 29, 2020, for the latest calendar year December 31, 2019; you see that near the top?

A. I do see that near the top, yes.

Q. And you see, after line 18, there's a line drawn through, and lines 1 through 18 are first mortgage bond taxable?

A. I do see that.

Q. And would you agree that adding up, or subject to check, all the first mortgage bonds listed here total $7.575 billion?

A. Subject to check, I would have to trust your math there. I haven't seen this schedule before.

Q. Now, would you accept, subject to check, that the long-term debt -- the total long-term debt, which is listed on line 34, after you exclude the leases, that that number is 8 billion 741- -- $8.741 billion?

A. Yeah. I don't have a calculator to check that, but subject to check, I trust your math there.

Q. And if we were to divide the $7.575 billion by the $8.741 billion, that that would be -- would you agree the math, subject to check, is 86.7 percent?

MR. MARZO: Mr. Chairman, I would just reiterate the objection that I made in DEC when a similar line of cross was used. This has nothing to do with Mr. Doss' testimony in this case, and maybe properly should have been asked to Ms. Smith in lieu of Mr. Doss, if we're just simply talking about revenue requirements and first mortgage bonds and debt rates.

COMMISSIONER CLODFELTER: Mr. Grantmyre, Mr. Doss is not the revenue requirements witness, so help me connect this up.

MR. GRANTMYRE: But he is the chief accountant. He is the director of property accounting for Duke, and this is just simple math that we're doing here. These are Duke numbers.

COMMISSIONER CLODFELTER: All right. Let's see where we're going with this. I'm going to allow the question to go forward.

Q. So you would agree that 86.7 percent is the proper number, subject to check?

A. I see that written on the bottom of this schedule. I do a lot of math, but I'm not that fast at math, so subject to check.

Q. But you realize these cross examination exhibits were filed and provided to your company back on September 8th; are you aware of that?

A. I am not aware of that. You said provided to our company?

Q. Yes, to your attorneys.

A. Yeah.

MR. MARZO: Commissioner Clodfelter, I'm going to object to that, because once again, the exhibits are not labeled by witness, and had we known that the intent would have been to use this particular exhibit with a witness whose testimony has nothing to do with the exhibit, Mr. Grantmyre may have received a call about the exhibit, itself, and not just the math.

COMMISSIONER CLODFELTER: Mr. Grantmyre?

MR. GRANTMYRE: Okay. I have not received a call on any exhibit. So, you know, this is just simple math. He is an accountant. And, unfortunately, I didn't read every bit of testimony Duke filed in this case, but this is -- he is an accountant, and it's just simple math. And I feel that it's proper for me to cross examine him for simple math.

COMMISSIONER CLODFELTER: Mr. Grantmyre, I'm going to allow you to continue, but I would also remind you that the Commission and Commission staff can do simple math from documents as well. We are also capable of doing simple math, so let's try to see what Mr. Doss might know that's particular to Mr. Doss' position and his expertise. I will allow you to continue, but I'm going to encourage you not to just do simple math.

MR. GRANTMYRE: Okay. I would ask that this next exhibit be identified as Public Staff -- this is Public Staff 98, and it's on page 3113.

And it shows -- we ask it be identified as Public Staff Doss/Spanos/Riley Rebuttal Cross Exam Exhibit 5 [sic].

COMMISSIONER CLODFELTER: Okay. It will be so marked.

(Doss/Spanos/Riley Rebuttal Public Staff Cross Exhibit Number 5 was marked for identification.)

Q. And you see on line 24, for the last three years, and it's highlighted, at least on my copy, those are the new debt that Duke plans to issue on those years?

A. Mr. Grantmyre, are you talking about line 14?

Q. I'm sorry. Line 14, yes; you're correct.

A. I do. On my copy it's highlighted. I see some amounts for long-term debt highlighted on this schedule. This is another schedule, unfortunately, I'm not familiar with.

Q. And move on to the next, and you see it's listed $900 million for 2021, 2022 is $950 million, and 2023 is $700 million?

A. I see those numbers.

Q. And this next exhibit is Public Staff number 99, and it's on page 3114, and it's a response to Data

Request 166, Item 4; do you have that available?

A. I do have that available.

MR. GRANTMYRE: And we ask that this be identified as Public Staff Doss/Spanos/Riley Rebuttal Cross Examination Exhibit Number 6 [sic].

