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December 4, 2020

Ms. Kimberly A. Campbell
Chief Clerk
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, North Carolina 27699-4300

**RE: Joint Proposed Order of Duke Energy Progress, LLC and the Public Staff**
**Docket No. E-2, Sub 1219, Docket No. E-2, Sub 1193**

Dear Ms. Campbell:

Enclosed for filing in the above-referenced dockets is the Joint Proposed Order of Duke Energy Progress, LLC (DEP) and the Public Staff (filed on behalf of both DEP and the Public Staff). The Joint Proposed Order does not contain Evidence and Conclusions for Findings of Fact regarding the Unresolved Issues in the Public Staff Partial Stipulations and certain terms of DEP's stipulations with other parties to this proceeding, and other contested issues with the parties, as DEP and the Public Staff have separate arguments as to these issues. Both DEP and the Public Staff will separately file inserts to the Proposed Order that reflect their individual positions.

If you have any questions, please let me know.

Sincerely,

*<u>/s/ Camal O. Robinson</u>*

Camal O. Robinson

Enclosure

cc: Parties of Record

**STATE OF NORTH CAROLINA**
**UTILITIES COMMISSION**
**RALEIGH**

DOCKET NO. E-2, SUB 1219
DOCKET NO. E-2, SUB 1193

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

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| DOCKET NO. E-2, SUB 1219<br><br>In the Matter of<br>Application of Duke Energy Progress, LLC for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina<br><br>DOCKET NO. E-2, SUB 1193<br><br>In the Matter of<br>Petition of Duke Energy Progress, LLC for an Accounting Order to Defer Incremental Storm Damage Expenses Incurred as a Result of Hurricanes Florence and Michael and Winter Storm Diego | JOINT PROPOSED ORDER OF DUKE ENERGY PROGRESS, LLC AND THE PUBLIC STAFF |

HEARD: Thursday, February 27, 2020, at 7:00 p.m., in the Jury Assembly Room, 3rd Floor, Richmond County Judicial Center, 105 West Franklin Street, Rockingham, North Carolina

Monday, March 2, 2020, at 7:00 p.m., in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

Tuesday, March 3, 2020, at 7:00 p.m., in the New Hanover County Courthouse, Courtroom 317, 316 Princess Street, Wilmington, North Carolina

Wednesday, March 4, 2020, at 7:00 p.m., in Greene County Courthouse, 301 North Greene Street, Snow Hill, North Carolina

Thursday, March 12, 2020, at 7:00 p.m., in Courtroom 1A, Buncombe County Courthouse, 60 Court Plaza, Asheville, North Carolina

Monday, August 24, 2020, at 2:00 p.m., held via Videoconference and re-convened on Tuesday, September 29, 2020 at 9:00 a.m., via Videoconference

BEFORE: Commissioner Daniel G. Clodfelter, Presiding; Chair, Charlotte A. Mitchell; and Commissioners ToNola D. Brown-Bland; Lyons Gray; Kimberly W. Duffley; Jeffrey A. Hughes, and Floyd B. McKissick, Jr.

APPEARANCES:

For Duke Energy Progress, LLC (DEP or the Company):

Brian Heslin and Camal O. Robinson, Duke Energy Corporation, 550 South Tryon Street, Charlotte, North Carolina 28202

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

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

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

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

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

For the Carolina Industrial Group for Fair Utility Rates II (CIGFUR):

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

For Carolina Utility Customers Association, Inc. (CUCA):

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

For the Commercial Group:

Alan R. Jenkins, Jenkins at Law, LLC, 2950 Yellowtail Avenue, Marathon, Florida 33050

Brian O. Beverly, Young Moore and Henderson, P.A., Post Office Box 31627, Raleigh, North Carolina 27622

For the Fayetteville Public Works Commission (FPWC):

James P. West, Fayetteville PWC, P.O. Box 1089, Fayetteville, North Carolina 28302-1089

For Harris Teeter LLC (Harris Teeter):

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

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

For Hornwood Inc. (Hornwood):

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

For North Carolina Waste Awareness and Reduction Network (NC WARN):

Matthew D. Quinn, Lewis & Roberts, PLLC, 3700 Glenwood Avenue, Suite 410, Raleigh, North Carolina 27602

For North Carolina Sustainable Energy Association (NCSEA):

Peter H. Ledford and Ben W. Smith, North Carolina Sustainable Energy Association, 4800 Six Forks Road, Suite 300, Raleigh, North Carolina 27609

For North Carolina Clean Energy Business Alliance (NCCEBA):

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

For the North Carolina Justice Center (NCJC), North Carolina Housing Coalition (NC Housing Coalition), Natural Resources Defense Council (NRDC), and Southern Alliance for Clean Energy (SACE) (collectively, NCJC, et al.):

> Gudrun Thompson, David Neal, and Tirrill Moore, Southern Environmental Law Center, 601 West Rosemary Street, Suite 220, Chapel Hill, North Carolina 27516

For North Carolina League of Municipalities (NCLM):

> Deborah K. Ross, Fox Rothschild LLP, 434 Fayetteville Street, Suite 2800, Raleigh, North Carolina 27601

For the Sierra Club:

> Bridget M. Lee, Sierra Club, 9 Pine Street, Suite D, New York, New York 10005

> Catherine Cralle Jones, Law Office of F. Bryan Brice, Jr., 127 W. Hargett Street, Suite 600, Raleigh, North Carolina 27601

For Vote Solar:

> Thadeus B. Culley, Vote Solar, 1911 Ephesus Church Road Chapel Hill, North Carolina 27517

For the United States Department of Defense and All Other Federal Executive Agencies (Dept. of Defense):

> Emily W. Medlyn, U.S. Army Legal Services Agency, ELD Division, Suite 4300, 9275 Gunston Road, Fort Belvoir, Virginia 22060

> Paul A. Raaf, Office of the Forscom SJA, 4700 Knox Street, Fort Bragg, North Carolina 28310

For the Using and Consuming Public:

> Teresa L. Townsend, Special Deputy Attorney General and Margaret A. Force, Assistant Attorney General, North Carolina Department of Justice, Post Office Box 629, Raleigh, North Carolina 27602

> Dianna W. Downey, Chief Counsel, Elizabeth D. Culpepper, Staff Attorney, Layla Cummings, Staff Attorney, Tim R. Dodge, Staff Attorney, Lucy E. Edmondson, Staff Attorney, William E. Grantmyre, Staff Attorney, Gina C. Holt, Staff Attorney, Megan Jost, Staff Attorney, John D. Little, Staff Attorney, and Nadia L. Luhr, Staff Attorney, Public Staff-North Carolina

Utilities Commission (Public Staff), 4326 Mail Service Center, Raleigh, North Carolina 27699-4300

BY THE COMMISSION: On September 30, 2019, pursuant to Commission Rule R1-17(a), DEP filed notice of its intent to file a general rate case application. On October 30, 2019, the Company filed its Application to Adjust Retail Rates and Request for an Accounting Order (the Application), along with a Rate Case Information Report Commission Form E-1 (Form E-1), and the Direct Testimony and exhibits of Stephen G. De May, North Carolina President, DEP, Duke Energy Carolinas, LLC (DEC) and Progress Energy, Inc.; Shana W. Angers, Accounting Manager for Duke Energy Progress, Duke Energy Business Services, LLC (DEBS);[1] Jessica L. Bednarcik, Vice President, Coal Combustion Products Operations, Maintenance and Governance, DEBS; Janice Hager, President, Janice Hager Consulting; Kelvin Henderson, Senior Vice President of Nuclear Operations, Duke Energy Corporation (Duke Energy);[2] James P. Henning, Senior Vice President of Customer Service, Duke Energy; Robert B. Hevert, Partner, ScottMadden, Inc.; Rufus S. Jackson, Vice President for Carolina East Operations, Duke Energy; Kimberly D. McGee, Rates & Regulatory Strategy Manager, DEC and DEP; Karl W. Newlin, Senior Vice President, Corporate Development and Treasurer, DEBS; Jay W. Oliver, General Manager, Grid Solutions Engineering and Technology, DEBS; John Panizza, Director, Tax Operations, DEBS; Michael J. Pirro, Director, Southeast Pricing & Regulatory Solutions, DEC, DEP and Duke Energy Florida, LLC; Donald L. Schneider, Jr., General Manager, Advanced Metering Infrastructure (AMI) Program Management, DEBS; Kim H. Smith, Director of Rates & Regulatory Planning, DEC; John J. Spanos, President, Gannett Fleming Valuation and Rate Consultants, LLC; and Julie K. Turner, Vice President of Carolinas Natural Gas Generation, DEP and DEC.

On November 18, 2019, the Company filed its Notice of Corrected Filing regarding the exhibits of witness Bednarcik. On November 19, 2019, the Company filed a supplemental filing for E-1 Item 23. On November 22, 2019, the Company filed corrections to the testimony and Exhibit RBH-7 of witness Hevert, corrections to Exhibit 2 of witness Pirro, and corrections to E-1 Item 42. On December 16, 2019, the Company filed a Notice of Corrected Filing revising Exhibits 8 and 11 to witness Bednarcik's Direct Testimony. On December 20, 2019, the Company filed a Motion for Leave to File Direct Testimony of Larry E. Hatcher Adopting the Direct Testimony of James P. Henning. On December 23, 2019, the Commission issued its Order Accepting Prefiled Direct Testimony of Larry E. Hatcher. On February 14, 2020, the Company filed DEP Revised-Enlarged Oliver Exhibit 7. On March 4, 2020, DEP filed Corrections to Exhibit 4 of Michael J. Pirro. On March 13, 2020, DEP filed its Supplemental Response to E-1 Item 14.

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[1] DEBS provides various administrative and other services to DEP and other affiliated companies of Duke Energy. (Tr. vol. 11, 105.)

[2] DEP is a wholly owned subsidiary of Duke Energy Corporation. (Tr. vol. 11, 191.)

Petitions to intervene were filed by NCSEA on October 3, 2019; Vote Solar on October 22, 2019; CUCA on October 24, 2019; CIGFUR on October 28, 2019; FPWC on November 4, 2019; NC WARN on November 6, 2019; Sierra Club on November 18, 2019; the Commercial Group on November 22, 2019; Hornwood on December 10, 2019; Harris Teeter on January 3, 2020; NCCEBA on January 8, 2020; NCJC et al. on January 10, 2020; NCLM on January 15, 2020; and the Dept. of Defense on March 4, 2020. Notice of intervention was filed by the Attorney General (AG) on October 30, 2019.

The Commission entered orders granting the petitions of NCSEA on October 4, 2019; Vote Solar, CIGFUR and CUCA on October 30, 2019; FPWC on November 5, 2019; NC WARN on November 7, 2019; Sierra Club on November 19, 2019; the Commercial Group on November 24, 2019; Hornwood Inc. and Harris Teeter on January 6, 2020; NCJC et al. and NCCEBA on January 15, 2020; NCLM on January 16, 2020; and the Dept. of Defense on March 5, 2020. The AG's intervention is recognized pursuant to N.C. Gen. Stat. § 62-20. The Public Staff's intervention is recognized pursuant to N.C.G.S. § 62-15(d) and Commission Rule R1-19.

On October 30, 2019, DEP filed its Objections to the Public Staff Data Requests Numbers, 2, 3, 4, 5 and 6. On October 31, 2019, the Public Staff and AG filed a Joint Motion to Compel. On November 1, 2019, DEP filed its Opposition to the Public Staff's and Attorney General's Office's Motion to Compel Discovery. On December 20, 2019, the Commission issued its Order on Joint Motion to Compel by the Public Staff and the Attorney General's Office. On April 30, 2020, DEP filed its Motion to Compel Response to Second Data Request to CUCA. CUCA filed its Reply to Motion to Compel on May 5, 2020, and the Company filed its Reply in Support of Motion to Compel on May 6, 2020. On May 12, 2020, the Commission issued its Order Granting in Part and Denying in Part Motion to Compel by Duke Energy Progress, LLC and on May 19, 2020, CUCA filed its response in compliance with the order.

On November 14, 2019, the Commission issued its Order Establishing General Rate Case and Suspending Rates. On December 6, 2019, the Commission issued its Order Scheduling Investigation and Hearings, Establishing Intervention and Testimony Due Dates and Discovery Guidelines, and Requiring Public Notice. On December 19, 2019, the Commission issued its Order Rescheduling Public Witness Hearing, Revising Public Notice and Revising Requirement for Mailing Public Notice.

On December 5, 2019, the Company filed a letter notifying the Commission that it was removing certain costs related to CertainTEED gypsum payment obligations from its Application as a result of the Commission's order in Docket No. E-2, Sub 1204.

On January 23, 2020, the Commission issued an Order Directing the Public Staff to File Testimony concerning certain topics related to affordability and coal ash cost recovery.

On February 24, 2020, the Commission issued an Order Rescheduling Public Witness Hearing in Asheville for Thursday, March 12, 2020.

DEP filed the Supplemental Testimony and Exhibits of Company witnesses Angers, McGee, Pirro and Smith on March 13, 2020.

On March 24, 2020, Public Staff filed a Motion for Extension of Time for Public Staff and other intervenors to file direct testimony and exhibits due to the novel Coronavirus (COVID-19) pandemic. That same day, the Commission issued an Order Suspending Procedural Schedule and Continuing Hearing due to the continuing uncertainty surrounding the COVID-19 pandemic.

The evidentiary hearing in this matter was initially set to commence on May 4, 2020. However, due to the unprecedented and unfolding COVID-19 pandemic and declared State of Emergency issued by Governor Roy Cooper, on April 3, 2020, the Company filed a Motion for an Order Addressing Procedural Issues. As part of the motion, DEP acknowledged that one complicating factor was the potential running of the 270-day suspension period specified in the Commission's November 14, 2020 Order and the potential mandatory placement of DEP's proposed rates into effect under N.C.G.S. § 62-134(b). Therefore, subject to its right to implement temporary rates under N.C.G.S. § 62-135, DEP asked the Commission to issue an order acknowledging and accepting DEP's notice of the prospective waiver through December 31, 2020, of its right to seek to implement its original proposed rates in this proceeding by operation of N.C.G.S. § 62-134(b) in the event that the postponement sought rendered the issuance of a Commission determination on just and reasonable rates in this proceeding prior to the end of the suspension period infeasible. That same day, the AG filed its Response of the Attorney General's Office to DEP's Motion for an Order Addressing Procedural Issues and DEP filed its Reply in Support of Motion for an Order Addressing Procedural Issues.

On April 7, 2020, the Commission issued its Order Addressing Procedural Matters providing for revised testimony filing deadlines and discovery guidelines for the Company's rebuttal testimony.

On April 13, 2020, the Public Staff filed the Direct Testimony and Exhibits of Shawn L. Dorgan, Staff Accountant with the Accounting Division of the Public Staff; Jack L. Floyd, Utilities Engineer with the Electric Division of the Public Staff; L. Bernard Garrett, Secretary/Treasurer, Garrett and Moore, Inc.; John R. Hinton, Director of the Economic Research Division of the Public Staff; Jay B. Lucas, Utilities Engineer with the Electric Division of the Public Staff; Michael C. Maness, Director of the Accounting Division of the Public Staff; Roxie McCullar, Consultant, William Dunkel & Associates; James S. McLawhorn, Director of the Electric Division of the Public Staff; Dustin Ray Metz, Utilities Engineer with the Electric Division of the Public Staff; Vance F. Moore, President, Garrett and Moore, Inc.; Scott J. Saillor, Utilities Engineer with the Electric Division of the Public Staff; Jeff Thomas, Utilities Engineer with the Electric Division of the Public Staff; joint testimony of David M. Williamson, Utilities Engineer with the Electric Division of the Public Staff, and Tommy C. Williamson, Jr., Utilities Engineer with the Electric Division of the Public Staff; and J. Randall Woolridge, Professor of Finance, Pennsylvania State University. On April 13, 2020, the Public Staff also filed Corrected Direct Testimony of witness Metz. On April 13, 2020, the AG filed the Direct Testimony and Exhibits of Richard

A. Baudino, Consultant, J. Kennedy and Associates, Inc. and Steven C. Hart, President and Principal Hydrogeologist, Hart & Hickman PC.

On April 13, 2020, CIGFUR filed the Direct Testimony and Exhibits of Nicholas Phillips, Jr., Managing Principal, Brubaker & Associates, Inc.; CUCA filed the Direct Testimony and Exhibits of Kevin W. O'Donnell, President, Nova Energy Consultants, Inc.; FPWC filed the Direct Testimony and Exhibits of Gary D. Brunault, Principal and Regional Manager of Orlando Office, GDS Associates, Inc.; Harris Teeter filed the Direct Testimony and Exhibits of Justin Bieber, Senior Consultant, Energy Strategies, LLC; Hornwood filed the Direct Testimony and Exhibits of Brian W. Coughlan, President, Utility Management Services, Inc.; NCJC et al. and NCSEA filed the Direct Testimony and Exhibits of Paul J. Alvarez, President of Wired Group and Dennis Stephens, an independent consultant; NCJC, et al. filed the Direct Testimony and Exhibits of John Howat, Senior Policy Analyst, National Consumer Law Center and Jonathan F. Wallach, Vice President, Resource Insight, Inc.; Sierra Club filed the Direct Testimony and Exhibits of Rachel Wilson, Principal Associate, Synapse Energy, and Mark Quarles, Senior Consultant, BBJ Group; NC WARN filed the Direct Testimony and Exhibits of William E. Powers, Principal, Powers Engineering; NCSEA filed the Direct Testimony and exhibits of Justin R. Barnes, Director of Research, EQ Research LLC; Vote Solar filed the Joint Direct Testimony and Exhibits of James Van Nostrand, Energy Policy Expert, EQ Research and Tyler Fitch, Southeast Regulatory Manager, Vote Solar; and the Commercial Group filed the Direct Testimony and Exhibits of Steve W. Chriss, Director, Energy Services, Walmart, Inc.

On April 23, 2020, Public Staff filed the Supplemental Testimony and Exhibits of Public Staff witnesses Dorgan, Floyd, Lucas, Maness, and Saillor. On April 27, 2020, Harris Teeter filed the Corrected Direct Testimony of Justin Bieber.

On April 27, 2020, Harris Teeter filed the Corrected Direct Testimony of witness Bieber.

On May 4, 2020, DEP filed the Rebuttal Testimony and Exhibits of Company witnesses Angers; Conitsha B. Barnes, Regulatory Affairs Manager, DEC; Bednarcik; Rudolph Bonaparte, Chairman and Senior Principal, Geosyntec Consultants, Inc.; De May; David L. Doss Jr., Director of Asset Accounting, DEBS; Steven M. Fetter, President, Regulation UnFettered; Hatcher; Hager; Henderson; Hevert; Lon Huber, Vice President, Rate Design and Strategic Solutions, Duke Energy; Erik C. Lioy, Partner, Dixon Hughes Goodman LLP; Renee Metzler, Managing Director – Total Rewards, DEBS; Newlin; Oliver; Pirro; Sean P. Riley, Assurance Partner, PricewaterhouseCoopers LLP; Smith; Spanos; Turner; James Wells, Vice President – Environmental Health and Safety, Programs and Environmental Sciences, DEBS; Marcia E. Williams, Senior Vice President, Nathan Associates, Inc.; and Steven K. Young, Executive Vice President and Chief Financial Officer, Duke Energy.

On May 6, 2020, the Public Staff, DEC and DEP (DEC and DEP herein referred to collectively as the Companies) filed a Joint Motion to Consolidate Evidentiary Hearing noting that many of the issues in the two rate cases were based on substantially similar testimony.

On May 27, 2020, the Public Staff filed corrected pages to the testimony of witness Lucas.

On May 29, 2020, the Commission issued its Order Proposing Procedures for Partially Consolidated Expert Witness Hearing, Scheduling Pre-Hearing Conference, revising the schedule for the expert witness hearing and consolidating the hearing with the currently pending DEC Rate Case expert witness hearing in Docket No. E-7, Sub 1214.

On June 2, 2020, DEP and the Public Staff entered into and filed an Agreement and Stipulation of Partial Settlement (the First Partial Stipulation) settling some issues in the case. That same day, the Company filed settlement testimony of witness De May and settlement testimony and exhibits of witness Smith.

On June 4, 2020, the Company jointly filed with DEC, Pre-Hearing Conference Correspondence.

A pre-hearing conference was held on June 5, 2020. That same day, the Public Staff filed the Settlement Testimony of witness Maness.

On June 8, 2020, DEP filed a Settlement Agreement with Harris Teeter (the Harris Teeter Stipulation).

On June 9, 2020, the Company filed a Settlement Agreement with the Commercial Group (the Commercial Group Stipulation).

On June 17, 2020, the Commission issued its Order Adopting Procedures for Expert Witness Hearings, which provided that the consolidated hearing would be held remotely starting on July 27, 2020, to consider evidence that is identical in both the DEC and DEP rate cases and among other things, requiring the parties to file a statement consenting to the consolidated portion of the hearings being held remotely.

On June 22, 2020, the Company filed a Petition for Accounting Order to Defer Impacts of Its Suspended Rate Case In Lieu of Implementing Temporary Rates Under Bond.

On June 25, 2020, the Commission issued its Errata Order correcting certain filing deadlines provided for in the June 17, 2020 order.

On June 26, 2020, DEP filed an Agreement and Stipulation of Settlement with CIGFUR (the CIGFUR Stipulation). The Harris Teeter Stipulation, CIGFUR Stipulation, and Commercial Group Stipulation are collectively referred to herein as the Customer Group Stipulations.

Consents to remote hearing were filed by the Public Staff and NCLM on June 26, 2020; Hornwood on June 29, 2020; Harris Teeter, NCSEA, Vote Solar, NC WARN, CUCA, NCCEBA, and Commercial Group on June 30, 2020; FPWC on July 1, 2020; and CIGFUR, AG, Sierra Club, NCJC et al., DEC, and DEP on July 2, 2020.

On June 29, 2020, DEP submitted a Motion for Leave to File Direct and Rebuttal Testimony and Exhibits of Dylan W. D'Ascendis Adopting the Direct and Rebuttal Testimony and Exhibits of Robert B. Hevert.

On July 2, 2020, upon consultation with the parties to this proceeding, the Companies filed a proposed list of issues to be heard during the consolidated, remote phase of the hearing. That same day, DEP filed the Second Supplemental Direct Testimony and Exhibits of witness Smith and Second Supplemental Direct Testimony of witness Pirro, which provided updates to certain pro forma adjustments through May 2020 (the May 2020 Updates).

On July 7, 2020, the Commission issued its Order Accepting Prefiled Testimony of Dylan W. D'Ascendis and that same day the Public Staff filed its Response to Second Supplemental Testimony and Exhibits addressing the Company's May 2020 Updates filings, which it subsequently filed corrections to later that day. Also, later that day, the Company filed Amended Rebuttal Testimony of Dylan W. D'Ascendis.

On July 9, 2020, the Commission issued an Order Accepting Recommended Consolidated Issues for Remote Expert Witness Hearings and Postponing Separate Issue Hearings. On that same day, DEP and DEC filed a Joint Reply to the Public Staff's Responses to the Companies' Second Supplemental Direct Testimony and Exhibits and also filed an Agreement and Stipulation of Settlement with Vote Solar (the Vote Solar Stipulation). The Company also filed the Corrected Second Supplemental Direct Testimony and Exhibits of witness Smith.

On July 10, 2020, the Commission issued its Order Denying Deferral of Revenue and an Order Requiring Filing of Evidentiary and Other Procedural Motions, and the same day the AG filed the Supplemental Testimony of witness Baudino and a letter with correction of the AG's Motion for Admission of Supplemental Expert Testimony.

On July 15, 2020, the Companies submitted a Joint Response to AGO Motion to Admit Supplemental Expert Testimony stating that the Companies had no objection to the filing of witness Baudino's supplemental testimony provided the Companies were permitted to file supplemental rebuttal testimony in response thereto. That same day, the Public Staff filed its Response to Joint Reply of Duke Energy Carolinas and Duke Energy Progress.

On July 16, 2020, the Commission issued its Order Granting Motions to File Supplemental and Rebuttal Testimony.

On July 20, 2020, DEP filed the Supplemental Rebuttal Testimony of witness D'Ascendis.

On July 21, 2020, the Commission issued its Order on Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Second Supplemental Testimony.

On July 22, 2020, the Commission issued its Order Requiring Parties to File a Motion for Leave Before Filing Additional Testimony and Order Providing Additional Clarification for Consolidated, Remote Expert Witness Hearing.

On July 23, 2020, the Commission issued its Order Requiring Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC to File Additional Testimony on Grid Improvement Plans and Coal Combustion Residuals. That same day, the Company filed its Agreement and Stipulation of Settlement with NCSEA and NCJC et al. (the NCSEA and NCJC et al. Stipulation).

On July 24, 2020, upon oral motion by the Public Staff citing continued settlement discussions with the Companies, the Commission issued its Order Granting Continuance of Consolidated, Remote Hearing rescheduling the consolidated hearing to commence on July 28, 2020.

On July 27, 2020, the Public Staff and the Companies filed a Joint Motion to Postpone Hearing and Additional Procedural Deadlines. That same day, the Commission issued its Order Granting Joint Motion and Further Rescheduling Consolidated, Remote Hearing, which inter alia, rescheduled the consolidated, remote hearing for August 24, 2020.

On July 31, 2020, DEP and the Public Staff entered into the Second Agreement and Stipulation of Partial Settlement (the Second Partial Stipulation, collectively with the First Partial Stipulation, the Public Staff Partial Stipulations) settling additional issues in the case. The Public Staff Partial Stipulations resolve many of the issues between the two parties in this docket. That same day, in support of the Second Partial Stipulation, the Public Staff filed the testimony of witnesses Maness, McLawhorn, and Woolridge, and the Company filed the settlement supporting testimony of witnesses De May, D'Ascendis, Smith, and Newlin.

As a result of the Second Partial Stipulation, on August 5, 2020, the Company filed amendments to the Commercial Group Stipulation and Vote Solar Stipulation, on August 6, 2020, the Company filed amendments to the CIGFUR Stipulation and Harris Teeter Stipulation, and on August 10, 2020, the Company filed an amendment to the NCSEA & NCJC et al. Stipulation, whereby the parties agreed that if the Commission enters a final order in this docket approving a 9.6% ROE based on a 52% equity and 48% long-term debt capital structure, that the parties agree that the provisions of the stipulations regarding those issues will have been fulfilled.

On August 5, 2020, the Company filed the joint testimony and exhibits of witnesses Oliver and Smith in response to the Commission's July 23, 2020, Order Requiring Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC, to File Additional Testimony on Grid Improvement Plans and Coal Combustion Residual Costs.

On August 7, DEP filed its Motion for Approval of Notice Required by N.C.G.S. § 62-135 to Implement Temporary Rates, Subject to Refund, and Authorization of EDIT Riders and Motion for Approval of Undertaking Required by N.C.G.S. § 62-135 to Implement Temporary Rates, Subject to Refund.

On August 10, 2020, the Commission issued its Order Rescheduling Separate Expert Witness Hearings to be Conducted Remotely.

On August 11, 2020, the Commission entered an Order Consolidating Dockets, consolidating the rate case and the Company's Application for an Accounting Order to Defer Incremental Storm Damage Expenses Incurred as a Result of Hurricanes Florence and Michael and Winter Storm Diego in Docket No. E-2, Sub 1193.

On August 11, 2020, the Commission issued its Order Approving Public Notice of Interim Rates Subject to Refund and Financial Undertaking.

On August 13, 2020, DEP filed witness Doss's Rebuttal Exhibit 1.

On August 14, 2020, the Commission filed its Order Providing Additional Requirements for Separate Expert Witness Hearings.

On August 19, 2020, the Companies filed a Joint Motion for Leave to File Settlement Supporting Testimony and Exhibits of Witness Michael J. Pirro, which the Commission granted in its August 20, 2020 Order Granting Motion to file Settlement Testimony and Exhibits.

On August 20, 2020, the Public Staff and the Companies filed a Joint Motion for Clarification and/or Reconsideration of Order Providing Additional Clarification for Consolidated, Remote Expert Witness Hearing requesting clarification on the process for procedural matters during the consolidated hearing. On August 21, 2020, the Commission issued its Order Granting in Part Joint Motion for Additional Clarification for Consolidated Expert Witness Hearing.

On August 21, 2020, the Company filed the Second Settlement Testimony of witness Pirro.

On August 21, 2020, the Company filed its Temporary Rates Compliance Filing.

The public hearings were held as scheduled. The following public witnesses appeared and testified:

Rockingham: No public witnesses appeared.

Raleigh: Joe Adamsky, Lib Hutchby, April Springer, Ananya Seelam, Christopher Thompson, Hwa Huang, Bob Rodriguez, Steve Hahn, Kay Reibold, Jean-Luc Duvall, Mary Black, Beverly Moriarty, Barbara Cain, Sarah

Macleod Owens, Carolyn Guckert, and Eleanor Weston

Wilmington: Herb Harton, George Vlasits, Clarice Reber, Beth Hansen, Jimmie Davis, Dwight Willis, Roberta Buckles, Shelli Sordellini, Priss Endo, Peter Perschbacher, Tim Holder, Deborah Dicks Maxwell, Adair Wright, and Harper Peterson

Snow Hill: Bobby Jones, Lorrine Washington, Antonio Blow, Kristiann Herring, and Benjamin Lanier

Asheville: Roger Hollis, Viola Williams, Ben Scales, Stephanie Biziewski, Amanda Strawderman, Cody Kelly, Amanda Seta, Dr. Steven Norris, Cathy Holt, Jeff Jones, Philip Bisesi, Padma Dyvine, David Saulsbury, Max Mandler, Sonny Charles Rawls, Chloe Moore, Judy Mattox, Ken Brame, Alex Lines, Melanie Noyes, Debbie Resnick, Kim Roney, and Kenneth Bradley Lenz

The Commission received numerous consumer statements of position in this matter. All public witness testimony and consumer statements of position have been considered by the Commission and made a part of the record.

The matter came on for a consolidated evidentiary hearing on August 24, 2020, solely for the purposes of hearing testimony on the following topics for which the evidence is identical and equally admissible to DEP and to DEC: financial issues including ROE, capital structure, and credit quality; EDIT; the GIP; and affordability. For the financial issues portion of the consolidated hearing, DEP and DEC presented the panel testimony of witnesses D'Ascendis and Newlin and rebuttal testimony of witness Young. The Public Staff presented the testimony of witness Hinton. The AG presented the testimony of witness Baudino. CUCA presented the testimony of witness O'Donnell. For the EDIT issues during the consolidated hearing, the Companies presented the panel testimony of witnesses Newlin, Smith, and Jane L. McManeus, Director of Rates & Regulatory Planning, DEC, testifying on behalf of DEC. The Public Staff presented the panel testimony of witnesses Boswell, Dorgan, and Hinton. For the GIP issues, the Companies presented the testimony of witness Oliver and the panel testimony of witnesses McManeus and Smith. The Public Staff presented the panel testimony of witnesses T. Williamson, D. Williamson, Thomas, and Maness. CUCA presented the testimony of witness O'Donnell. NCSEA and NCJC et al., presented the panel testimony of witnesses Alvarez and Stephens. For the affordability issues portion of the consolidated hearing, the Companies presented the testimony of witness C. Barnes. Public Staff presented the testimony of witness Floyd. NCJC et al. presented the testimony of witness Howat.

On August 28, 2020, the Company filed Supplemental Testimony of witnesses Bednarcik and Doss.

On August 31, 2020, the Public Staff filed a Motion for Leave to Conduct Discovery and File Testimony. That same day, DEP also filed a Corrected Bednarcik Supplemental Exhibit 3 to the Supplemental Testimony of witness Bednarcik filed on August 28, 2020.

On September 2, 2020, the Commission issued its Order Granting Extension of Time and Providing Additional Requirements for Separate Expert Witness Hearing.

On September 4, 2020, the Commission issued its Order Granting Public Staff's Motion to Conduct Discovery and File Testimony, and Allowing Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC to File Rebuttal Testimony.

On September 15, 2020, the Public Staff filed the Supplemental Testimony of witness Metz, and Supplemental Testimony of witness T. Williamson.

On September 16, 2020, the Public Staff filed the Second Supplemental Testimony and Exhibits of witness Saillor, Second Supplemental Testimony and Exhibits of witness Floyd, Second Supplemental Coal Ash Testimony of witness Maness, and the Supplemental Testimony Supporting Second Partial Settlement and Exhibits of witness Maness.

Also, on September 16, 2020, the Commission issued its Order Scheduling Remote Expert Witness Hearing and Requiring Duke Energy Progress, LLC to File an Updated Witness List. Also, on September 16, 2020, recognizing that the Commission may be unable to issue an order in this rate case prior to December 31, 2020, the Company filed a Motion for an Order Accepting the Company's Notice of its Extension of its Waiver of its Right to Implement its Original Proposed Rates per N.C.G.S. § 62-134(b) providing notice of the Company's extension of its prospective waiver from December 31, 2020 to March 1, 2021.

On September 18, 2020, the Commission issued its Order Acknowledging the Notice Given by Duke Energy Progress, LLC, of its Prospective Waiver of its Right to Seek to Implement its Original Proposed Rates by Operation of N.C.G.S. § 62-134(b).

On September 23, 2020, the Company filed the Supplemental Rebuttal Testimony of witness Oliver and Joint Supplemental Rebuttal Testimony of witnesses Pirro and Huber.

On September 24, 2020, on behalf of the various stipulating parties, the Public Staff filed a Joint Stipulation of COS, Rates and Rate Design. That same day, DEP filed a Joint Stipulation of Live Testimony and Exhibits of Larry Hatcher and Stephen DeMay.

On September 25, 2020, the Commission issued its Order Acknowledging Joint Stipulation of Live Testimony and Exhibits of Certain Rate Design and Cost Allocation Witnesses. That same day, the Company filed a Joint Stipulation of Live Testimony and Exhibits of Jane L. McManeus between DEP and the AG.

On September 28, 2020, the Company filed a Joint Stipulation Regarding Admission of Certain Live Testimony and Exhibits and later that same day filed an Amended Joint Stipulation Regarding Admission of Certain Live Testimony and Exhibits.

On September 29, 2020, the Commission issued an Order Acknowledging Amended Joint Stipulation Filed with the Commission on September 28, 2020. That same day, Hornwood filed an Errata Sheet and Corrected Direct Testimony of Brian Coughlan.

On September 29, 2020, the DEP-specific portion of the hearing commenced and during that portion of the hearing, DEP presented the panel testimony of witnesses De May and Hatcher; Turner; the panel testimony of witnesses Pirro, Hager, and Huber; Bednarcik; Smith; Riley; rebuttal testimony of witness Oliver; rebuttal panel testimony of witnesses Doss, Spanos, and Riley; rebuttal testimony of witness Bednarcik; rebuttal testimony of witness Fetter; and the panel rebuttal testimony of witnesses Wells and Williams. The Public Staff presented the panel testimony of witnesses Floyd and McLawhorn; panel testimony of witnesses Garrett and Moore; panel testimony of witnesses Lucas and Maness; and testimony of T. Williamson. The AG presented the testimony of witness Hart. NCSEA presented the testimony of witness J. Barnes. CUCA presented the testimony of witness O'Donnell. The Sierra Club presented the testimony of witnesses Quarles and Wilson. CIGFUR presented the testimony of witness Phillips. Hornwood presented the testimony of witness Coughlan. The pre-filed testimony of those witnesses who testified at the evidentiary hearing, as well as all other witnesses filing testimony in this docket and excused from the hearing by the Commission, was copied into the record as if given orally from the stand.

On October 1, 2020, the Company filed an Amended Joint Stipulation Matrix. That same day, the Commission issued its Order Responding to Letter Requesting Clarification regarding late-filed exhibit requests made by the Commission during the hearing.

On October 5, 2020, the Company filed a Joint Stipulation of Facts between DEP, the Public Staff, and Hornwood. That same day, the Public Staff filed a Motion for Leave to File Corrected Exhibit.

On October 6, 2020, the Commission issued an Order Allowing Motion for Leave to File Corrected Exhibit of Jay B. Lucas.

On October 8, 2020, the Public Staff filed a Motion to Extend Time to file Late-Filed Exhibits and later that same day filed an Amended Motion to Extend Time to file Late-Filed Exhibits.

On October 9, 2020, the Commission issued its Order Allowing Public Staff's Amended Motion for Extension of Time to file Late-Filed Exhibits. That same day, the Commission also issued a Notice of Due Date for Proposed Orders and/or Briefs stating that the transcript of testimony had been made available and that the parties were to submit briefs and/or proposed orders no later than December 4, 2020.

On October 13, 2020, the Commission issued its Order Establishing Procedures and Dates for Filing Motions Requesting Judicial Notice and Allowing Filing of Amended Motion.

On October 16, 2020, the Commission issued an Order Supplementing Late-Filed Exhibit Requests for Waste Coal Ash Documents and Setting Filing Date. That same day, the Public Staff filed a Motion for Second Extension of Time to File Late-Filed Exhibits.

On October 19, 2020, the Commission issued its Order Allowing Public Staff's Motion for Second Extension of Time to File Late-Filed Exhibits.

On November 19, 2020, DEP filed a Motion for Judicial Notice.

On November 20, 2020, the AG filed a Motion to Admit Late-filed Exhibit and Supplemental Authorities and also a Motion for Judicial Notice.

On November 23, 2020, DEC and DEP filed a Response to the Attorney General Office's Motion to File Late-Filed Exhibit and Supplemental Authorities. That same day the Public Staff filed a Motion Requesting that the Commission Take Judicial Notice of Certain Evidence in the Duke Energy Progress, LLC, Proceeding.

On November 30, 2020, the Commission issued its Order Allowing the Attorney General's Motion to Take Judicial Notice of Additional Evidence, and Denying in Part, and Dismissing in Part, the Attorney General's Motion to File Late-Filed Exhibit and Supplemental Authorities.

On December 1, 2020, the Commission issued its Order Allowing Public Staff Motion Requesting that the Commission Take Judicial Notice of Certain Evidence and also an Order Allowing Duke Energy Progress, LLC's Motion Requesting that the Commission Take Judicial Notice of Certain Evidence Introduced in the Duke Energy Carolinas, LLC, Specific Hearing.

The parties submitted post-hearing briefs and proposed orders on December 4, 2020 in accordance with the Commission's deadline.

Based upon the foregoing and the entire record in this proceeding, the Commission makes the following

## FINDINGS OF FACT

### Jurisdiction

1. DEP is duly organized as a public utility operating under the laws of the State of North Carolina and is subject to the jurisdiction of this Commission. The Company is engaged in the business of generating, transmitting, distributing, and selling electric power to the public in a broad area in eastern North Carolina and an area in western North Carolina in and around the city of Asheville. DEP is a wholly owned subsidiary of

Duke Energy, and its office and principal place of business are located in Raleigh, North Carolina.

2. The Commission has jurisdiction over the rates and charges, rate schedules, classifications, and practices of public utilities operating in North Carolina, including DEP, under Chapter 62 of the General Statutes of North Carolina.

3. DEP is lawfully before the Commission based upon its Application for a general increase in its retail rates pursuant to N.C.G.S. §§ 62-133 and 62-134 and Commission Rule R1-17.

4. The appropriate test period for use in this proceeding is the 12 months ended December 31, 2018, adjusted for certain known changes in revenue, expenses, and rate base initially through February 29, 2020, and for certain items, subsequently through May 31, 2020, subject to the terms of the Second Partial Stipulation.

**The Application**

5. DEP, by its Application and initial direct testimony and exhibits, originally sought a base rate increase of approximately $585.9 million, or 15.6%, in its annual electric sales, offset by a rate reduction of $120.2 million to refund certain tax benefits and $2.1 million related to the proposed Regulatory Asset and Liability Rider, for a net revenue increase of $463.6 million, or 12.3% from its North Carolina retail electric operations, including a rate of return on common equity of 10.30% and a capital structure consisting of 47% debt and 53% equity.

6. DEP submitted evidence in this case with respect to revenue, expenses, and rate base using a test period consisting of the 12 months ended December 31, 2018, adjusted for certain known changes in revenue, expenses, and rate base.

7. DEP, by its Second Settlement Testimony and Exhibits, revised its requested base revenue requirement increase to $408,933,000 to incorporate the Company's adjustments filed in its Second Settlement Testimony and Exhibits filing and the Company's Second Supplemental Testimony and Exhibits filing, offset by a rate increase of $7,381,000 for the Revised Annual EDIT Rider 1 and reduction of ($152,348,000) for the Annual EDIT Rider 2 to refund certain tax benefits,[3] and ($2,091,000) for the Regulatory Asset and Liability Rider, for a net revenue increase of $261,875,000.