COMMISSIONER CLODFELTER: It will be so marked. But let me just say, Madam Court Reporter, I think our naming convention we've agreed is to put the panel or witness name first, the examining party second, and whether it's direct cross and so forth. So I understand, Mr. Grantmyre, and we will mark it accordingly as number 6 according to the naming convention.

MR. GRANTMYRE: Okay.

(Doss/Spanos/Riley Rebuttal Public Staff Cross Exhibit Number 6 was marked for identification.)

Q. You see the response. Could you read the first sentence of the response into the record, please.

A. The first sentence of the response says:

"In a relatively normal or typical period in the bond market, an A2 (issuer rating) /Aa3 (senior secured rating) utilities similar to DE Progress would be expected to price up to 10 basis points wider as an

A3 (issuer rating) /A1 (senior secured rating) utility."

MR. MARZO: I'm just going to renew the objection, Commissioner Clodfelter. Clearly, there are witnesses even following Mr. Doss, for example, Mr. Fetter, who questions like this could get asked to, or Ms. Smith.

COMMISSIONER CLODFELTER: So I'm going to let Mr. Grantmyre continue with this. If you want to clean up with direct -- supplemental direct examination of additional witnesses to clarify these points, you have that opportunity, you'll be allowed to do so. Mr. Doss is the accounting officer for the Company, and I think Mr. Grantmyre here is pursuing a line of questioning relative to the finances of the Company. I'm going to give him some latitude provided he's not just reading things.

MR. GRANTMYRE: Excuse me, I didn't hear you Commissioner.

MR. MARZO: Thank you. Commissioner Clodfelter.

COMMISSIONER CLODFELTER: I said provided you're not doing anything other than just reading things off of paper.

MR. GRANTMYRE: Okay. And I would ask this Public Staff Cross Examination Exhibit 100, which is page 3116, and it's -- I would ask that this be identified as Public Staff Doss/Spanos/Riley Cross Examination Exhibit Number 7 [sic], or whatever Commissioner Clodfelter corrects me to is fine with me.

Q. Do you have that in front of you?

A. I do have that in front of me, yes.

COMMISSIONER CLODFELTER: -- Spanos/Doss/Riley Public Staff Cross Examination Exhibit 7 [sic].

(Doss/Spanos/Riley Rebuttal Public Staff Cross Exhibit Number 7 was marked for identification.)

Q. Now, on page 2, it lists certain factors that were used in these calculations; do you see that in the middle of the page?

A. I do see that.

Q. And for the equity line, it's 52 percent?

A. I see the 52 percent.

Q. And the ROE or cost rate for equity is 9.6 percent?

A. I see that.

Q. And the long-term debt rate is 4.04 percent?

A. I see that as well.

Q. And will you accept, subject to check, that those are numbers that were used in the stipulation between the Public Staff and the Company?

A. Again, it would have to be subject to check. I'm -- as the director of asset accounting, this is not something that I would typically deal with, so I'd have to accept that subject to check.

Q. Now, you saw a similar cross examination exhibit for you in the Duke Carolinas case, correct?

A. That's correct.

Q. So you're familiar with the calculations here, even though it's -- these are specific to Duke Energy Carolinas, rather than -- I'm sorry, Duke Energy Progress, rather than Duke Energy Carolinas?

A. Well, I don't know how familiar I was -- I remember, in the previous case for Duke Energy Carolinas, I was able to follow the numbers on the schedule, and so far I'm able to follow these numbers on this schedule.

Q. And you would agree that it's entitled "ARO-related coal ash revenue requirements, Company vs.

Public Staff"?

A. Yes, that's the title on the top; yes, it is.

Q. And below that, it says, "Summary for DEP includes differences due to imprudence, disallowances, and equitable sharing"; do you see that?

A. I'm sorry, Mr. Grantmyre, could you point me to where that is.

Q. It's right below the title. It's right above where it says estimated balances 831. It's that quote -- it's that --

A. I'm sorry, I'm still on page 2. Are you on page --

Q. I'm sorry. On page 1. I'm on page 1.

A. Okay. I -- I think I'm with you now.

Q. But you agree it says, "Summary for DEP includes differences due to imprudence, disallowances, and equitable sharing"; do you agree that?