[3] Note that the Annual EDIT Rider 2 Year 1 flowback estimate of ($152,348,000) is based on an estimate of the amount to be flowed back to customers through the Company's interim rates and is subject to change based on the actual amount flowed back when the revised rates approved in this Order go into effect.

**The Public Staff Partial Stipulations**

8. On June 2, 2020, DEP and the Public Staff entered into and filed the First Partial Stipulation resolving some of the issues in this proceeding between the two parties, and on July 31, 2020, the Public Staff and the Company entered into and filed the Second Partial Stipulation resolving several other issues in this proceeding. Those issues that were not resolved by the Public Staff Partial Stipulations are referred to herein as the Unresolved Issues.

9. The Commission, having carefully reviewed the Public Staff Partial Stipulations and all of the evidence of record, finds and concludes that the Public Staff Partial Stipulations are the product of the give-and-take settlement negotiations between DEP and the Public Staff, are material evidence in this proceeding, and are entitled to be given appropriate weight in this proceeding, along with other evidence from the Company and intervenor parties, and along with statements from customers of the Company as well as testimony of public witnesses concerning the Company's Application.

10. The Commission finds and concludes, based on all of the evidence presented, that the provisions of the Public Staff Partial Stipulations are just and reasonable to all parties to this proceeding and serve the public interest. Therefore, the Public Staff Partial Stipulations should be approved in their entirety. The specific terms of the Public Staff Partial Stipulations are addressed in the following findings of fact and conclusions.

**The Public Staff Stipulated Accounting Adjustments**

11. The Public Staff Partial Stipulations provide for certain accounting adjustments that DEP and the Public Staff have agreed upon; the revenue requirement effects of the agreed-upon issues are set out in detail in Smith Partial Settlement Ex. 3, Smith Second Settlement Ex. 3, Maness Stipulation Ex. 1, Schedule 1, and Maness Second Stipulation Ex. 1, Schedule 1 (the Partial Stipulation Revenue Requirement Exhibits). DEP and the Public Staff agree that settlement on those issues will not be used as a rationale for future arguments on contested issues brought before the Commission. The Commission finds and concludes that for the present case, the agreed-upon accounting adjustments outlined in the Partial Stipulation Revenue Requirement Exhibits, as adjusted, subject to resolution of the Unresolved Issues, are just and reasonable to all parties in light of all the evidence presented.

**Storm Costs**

12. DEP's Storm Costs (i.e., the costs of responding to Hurricanes Florence, Michael, Dorian, and Winter Storm Diego), as presented by the Company and agreed to in the First Partial Stipulation with the Public Staff, are just and reasonable and were prudently incurred, to the extent such costs represent actual amounts as of May 31, 2020. Any estimated costs as of that date or incurred afterward remain subject to review in a proceeding conducted pursuant to Senate Bill 559 (SB 559) – An Act to Permit Financing

for Certain Storm Recovery Costs, or to consideration for recovery in a future general rate case proceeding, pursuant to the provisions of N.C.G.S. § 62-172(a)(14(c).

13. DEP's actual Storm Costs total $714.0 million, consisting of approximately $567.3 million in actually incurred or projected storm response O&M costs, approximately $68.6 million in capital investments, and approximately $78.1 million in carrying costs (calculated using the Company's approved weighted average cost of capital through August 31, 2020) on its actually incurred storm response costs.

14. Consistent with the First Partial Stipulation and the testimony of witness De May, DEP has withdrawn these costs, including capital investments, from the current rate case, except regarding the prudence determination reached in Finding of Fact No. 12.

15. Consistent with Finding of Fact No. 10, approving the First Partial Stipulation, it is appropriate for the Company to use the assumptions the Public Staff and DEP agreed to in § III.3. of the First Partial Stipulation in order to demonstrate quantifiable benefits to customers, in accordance with N.C.G.S. § 62-172(b)(1)g., which will be verified upon review of the Company's petition for a financing order to securitize its storm costs in Docket No. E-2, Sub 1262.

16. It is appropriate that DEP continue to defer these costs in a regulatory asset account until the date storm recovery bonds are issued pursuant to an approved financing order in accordance with N.C.G.S. § 62-172, or the Company seeks recovery of the storm costs through an alternative method of cost recovery, subject to the assumptions and conditions agreed to in the First Partial Stipulation.

17. It is further appropriate that DEP continue to accrue and record carrying costs, at the Company's approved weighted average cost of capital, on the deferred balances in its Storm Cost recovery deferred account pending recovery through securitization, subject to the assumptions and conditions agreed to in the First Partial Stipulation.

18. The Public Staff's proposed ten-year normalization proposal for non-securitizable Storm Costs, as agreed to by the Company, is appropriate for use in this proceeding.

19. It is appropriate to establish a Storm Cost Recovery Rider for the Company and to set the initial balance for that rider at $0 in conformance with the provisions of the First Partial Stipulation.

**Regulatory Asset and Liability Rider**

20. The Commission finds and concludes that the Company's proposed Regulatory Asset and Liability rider (RAL-1), which refunds approximately $2.1 million to customers over a one-year period, is just and reasonable, consistent with the Commission's directive relating to the treatment of net over-amortizations of expired

regulatory assets and liabilities since the Company's last general rate case, and should be approved.

**Excess Deferred Income Taxes**

21. The Commission finds and concludes that the Company's proposed revision to its previously approved North Carolina EDIT rider (EDIT-1) to reflect the change in the federal tax rate from 35% to 21%, is just and reasonable and should be approved.

22. In Docket No. M-100, Sub 148, the Commission ordered the Company to maintain EDIT that resulted from the reduction in the federal income tax rate as part of the 2017 Tax Cuts and Jobs Act (Tax Act) in a regulatory liability account. The Company has an obligation to refund the EDIT to its customers and in its Application, the Company proposed a method of returning EDIT to its customers through a rider. As part of the stipulations between them, DEP and the Public Staff agreed to the method to refund the various EDIT components back to customers. The Commission finds and concludes that the Public Staff Partial Stipulations are material evidence entitled to appropriate weight in determining the appropriate flowback mechanism of EDIT to customers.

23. As part of the Public Staff Partial Stipulations, the Company and the Public Staff agreed to flowback EDIT to customers of DEP as follows:

(a) Protected federal EDIT will be returned to customers in base rates via the Average Rate Assumption Method;

(b) Total unprotected federal EDIT will be returned to customers through a levelized rider calculation methodology as described and set forth in the testimony and exhibits of the Public Staff and will be amortized over a period of five years;

(c) North Carolina EDIT will be returned to customers through a levelized rider calculation methodology as described and set forth in the testimony and exhibits of the Public Staff and will be amortized over a period of two years; and

(d) Deferred revenues related to the provisional overcollection of federal income taxes will be returned to customers through a levelized rider calculation methodology as described and set forth in the testimony and exhibits of the Public Staff and will be amortized over a period of two years.

24. DEP and the Public Staff also reached agreement concerning how to address changes in the federal income tax rate or North Carolina state income tax rate, which may occur during the respective amortization periods.

25. The Public Staff Partial Stipulation terms regarding EDIT are just and reasonable, and will result in rates that are just and reasonable, and should be implemented.

**Capital Structure, Cost of Capital, and Overall Rate of Return**

26. The rate of return on common equity that the Company should be allowed the opportunity to earn is 9.60%, as set forth in § III.B. of the Second Partial Stipulation and is reasonable and appropriate for use in this docket.

27. The overall rate of return that the Company should be allowed the opportunity to earn on the cost of the Company's used and useful property is 6.93%, as set forth in § III.B. of the Second Partial Stipulation, and is reasonable and appropriate for use in this docket.

28. The authorized levels of overall return and rate of return on common equity set forth above are supported by competent, material, and substantial record evidence, are consistent with the requirements of N.C.G.S. § 62-133 in light of changing economic conditions, and will allow the Company to maintain its facilities and services in accordance with the reasonable requirements of the Company's customers.

29. With respect to the foregoing findings on the appropriate overall rate of return on rate base and allowed rate of return on common equity for use in this proceeding, the Commission makes the following more specific findings of fact:

a. The overall rate of return on rate base and allowed rate of return on common equity underlying DEP's current base rates are 7.09% and 9.90%, respectively.[4]

b. DEP's current base rates became effective for service rendered on and after March 16, 2018, and have been in effect since that date.

c. In its Application, DEP sought approval for rates that were based on an overall rate of return on rate base of 7.41% and an allowed rate of return on common equity of 10.30%.

d. As set forth in the Second Partial Stipulation, DEP and the Public Staff seek approval of an overall rate of return on rate base of 6.93% and an allowed rate of return on common equity of 9.60%.

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[4] Order Accepting Stipulation, Deciding Contested Issues, and Granting Partial Rate Increase*, Application of Duke Energy Progress, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina,* No. E-2, Sub 1142 (N.C.U.C. Feb. 23, 2018), *appeal docketed*, No. 401A18 (N.C. Nov. 7, 2018) (2018 DEP Rate Order).

e. The reduction in overall rate of return on rate base and rate of return on common equity from both DEP's existing base rates and the Application, as reflected in the Second Partial Stipulation, is a substantial economic benefit to DEP's customers.

f. The stipulated overall rate of return on rate base of 6.93% and rate of return on common equity of 9.60% are supported by competent, material, and substantial evidence.

g. The evidence indicates that as a result of COVID-19, economic conditions in North Carolina have changed since the Company initially filed its Application, but the challenges remain largely similar to those encountered in the rest of country, with North Carolina experiencing slightly lower unemployment rates and a faster recovery than the country as a whole.

h. Irrespective of the economic conditions being experienced in North Carolina at this time, some customers of DEP will struggle to pay their utility bills under the rate increases authorized herein.

i. Continuous safe, adequate, and reliable electric service by DEP is essential to the support of businesses, jobs, hospitals, government services, and the maintenance of a healthy environment.

j. The rate of return on common equity and capital structure approved by the Commission appropriately balances the benefits received by DEP's customers from DEP's provision of safe, adequate, and reliable electric service in support of businesses, jobs, hospitals, government services, and the maintenance of a healthy environment with the difficulties that some of DEP's customers will experience in paying the Company's increased rates.

30. The capital structure set forth in § III.B. of the Second Partial Stipulation, consisting of 52.00% common equity and 48.00% long-term debt, is reasonable and appropriate for use by DEP in this case.

31. The embedded cost of debt of 4.04% set forth in § III.B. of the Second Partial Stipulation is reasonable and appropriate for use by DEP in this case.

32. The capital structure and rates of return on rate base and common equity set forth in the Second Partial Stipulation result in a cost of capital that appropriately balances DEP's interest in maintaining both its credit ratings and its ability to obtain equity financing on reasonable terms, and its customers' interest in receiving electric utility service at the lowest possible rate.

**Grid Improvement Plan**

33. It is appropriate for the Company to pursue grid modernization efforts through the eight GIP programs agreed to with the Public Staff in the Second Partial Stipulation.

34. It is appropriate to allow deferral accounting treatment of the costs of implementing the eight GIP programs set forth in the Second Partial Stipulation pursuant to the terms and conditions of that agreement.

35. DEP shall file reports semiannually consistent with the Company's Second Partial Stipulation with the Public Staff.

**Cost of Service**

36. Consistent with the Second Partial Stipulation, the Commission finds and concludes that for purposes of this proceeding, the Company may continue to use the summer coincident peak methodology for allocation of demand-related production and transmission costs between jurisdictions and among customer classes.

37. The Commission finds that § IV.B. of the Second Partial Stipulation, in which the Company agreed to perform additional cost of service studies, is just and reasonable to all parties in light of the evidence presented.

38. The Commission finds that the Company's use of the minimum system method to allocate customer-related distribution costs is reasonable and appropriate for the purpose of allocating costs to the respective rate classes.

39. The Commission finds that the Company's use of a non-coincident peak demand allocator to allocate demand-related distribution costs is reasonable and appropriate for the purpose of allocating costs to the respective rate classes.

40. The Commission finds that the Company's use of an energy allocation factor to allocate CCR costs is reasonable and appropriate.

**Rate Design**

41. Section IV.D. of the Second Partial Stipulation provides that the proposed modifications to the Company's rate schedules are reasonable for purposes of this proceeding. DEP and the Public Staff also agreed that the Company shall assign the approved revenue requirement consistent with the principles regarding revenue apportionment described in § IV.C. of the Second Partial Stipulation. Based on all the evidence presented in this proceeding, the Commission finds and concludes that the rate design provisions in §§ IV.C. and IV.D. of the Second Partial Stipulation are just and reasonable to all parties in light of all the evidence presented. The Company shall implement its proposed rate design in accordance with §§ IV.C. and IV.D. of the Second Partial Stipulation.

42. The Company does not propose in this case to modify any of its currently approved Basic Customer Charges for any of the customer classes. The Basic Customer Charges as set forth in Pirro Exhibit 7 are just and reasonable and are therefore approved by the Commission.

43. The proposed amendments to DEP's service regulations are just and reasonable, serve the public interest, and should be approved.

44. DEP's proposed modifications of certain outdoor lighting fees and schedules to modernize the Company's outdoor lighting products and services to reflect the continued adoption of light-emitting diode (LED) technology are just and reasonable to all parties in light of the evidence presented and should be approved.

**Comprehensive Rate Design Study**

45. Section IV.E. of the Second Partial Stipulation provides that the Commission should order a comprehensive rate design study. Both DEP and the Public Staff recommend that this study should incorporate stakeholder participation, and § IV.E. outlines various rate design topics that should be considered during this study. Based on all of the evidence presented in this proceeding, the Commission finds and concludes that §§ IV.E. of the Second Partial Stipulation is just and reasonable to all parties in light of the evidence presented.

**Affordability**

46. The Company's proposal to host a collaborative to consider ways to assist DEP's low-income customers with the affordability of their electric service is hereby approved.

**Electric Vehicles**

47. DEP shall develop and propose electric vehicle (EV) rate designs as part of the comprehensive rate design study outlined in the Second Partial Stipulation.

**Rider MRM**

48. Section IV.H. of the Second Partial Stipulation provides that the costs associated with the Manually Read Metering (MRM) option in Rider MROP not recovered by the rider itself should be socialized and recovered from all customers. Based on all the evidence presented in this proceeding, the Commission finds and concludes that the current charges for the MRM option in Rider MROP provide a reasonable hurdle to discourage a customer from opting out of AMI metering without a legitimate reason and that § IV.H. of the Second Partial Stipulation is just and reasonable to all parties in light of all the evidence presented.

**Audits and Reporting Obligations**

49. Consistent with § IV.I. of the Second Partial Stipulation, and in light of all the evidence presented, the Commission finds that the Company should work with the Public Staff on document retention, project reporting, and other reasonably applicable matters to better assist the Public Staff in future audits of plant within 90 days after the Commission issues its final order in this rate case.

50. Consistent with § IV.J. of the Second Partial Stipulation, and in light of all the evidence presented, the Commission finds that the Company should conduct an independent review/audit of its material and supplies (M&S) inventory to be performed by the Company's internal Corporate Audit Services department, and that the terms of the audit should, at a minimum, meet those recommended in the Direct Testimony of Public Staff witness Metz.

51. Consistent with § IV.K. of the Second Partial Stipulation, and in light of all the evidence presented, the Commission finds that the Company and the Public Staff should meet to discuss the Company's plant unitization policies and reach agreement on reporting obligations.

52. Consistent with § IV.L. of the Second Partial Stipulation, and in light of all the evidence presented, the Commission finds that the Company shall file an annual report of its Vegetation Management performance similar to the DEC's report format provided in Docket Nos. E-7, Subs 1146 and 1182.

53. Consistent with § IV.M. of the Second Partial Stipulation, and in light of all the evidence presented, the Commission finds it appropriate to update the filing requirements for service reliability index reporting in Docket No. E-100, Sub 138A to report the individual categories that make up the total System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI), and include the Customers Experiencing Multiple Interruptions (CEMI-6) index.

**Quality of Service**

54. Consistent with § IV.N. of the Second Partial Stipulation and in light of all the evidence presented, the Commission finds and concludes that the overall quality of electric service provided by DEP is good.

**Base Fuel and Fuel-Related Cost Factors**

55. Consistent with § IV.O. of the Second Partial Stipulation, and in light of all the evidence presented, the Commission finds and concludes that the base fuel and fuel-related cost factors, by customer class, represented by the sum of the (a) respective base fuel and fuel-related cost riders set in Docket No. E-2, Sub 1142, and (b) the annual non-EMF fuel and fuel-related cost riders, by customer class, approved by the Commission in Docket No. E-2, Sub 1250, are just and reasonable to all parties.

**Shareholder Contribution**

56. Consistent with the Second Partial Stipulation, the Commission finds and concludes that the Company's agreement to make certain contributions to the Energy Neighbor Fund is just and reasonable to all parties in light of all the evidence presented.

**Advanced Metering Infrastructure**

57. DEP's AMI costs are reasonable and prudent, and DEP should be allowed to recover its AMI costs.

**Roxboro Wastewater Treatment Plant Deferral**

58. DEP's request for an accounting order to establish a regulatory asset upon retirement of the Roxboro Wastewater Treatment Plant, at the time of the plant's anticipated early retirement in 2021, to defer the unrecovered remaining net book value of the plant and costs related to obsolete inventory, net of salvage, at the time of retirement is reasonable and approved.

## EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-4

The evidence supporting these findings and conclusions is contained in the verified Application and Form E-1 of DEP, the testimony and exhibits of the witnesses, the Public Staff Partial Stipulations, and the entire record in this proceeding. These findings and conclusions are informational, procedural, and jurisdictional in nature, and are not contested by any party.

## EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 5-10

The evidence supporting these findings and conclusions is contained in the Public Staff Partial Stipulations, DEP's verified Application and Form E-1, the testimony and exhibits of DEP witness De May; Public Staff witnesses Dorgan and Maness; and the entire record in this proceeding.

On October 30, 2019, DEP filed its Application and initial direct testimony and exhibits, seeking a net increase of approximately $585.9 million, or 15.6%, in its annual electric sales revenues from its North Carolina retail electric operations. The Company offset its requested increase by a rate reduction of $120.2 million to refund certain tax benefits resulting from the Tax Act through a proposed rider and $2.1 million related to the Regulatory Asset and Liability Rider. Thus, the Company proposed a net revenue increase of approximately $463.6 million, an overall 12.3% increase in annual revenues. DEP submitted evidence in this case with respect to revenue, expenses, and rate base using a test period consisting of the 12 months ended December 31, 2018, updated for certain known and actual changes.

**The Public Staff Partial Stipulations**

On June 2, 2020, DEP and the Public Staff entered into and filed the First Partial Stipulation, which resolves many of the issues in this proceeding between these two parties. The First Partial Stipulation is based upon the same test period as the Company's Application, adjusted for certain known changes in revenue, expenses, and rate base through February 29, 2020.

Witness De May explained that the First Partial Stipulation resolves several of the revenue requirement issues between the Company and the Public Staff. (Tr. vol. 11, 782.)

Revenue requirement adjustments were agreed upon in the First Partial Stipulation for Storm Costs, Aviation, Executive Compensation, Board of Directors, Lobbying, Sponsorships & Donations, Rate Case Expenses, Outside Services, Severance, Incentive Compensation, the Asheville Combined Cycle (CC) project, W. Asheville Vanderbilt 115 kV project, Credit Card Fees, End of Life Nuclear Reserve, Protected Federal EDIT, and treatment of the CertainTEED payment obligation in this rate case. (Id. at 783-84.) These accounting and ratemaking adjustments and the resulting revenue requirement effect of the First Partial Stipulation are shown in Schedule 1 of Maness Stipulation Ex. 1 and Smith Partial Settlement Ex. 3, which provide sufficient support for the annual revenue required on the issues agreed to in the First Partial Stipulation. The revenue requirement impact of the issues settled in the First Partial Stipulation results in a reduction of the base revenue requirement by a range of approximately $123,904,000 to $130,106,000, depending on the resolution of the Unresolved Issues.[5]

On July 31, 2020, DEP and the Public Staff entered into the Second Partial Stipulation, which resolved additional issues in the proceeding. The Second Partial Stipulation is based upon the same test period as the Company's Application, adjusted for certain known changes in revenue, expenses, and rate base through February 29, 2020 and May 31, 2020.