A. I agree that's what it says.

Q. And do you agree that the first column is what the Public Staff revenue requirement would be on an annual basis without any return on rate base?

A. That column is labeled Public Staff-recommended revenue requirement.

Q. And the second one is what the Public Staff has calculated as the Company's position earning a return in amortization over five years?

MR. MARZO: Commissioner Clodfelter, I would just renew the objection. We're back to reading an exhibit that the witness is not familiar with and can only confirm that the exhibit says what it says. If we need to simply stipulate that the exhibit says what it says, I think we could say it says what it says without having to go through this process with Mr. Doss, who is not familiar with it.

COMMISSIONER CLODFELTER: Mr. Grantmyre, the witness did not prepare this exhibit, is not familiar with this exhibit. If your goal is to get the exhibit into evidence and have it show what it shows, then I think we can do that by having a witness who prepared the document authenticate it and then move it into the record. Or perhaps -- I even heard Mr. Marzo possibly even agreeing to stipulate the admissibility into the record.

MR. GRANTMYRE: Well, I would be glad to stipulate the admissibility of this exhibit and the next exhibit, Public Staff Potential 101, which, again, is simple math using these numbers and the numbers we previously went over. I don't want to, you know, go through every number. The Commission staff could run these numbers and verify it. I do point out these exhibits were given to the Company 24 days ago on September 8th. And if they chose not to give it to this witness, because it's similar to what I asked him in Duke Carolinas, that's up to the Company. All I want to do is get in evidence these numbers.

MR. MARZO: Commissioner Clodfelter, I think you just raised exactly the issue that I have. I do think Mr. Maness is -- this is not a Duke Energy Progress document. Mr. Maness should be authenticating this document. We should be allowed to cross examine Mr. Maness on this document. The fact that Public Staff chose not to use their own witness to facilitate the entry of this document, I would not stipulate to this document.

I will stipulate to Duke Energy Progress' produced documents, if that's what we're talking about. But to the extent that Mr. Grantmyre is trying to use a Duke witness who is not familiar with this document to authenticate -- otherwise authenticate a document that should have been entered by his own witness, I do object.

COMMISSIONER CLODFELTER: Mr. Grantmyre?

MR. GRANTMYRE: Well, first of all, Duke easily could have had this witness become familiar with the document. He's the director of accounting, property accounting, and he has lots of accountants working for him. And the fact Duke has chosen not to let this witness be familiar with it so they could try to exclude it.

Now, if the parties would agree, we could have Mr. Maness called back tomorrow for supplemental testimony and have him authenticate these.

COMMISSIONER CLODFELTER: Mr. Marzo, again, this is not a productive exercise we're going through right now. I'm going to -- if the Public Staff's only purpose is to authenticate the document and move it into the record so that it may be considered for whatever it shows, simple math that it may be, I think that's appropriate and proper. I do think that it properly should have been done as Public Staff's case; however, I am going to give Mr. Grantmyre the opportunity to get this into the record one way or the other.

So if he wants to move it into the record, I'm going to give him an opportunity to do that. So I would ask you to -- Mr. Grantmyre, let's move on to something else right now, and I'm going to ask Mr. Marzo to consider overnight one of two options. Either just stipulating the admission of the document into the record of the case; or if not, then at an appropriate time without disrupting the flow, I'm going to allow the Public Staff to reopen their case just for the sole and limited purpose of moving the documents into the record.

MR. GRANTMYRE: I would ask that Public Staff Potential Cross Examination Exhibit 101 be identified as Public Staff Spanos -- Public Staff Doss/Spanos/Riley Rebuttal Cross Examination Exhibit 8 [sic] so that at least it can be identified. That is the last -- that is my last exhibit.

COMMISSIONER CLODFELTER: All right. It will be so marked and so identified.

(Doss/Spanos/Riley Rebuttal Public Staff Cross Exhibit Number 8 was marked for identification.)

COMMISSIONER CLODFELTER: So I think the -- now why don't we just have it apply to Exhibit 6, 7, and 8.

MR. MARZO: Thank you, Commissioner Clodfelter. And let me confer with my client, and I can give you an answer in the morning.

COMMISSIONER CLODFELTER: I respect that. And as I say, I'm not going to do this in a way that disrupts your rebuttal case, but if necessary, we will provide a proper vehicle for getting this into the record.