The Second Partial Stipulation outlines the Unresolved Issues as follows: (1) cost recovery of the Company's coal ash costs, recovery amortization period and return during the amortization period; (2) the depreciation rates appropriate for use in this case, including the Company's proposal to shorten the lives of certain coal-fired generating facilities; and (3) any other revenue requirement or non-revenue requirement issue other than those issues specifically addressed in this Second Partial Stipulation, the First Partial Stipulation, or agreed upon in the testimony of DEP and the Public Staff. (Second Partial Stipulation, § II.)

[5] The Commission's determination of the Unresolved Issues is included in Evidence and Conclusions for Findings of Fact Nos. ____ herein. The final revenue requirement resulting from the Commission's determination of the Unresolved Issues can be found in Finding and Conclusion No. ___.

Witness De May testified that DEP and the Public Staff were able to reach the Second Partial Stipulation, which resolves most, but not all of the remaining revenue requirement issues between DEP and the Public Staff. (Id. at 789.) Witness De May provided an overview of the major components of the Second Partial Stipulation, including an agreement regarding shareholder contributions to the Energy Neighbor Fund, cost of capital, return of state and federal EDIT to customers, deferral accounting treatment of certain GIP programs, cost of service methodology for this case, inclusion of the May 2020 Updates to certain pro forma adjustments subject to the Public Staff's audit of the updates and other terms concerning the May updates, the annual funding amount for the Company's Nuclear Decommissioning Trust Fund, and the amortization period for non-ARO environmental costs. (Id. at 789-92.) In addition, witness De May outlined other areas of agreement, including terms governing the start date of the evidentiary hearings to allow time for the Public Staff to audit the May Updates, ongoing assessments of the cost effectiveness of GIP-related projects, clarification of GIP costs that are eligible for deferral, commitments to future cost of service studies, rate design issues, and commitments to conduct audits and reporting obligations regarding plant, materials & supplies inventory, vegetation management, and service reliability index reporting. (Id. at 792.) These accounting and ratemaking adjustments and the resulting revenue requirement effect of the Second Partial Stipulation are shown in Maness Second Stipulation Ex. 1, Schedule 1 and Smith Second Settlement Ex. 3, which provide sufficient support for the annual revenue required on the issues agreed to in the Second Partial Stipulation. The Company's calculation of the revenue requirement impact of the issues settled in the Second Partial Stipulation is an increase in the base revenue requirement of approximately $19,495,000,[6] to be further adjusted by the Public Staff's recommendations in its testimony filed on September 15 and 16, 2020[7] and pending resolution of the Unresolved Issues. However, the total increase in base rate revenues and the resulting average increase of the Public Staff Partial Stipulations cannot be determined until the Commission resolves the Unresolved Issues.[8]

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[6] Smith Second Settlement Ex. 3. While the Second Partial Stipulation impact is an increase in the revenue requirement, the amount of money being returned to customers through the EDIT Rider 2 also increased from ($96,289,000) (*see* Smith Second Supplemental_S Ex. 2 Corrected) to ($152,348,000) (*see* Smith Second Settlement Ex. 2) as discussed in Evidence and Conclusions for Findings of Fact Nos. 21-25. Note that the EDIT flowback estimate of ($152,348,000) is based on an estimate of the amount to be flowed back to customer through the Company's interim rates and is subject to change based on the actual amount flowed back when the revised rates approved in this Order go into effect.

[7] The total impact on the base revenue requirement of the Public Staff's Second Partial Stipulation settled items is listed as ($318,000) on Maness Second Stipulation Ex. 1, but this value does not include the impact of Public Staff witness Metz's September 15, 2020 adjustments to remove the capital costs associated with Project Focal Point ($3,021,933.96 (system costs) (Tr. vol. 15, 859)), which the Company accepts. These amounts are embedded in the Public Staff's adjustments to plant in service, accumulated depreciation, and depreciation rates in the Unsettled Issues listed in Maness Second Stipulation Ex. 1.

[8] Smith Second Settlement Ex. 2 shows DEP's revised requested increase incorporating the provisions of the Second Partial Stipulation and the Company's position on the Unresolved Issues. The resulting proposed revenue requirement of the Company is $261,875,000, to be further adjusted by the Public Staff's recommended May 2020 Updates adjustments, which the Company accepts. Maness Second

Witness De May testified that he attended public hearings held by the Commission in this matter and personally heard from dozens of customers who are concerned about the impacts of any rate increase on their families and businesses and noted that the Company is very mindful of these concerns. (Id. at 793.) Witness De May further stated his belief that the concessions the Company has made in the Public Staff Partial Stipulations fairly balance the needs of DEP customers with the Company's need to recover investments made in order to continue to comply with regulatory requirements and safely provide high quality electric service to its customers, particularly so in the Second Partial Stipulation in light of the current economic conditions of many of the Company's customers due to the COVID-19 pandemic. (Id. at 793.)

Public Staff witness Maness testified that from the perspective of the Public Staff, the most important benefits provided by the Public Staff Partial Stipulations are: (a) an aggregate reduction in the Company's proposed revenue increase as to specific expense items agreed to by DEP and the Public Staff in this proceeding, and (b) the avoidance of protracted litigation between DEP and the Public Staff before the Commission and possibly the appellate courts. (Tr. vol. 16, 35.) Based on these ratepayer benefits, as well as the other provisions of the Public Staff Partial Stipulations, the Public Staff believes the Public Staff Partial Stipulations are in the public interest and should be approved. (Id.)

As the Public Staff Partial Stipulations have not been adopted by all the parties to this docket, its acceptance by the Commission is governed by the standards set out by the North Carolina Supreme Court in *State ex rel. Utils. Comm'n v. Carolina Util. Customers Ass'n, Inc.*, 348 N.C. 452 (1998) (*CUCA I*), and *State ex rel. Utils. Comm'n v. Carolina Util. Customers Ass'n, Inc.*, 351 N.C. 223 (2000) (*CUCA II*). In *CUCA I*, the Supreme Court held that

> [A] stipulation entered into by less than all of the parties as to any facts or issues in a contested case proceeding under Chapter 62 should be accorded full consideration and weighed by the Commission with all other evidence presented by any of the parties in the proceeding. The Commission must consider the nonunanimous stipulation along with all the evidence presented and any other facts the Commission finds relevant to the fair and just determination of the proceeding. The Commission may even adopt the recommendations or provisions of the nonunanimous stipulation as long as the Commission sets forth its reasoning and makes "its own independent conclusion" supported by substantial evidence on the record that the proposal is just and reasonable to all parties in light of all the evidence presented.

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Stipulation Ex. 1 shows a portion of the Public Staff's revised recommended change in revenue requirement incorporating the provisions of the Second Partial Stipulation and a number of downward adjustments reflecting the Public Staff's position on the Unresolved Issues, which also incorporate the Public Staff's May 2020 Updates adjustments to Plant In Service, Accumulated Depreciation and Depreciation Rates.

348 N.C. at 466. However, as the Court made clear in *CUCA II*, the fact that fewer than all of the parties have adopted a settlement does not permit the Court to subject the Commission's order adopting the provisions of a nonunanimous stipulation to a "heightened standard" of review. 351 N.C. at 231. Rather, the Court said that Commission approval of the provisions of a nonunanimous stipulation "requires *only* that the Commission ma[k]e an independent determination supported by substantial evidence on the record [and] ... satisf[y] the requirements of chapter 62 by independently considering and analyzing all the evidence and any other facts relevant to a determination that the proposal is just and reasonable to all parties." Id. at 231-32 (emphasis added).

The Commission credits the testimony of the Company and Public Staff witnesses regarding the Public Staff Partial Stipulations and finds and concludes that the Public Staff Partial Stipulations are the product of the give-and-take negotiations between DEP and the Public Staff in an effort to appropriately balance the Company's need for rate relief with the impact of such rate relief on customers. The Commission has fully evaluated the provisions of the Public Staff Partial Stipulations and concludes, in the exercise of its independent judgment, that the provisions of the Public Staff Partial Stipulations are just and reasonable to all parties to this proceeding in light of the evidence presented, and serve the public interest. The provisions of the Stipulations strike the appropriate balance between the interests of DEP's customers in receiving safe, adequate, and reliable electric service at the lowest reasonably possible rates, and the interests of DEP in maintaining the Company's financial strength at a level that enables the Company to attract sufficient capital for investments. Further, the Commission finds and concludes that the revenue requirement, rate design, and the rates that will result from the Public Staff Partial Stipulations, subject to the Commission's decisions set out below on the Unresolved Issues, will provide just and reasonable rates for DEP and its retail customers. The Public Staff Partial Stipulations are, therefore, material evidence to be given appropriate weight in this proceeding.

As detailed below, there is ample evidence in the record to support all of the provisions of the Public Staff Partial Stipulations, including those that have been contested by some intervenors other than DEP and the Public Staff. Accordingly, the Commission is fully justified in adopting the Public Staff Partial Stipulations through the exercise of its own independent judgment, and finding and concluding through such independent judgment that the Public Staff Partial Stipulations "[are] just and reasonable to all parties in light of all the evidence presented." *CUCA I*, 348 N.C. at 466. The Commission hereby adopts the Public Staff Partial Stipulations in their entirety, and the conclusions as to the individual provisions of the Public Staff Partial Stipulations are set forth more fully below. In addition, the Commission finds and concludes that the Public Staff Partial Stipulations are entitled to substantial weight and consideration in the Commission's decision in this docket.

**EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 11**

The evidence supporting this finding and conclusion is contained in the Public Staff Partial Stipulations, DEP's verified Application and Form E-1; the testimony and exhibits of DEP witnesses De May, D'Ascendis, Angers, Doss, Hatcher, Henderson, Metzler, Pirro, Smith and Turner; and Public Staff witnesses Dorgan, Floyd, Hinton, Maness, Metz, and McLawhorn; and the entire record in this proceeding.

As discussed above, DEP and the Public Staff reached partial settlements with respect to some of the revenue requirement issues presented by the Company's Application, including those arising from the supplemental and rebuttal testimonies and exhibits.[9] The accounting adjustments to which DEP and the Public Staff have agreed are outlined in § III of the First Partial Stipulation, as well as §§ III.J. – III.L. of the Second Partial Stipulation. The accounting adjustments that are not specifically addressed in other findings and conclusions are discussed in more detail below.

**Executive Compensation and Incentive Compensation**

In its Application, the Company removed 50% of the compensation of the five Duke Energy executives with the highest level of compensation allocated to DEP in the Test Period. Witness Smith explained that while the Company believes these costs are reasonable, prudent, and appropriate to recover from customers, DEP has, for purposes of this case, made an adjustment to this item. (Tr. vol. 13, 140.)

Public Staff witness Dorgan recommended an additional adjustment to remove 50% of the benefits associated with these top five Duke Energy executives. (Tr. vol. 15, 741.) He contended that this adjustment is consistent with the positions taken by the Public Staff and approved by the Commission in past general rate cases involving investor-owned electric utilities serving North Carolina retail customers. (Id.) He testified that the Public Staff believes that it is appropriate and reasonable for the shareholders of the larger electric utilities to bear some of the cost of compensating those individuals who are most closely linked to furthering shareholder interests. (Id. at 742.)

Witness Dorgan also recommended disallowance of incentive compensation related to earnings per share (EPS) and total shareholder return (TSR). (Id. at 744-45.) He asserted that incentive compensation tied to EPS and TSR metrics should be excluded because it provides a direct benefit to shareholders only, rather than to customers. (Id.)

In her rebuttal testimony, Company witness Metzler testified that the Public Staff's proposed adjustments are inappropriate and should be rejected by the Commission. (Tr. vol. 11, 106.) According to witness Metzler, employee compensation and incentives tied

[9] The First Partial Stipulation provides that no Stipulating Party waives any right to assert a position in any future proceeding or docket before the Commission or in any court, as the adjustments agreed to in the Stipulation are strictly for purposes of compromise and are intended to show a rational basis for reaching the agreed-upon revenue requirement without either party conceding any specific adjustment. DEP and the Public Staff also agreed that settlement on these issues will not be used as a rationale for future arguments on contested issues brought before the Commission.

to metrics such as EPS and TSR benefit customers because those metrics reflect how employees' contributions translate into overall financial performance. (Id. at 113.)

Additionally, witness Metzler explained that in order to attract a well-qualified and well-led workforce, the Company must compete in the marketplace to obtain the services of these employees. (Id. at 114.) Finally, witness Metzler pointed out that no witness in this proceeding challenges the reasonableness of the level of compensation expenses reflected in the ratemaking test period for the Company. (Id.)

The First Partial Stipulation provides that "[t]he Company accepts the Public Staff's proposed adjustment to executive compensation to remove 50 percent of the benefits associated with the five Duke Energy executives with the highest amounts of compensation, in addition to the 50 percent of their compensation removed in the Company's initial Application." (First Partial Stipulation, § III.7.)

As part of the First Partial Stipulation, DEP and the Public Staff agreed to accept the Public Staff's adjustment with a modification to limit the incentives removed. This agreement is reflected in § III.10. of the First Partial Stipulation, which provides that the Company's employee incentives should be adjusted to remove incentive pay related to EPS and TSR for the top levels of Company leadership.

**Aviation Expenses**

In its initial filing, the Company removed 50% of the corporate aviation costs to account for flights that may not be related to provision of electric service. (Tr. vol. 13, 144.) The Public Staff made a further adjustment after investigating the aviation expenses charged to DEP during the test year. (Tr. vol. 15, 745.) Public Staff witness Dorgan contended that based on his review of the flight logs, some of the flights appeared to be unrelated to the provision of utility services. (Id. at 745-46.) He also removed the DEP allocated portion of commercial international flights due to the Public Staff's determination that those flights were unrelated to the provision of utility service. (Id. at 746.) On rebuttal, Company witness Smith explained that all of the costs of the corporate aircraft have been allocated in accordance with the Company's cost allocation manual and that the Company's proposal to remove 50% of the costs is consistent with the Commission's order in Docket No. E-2, Sub 1142. (Tr. vol. 13, 190.) She also pointed out that the Public Staff's recommendation would result in recovery of only 10% of corporate aviation costs. (Id.) For the purposes of settlement, the parties agreed to an adjustment that removes aviation expenses associated with international flights, in addition to the 50% of the Company's corporate aviation O&M expense removed in the Company's initial Application. (First Partial Stipulation, § III.9.)

**Sponsorships and Donations**

Public Staff witness Dorgan adjusted the Company's O&M Expenses to remove amounts paid to the chambers of commerce, and other donations, reasoning that they should be disallowed because they do not represent actual costs of providing electric service. (Tr. vol. 15, 752.) In her rebuttal testimony, Company witness Angers testified that Chambers of Commerce promote business and economic development, which in turn helps to retain and attract customers to DEP's service territory. (Tr. vol. 11, 208.) She explained that funds paid to Chambers of Commerce that are not specified as a donation or lobbying on the Chamber invoice are supporting business or economic development and are considered to be properly charged as a utility operating expense that should be included in the Company's cost of providing electric service to customers. (Id.) Nevertheless, as part of the First Partial Stipulation, the Company agreed to accept the Public Staff's position on sponsorships and donations expense, which removed certain expenses related to the chambers of commerce and donations. (First Partial Stipulation, § III.11.)

**Outside Services**

The Public Staff reviewed costs for outside services associated with expenses that were indirectly charged to DEP by DEBS as well as those incurred by DEP directly and found certain expenses related to legal and non-legal invoices, which the Public Staff contends should not be charged to ratepayers. (Tr. vol. 15, 746.) In her Rebuttal Testimony, DEP witness Smith partially agreed with the items identified by the Public Staff related to certain outside services. (Tr. vol. 13, 186.) She agreed that certain outside services should be excluded; however, the Company maintains those costs have already been removed from the revenue requirement as mischarges due to human error. (Id. at 186-87.) She explained that in her supplemental direct testimony filed March 13, 2020, the Company proactively removed $0.2 million of system electric operating expenses from allocation to North Carolina retail electric expenses to cover any mischarges identified during the course of the rate case proceeding. (Id. at 187.) As such, the Company believes no additional adjustment to the proposed revenue increase is required for these costs. (Id.) In addition, the Company disagrees with the Public Staff's removal of outside services charges of $42,000 for missing invoices explaining that the support for those charges, including invoices, was provided in response to Public Staff Data Request 105. (Id.) She testified that it is the Company's understanding that the Public Staff agrees this adjustment was an error. (Id.) She further testified that the Company also disagrees with the description on Line 1 of Dorgan Exhibit and Supplemental Exhibit 1 Schedule 3-1(k), "Remove items related to coal ash litigation." (Id.) Witness Smith explained that the costs that comprise this line item do not include items related to coal ash litigation. (Id.) However, in reaching a compromise, the Company agreed that certain outside services expenses should be excluded. (First Partial Stipulation, § III.11.)

**Rate Case Expenses**

In its Application, the Company requested to amortize the incremental rate case costs incurred for this docket over a five-year period. (Tr. vol. 13, 144.) The Public Staff adjusted rate case expense to remove the unamortized portion of rate case expense in rate base, reasoning that the amortization of rate case expense should reflect a normalization of the costs associated with the filing of a rate case, based on a historical average of the number of years between rate case filings. (Tr. vol. 15, 751-52.) Public Staff witness Dorgan testified that the Public Staff takes the position that rate case expense does not rise to the level of being extraordinary in nature, and, therefore, does not require rate base treatment. (Id.) In her rebuttal testimony, witness Smith testified that the Company opposed the Public Staff's adjustment arguing that if the Public Staff had used the historical average costs and number of years between rate case filings since 2013, the amortization amount would have been $1.1 million, which is higher than the Company's proposed amortization amount. (Tr. vol. 13, 191.) Because the costs are known and measurable, the Company argues that inclusion of the costs in rate base is appropriate and that rate case expenses are incremental costs that have been incurred and funded by investors prior to new rates becoming effective. (Id.) However, in the spirit of settlement, DEP and the Public Staff agreed to amortize the rate case expenses over a five-year period, but the unamortized balance will not be included in rate base. (First Partial Stipulation, § III.8.)

**Severance Costs**

The Company made an adjustment to remove atypical severance and retention costs included in the Test Period and also requested to establish a regulatory asset to defer the North Carolina retail amount of $34.9 million of severance costs beginning when rates go in effect, to be amortized over a three-year period. (Tr. vol. 15, 752; Application at 16.) Public Staff witness Dorgan adjusted the severance costs to reflect a normalized level over a five-year period, consistent with how the Public Staff has treated severance program costs in other utility rate cases. (Id. at 752-53.) In its rebuttal testimony, the Company opposed the Public Staff's adjustment arguing that the adjustment only changed the proposed amortization period and did not calculate a normalized five-year level of severance expense, which would have been greater than the Company's proposed amortization amount. (Tr. vol. 13, 192-93.) Nevertheless, in the spirit of settlement, DEP and the Public Staff agreed that the severance expenses should be amortized over a three-year period, but the unamortized balance will not be included in rate base. (First Partial Stipulation, § III.12.)

**Lobbying Expenses**

With respect to lobbying expenses, Public Staff witness Dorgan noted that the Company assigned some lobbying expenses from the test year to below-the-line accounts, and therefore those costs were not included in the cost of service. (Tr. vol. 15, 746.) He further adjusted O&M expenses to remove what he characterized as additional lobbying costs, including O&M expenses that he believed were associated with stakeholder engagement, state government affairs, and federal affairs that were recorded above the line. (Id. at 746-47.) In her Rebuttal Testimony, DEP witness Angers explained why the Company opposed this adjustment and disagreed with witness Dorgan's characterization of these expenses. (Tr. vol. 11, 201-02.) Witness Angers testified that the Company's lobbying expenses are below-the-line, and thus not included in rates. (Id.) Witness Angers further testified that the amounts the Company has booked above the line align with an independent study performed by KPMG. (Id. at 202-05.)

In addition, witness Angers testified that it appeared that the Public Staff also removed a percentage of above-the-line expenses related to dues paid to Edison Electric

Institute (EEI). (Id. at 205.) Witness Dorgan did not address this adjustment in his testimony, but the Company was able to confirm the adjustment through discovery. (Id. at 205-06.) Witness Angers explained that the Company already books any costs for EEI that are related to lobbying, political activities, or contributions to a charitable foundation, below the line. (Id. at 206.) Company witness Angers further stated that EEI provides a Schedule of Expenses that details EEI's budgeted spend for lobbying and the Company uses that schedule to record the portion of the payment related to lobbying below-the-line. (Id.) Thus, the Company believes the Public Staff made this adjustment in error. (Id.) However, if the adjustment was not a mistake, witness Angers testified that the Public Staff offered no explanation in testimony to exclude additional amounts over and above those the Company has already recorded below-the-line. (Id.) The Public Staff later acknowledged that the adjustment related to EEI dues was made in error, and the Company accepted the Public Staff adjustment to lobbying expenses, as adjusted and corrected in Smith Partial Settlement Exhibit 3.

In the spirit of settlement and in the context of the First Partial Stipulation as a whole, the Company and the Public Staff reached settlement on the contested expenses, and the Company agreed to accept the Public Staff's recommended adjustments to remove certain expenses, as adjusted and corrected, in Smith Partial Settlement Exhibit 3. (First Partial Stipulation, § III.13.)

**Board of Director Expenses**

Witness Dorgan made an adjustment to remove 50% of the expenses associated with the Board of Directors of Duke Energy that have been allocated to DEP. (Tr. vol. 15, 743.) He argued that the premise of this adjustment is closely linked to the premise of the adjustment the Public Staff made related to executive compensation, in that the Board of Directors has a fiduciary duty to protect the interests of shareholders, which may differ from the interests of ratepayers. (Id.) Accordingly, the Public Staff believes it is appropriate for the shareholders of the larger electric utilities to bear a reasonable share of the costs of compensating the Board of Directors, as well as the cost of insurance for these individuals, which has been utilized to defend the Board of Directors in suits brought by shareholders. (Id.) Witness Metzler explained that the Company is required to have a Board of Directors and that the costs of being an investor-owned utility, including Board costs, are in fact costs of service. (Tr. vol. 11, 116.) She argued that it is not fair or reasonable to penalize the Company for being an investor-owned utility with attendant requirements to that corporate structure. (Id.) As part of the First Partial Stipulation, the Company agreed to accept the Public Staff's recommended adjustments to the Board of Directors' expenses. (First Partial Stipulation, § III.13.)

**W. Asheville Vanderbilt 115kV Project**

The Company recorded the Vanderbilt – W. Asheville 115kV transmission line project in the cost of service as a distribution project. (Tr. vol. 15, 735.) Public Staff witness Metz explained that the project involved reconductoring approximately two miles of the existing Vanderbilt to West Asheville 115 kV transmission line to accommodate power flows associated with generation additions in the Asheville area. (Id. at 851.) During the course of his review, witness Metz discovered the Company had inadvertently booked this project to distribution plant, rather than transmission plant; therefore, the Company should reclassify and rebook this project as a transmission plant and reallocate the costs accordingly. (Id.) Therefore, based on the recommendation of Public Staff witness Metz, Public Staff witness Dorgan made an adjustment to reflect a change in the allocation percentage to North Carolina retail to reflect that this project should have been recorded as transmission plant and not distribution plant. (Id.) In her pre-filed Rebuttal Testimony, DEP witness Smith testified that the Company opposes this adjustment because the Company had already made an adjustment in post-test year additions for this project in Smith Supplemental Exhibit 1. (Tr. vol. 13, 194.) As part of the First Partial Stipulation, in § III.14., the Public Staff and DEP agreed to the adjustment to the W. Asheville Vanderbilt II5 kV project as reflected in Maness Stipulation Exhibit 1 and Smith Partial Settlement Exhibit 1 (subject to then unsettled jurisdictional and class allocation factor methodology differences).[10] The First Partial Stipulation further provides that the Company appropriately classified the line as transmission in its supplemental filing and the settlement adjustment makes a small correction to the Company's adjustment in its supplemental filing. No other party contested this adjustment and the Commission finds the adjustment to be an appropriate resolution of this issue.

**Credit Card Fees**

In its Application, DEP requests approval of a fee-free payment program for credit, debit, and ACH payment methods used by the Company's residential customers to pay their electric bills. (Application, at 12.) Currently, customers are required to pay a $1.50 convenience fee, collected by a third-party vendor, for payments made by a credit card. (Tr. vol. 11, 863.) To offer this program, the Company proposes to pay these costs on behalf of its residential customers and recover these costs as part of its cost of service. (Id. at 866.) Company witness Smith describes in direct testimony the Company's proposal to adjust its O&M expense to adjust for credit card fee expenses and in her Supplemental Direct Testimony, makes an adjustment to reflect actual numbers of credit card transactions through February 2020. (Tr. vol. 13, 146, 175.) Company witness Hatcher testified to the value and need for the customer-driven program. (Tr. vol. 11, 863-66.)

Witness Hatcher explained that the requirement to pay a convenience fee when making a payment is one of the largest frustrations the Company's residential customers experience. (Id. at 862.) The Company's Customer Service department routinely receives inquiries about no-cost electronic payment options as evidenced by the Company's monthly residential transaction surveys. (Id. at 864-65.) According to witness Hatcher, customers have grown accustomed to paying for other products and services with a credit card or debit card without a separate, additional fee. (Id. at 865.) As customer

[10] These cost allocation methodology differences were later settled between the Company and the Public Staff. (*See* Second Partial Stipulation, § III.I.)

expectations change and more payments are done electronically, utility companies are now offering fee-free payment programs for their residential customers for all methods of payment. (Id. at 863.) Accordingly, witness Hatcher believes DEP residential customers will appreciate being able to use these payment methods with the Company the same way they can with other companies. (Id. at 863.) As stated by witness Hatcher, Duke Energy has seen 14% average year-over-year growth in credit/debit transactions over the past several years, and with this change the Company expected the growth rate to double – so 28% more transactions in 2019 than in 2018. (Id. at 863-64.)

While no party contested the value or benefits of the fee-free credit card program for residential customers, Public Staff witness Dorgan noted that the Company did not calculate any impacts to late payments or uncollectibles associated with the request to include credit card fees and has not removed the expenses related to the forms of payment that were utilized in the 2018 cost of service. (Tr. vol. 15, 748.) Therefore, the Public Staff made an adjustment to remove the O&M expenses included in the cost of service for 2018 associated with the increase in credit card transactions from the 2018 to 2019 period, to avoid double-counting costs associated with the same payments. (Id.)

In her pre-filed Rebuttal Testimony, Company witness Smith testified that the Company partially agreed with the Public Staff's adjustment, and accepted the concept of the Public Staff's adjustment to remove O&M expense associated with the increase in fee-free program transactions from 2018 to 2019. (Tr. vol. 13, 186.) However, witness Smith testified that the Company has updated the calculation to reflect avoided transaction costs related to payment by check as reflected in Smith Rebuttal Ex. 1. (Id.)

As part of the First Partial Stipulation, the Public Staff agreed to the Company's rebuttal position on credit card fees. (First Partial Stipulation, § III.15.)

**End-of-Life Nuclear Materials & Supplies**

In his direct testimony, Public Staff witness Metz testified that he reviewed the Company's Materials & Supplies (M&S) inventory. Based on that review, he recommended disallowance of $8.9 million in repair hold (RH) and quality assurance hold (QH) costs associated with inventory that has been in a hold status for four years or greater. Witness Metz stated that if inventory and its associated cost cannot be used for extended time periods, those parts (inventory) are unavailable for use, and ratepayers should not be burdened with those costs. (Tr. vol. 15, 841-44.) Witness Metz also proposed a positive salvage value of 10% be assigned to the M&S inventory, as opposed to the 0% value proposed by DEP. (Id. at 847-49.) Public Staff witness Dorgan made a corresponding adjustment based on the testimony of witness Metz to reflect the recommendation to remove certain items from inventory, as well as the application of a 10% salvage value to end-of-life (EOL) inventory. (Tr. vol. 15, 748.)

In his Rebuttal Testimony, Company witness Henderson testified that DEP did not agree with the proposed adjustment regarding RH and QH M&S inventory. Witness Henderson stated that this inventory is held to support plant operations and is therefore of benefit to customers. (Tr. vol. 11, 146.) Witness Henderson explained that it is appropriate to include RH and QH items that are four or more years old in nuclear M&S inventory, because such items ultimately benefit customers by ensuring adequate spare parts and material are available to support the safe and efficient operation of the plants. (Id. at 147.) Witness Henderson explained further that the Company balances priority and cost in order to maximize safety and reliable operation, which in turn benefits customers. (Id. at 148.) Witness Henderson described the Company's work to comply with the Commission's directive in the Sub 1142 Order to conform DEP's practices and procedures for managing nuclear and non-nuclear M&S to DEC's current practices and procedures to ensure that proper levels of inventory are maintained. (Id. at 150.) Regarding witness Metz's recommendation regarding EOL nuclear reserve, witness Henderson testified that while DEP generally agrees that there will be some small amount of salvage value for nuclear M&S inventory at its end of life, this value will be offset because the Company had not applied inflation rates to the inventory values presented in this case. Witness Henderson stated that DEP therefore believed that current inventory value is a reasonable approximate of EOL value less any salvage amounts. (Id. at 151.)

Section III.16 of the First Partial Stipulation provides that the Company accepts the Public Staff's adjustment to end-of-life nuclear M&S reserve expense, reduced as described in the direct testimony of Public Staff witness Metz. Company witness Smith (Tr. vol. 13, 231) and Public Staff witness Maness (Tr. vol. 16, 29) supported this provision through their testimony in support of the First Partial Stipulation.

No other party offered any evidence addressing these issues. Accordingly, the Commission finds and concludes it to be just and reasonable to all parties in light of all the evidence presented, for purposes of this proceeding, that the Company should reduce end-of-life nuclear materials and supplies reserve expense as described in the Direct Testimony of Public Staff witness Metz.

**CertainTEED Payment Obligations**

In its Application, the Company included a conditional request for recovery of payment obligations related to a settlement agreement with CertainTEED Gypsum NC, Inc. (CertainTEED). (Tr. vol. 13, 149.) Recovery of these same expenses were also at issue in the Company's fuel and fuel-related charge adjustment proceeding in Docket No. E-2, Sub 1204, pending a determination of whether the costs are considered fuel costs under North Carolina law, such that they are recoverable through the fuel clause. (Id.) The Company's Pro forma Adjustment #33 "Adjust for CertainTEED payment obligation" thus served as a placeholder in the event the Commission determined that the CertainTEED expenses were not eligible for recovery through the fuel clause. (Id.)

On November 25, 2019, the Commission issued its Order Approving Interim Fuel Clause Adjustment, Requiring Further Testimony, and Scheduling Hearing in Docket No. E-2, Sub 1204 finding that the Company's payments to CertainTEED can be recovered as fuel-related costs pursuant to N.C.G.S. § 62-133.2(a1)(9) in the event that the Company's decisions and actions in connection with the settlement agreement are found to be reasonable and prudent. (Tr. vol. 13, 176.) Accordingly, on December 5, 2019, the

Company filed a Letter Regarding Removal of CertainTEED Costs, indicating to the Commission its intent to remove the CertainTEED costs from its base rate request through its Supplemental Filing, which it subsequently made on March 13, 2020. (Id.) The Public Staff, for its part, requested that the Commission remove the CertainTEED payment obligation from the Company's rate base through the direct testimony of witness Dorgan, but later agreed to withdraw this recommended adjustment due to the fact that the Company had already removed the expense from this proceeding in its Supplemental Filing. (Tr. vol. 15, 751; First Partial Stipulation, § III.19.) The Public Staff and the Company therefore agree that the CertainTEED Payment Obligation is appropriately removed from this proceeding. (Id.)

**May 2020 Updates**

On July 2, 2020, the Company filed Second Supplemental Direct Testimony and Exhibits of Company witness Smith updating certain material pro forma adjustments through May 31, 2020 (the May 2020 Updates). The Company updated revenue requirements through May 2020 for the following pro forma adjustments: customer growth; post-test year additions to plant in service; accumulated depreciation; depreciation expense; property taxes; O&M non-labor expenses; O&M labor expenses; merger related costs; interest synchronization; cash working capital; and an adjustment to update and remove storm costs for securitization. (Tr. vol. 13, 240-42.) Though the May 2020 Updates were initially opposed by the Public Staff, DEP and the Public Staff eventually reached agreement regarding the consideration of the May 2020 Updates in the Second Partial Stipulation and agreed to include the adjustments, pending and subject to the Public Staff's audit of the updates. (Second Partial Stipulation, §§ III.J., IV.A.) DEP and the Public Staff also agreed to include updates for benefits and executive compensation. (Second Partial Stipulation, § III.J.) Finally, DEP and the Public Staff agreed to limit the updates on revenues to 75% of the difference between the May 2020 Updates and the Company's February 2020 update to recognize the uncertainty regarding the effects of COVID-19, the 75% limitation is applicable only if the net effect of the updates on revenues is a revenue requirement increase. (Id.)

After completing the aforementioned audit, on September 16, 2020, Public Staff witness Maness filed Supplemental Testimony Supporting the Second Partial Settlement and exhibits updating and revising the Public Staff's calculation of its recommended revenue requirement, including the impacts of the Second Partial Stipulation and the accompanying review of the Company's May 2020 Updates. The Public Staff reviewed the Company's proposed updates to net plant, depreciation expense and accumulated depreciation, new depreciation rates, and revenues and related expenses (weather, and customer growth and usage). The Public Staff recommended certain adjustments to these items, and also recommended an adjustment to update certain employee benefits, the Asheville production displacement adjustment, O&M non-labor expense (inflation), and cash working capital, which are reflected in Maness Second Stipulation Ex. 1. (Tr. vol. 16, 43-44). The adjustments to the revenue requirement for those items previously settled between the Company and the Public Staff (benefits, weather, customer growth and usage, Asheville production displacement, and inflation) totaled ($318,000), exclusive of the impact on cash working capital.[11]

**Weather Normalization, Customer Growth, and Usage**

DEP witness Pirro testified that he provided the retail sales and number of customers to DEP witness Smith for use in calculating the pro forma adjustment to growth in customers. (Tr. vol. 11, 1082.) He explained that to arrive at the appropriate number of customers served and the attendant annualized sales levels at the end of the Test Period, the Company used a combination of regression analysis and a customer-by-customer approach. (Id. at 1083-84.) In his Supplemental Direct Testimony, witness Pirro testified that the Company had proactively modified its adjustments to annual revenues for customer growth, change in usage, and weather normalization based on Public Staff witness Saillor's recommended modifications in the DEC Rate Case in Docket No. E-7, Sub 1214, which the Company agrees with in principle. (Id. at 1116-17.) Namely, witness Saillor's proposed modifications to the adjustments to annual revenues for customer growth and change in usage include:

- Modifying DEP's customer-by-customer approach for openings in the Test Period by determining average monthly usage through taking the average of the 12 months of billing data following initial month of service;

- Modifying DEP's customer-by-customer approach for openings in the Extended Period (through February 29, 2020) by removing the initial month of service from the average usage calculation;

- Removing the Basic Customer Charge revenues from the change in usage calculations;

- The removal of the change in usage revenue adjustment for the Lighting rate class; and

- The inclusion of a change in usage adjustment for the General and Industrial rate classes.

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[11] The Company submitted a new Lead-Lag Study as part of its Application (*see* Angers Ex. 3), which the Company subsequently revised as part of the supplemental testimony of DEP witness Angers (*see* Angers Supplemental Ex. 3). In his direct pre-filed testimony, Public Staff witness Dorgan proposed adjustments to cash working capital based on the Public Staff's review of the Lead-Lag Study. Witness Angers testified that the Company agreed with the Public Staff's adjustments to cash working capital and noted that the adjustments are consistent with the changes she described in her supplemental testimony that are included in the revised Lead-Lag Study. (Tr. vol. 11, 200-01.) Thus, the cash working capital adjustments for rates approved in this proceeding shall be based on the revised Lead-Lag Study, which the Commission approves as reasonable and appropriate.

(Id.) For the weather normalization adjustment, witness Saillor had recommended the following modifications:

- The removal of Basic Customer Charge revenues from the calculations of average customer class rates; and
- Summing of the monthly NC Retail kWh weather adjustments within the test period for each customer class in place of multiplying the test period System Retail kWh weather adjustment times the annual NC Retail-to-System sales ratio.

(Id. at 1117.)

In his pre-filed Direct Testimony, Public Staff witness Saillor testified that he did not have any recommended changes to the adjustments to annualize retail revenues for current rates. (Tr. vol. 15, 701.) For the weather normalization revenue adjustment, he removed the basic facilities charge revenues from DEP's calculations for the average customer class rates under the rationale that weather effect does not change the number of bills rendered during the test period. (Id. at 702.) He also summed the monthly North Carolina Retail kWh weather adjustments updated through December 2019, for each month of the test period for each customer class, which he believes more accurately reflects the normal weather adjustment being represented by DEP. (Id.) Witness Saillor testified that the Company agrees with these modifications. (Id. at 703.) He also proposed two modifications to the end of test period methodology proposed by DEP: (1) summing the 12 months of billing data following the initial month of service and dividing by 12, and (2) replacing actual sales with weather-normalized sales in the adjustments for the SGS rate class. (Id. at 708.) He also explained his proposed modifications to the customer growth and change in usage adjustments and testified that the Company agrees with each modification except for the change to weather-normalized sales for the SGS rate classes, which was not addressed in witness Pirro's Supplemental Direct Testimony. (Id. at 709-10.)

In his pre-filed Rebuttal Testimony, witness Pirro testified that the Company agreed with the formulaic changes suggested by witness Saillor. In addition, the Company inadvertently did not address witness Saillor's calculation methodology to weather-normalize sales for the SGS rate class, with which the Company also agrees. (Tr. vol. 11, at 1125-26.) However, the Company disagreed with witness Saillor's use of customer growth projections through February 2020 because of the significant reduction in its load and associated revenues experienced during the COVID-19 emergency, some of which, the Company believes, could become permanent. (Id. at 1126.) Thus, the Company asserted that reflecting these changes closer in time to the hearing would result in a more accurate depiction of the Company's load forecast. (Id.) DEP witness Pirro testified that for purposes of his rebuttal testimony, he supported the adjustment as reflected in witness Smith's supplemental testimony and exhibits filed on March 13, 2020 and that the Company would update its customer growth, change in usage and weather normalization adjustments closer to the hearing. (Id.) Witness Pirro also testified that there appeared to be a spreadsheet issue with the change in number of bills displayed in witness Dorgan's

Supplemental Exhibit 1, Schedule 3-1(b) compared to the change in number of bills displayed in Saillor Supplemental Exhibit 3. (Id. at 1127.) He testified that he understood that the Public Staff agrees that the number of bills displayed on Line 15 in Dorgan Supplemental Ex. 1, Schedule 3-1(b) should be 473,731 consistent with Saillor Supplemental Ex. 3. (Id.)

Subsequently, in his Second Supplemental Direct Testimony, witness Pirro testified that the Company updated its customer growth adjustment through May 31, 2020, to incorporate certain known and measurable changes. (Tr. vol. 11, 1143.) He explained that the updated customer growth adjustment reflects a significant reduction in the Company's load and associated revenues as a result of many commercial and industrial customers as well as schools and colleges scaling back operations, as well as an increase in residential usage, during the COVID-19 pandemic. (Id. at 1144.) Witness Pirro's updated customer growth adjustment reflects the reduction in non-residential load and increase in residential usage through May 31, 2020. (Id. at 1144.)

As noted above, DEP and the Public Staff eventually reached agreement regarding the consideration of the May 2020 Updates in the Second Partial Stipulation and agreed to include the adjustments, pending and subject to the Public Staff's audit of the updates, and also subject to a limit of the updates on revenues to 75% of the difference between the May 2020 Updates and the Company's February 2020 update to recognize the uncertainty regarding the effects of COVID-19 if the net effect of the updates on revenues is a revenue requirement increase. Witness Pirro filed Pirro Second Settlement Ex. 4 to reflect the revised revenue requirement resulting from the Second Partial Stipulation and the Company's position on unsettled items.

**Non-Labor O&M Expense (Inflation)**

The Company adjusted annual non-labor, non-fuel O&M costs, to reflect the increase in costs during the test year that occurred due to the effect of inflation as of December 31, 2018. (Tr. vol. 15, 730.) Public Staff witness Dorgan adjusted the Company's inflation adjustment to reflect the inflation factor through December, 31, 2019, and modified the Company's inflation adjustment to reflect the Public Staff's adjustment to include variable O&M expenses for changes in customer growth and the removal of aviation expenses, Board of Directors expenses, outside services expenses, uncollectibles, sponsorships and donations, and advertising. (Id. at 740-41.) In rebuttal testimony, Company witness Smith did not oppose the adjustment. Subsequently, in the May update, the Public Staff 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. The Company agrees with this adjustment. (Tr. vol. 16, 49.)