MR. MARZO: Thank you, Commissioner Clodfelter.

COMMISSIONER CLODFELTER: Yes indeed.

All right, Mr. Grantmyre?

Q. Yes, Mr. Doss. Now we will go to your testimony. I have several questions. I turn you to page 3.

A. Yes, Mr. Grantmyre, I'm on page 3.

Q. And you talk about -- you're basically rebutting Mr. Maness' testimony; is that correct? Towards the bottom of the page. And you're saying he was wrong to call it a deferred expense, these ARO ash basin removal costs?

A. Yes. I -- well, two things I disagreed with. Number one, the classification or his characterization of this as a deferred expense where clearly the accounting rules as laid out in my testimony, as laid out in the testimony of witness Riley as well, that these costs are part of the -- they're integral to the plant that gave rise to the costs. They're capitalized when we record our asset retirement obligation. It's clear in both GAAP, General Accepted Accounting Principles, and the Federal Energy Regulatory Commission rules that, when we have established that asset retirement obligation, the offset to that is proper plant and equipment where we capitalize that cost as an integral part of the plant that gave rise to that retirement obligation.

Q. But you realize that, in the Dominion Energy case order February 24, 2020, the Commission ruled that they were deferred operating expenses; do you -- have you read that order?

A. I scanned that order. You know, as an employee of Duke Energy, I'm not that familiar with Dominion. I do know that in the previous Duke Energy

Progress and Duke Energy Carolinas cases, that's not what was found for our companies. The Commission agreed with our position that these are not deferred expenses, and was very clear in its orders in that regard.

Q. Now, with regard -- moving on to -- so basically, Mr. Maness' position that they're deferred operating expenses is the same as the Commission's February 24, 2020, Dominion order, as far as deferred operating expenses?

A. I would have to -- I would have to go read that order. Again, I'm not that familiar with it.

Q. Now, on the top of page 4, he -- you quote Mr. Maness where he says:

"If it was not for the approval of the deferral expenses, these expenses would have been written off already."

Do you agree with that? Do you agree that they would have been written off had they not been deferred?

A. Well, let's step back for a minute, as far as being immediately written off. What we have to do in the accounts of a regulated utility, we have to make an assessment for costs. We have to determine if there should be recognized an expense as an expense in the current period, or if they should be deferred to a future period to be matched with future revenues. So in that -- in making that determination, there's an assessment that we have to make. So what we look at is we look for some evidence, and we look for -- the best evidence that we can get, obviously, is a rate order from the Commission allowing deferral of the cost. Maybe the next best thing that you can look for is a deferral order from the Commission allowing deferral of the cost and just come back later to seek recovery of the cost.

You can look at any number of the things for evidence around whether you should put these costs into a regulatory asset as opposed to expensing them. So that would be things like what is -- what is past precedent within that state of jurisdiction. So what the Commission has followed in the past; what have they done for other utilities; what's happening around the industry. All sorts of other forms of evidence that you would look at, and you have to make an assessment as to whether it would be expensed or not, regardless of whether you have a Commission directive or a Commission order in hand.

There's lots of times when we do not necessarily have a Commission directive, whether it's a deferral order or a rate order, where we are required by GAAP rules and by FERC rules to make an assessment about the probability of recovery. Meaning the probability that that cost will be matched with a future revenue.

That's what we do all the time. A common example would be storm costs, storm expenses. There may be a hurricane, a large storm, a lot of expenses. We don't necessarily have all the costs accumulated yet, we don't necessarily have time to go seek a deferral order, but we look at the history within that jurisdiction and what that Commission has done in the past and make an assessment of whether we think that's probable of recovery.

So what I would say here is that it may be a common thought that, absent a deferral request, amounts are immediately written off. That's a pretty common thought, but there's a lot of nuances to it. And it really boils down to what is the evidence that the accountants have to look at to determine whether it's probable that cost would be deferred to a future period to the matched revenues in a future period.

Q. But won't you agree that normally the cost of excavating coal ash out of a basin and hauling it away by truck or train is normally an operating expense?

A. No. No, absolutely not. If it's done in connection with an asset retirement obligation, which is a legal obligation as we put upon the Company to associate it with the retirement of an asset, it's very clear, from an accounting perspective, that's not an expense. That's an amount that's capitalized as part of the plant that gave rise to that obligation, and that's the entry that we make to property plant and equipment. That's the offset. It's an equal and offset -- equal offsetting amount to the amount that you record as the obligation. So it's very clear from the accounting rules that GAAP and FERC both view that as a capitalized cost.