The specific updated Public Staff adjustments discussed in witness Maness's testimony to which the Company agrees are as follows:

### *Plant in Service and Accumulated Depreciation*

Public Staff witness Maness updated net plant for known and actual changes to depreciation expense and non-generation plant retirements recorded between the end of the test year and May 31, 2020. (Tr. vol. 16, 46.) Witness Maness also included adjustments recommended by Public Staff witness Metz removing costs related to the Company's Project Focal Point. (Id.) The impact of the removal of costs associated with Project Focal Point, which was part of the Public Staff's adjustments to the update of plant, depreciation expense, and accumulated depreciation, are included in the unsettled update to plant and accumulated depreciation as of May 31, 2020 listed on Schedule 1, Line 5 of Maness Second Stipulation Ex. 1. Although the Public Staff and the Company agree the item should be removed from plant in service and accumulated depreciation, the item remains unsettled until the Commission determines the appropriate depreciation rates, which are included in the calculation of the adjustment. The Company agrees these adjustments should be included in the calculation of the final revenue requirement determined in the present case.

### *Updated Revenues*

Public Staff witness Maness 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, and corrected a Public Staff formula error in the schedule. (Tr. vol. 16, 47.) Witness Maness also updated the customer growth and usage amounts per the recommendation of Public Staff witness Saillor. (Id. at 47-48.) The Company agrees with this adjustment. (Id. at 48.)

### *Asheville Production Displacement*

As discussed further below, Public Staff witness Maness 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 DEP and the Public Staff in the Second Partial Stipulation. (Id.)

### *Benefits*

Public Staff witness Maness updated the benefits related to other post-employment benefits, pension, FASB 112, and non-qualified pensions to reflect the updated 2020 actuarial amounts that became available after the initial update period. The Company agrees with this adjustment. (Id.)

## Asheville CC

On March 28, 2016, the Commission approved a certificate of public convenience and necessity (CPCN) for the Asheville Combined Cycle (CC) units (Asheville CC Project), finding that its construction was needed to meet the projected growth in the Company's Western Region and to meet DEP's total system needs. (*See* Order Granting

Application in Part, with Conditions, and Denying Application in Part, Docket No. E-2, Sub 1089 (Mar. 28, 2016) Tr. vol. 11, 982.) At the time the Company filed its Application in this rate case, the Asheville Steam Electric Generating Plant was anticipated to be retired in December 2019 with the new Asheville CC Project scheduled to be in service that same month. (Application, at 5.) Company witness Turner testified that the Asheville CC Project comprises two 1x1 CC dual fuel units (power blocks) and that each power block contains a combustion turbine (CT) generator and a steam turbine generator, and has a capacity of 280 MW. (Tr. vol. 11, 981.)

As part of its Application, the Company requested that given the addition of the new Asheville CC Project to the Company's generating fleet, that the costs associated with the plant (depreciation, property taxes, incremental O&M and return) incurred from the time the facility is placed into service until the time the approved costs will be reflected in the new rates from this proceeding be deferred and amortized beginning with the effective date the Commission approves new rates in this proceeding. (Application, at 19; Tr. vol. 13, 166.) In her pre-filed Direct Testimony, DEP witness Smith testified that without approval of the Company's request to defer the Asheville CC Project costs, the Company would face an earnings degradation of approximately 80 basis points. (Tr. vol. 13, 166.) She further explained that approval of the Company's accounting order request for the Asheville CC Project would be consistent with prior Commission practice regarding significant new generation plants and would better align costs with revenues. (Id.)

The Company made a pro forma adjustment to include the amortization of the deferred costs related to the Asheville CC Project that includes an annual level of amortization of deferred costs, including a return on investment, over a three-year period. (Tr. vol. 15, 736.) As part of this adjustment, DEP included a separate pro forma adjustment to include a proxy for the ongoing O&M expenses and M&S inventory for the Asheville CC Project. (Id.) The Company also included a pro forma adjustment to reflect Power Block 1, including the common plant, and a combustion turbine from Power Block 2 in plant additions as of December 31, 2019, which represented 480 MW of the 580 MW (nameplate capacity) Asheville CC facility that were placed in service as of December 31, 2019. (Id.)

In her pre-filed Supplemental Direct Testimony, Company witness Smith testified that the Company had updated the Asheville CC deferred balance amortization to reflect the estimated deferred costs and associated regulatory asset established for the Asheville CC. (Tr. vol. 13, 176-77.) She explained that at the time of DEP's Application, the plant was expected to be in service in late 2019 and as of February 29, 2020, Units 5, 6, and 7 were placed in service with Unit 8 expected to be in service before the start of the evidentiary hearing, initially scheduled to commence on May 4, 2020. (Id. at 177.)

In his pre-filed Direct Testimony, Public Staff witness Metz testified that three of the four units at DEP's Asheville CC Project had been placed in service and explained that the plant was only partially in service due to unexpected events that occurred during testing at one of the steam turbines, which required repairs and further testing. (Tr. vol. 15, 823.) Witness Metz encouraged DEP to continue negotiations with the original equipment manufacturer (OEM) to obtain a "no cost" extended warranty on at least the steam turbine and its associated generator that had experienced damage. (Id. at 824-25.) Additionally, he recommended the Commission require the Company to file a letter in this docket notifying the Commission when the Power Block 2 steam turbine was completed and available for full economic dispatch. (Tr. vol. 15, 825-26.) Witness Metz also proposed an adjustment to the Asheville CC Project to account for the time delay between the Company's request in this case and the time rates will actually go in effect and to establish an estimated amount of expected plant expenses. (Id. at 849.)

Witness Metz revised the Asheville CC Project O&M estimated expense to reflect a revised cost and change in the cost calculation methodology, both applying a weighted average (instead of simple average employed by DEP) of CC expense versus nameplate capacity, and removing certain costs he found to be duplicative or incorrectly charged. (Id. at 850-51.) As a result of witness Metz's findings, Public Staff witness Dorgan adjusted the annual O&M expenses utilized by the Company for the Asheville CC Project and testified that it was his understanding that the Company accepts the Public Staff's methodology for calculating a proxy for O&M expenses. (Id. at 736-37.) Further, witness Dorgan recommended that the deferred Asheville CC Project costs for North Carolina retail be recovered through a levelized amortization over a five-year period. (Id. at 738.) Witness Dorgan also explained that the Company made an adjustment to include 480 MW of the Asheville CC Project in service on December 31, 2019 and that, based on the Public Staff's understanding, the remaining 100 MW was placed in service on April 5, 2020 and would be addressed by the Company in a subsequent supplemental testimony filing. (Id. at 737, 753-54.)

Finally, witness Dorgan testified that with the net addition of kWh due to the Asheville CC Project, other DEP resources will operate less frequently or at lower levels of output, and thus incur fewer non-fuel variable O&M expenses. (Id. at 754.) To account for this, he reduced non-fuel variable O&M expenses in a displacement adjustment to prevent the inclusion in cost of service of more than the end-of-period level of these types of expenses. (Id.) NC WARN witness Powers testified the project cannot be considered used and useful because both phases were not online until April 5, 2020. (Id. at 886.)

Regarding witness Metz's recommendations, in her pre-filed Rebuttal Testimony, DEP witness Turner noted that the repairs performed by the OEM restored the steam turbine generator component of Power Block 2 to new condition, and that the existing contract with the OEM provides for a two-year warranty on both power blocks. (Tr. vol. 11, 984.) Witness Turner stated that DEP's negotiations with the OEM regarding Power Block 2 are ongoing and include representatives from DEP's legal, supply chain, and project management organizations. (Id.) Regarding his recommendation for a letter update, she testified that subsequent to the completion of the repair to the Power Block 2 steam turbine, DEP submitted an update to the Commission in Docket No. E-2, Sub 1089 on April 6, 2020, stating that the Power Block 2 steam turbine generator went into commercial operation on April 5, 2020. Witness Turner described the graphic representation of the Power Block 2 steam turbine's hourly generation profile as provided in an exhibit to her rebuttal testimony, and noted that based on discussion with the Public

Staff, DEP believed the letter and exhibit met the Public Staff's recommendation in this regard. (Id. at 984-85.)

Regarding the Public Staff's displacement adjustment for the Asheville CC Project, witness Turner testified that the adjustment is not warranted, explaining that the Asheville CC Project represents the addition of two new CC facilities to the DEP fleet that need to be operated and maintained. (Id. at 983.) In addition to meeting the Company's obligations under the Mountain Energy Act, she noted that these units will also serve a growing number of customers in the surrounding area and the associated growth of energy and peak demand requirements. (Id.)

In her pre-filed Rebuttal Testimony, Company witness Smith stated that DEP accepted the Public Staff's methodology for calculating annualized O&M for the Asheville CC Project, but opposed the adjustment to use the annuity factor method to calculate amortization expense, removing the deferral and ADIT balances from the rate base, and disagreed with the dollar amount of the adjustment because it needed to be updated to include Unit 8, which went into service on April 5, 2020. (Id. at 187, 193-94.) In addition, she testified that DEP opposed the Public Staff's recommended amortization period of five years, instead of the three-year amortization period it proposed, for the deferred Asheville CC Project costs. (Id. at 194). She explained that the Company's current case includes several regulatory amortizations in addition to the Asheville CC Project deferred costs, and that many of those deferrals involve larger dollar amounts and longer amortization periods. (Id.) Therefore, because the Asheville CC Project deferred cost amounts are much smaller, the Company believes a shorter amortization period is appropriate. (Id.) Finally, she adjusted the deferred balance of the Asheville CC Project that went into service on April 5, 2020. (Id. at 215.)

In his pre-filed Supplemental Testimony, Public Staff witness Dorgan updated his adjustment to the Asheville CC Project to reflect DEP's actual costs as of February 2020, and incorporated adjustments to the levelization calculation to reflect that Power Block 2 came online on April 5, 2020, and the entire Asheville CC Project can be economically dispatched. (Tr. vol. 15, 772.)

Subsequently, the Company and the Public Staff entered into the First Partial Stipulation, which settled the contested issues between the parties regarding the Asheville CC Project. Section III.17 of the First Partial Stipulation provides that the Asheville CC Project is complete, placed in service, and available for economic dispatch. Section III.17.a provides that the Stipulating Parties agree that the appropriate amortization period for the deferred expenses for the Asheville CC Project is four years with a levelized return. Section III.17.b provides that the Stipulating Parties agree that the Company's non-fuel variable O&M expense related to the Asheville CC Project should be reduced to account for a production displacement adjustment. Section III.17.c of the First Partial Stipulation provides that the amount of Asheville CC plant in service appropriate to include in rate base and used for the deferral calculation in this proceeding is the amount reflected in the Company's rebuttal testimony (subject to unsettled jurisdictional and class allocation factor methodology differences[12]), and that the Public Staff reserves the right to review any actual reimbursements received from the EPC contractor in a subsequent rate case. Section III.20 of the First Partial Stipulation provides that the Stipulating Parties agree to include annualized accumulated depreciation for the Asheville CC Project not previously included in supplemental or rebuttal filings. In her pre-filed Settlement Supporting Testimony, Company witness Smith explained that the Public Staff and DEP agree to an adjustment to accumulated depreciation reserve related to the Asheville CC Project to correct an error in the Company's rebuttal filing. (Tr. vol. 13, 232.)

In his Supplemental Second Settlement Testimony, Public Staff witness Maness stated that he 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. He stated that in its calculation, the Company had based the calculation on the SWPA allocation factors. (Tr. vol. 16, 48.)

Company witness Smith (Tr. vol. 13, 231-32) and Public Staff witness Maness (Tr. vol. 16, 29) supported these provisions related to the Asheville CC Project through their testimony in support of the First Partial Stipulation. While NC WARN opposed inclusion of the Asheville CC Project in rate base, as previously noted, we already addressed the need for this generation when we issued the CPCN on March 28, 2016. Accordingly, the Commission finds and concludes it to be just and reasonable to all parties in light of all the evidence presented that the Asheville CC Project is complete, placed in service, and available for economic dispatch; that the appropriate amortization period for the deferred expenses for the Asheville CC Project is four years with a levelized return; that the Company's non-fuel variable O&M expense related to the Asheville CC Project should be reduced to account for a production displacement adjustment; that the amount of Asheville CC plant in service appropriate to include in rate base and used for the deferral calculation in this proceeding is the amount reflected in the Company's rebuttal testimony (as adjusted by Public Staff witness Maness in his Supplemental Second Settlement Testimony); that the Public Staff reserves the right to review any actual reimbursements received from the EPC contractor in a subsequent rate case; and that annualized accumulated depreciation for the Asheville CC Project not previously included in supplemental or rebuttal filings should be included.

**Nuclear Decommissioning Trust Fund**

Public Staff witness Hinton testified that in this case DEP proposes a total Nuclear Decommissioning Trust Fund (NDTF) expense of approximately $19.6 million, the same level included in the Company's 2017 general rate case in Docket No. E-2, Sub 1142. (Tr. vol. 15, 334.) He explained that the $19.6 million approved decommissioning expense

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[12] These cost allocation methodology differences were later settled between the Company and the Public Staff. (*See* Second Partial Stipulation, § III.I.)

was based on the Company's 2015 Nuclear Decommissioning Studies. (Id.) He further explained that the Company filed a Nuclear Decommissioning Cost and Funding Report in 2015, which the Company made several updates and adjustments to for the 2017 DEP Rate Case. (Id. at 336.) Witness Hinton testified that the Public Staff has concerns with the current use of a cost estimate filed in 2015, based on dollars from 2014. (Id. at 336-37.) DEP's Decommissioning Cost Analyses filed on March 12, 2020, in Docket No. E-100, Sub 56, estimated the cost to decommission DEP's four nuclear units as approximately 18% higher than estimated in the 2015 Cost Analyses. (Id.) Thus, the Public Staff recommends basing the decommissioning expense in this rate case on the 2020 Cost Analyses. (Id.) Witness Hinton testified that he found the Company's assumptions for calculating the Decommissioning expense to be reasonable with the exception of DEP's proposed rates of return for its qualified trust fund (4.56% average projected long-run rate of return for DEP's qualified trust funds), which he testified "are unreasonable and overly conservative." (Id. at 340.) Relying on witness Woolridge's CAPM testimony regarding a reasonable expected rate of return for the Company's cost of equity, witness Hinton testified that he believes a 9.0% to 9.50% expected rate of return for these assets is reasonable. (Id. at 341.) He also provided a Confidential Exhibit 6 showing the historical annual rates of return on the funds and testified that DEP's long-run rate of return of 4.56% is overly conservative based on his review of past performance after taxes and fees. He noted that the historical rates of return shown in Exhibit 6 reflected three recessionary periods that were followed by periods of positive growth in the value of DEP's qualified funds. (Id.) In addition, he argued that the Company's pension and decommissioning funds have similar asset allocations and annual earned rates of return but use a different overall rate of return on its overall fund investments. (Id. at 342.) Finally, witness Hinton testified that he considered other sources; such as Dominion Energy North Carolina's (Dominion) current decommissioning funding study that reflects Dominion's projection of its rate of return on its qualified funds filed in Docket No. E-100, Sub 56. Based on these factors and analysis, witness Hinton recommended use of an overall expected 6% rate of return for DEP's qualified trust funds and that the Commission reduce the Company's decommissioning expense to $0. (Id. at 345.)

In rebuttal, DEP witness Doss provided an overview of the Commission's Guidelines for determining and reporting nuclear decommissioning costs and the process for determining the amount of nuclear decommissioning costs included in the Company's revenue requirement. (Tr. vol. 16, 346-53.) He explained that when the Company's Application was filed on October 30, 2019, the Company opted to keep the revenue requirement relating to nuclear decommissioning expense the same as the amount approved in the 2017 Rate Case given that a new study was expected by the end of 2019, and the Company would be going through the lengthy process of updating the cost and funding model in 2020, which was not anticipated to be complete prior to the close of this rate case. (Id. at 354.) In response to Public Staff witness Hinton's recommendation that the Commission update the Company's decommissioning expense outside of the typical process, witness Doss explained that the process of developing a cost and funding model is complicated and includes many inputs and assumptions. (Id. at 356.) He testified that "[s]imply put, there is a reason the Commission requires the Company to go through the exercise of developing a cost and funding model and that the Commission allows 210 days from the receipt of costs estimates for the Company to complete the funding report." (Id.) Witness Doss explained "that process is currently underway and should not be allowed to be short-circuited by the Public Staff." (Id.) Regarding witness Hinton's comparison to market returns relating to ROE as a basis for his recommended NDTF return, DEP witness D'Ascendis testified that witness Hinton's recommendation incorrectly assumes there is no distinction between expected returns assumed in NDTF funding assumptions and other managed asset funds such as pension funds and the required returns that are the subject of his and witness Woolridge's testimony. (Tr. vol. 11, 577.) Witness D'Ascendis explained that the investor-required return on the market is not equivalent to the expected market return estimates used by asset fund managers, and that one cannot be substituted for the other. (Id. at 578.) He explained that investors may use a more conservative required return estimate for asset fund management purposes than the required return that applies to individual equity investments. (Id.) He explained that asset fund managers are concerned with investing funds at an expected return to meet expected liabilities over a finite period, while individual equity investors decide whether to commit capital to a given security based on the return that they require to be compensated for the risks associated with that security, in perpetuity. (Id. at 579.) Further, witness D'Ascendis testified that the Commission has previously recognized the distinction between expected returns and required returns. (Id. at 579-80.)

As part of the Second Partial Stipulation, DEP and the Public Staff agreed to reduce the annual funding for the Company's NDTF by $8.7 million, and further agreed to support this funding amount in DEP's current cost and funding decommissioning Docket No. E-100, Sub 56. To the extent the Commission orders in that docket a different level of funding than the amount the parties agreed to in the Second Partial Stipulation, the parties agree that the Company will defer the difference in a regulatory asset or liability to be considered in the next rate case. (Second Partial Stipulation, §III.K.)

**Amortization Period for Deferred Non-ARO Environmental Costs**

Public Staff witness Maness testified that pursuant to the Commission's approval of the 2016 request for deferral filed in Docket No. E-2, Sub 1103, the Company is proposing to defer and amortize certain depreciation and return requirements related to certain capital projects placed into plant in service since its most recent rate proceeding. (Tr. vol. 15, 1583.) He explained that these projects are not classified by the Company as legal obligations associated with the retirement of coal ash facilities or the generating plants with which those facilities are associated; instead, they are intended to address coal ash issues related to the continuing operation of the applicable generating plants. (Id.) Although they are not part of the legal obligation that gives rise to DEP's coal ash asset retirement obligation (ARO), the Company and Public Staff agree that these costs are eligible for deferral pursuant to the terms of the Sub 1103 deferral accounting request, because they are needed to fulfill the Company's responsibilities under North Carolina's Coal Ash Management Act (CAMA) and the United States Environmental Protection Agency's Coal Combustion Residuals Rule (CCR Rule). (Id.) However, witness Maness testified that although he does not oppose deferral of the capital (return and depreciation) costs of the projects in this case, he does not agree with the five-year period proposed by the Company over which to amortize the deferred costs and instead recommends an amortization period of ten years, which would lower the revenue requirement and substantially ease the annual impact of the deferral and amortization on the ratepayer, and that the reduction would not directly harm the Company in that the unamortized amount would earn a return through being included in rate base. (Id. at 1584.)

In rebuttal, DEP witness Smith testified that the Company does not agree with witness Maness's recommendation to increase the amortization period for non-ARO related deferred capital expenditures. (Tr. vol. 13, 209.) She explained that the Public Staff has recommended extending amortization periods proposed by the Company when the amortization involves amounts to be collected from customers, but recommends shortening the periods when the amortization involves amounts to be refunded to customers. (Id.) She explained that the Company considered annual rate impacts in its recommendation of the five-year amortization and considered the Commission's decision in the 2017 Rate Case in arriving at its proposed amortization period. (Id.) Nevertheless, in the spirit of settlement, DEP and the Public Staff have agreed to amortize deferred non-ARO environmental costs over an eight-year period. (Second Partial Stipulation, § III.L.)

Upon consideration of all of the evidence in this proceeding, including the Public Staff Partial Stipulations, which the Commission accepts in their entirety and upon which the Commission places great weight, the Commission finds and concludes that the stipulated adjustments discussed herein are just and reasonable to all parties.

## EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 12-19

The evidence supporting these findings and conclusions are contained in the verified Application and Form E-1 of DEP; pre-filed testimony and exhibits of Company witnesses Jackson, Smith, and De May; and Public Staff witnesses Dorgan and Maness; the Company's Application and its Petition for an Accounting Order to Defer Incremental Storm Damage Expenses Incurred as a Result of Hurricanes Florence and Michael and Winter Storm Diego (Storm Cost Petition) in Docket No. E-2, Sub 1193; the First Partial Stipulation; and the entire record in this proceeding.

In its Storm Cost Petition, filed in Docket No. E-2, Sub 1193, the Company sought authorization from the Commission to defer certain storm response costs incurred by the Company in responding to Hurricanes Florence and Michael and Winter Storm Diego.

In its Application, the Company proposed to consolidate its Storm Cost Petition with the rate case and to recover its Storm Costs through a revision to its base rates. It also proposed to consolidate its request for storm cost recovery related to 2019 storm Hurricane Dorian with its request for cost recovery related to Hurricanes Florence, Michael, and Winter Storm Diego. In the testimony of Company witness De May, however, the Company linked its Storm Costs recovery request to the passage of Senate Bill 559 (SB 559) – An Act to Permit Financing for Certain Storm Recovery Costs, and indicated that if that then-pending legislation was enacted by the General Assembly, the Company would seek recovery of its Storm Costs through a securitization filing instead of in base rates.

In his prefiled Direct Testimony, Company witness Jackson provided testimony detailing DEP's general storm response and recovery systems and procedures. (Tr. vol. 11, 61-77.) This testimony described, in detail, how DEP plans for, prepares to respond, and ultimately does respond to major storm events impacting its system. Witness Jackson's Direct Testimony also described, in detail, three major storms impacting DEP's system in 2018 (Hurricanes Florence and Michael, and Winter Storm Diego), as well as a 2019 storm, Hurricane Dorian. (Id. at 77-87.) Company witness Jackson described the Company's extensive responses to these storms and the gross capital investments and O&M expense associated with those responses. (Id. at 88-103.) Finally, Company witness Jackson offered testimony that, in his opinion, the Company's response to the storms, including its restoration efforts, was reasonable and prudent and resulted in the restoration of power to DEP's impacted customers as quickly and safely as was reasonably possible. (Id. at 102-03.)

In her prefiled Direct Testimony, Company witness Smith proposed to recover the incremental cost in excess of normal storm expenses, including a return on the unrecovered balance. Company witness Smith proposed to begin amortization of the costs when proposed new base rates became effective, and to include a return on the deferred balance through the end of the proposed fifteen-year amortization period. In its Application, DEP's Storm Costs, projected through August 31, 2020, totaled approximately $655.8 million, consisting of approximately $569.2 million in actually incurred or projected storm response O&M costs and approximately $86.6 million in deferred depreciation expense and carrying costs (calculated using the Company's approved weighted average cost of capital) on its actually incurred storm response costs. Company witness Smith's Second Supplemental Direct Testimony and Schedules included updated actual amounts of DEP's Storm Costs totaling $714.0 million, consisting of $567.3 million in actually incurred or projected storm response O&M costs, $68.6 million in capital investments, and $78.1 million in carrying costs (calculated using the Company's approved weighted average cost of capital through August 31, 2020). As agreed in the First Partial Stipulation with the Public Staff, DEP removed the Storm Costs and associated capital investments from the rate case to pursue securitization.

The only other witness to offer testimony on storm response and recovery costs in this proceeding was Public Staff witness Dorgan, other than a correction to the deferred amounts presented by witness Maness in his Testimony in Support of Partial Settlement, filed on June 5, 2020. Witness Dorgan, in his direct testimony, indicated that the Public Staff had reviewed the Storm Costs sought to be recovered in this proceeding and had concluded that they were prudently incurred. (Tr. vol. 15, 750.) Witness Dorgan also indicated that he had made an accounting adjustment to remove these Storm Costs from the rate relief requested in this docket on the basis of Company witness De May's prior testimony that if the (then pending) storm cost securitization legislation was enacted, DEP would seek to recover its Storm Costs through the alternative securitization mechanism provided by that legislation. (Id. at 749.)[13] Finally, witness Dorgan adjusted DEP's revenue request in the rate case to allow for a ten-year normalization of storm costs not sufficient to support a separate securitization filing. (Id. at 750.)

On May 4, 2020, in his Rebuttal Testimony, witness De May indicated that the Company looked forward to pursuing recovery of its Storm Costs through a separate securitization filing but that the Company believed that a determination of the reasonableness and prudence of its Storm Costs should be preserved in the general rate case for determination by the Commission. (Tr. vol. 11, 777-78.)

On June 2, 2020, DEP and the Public Staff filed the First Partial Stipulation in this proceeding in which these parties reached agreement as to the proper resolution of several pending issues in the general rate case proceeding, including the treatment of Storm Costs. In the First Partial Stipulation, DEP and the Public Staff agreed to adjustments "to remove the capital and O&M costs associated with the Storms and to reflect a 10-year normalized level of storm expense for storms that would not otherwise be large enough for the Company to securitize." (First Partial Stipulation, § III.1.) The parties also agreed to a presumptive filing schedule and filing parameters for DEP's securitization filing for its Storm Costs, and reserved their respective rights if such filing was not made by the Company. (Id. at § III.2.) Finally, the parties agreed that a storm cost recovery rider should be established for DEP with an initial balance of $0. (Id. at § III.5.)

More specifically regarding the filing schedule, DEP agreed to file a petition for a financing order pursuant to N.C.G.S. § 62-172 no later than 120 days from the issuance of an order by the Commission in this rate case in which the Commission makes findings and conclusions regarding the Storm Costs and the First Partial Stipulation, unless a party in the rate case appeals the Commission's order as it relates to the Storm Costs or the provisions of the First Partial Stipulation related to the Storm Costs and securitization. If an appeal is filed, the 120-day limit shall be suspended until the Commission's decision is affirmed, or if not affirmed, until the issuance of a Commission Order on remand following the decision on the appeal, unless the Company chooses before that time to pursue recovery as further described below, in which case the original 120-day limit shall be deemed to have applied. Should DEP fail to file a petition within the time period specified in this paragraph, the parties agreed that in any subsequent ratemaking proceeding held to provide for recovery of the Storm Costs, the parties reserve the right to assert their respective positions regarding the appropriate ratemaking treatment of the Storm Costs. (Id. at § III.2.)

With regard to the parameters that would be followed in the securitization proceeding, the parties agreed that to demonstrate quantifiable benefits to customers in accordance with N.C.G.S. § 62-172(b)(1)g., the Company must show that the net present

[13] SB 559 was enacted in S.L. 2019-244.

value of the costs to customers using securitization is less than the net present value of the costs that would result under traditional storm cost recovery. For purposes of settlement for the Storm Costs only, the parties agreed that when conducting this comparison in the subsequent securitization docket for the Storms, the following assumptions shall be made:

a. For traditional storm cost recovery, 12 months of amortization for each Storm was expensed prior to the new rates going into effect;

b. For traditional storm cost recovery, no capital costs incurred due to the Storms during the 12-month period were included in the deferred balance;

c. For traditional storm cost recovery, no carrying charges were accrued on the deferred balance during the 12-month period following the date(s) of the Storm(s);

d. For traditional cost recovery, the amortization period for the Storms is a minimum of 15 years; and

e. For securitization, the imposition of the Storm recovery charge begins nine months after the new rates go into effect.

(Id. at § III.3.)

The parties further agreed that pursuant to N.C.G.S. § 62-172, the amortization of securitized Storm Costs shall not begin until the date the storm recovery bonds are issued. (Id. at § III.4.)

The parties also agreed that a storm cost recovery rider in this proceeding that will be initially set at $0 should be established in the rate case. (Id. at § III.5.) Should the Company not file a petition for a financing order or is unable to recover the Storm Costs through N.C.G.S. § 62-172, the Company may request recovery of the Storm Costs from the Commission by filing a petition requesting an adjustment to this rider. (Id.) In such case, DEP and the Public Staff reserve the right to argue their respective positions regarding the appropriate ratemaking treatment for recovering the Storm Costs. (Id.)

Finally, the parties agreed to file a joint petition for rulemaking to establish the standards and procedures that will govern future financing petitions under N.C.G.S. § 62-172 upon the issuance of storm recovery bonds for the Storm Costs. (Id. at § III.6.)

No other party provided evidence on DEP' Storm Costs or its storm response and recovery procedures and no party contested the conclusions of the Company and the Public Staff that DEP's Storm Costs were reasonable and prudent.

Based upon the foregoing evidence, and the absence of any evidence to the contrary, the Commission concludes that the Company's actual costs incurred to respond to and recover from Hurricanes Florence, Michael, Dorian, and Winter Storm Diego, which total $714.0 million, consisting of approximately $567.3 million in actually incurred or projected storm response O&M costs, capital investments of $68.6 million (including deferred depreciation expense), and $78.1 million in carrying costs (calculated using the Company's approved weighted average cost of capital, through August 31, 2020) were reasonable and prudent, to the extent such costs represent actual amounts as of May 31, 2020. Any estimated costs as of that date or incurred afterward remain subject to review in the financing proceeding conducted pursuant to SB 559, or to consideration for recovery in a future general rate case proceeding, pursuant to the provisions of N.C.G.S. § 62-172(a)(14)c. Any updates to the deferred Storm Costs projections for storm recovery activities still underway should be provided at the time of the securitization filing.

The Commission also accepts the decision of DEP, as agreed to by the Public Staff, to remove the Company's Storm Costs from the revenue requirement requested in this general rate case in favor of a separate anticipated securitization filing and further accepts the ten-year normalized adjustment to DEP's requested revenue requirement to account for anticipated storm expenses that are too small to securitize.

It is appropriate and consistent with SB 559 that DEP continue to defer its Storm Costs intended to be securitized in a regulatory asset account until the date storm recovery bonds are issued pursuant to an approved financing order in accordance with N.C.G.S. § 62-172, or the Company seeks recovery of the storm costs through an alternative method of cost recovery, subject to the assumptions and conditions agreed to in the First Partial Stipulation, with the amounts recorded therein subject to review by intervening parties and the Commission in the securitization proceeding. It is further appropriate and consistent with the statute that DEP continue to accrue and record carrying costs, at the Company's approved weighted average cost of capital, on the deferred balances in its Storm Costs recovery deferred account pending recovery through securitization, subject to the assumptions and conditions agreed to in the First Partial Stipulation and review by intervening parties and the Commission in the securitization proceeding.

After careful consideration, the Commission also concludes that the provisions of the First Partial Stipulation regarding the assumptions and methods to be utilized in the demonstration of quantifiable benefits to customers in accordance with N.C.G.S. § 62-172(b)(1)g are appropriate and reasonable. The utilization of the assumptions and methods will help ensure that securitization provides a rate benefit to the Company's customers.

Finally, the Commission also finds appropriate and reasonable the provisions of the First Partial Stipulation regarding the filing procedure for the securitization proceeding, the agreed-to delay in beginning the amortization of securitized costs, the provisions for a contingent storm cost recovery rider, and the commitment to pursue a rulemaking proceeding for future securitizations. These provisions serve to protect the interests of the Company and its ratepayers.

## EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 20

The evidence supporting these findings and conclusions is contained in the Company's verified Application and Form E-1; the testimony and exhibits of DEP witnesses Smith and Pirro; the testimony and exhibits of Public Staff witnesses Dorgan and Maness; and the entire record in this proceeding.

In the 2018 DEP Rate Order, the Commission ordered that "if DEP receives revenue for any deferred cost for a longer period of time than the amortization period approved by the Commission for that deferred cost, the Company shall continue to record all revenue received for that deferred cost in the specific regulatory asset account established for that deferred cost until the Company's next general rate case." (*See* 2018 DEP Rate Order, at 234, Ordering ¶32.)

Company witness Smith testified that the Company has continued to record all revenue received for deferred amounts related to regulatory asset and liability accounts until the Company's next general rate case – i.e., this rate case – in compliance with the Commission's directive. (*See* Tr. vol. 13, 134.) The Company is requesting that customer rates be decreased by $2.1 million as a result of regulatory assets or liabilities that have been over-amortized since the last general rate case. (Id. at 133.) The Company is proposing a Regulatory Asset and Liability rider (RAL-1) to return this balance to customers over a one-year period. (Id. at 134.) Smith Exhibit 5 shows the calculation of the resulting net over amortization balance. (Id.) Witness Pirro testified that a proposed uniform rate of $0.00005 per kWh for Rider RAL-1 is derived in Smith Exhibit 5 and will be effective for 12 months. (Tr. vol. 11, 1112.) He noted that the proposed Rider RAL-1 tariff is provided in the Company's proposed tariffs filed as Exhibit B to the Company's Application. (Id.) Public Staff witness Dorgan testified in his initial direct testimony that the Public Staff had reviewed the Company's proposed Regulatory Asset and Liability Rider, and agreed with the calculation. The rider continued to be reflected in Public Staff witness Maness's Second Stipulation Exhibit 1, supporting the Second Partial Stipulation. None of the other parties opposed or otherwise addressed Rider RAL-1.

The Commission finds and concludes that the Company's proposed Regulatory Asset and Liability rider (RAL-1) is just and reasonable, consistent with the Commission's directive relating to the treatment of net over-amortizations of expired regulatory assets and liabilities since the Company's last base rate case, and should be approved.

## EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 21-25

The evidence supporting this finding and conclusion is contained in the verified Application and Form E-1, the testimony and exhibits of DEP witnesses Newlin, Panizza and Smith; Public Staff witnesses Dorgan, Maness, and Hinton; the Public Staff Partial Stipulations, and the entire record in this proceeding.

In its Application, the Company proposed a change to the existing North Carolina EDIT rider (EDIT-1) approved in Docket No. E-2, Sub 1142, and the proposed implementation of a new EDIT rider (EDIT-2) to amortize EDIT regulatory liabilities it had deferred as a result of the reduction in the federal income tax rate as part of the Tax Act. (Application, at 4, 9.)

The Company's Application stated that the EDIT-1 rider approved in the 2018 DEP Rate Order used a 35% federal tax rate for the tax gross up and the Company proposed to revise the EDIT-1 Rider as recalculated using the new 21% federal tax rate which would reduce the currently approved EDIT-1 rider revenue decrement from $42.6 million to $35.2 million. (Id.)

The Company's proposed rider (EDIT-2) contained five categories of benefits for customers as follows:

1. Federal EDIT - Protected
2. Federal EDIT – Unprotected, Property, Plant and Equipment (PP&E)-related
3. Federal EDIT – Unprotected, non-PP&E-related
4. Deferred revenue - Federal income tax
5. NC EDIT

(Tr. vol. 13, 152.) Company witnesses Smith and Panizza described the EDIT subcategories in their pre-filed Direct Testimony. (Tr. vol. 11, 740-41 (Panizza), Tr. vol. 13, 153-55 (Smith).) Witness Smith explained that the protected federal EDIT is generally related to PP&E and is subject to specific IRS requirements mandating that this amount be returned to customers no more quickly than as prescribed by the IRS. (Tr. vol. 13, 153.) For unprotected PP&E-related EDIT, the Company explained that the amounts are also related to PP&E but do not fall under IRS guidelines for protected status. (Id. at 154.) The Company recommended a 20-year flowback period for the unprotected PP&E-related federal EDIT to balance the customer and Company's interests, by minimizing customer rate volatility while addressing the Company's cash flow concerns. (Id.) For unprotected non-PP&E-related EDIT, the Company proposed to flowback those amounts to customers over five years. (Id.) The NC EDIT category resulted from the reduction in the North Carolina corporate state tax rate in prior years, and witness Smith explained that the current EDIT Rider in place (EDIT-1) does not include EDIT related to the reduction in the North Carolina state corporate tax rate from 3% to 2.5%, which went into effect on January 1, 2019. (Id. at 155.) The Company proposed to return the NC EDIT portion to customers over five years. (Id.) Finally, witness Smith explained that the deferred revenue component includes the impact on customer rates of the reduction in the federal corporate income tax rate from 35% to 21%, which the Company began deferring January 1, 2018, as directed in Docket No. M-100, Sub 148, and DEP requested to return these amounts over a two-year period. (Id. at 155-56.)

Witness Smith testified that the Company's proposed rider would include the annual amortization for each of the five categories of benefits. (Id. at 156.) She explained that since these EDIT amounts are a reduction in rate base, as these amounts are refunded to customers, rate base will increase; therefore, the rider also calculates the adjustment to return on rate base related to the increase in rate base resulting from the refund of EDIT to customers. (Id.) The Company proposed to file the rider amounts, along with the spread and derivation of the rate for each subsequent year, with the Commission annually in this docket. (Id. at 157.)

In his pre-filed Direct Testimony, Public Staff witness Dorgan testified that the Public Staff believes that the categories of refunds above should be handled separately due to the differing natures of the amounts and the amortization periods to provide a more transparent means of tracking the Tax Act and state tax-related refunds to customers for each year. (Tr. vol. 15, 757.) The Public Staff proposed removing protected federal EDIT from the Company's proposed EDIT Rider and instead leaving those amounts in base rates and amortizing the balance over 39.6 years in base rates and removing the first year of amortization from the deferral amount for purposes of this proceeding. (Id. at 758.) The Public Staff did not differentiate between different categories of unprotected federal EDIT, and instead recommended removing the EDIT regulatory liability associated with the unprotected differences from rate base, and placing it in a rider to be refunded to ratepayers over five years on a levelized basis, with carrying costs. (Id. at 759.) For the deferred revenue component, witness Dorgan recommended it be recovered in a separate levelized rider to be amortized over a one-year period, and as a result of using the one-year amortization period, removed the balance from the working capital schedules. (Id. at 760.) Finally, the Public Staff recommended removing the entire state EDIT balance from rate base and also placing it in a separate rider with a one-year levelized return of the balance. (Id. at 761.)

In Rebuttal Testimony, DEP witness Newlin testified that the shorter flowback periods recommended by the Public Staff and intervenors would have an adverse impact on the Company's cash flow, which could negatively impact its credit ratings and ultimately affect its cost to serve customers. (Tr. vol. 11, 678-79.) Nevertheless, as part of the give and take of the settlement process and in light of other material terms agreed to by DEP and the Public Staff, as part of the Public Staff Partial Stipulations, the Company and the Public Staff agreed to flowback EDIT to customers as follows:

(a) Protected federal EDIT will be returned to customers in base rates via the Average Rate Assumption Method (Second Partial Stipulation, § III.A.(1));

(b) Total unprotected federal EDIT, North Carolina EDIT, and deferred revenues related to the provisional overcollection of federal income taxes will be returned to customers through a rider by using a levelized rider calculation methodology as described and set forth in the testimony and exhibits of the Public Staff and will be amortized over a period of five years for total unprotected EDIT and two years for North Carolina EDIT and deferred revenues (id. at §§ III.A.(2) – III.A.(5)).

DEP and the Public Staff also reached agreement concerning how to address changes in the federal income tax rate or North Carolina state income tax rate that may occur during the respective amortization periods as provided in detail in §§ III.A.(6) – III.A.(15) of the Second Partial Stipulation. No intervenor offered any evidence or testimony opposing the EDIT provisions of the Public Staff Partial Stipulations.

During the consolidated portion of the evidentiary hearing, in response to questioning from the AG's counsel, DEC witness McManeus who provided testimony in the DEC case regarding the proposed DEC EDIT rider, testified that while the Company has been able to use amounts relating to EDIT until they are flowed back through rates, customers are held harmless in the meantime:

> [Because EDIT is reducing rate base, it's reducing current rates. The Company has use of the money, as you indicate on this chart, and customers are held harmless of the Commission's decision to push this forward to a future rate case.

(Id. at 81-82.) On redirect, she explained how having the use of EDIT benefits customers:

> [W]e've talked previously about how deferred income taxes are a source of cash to the Company and, you know, they are an interest-free source of cash. And so when we collect monies in advance of paying to the IRS, then we are able to invest that money in our business and avoid the financing … costs. And that is all reflected in the Company's rates.

(Id. at 86.)