Q. But you understand that this Commission is not bound by the accounting rules, they set based on the North Carolina General Statutes and Supreme Court decisions; do you understand that?

A. Well, you're getting into a legal area there that I'm not an expert on.

Q. Okay. Now, I would ask you to go to page 9 of your testimony.

And line 12, you talk about Deloitte & Touche, and that is your outside auditors, your independent auditors; is that correct?

A. That's correct.

Q. Can you read that sentence beginning with "Deloitte & Touche" on page -- on line 12 and ends on the middle of line 15?

A. Yes.

"Deloitte & Touche also performs a review of the FERC Form 1 and issues its opinion that the regulatory basis financial statements are presented fairly in all material respects in conformity with the FERC Uniform System of Acts."

Q. Now, when they issue this regulatory basis financial statements, don't they look at that you have made entries on your books to conform to whatever the North Carolina Utility Commission has ordered?

A. Well, yes. They would look at the books from all aspects, and they would make sure that we had accounted properly for the effects of regulation on our business.

Q. And I direct you to page 14 of your testimony, at the bottom, line 15.

A. All right. I'm there.

Q. Could you read that from there to the bottom of the page into the record, beginning with "in addition"?

A. "In addition, as a regulated utility, DE Progress must comply with FASB ASC 980 regulated operations which requires cost-base, rate-regulated enterprise, such as DE Progress, to reflect the impacts of decisions of its regulators in their financial statements."

Continue?

Q. Yes. One more sentence.

A. "Pursuant to this requirement and as noted earlier in my testimony, DE Progress has reflected in its financial statements the impacts of the Commission's directives regarding the deferral of coal ash ARO-related costs."

Q. Now, after the last rate case, you reflected on your books or on your records the Commission's decision in 1142 for Progress Energy; is that correct?

A. We would account for that, yes. Any of the Commission orders are accounted for in our books and records.

Q. And in it you had the five-year amortization, and you recorded that they'd be getting a return; isn't that what you recorded?

A. Yes. In accordance with the Commission's orders in that case, we were allowed a return on those costs.

Q. So in this case, should the Commission adopt the Public Staff's position and amortize the costs over 25 years with no return, that would -- could easily be entered into your books just like the other case was, wouldn't it?

A. Well, as -- it could be entered into our books. Obviously, it could also have a very significant adverse impact on our books. So that's something that we would need to consider. That's something that Sean Riley spoke to in the last -- in the DEC portion of this case, the adverse impacts that potentially could affect the Company if that were to happen.

Q. Okay. But adverse impact, that's -- the Company makes that decision, whether or not it's adverse impacts and a further adjustment has to be made; isn't it true?

A. The Company has to make an assessment of the impacts of the Commission's orders.

Q. And if the independent auditors disagreed with the Company, then they would have discussions; isn't that how audits normally work?

A. Well, I'm not sure how that relates to this question here. Maybe you could expand on that.

Q. Well, you brought up the fact the adverse impacts. All I was asking in the question, isn't -- would it be simple to enter into the -- your books that you're not earning a return, and then you could deal with the materiality? But entering that on your books is pretty simple, isn't it?

A. Well, so as I understand it, the Public Staff has recommended an amortization period of some 25 years or more. I don't know exactly what it is. If the Commission were to approve that, what would happen is that the Company would have to assess what impact that potentially could have on our books and record any entries as appropriate if we determine that we need to record some impacts associated with that.

Q. Okay. Now, you will agree, there was testimony last time you testified. You testified a number of times that the Commission ordered you to defer in the orders in -- for Duke, the early order in 2003 and 2015.

Wouldn't it be more appropriate to say that the Company applied for a deferral and the Commission approved it?

A. In 2003?

Q. Yes. In the E-2, Sub 826 order, and the E-2, Sub 103 order.

Did the Commission merely approve the deferral request?

A. Yeah. In the case of the 2003 order that you're speaking to, that was in connection with the issuance of FAS 143 around ARO accounting. And across the industry, that created some significant impacts to the financial statements of regulated utilities, including Duke Energy Progress and Duke Energy Carolinas, that needed to be addressed. So Duke Energy Progress, Duke Energy Carolinas both, along with other utilities around the industry -- and this was brought up with FERC -- it was obviously a very big deal in 2003 to have these significant impacts. For the companies to, you know, make sure that they didn't have these significant impacts adversely impact them, we needed to seek some sort of order allowing us to defer those impacts.

Q. But you did request the deferral, correct?

A. Well, we did have to request the deferral.

When you have significant impacts like that that could be potentially billions of dollars -- you know, in that case it was nuclear decommissioning costs. I mean, billions of dollars like that, the Company, and really every utility that I'm aware of at that point in time, needed to request some sort of deferral treatment.

And, you know, whether you want to call that a choice, I don't know that that's a practical choice. A Company is not going to stay in business for too long and not going to be very popular with its debt and equity investors if we don't seek to approve -- or seek a recovery of costs incurred associated with regulations like that.

Q. And we could agree that the Commission orders say what they say as to whether or not they approve the deferral, or they ordered you to make a deferral; could you agree to that, that the Commission orders speak for themselves?

A. Well, the -- from the 2003 order, the Commission granted approval to defer the impacts of the FAS 143, which is ARO accounting. So I can agree that that is what the Commission granted in that order.

MR. GRANTMYRE: I have no further questions.

COMMISSIONER CLODFELTER: All right. Thank you, Mr. Grantmyre. And we may come back on the issue that you and Mr. Marzo were talking about, but we'll deal with that in the morning.

Ms. Force, I have you down for cross examination. Let me ask you this question. How much do you think you have? Because we started late after the break, and I might prevail upon Joann to maybe go an additional 10 minutes if you thought you could finish it up; if not, we'll break and start you in the morning.

MS. FORCE: I'm sorry, I don't think I can. I have a few more questions now.

COMMISSIONER CLODFELTER: All right. I tell you what, rather than break your testimony, we'll stop for the day here, and we'll pick up again tomorrow at 10 a.m. Remember, we're starting tomorrow at 10 a.m., and we're anticipating we will conclude the day by approximately 3 p.m. or so.

Mr. Robinson, I see you coming back; do you have something for me?

MR. ROBINSON: Sure. Commissioner Clodfelter, obviously at your discretion, just wanted to indicate we were only requesting for 10:00 if Steven Fetter or Marcia were on the stand at the time. Since they're not on the stand and won't be for a while, we don't need to start at 10:00. But it's up to your discretion what you want to do.

COMMISSIONER CLODFELTER: Well, that's a very helpful clarification, and thank you for reminding me of it, because I obviously wasn't clear enough about it. So, Mr. McCoy, can you hear me?

MR. McCOY: Yes, Commissioner.

COMMISSIONER CLODFELTER: You haven't revoked and set up new invitations for 10 a.m., have you, the existing --

MR. McCOY: I was about to, but no, I haven't done it yet.

COMMISSIONER CLODFELTER: Okay. So the existing invitations to everyone for 9 a.m. are still good?

MR. McCOY: Yes, sir.

COMMISSIONER CLODFELTER: Okay. Then with that said, I will modify, and we will recess for the day, and we will resume again tomorrow at 9 a.m. At 9 a.m. Usual time. Thank you all, and thank you, Mr. Robinson, for the intervention. I appreciate it.

MR. ROBINSON: Thank you, sir.

COMMISSIONER CLODFELTER: Okay. Please turn off your video and mute your mics.

(The hearing was adjourned at 4:28 p.m. and set to reconvene at 9:00 a.m. on Friday, October 2, 2020.)

CERTIFICATE OF REPORTER

STATE OF NORTH CAROLINA)
COUNTY OF WAKE)

I, Joann Bunze, RPR, the officer before whom the foregoing hearing was taken, do hereby certify that the witnesses whose testimony appear in the foregoing hearing were duly affirmed; that the testimony of said witnesses were taken by me to the best of my ability and thereafter reduced to typewriting under my direction; that I am neither counsel for, related to, nor employed by any of the parties to the action in which this hearing was taken, and further that I am not a relative or employee of any attorney or counsel employed by the parties thereto, nor financially or otherwise interested in the outcome of the action.

This the 9th day of October, 2020.

JOANN BUNZE, RPR
Notary Public #200707300112