The AG's counsel also asked a series of questions relating to a chart she described as a depiction of several recent orders wherein the Commission has addressed the timeframe over which EDIT and other tax items would be returned to customers. (*See* id. at 75-81; AGO McManeus Smith Cross Ex. 1.) On redirect, witness McManeus agreed that the Commission should evaluate the appropriate flowback period for unprotected EDIT on a case-by-case basis: "[t]he chart that Ms. Force walked through provided some information on a number of cases before the Commission, but I would be cautious about considering the timing of the flowback of EDIT as being a one-size-fits-all or a cookie-cutter approach." (Id. at 87.) In particular, witness McManeus discussed the variables of impact on credit metrics and rate volatility:

> And those two items are really very dependent on the amount of EDIT that a company has as well as the financial strength of the particular company. So I know nothing about those items for Aqua, Carolina Water, and I'm not familiar with the Piedmont amounts, but those things would all be taken into consideration, which in my mind means that you can't just assume that one amortization period is appropriate for all companies.

(Id. at 87-88.)

In light of the parties' testimony, all of the evidence presented, and the Public Staff Partial Stipulations, the Commission finds and concludes that the stipulated EDIT terms will result in rates that are just and reasonable, and should be implemented. The Commission therefore finds and concludes that the stipulated EDIT terms in the Public Staff Partial Stipulations balance the interests of investors and customers, and thus fulfill the Commission's mandate to be fair to both.

In addition, the Commission finds and concludes that the Company's proposed revision to the approved EDIT-1 rider to reflect the change in the federal income tax rate from 35% to 21%, which was supported by witness Smith and not disputed by any party, is just and reasonable and should be approved.

## EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 26-32

The evidence supporting these findings and conclusions are contained in DEP's verified Application and Form E-1; the testimony and exhibits of the public witnesses; the testimony and exhibits of Company witnesses D'Ascendis and Newlin; Public Staff witness Woolridge; AG witness Baudino; CIGFUR witness Phillips; Commercial Group witness Chriss; CUCA witness O'Donnell; the Second Partial Stipulation; the Customer Group Stipulations; the NCSEA and NCJC et al. Stipulation; the Vote Solar Stipulation; and the entire record in this proceeding.

### Return on Equity / Cost of Equity Capital

The Commission's consideration of the evidence and decision on this issue is set out below and is organized into three sections. The first is a summary of the record evidence on rate of return on common equity. The second is a summary of the law applicable to the Commission's decision on rate of return on common equity. The third is an application of the law to the evidence and a discussion and explanation of the Commission's ultimate decision on rate of return on common equity.

#### *Summary of Record Evidence on Return on Equity*

In his pre-filed Direct Testimony, DEP's Return on Equity (ROE) expert witness D'Ascendis recommended an ROE of 10.50%; however, in its Application, as a rate mitigation measure, the Company requested approval for its rates to be set using an ROE of 10.30% and an overall rate of return of 7.41%. The Company later stipulated to an ROE of 9.75% in individual settlement agreements with Harris Teeter, the Commercial Group, CIGFUR, Vote Solar, NCSEA and NCJC et al., which is a decrease from the 9.90% ROE and overall rate of return of 7.09% authorized by the Commission in the Company's last rate case. Subsequently, the Company and the Public Staff executed the Second Partial Stipulation that provides for a rate of return on equity of 9.60%. As a result, the Harris Teeter Stipulation, the Commercial Group Stipulation and the CIGFUR Stipulation (collectively, the Customer Group Stipulations), Vote Solar Stipulation, and NCSEA and NCJC et al. Stipulation were amended to provide that if the Commission enters a final order in this docket approving an ROE of 9.60% to be applied to a common equity component of the ratemaking capital structure consisting of 52.00% equity and 48.00% long-term debt, those parties would agree that the provisions of their settlement agreements concerning the ROE and capital structure have been fulfilled. Witnesses for the Public Staff, CIGFUR, the AG, the Commercial Group, and CUCA also filed direct testimony on the appropriate rate of return on equity. This evidence was followed by the Public Staff Partial Stipulations and the other intervenor settlements, supplemental testimony of Baudino, rebuttal, supplemental rebuttal, and settlement testimony of D'Ascendis, settlement testimony of Woolridge, and finally testimony of witnesses

D'Ascendis, Baudino, and O'Donnell, at the hearing of this matter. In addition to this expert testimony, the Commission received the testimony of a number of public witnesses on DEP's proposed rate increase as well as numerous statements of consumer position. All of this evidence is summarized below.

*Direct Testimony of Dylan W. D'Ascendis (DEP)*

Company witness D'Ascendis recommended in his direct testimony an ROE of 10.50%, which was the midpoint of his recommended range of 10.00% to 11.00%. (Tr. vol. 11, 250.) Witness D'Ascendis states that ROE, or the cost of equity:

> [I]is the return that investors require to make an equity investment in a firm. That is, investors will provide funds to a firm only if the return that they *expect* is equal to, or greater than, the return that they *require* to accept the risk of providing funds to the firm. From the firm's perspective, that required return, whether it is provided to debt or equity investors, has a cost. Individually, we speak of the "Cost of Debt" and the "Cost of Equity" as measures of those costs; together, they are referred to as the "Cost of Capital."
>
> . . .
>
> Although both debt and equity have required costs, they differ in certain fundamental ways. Most noticeably, the Cost of Debt is contractually defined and can be directly observed as the interest rate or yield on debt securities. The Cost of Equity, on the other hand, is neither directly observable nor a contractual obligation. Rather, equity investors have a claim on cash flows only after debt holders are paid; the uncertainty (or risk) associated with those residual cash flows determines the Cost of Equity.
>
> . . .
>
> Whereas the Cost of Debt can be directly observed, the Cost of Equity must be estimated or inferred based on market data and various financial models. As discussed throughout my Direct Testimony, each of those models is subject to specific assumptions, which may be more or less applicable under differing market conditions.

(Id. at 260-61.) (emphasis in original.)

Witness D'Ascendis noted that as all financial models are subject to various assumptions and constraints, equity analysts and investors tend to use multiple methods to develop their return requirements. (Id. at 251.) He therefore relied on three widely accepted approaches to develop his ROE determination: (1) the Constant Growth and Multi-Stage forms of the Discounted Cash Flow (DCF) model; (2) the Capital Asset Pricing Model (CAPM); and (3) the Bond Yield Plus Risk Premium approach. (Id.) He noted, however, weaknesses in the Constant Growth DCF Model, namely that those results are far removed from the returns recently authorized in other jurisdictions and fail to adequately reflect evolving capital market conditions, and, therefore, discounted those results. (Id. at 252.) The Constant Growth DCF Model produced ROE results ranging from a low of 8.78% to a high of 9.85% and the Risk Premium-based results, including the CAPM, Empirical CAPM, and Bond Yield Plus Risk Premium methods produced results ranging from a low of 8.44% to a high of 10.93% in connection with one variant of the Empirical CAPM. (Id. at 258.) Finally, the Expected Earnings analysis, which is used to assess the reasonableness of the DCF, CAPM, and Bond-Yield Plus Risk Premium results, produces an average ROE estimate of 10.47% and median ROE estimate of 10.54%. (Id. at 259.) Witness D'Ascendis noted that FERC uses the Expected Earnings analysis to determine the “zone of reasonableness”. (Id. at 272.)

Witness D’Ascendis provided extensive testimony concerning the capital market environment (id. at 309-22), and addressed the effect those market conditions have on the return investors require in order to commit their capital to equity securities. Witness D’Ascendis also focused upon capital market conditions as they affect the Company’s customers in North Carolina. (Id. at 299-309.) Specifically, his analysis found that the North Carolina and national economies continue to be highly correlated with one another:

> Economic conditions in North Carolina continue to improve from the recession following the 2008/2009 financial crisis, and they continue to be strongly correlated to conditions in the U.S., generally. In particular, unemployment, at both the state and county level, continues to fall and remains highly correlated with national rates of unemployment; real Gross Domestic Product (“GDP”) also remains fairly well correlated with U.S. GDP growth; and median household income in North Carolina has grown at a rate consistent with the rest of the U.S., and remains strongly correlated with national levels.

(Id. at 300-01.) He concluded, therefore, that North Carolina conditions “continue to be reflected in the models and data used to estimate the Cost of Equity.” (Id. at 301.)

In addition to his econometric models and evaluation of capital market risks, witness D’Ascendis also considered Company-specific business risks in arriving at his final ROE recommendation. These include (1) the risks associated with certain aspects of the Company’s generation portfolio and (2) the Company’s significant capital expenditure plan. (Id. at 283-84.)

In regard to economic conditions in North Carolina, witness D’Ascendis noted that North Carolina and the counties comprising DEP’s service area “continue[d] to steadily emerge from the economic downturn that prevailed during 2009-2010, and have experienced significant economic improvement during the last several years.” (Id. at 308.)

*Direct Testimony of J. Randall Woolridge (Public Staff)*

Public Staff witness Woolridge performed DCF and CAPM analyses for both his and witness D’Ascendis’s proxy groups of electric utilities. (Tr. vol. 15, 528-29.) Witness

Woolridge developed his DCF growth rate after reviewing growth rate measures including historic and projected growth rate measures and evaluating growth in dividends, book value, earnings per share (EPS), and growth rate forecasts from Yahoo, Reuters, and Zack's. (Id. at 589-90.) Public Staff witness Woolridge recommended an ROE of 9.00% based on a capital structure of 50.00% common equity and 50.00% long-term debt but in the alternative, recommended an ROE of 8.40% if the Commission authorized a 53.00% common equity and 47.00% long-term debt capital structure. (Id. at 523-30.) He applied the DCF model and CAPM that yielded the following results:

- Discounted Cash Flow (DCF) – Electric Proxy Group
  - 8.15% Equity Cost Rate

- DCF – D'Ascendis Proxy Group
  - 8.40% equity cost rate

- CAPM – Electric Proxy Group and D'Ascendis Proxy Group
  - 6.70% Equity Cost Rate

(Id. at 616.)

In witness Woolridge's CAPM analysis, he used the top end of the range of yields on 30-year U.S. Treasury bonds over the 2013-2020 time period of 3.50% for the risk-free interest rate. (Id. at 602.) He used the Value Line Investment Survey betas of 0.55 for both his and witness D'Ascendis's proxy groups. (Id. at 604.) Witness Woolridge gave most weight to the market premium estimates of KPMG, CFO Survey, Duff & Phelps, the Fernandez survey, and Damodaran, and used a market risk premium of 5.75%. (Id. at 614-15.) He testified that his 5.75% market risk premium is a conservatively high estimate. (Id. at 615.)

Witness Woolridge concluded that the appropriate equity cost rate for companies in his and witness D'Ascendis's proxy groups is in the 6.70% to 8.40% range. (Id. at 616.) However, witness Woolridge took into account the fact that his range was below the authorized rates of return on common equity for electric utilities nationally and made a primary recommendation of a 9.00% rate of return on equity, assuming a capital structure of 50.00% common equity and 50.00% long-term debt. (Id. at 617.) Witness Woolridge also provided an alternative recommendation of an 8.40% rate of return on common equity based on the Company's originally requested capital structure of 53.00% equity and 47.00% debt. (Id.)

Witness Woolridge did not perform an ECAPM analysis and testified that the ECAPM is an ad hoc version of the CAPM. (Id. at 653.)

Witness Woolridge also testified as to current capital market conditions as of the date of his testimony in April 2020. He stated that although the Federal Reserve increased the Federal Funds rate between 2015 and 2018, interest rates and capital costs remain at low levels. (Id. at 538, 542.) Witness Woolridge also pointed out that in 2019, interest rates fell dramatically with moderate economic growth and low inflation, while the Federal

Reserve cut the federal fund rate in July, September, and October and the 30-year yield traded at all-time low levels. (Id. at 540.) He noted that from January 1, 2020, through March 18, 2020, the yield on the benchmark 30-year Treasury bond had declined from 2.0% to 1.6%, even trading as low as 0.9%, an all-time low. (Id. at 672-73.) He found that the volatility in the markets since mid-February suggested a state of disequilibrium such that analyses using current market data would not provide reliable estimates of the cost of equity capital. Instead, he relied on data from the first week of February 2020. (Id. at 685.)

Witness Woolridge responded to witness D'Ascendis's assessment of the economic conditions in North Carolina prior to the COVID-19 pandemic. He generally agreed with witness D'Ascendis's general conclusion that economic conditions in North Carolina have improved since the Company's last rate case. Witness Woolridge stated that "[a]s highlighted by the correlations between U.S. and North Carolina economic data … economic conditions have improved with the overall economy over the past decade." (Tr. vol. 15, 667.) However, he testified that witness D'Ascendis's testimony predates the coronavirus crisis, which is detrimentally affecting the economic conditions of DEP's customers, North Carolina, and the national economy. (Id. at 667.) He argued, however, that although economic conditions generally had improved in North Carolina, it does not necessarily justify such a high rate of return and ROE. (Id.) He noted that DEP's ROE request is almost 100 basis above the average authorized rates of return on equity for electric utilities in 2018-2019. (Id.) Specifically, he noted that while the unemployment rates in North Carolina and DEP's service territory have fallen since their peaks in the 2009-2010 period, they are both above the national average of 3.70% and that while North Carolina's residential electric rates are below the national average, the median household income is more than 10% below the U.S. norm. (Id. at 668.)

*Direct and Supplemental Direct Testimony of Richard A. Baudino (AG)*

Witness Baudino, appearing on behalf of the AG, proposed an ROE of 9.00% based on a 51.50% equity and 48.50% long-term debt capital structure, utilizing, primarily, DCF-based market approaches along with the CAPM approach. (Tr. vol. 13, 444-45.) Witness Baudino later provided pre-filed Supplemental Direct Testimony where he updated interest rates and market data "since the beginning of March 2020 "when concerns about the COVID-19 pandemic began to roil financial markets with extreme volatility" (Id. at 511.) Witness Baudino testified regarding the recent volatility in the markets, including "sharp increase in betas for the companies in the proxy group" (id. at 520) resulting in a higher DCF ranging from 8.29 to 9.28, an increase from his initial DCF range of 8.21 to 9.02. (Id. at 518, Tr. vol. 2, 128.) Likewise, witness Baudino testified that nationally, the real GDP "declined in the first quarter of 2020 by -5.0%, according to the Bureau of Economic Analysis. (Tr. vol. 13, 523.) Nevertheless, he continued to recommend a 9.00% ROE in his Supplemental Direct Testimony. (Id.)

In his Direct Testimony, witness Baudino testified that his 9.00% ROE recommendation was "reasonably close to recently allowed ROEs." (Tr. vol. 13, 480.) As a reference point to determine "reasonably close" he relied upon average public utility commission allowed ROEs during 2016, 2017, 2018, and 2019 (Tr. vol. 2, 135-37), which he calculated as 9.60%, 9.68%, 9.56%, and 9.57%, respectively. (Tr. vol. 13, 478-79.) Using specifically the 68 basis point differential between his 9.00% ROE recommendation and the 9.68% average ROE determination by commissions in 2017, witness Baudino admitted that he "would say … [this 68 point differential] was reasonable." (Tr. vol. 2, 136.)

*Direct Testimony of Kevin O'Donnell (CUCA)*

Witness O'Donnell, for CUCA, proposed an ROE of 8.75%, primarily based upon DCF modeling and CAPM methodologies, as well utilizing a comparable earnings approach. (Tr. vol. 14, 229.) Witness O'Donnell's DCF analysis results ranged from 7.00% to 10.00% with a midpoint of 8.50%, his CAPM analysis ranged from 5.00% to 7.00% with a midpoint of 6.50%, and his comparable earnings analysis ranged from 9.25% to 10.25% with a midpoint of 9.75%. (Id.) He believed that the midpoint of his DCF was the most accurate representation of market conditions as supported by his CAPM analysis, but chose the upper end of his DCF range based on allowed returns from other jurisdictions. (Id.)

*Direct Testimony of Steve W. Chriss (Commercial Group)*

While he did not provide an ROE analysis in his testimony, witness Chriss for the Commercial Group testified that the Company's proposed ROE was significantly higher than ROEs previously approved by the Commission from 2016 to present, including the prior rate case in 2017. (Tr. vol. 14, 86-87.) Likewise, witness Chriss indicated that the Company's proposed ROE is significantly higher than most reported ROE decisions by utilities commissions from 2016 to the present. (Id. at 87-88.) He testified that according to S&P Global Market Intelligence, 154 decisions were rendered over that time frame, with results ranging from 8.40% to 11.95%, with the median authorized ROE at 9.60%. (Id. at 87.) Removing distribution-only utilities and distribution service rates from the analysis, he testified that the average ROE for vertically integrated utilities authorized from 2016 through the time of his direct testimony filing was 9.74%, and the trend in these averages has been relatively stable. (Id. at 87-88.) As previously noted, the Commercial Group subsequently entered into a settlement agreement where the parties agreed to a 9.75% ROE that was subsequently amended to provide that if the Commission authorized a 9.60% ROE, the parties agree that the provisions of their agreement on the ROE and capital structure shall have been fulfilled.

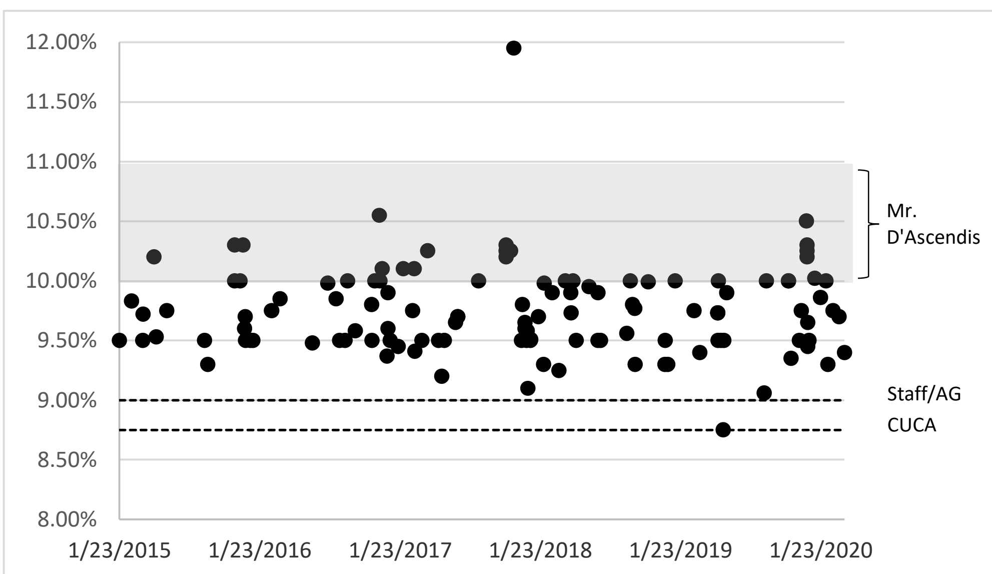
*Direct Testimony of Nicholas Phillips, Jr. (CIGFUR)*

In his pre-filed Direct Testimony, CIGFUR witness Phillips testified that DEP's requested ROE of 10.30% is unreasonable and should be rejected. (Tr. vol. 16, 316-17.) He presented evidence that the national average authorized ROE for vertically integrated electric utilities is currently 9.73%. (Id. at 317.) He recommended that a reasonable ROE for DEP should not exceed the current national average for vertically integrated electric utilities. (Id.) Similar to the Commercial Group, CIGFUR subsequently entered into a settlement agreement where the parties agreed to a 9.75% ROE that was subsequently amended to provide that if the Commission authorized a 9.60% ROE, CIGFUR would agree that the provisions of its agreement on ROE and capital structure shall have been fulfilled.

*Rebuttal Testimony Dylan W. D'Ascendis (DEP)*

In his Rebuttal Testimony, witness D'Ascendis responded to and discussed in detail the Intervenor witnesses' criticisms of his ROE conclusions and recommendations. He indicated that "none of their arguments caused me to revise my conclusions or recommendations." (Tr. vol. 1, 46.) Witness D'Ascendis stated that "financial models are important tools in determining returns and understand[s] that because all [models] are subject to assumptions, no one method is most reliable at all times, or under all conditions" and, therefore, it "remains critically important to apply reasoned judgment to determine where the Cost of Equity falls within that model's range of results." (Tr. vol. 11, 355.)

Generally, witness D'Ascendis advised that over the last five years, nearly all authorized ROEs for vertically integrated electric utilities have been above the intervenor witnesses' recommendations. (Id. at 353.) Witness D'Ascendis also included as Chart 1 of his Rebuttal Testimony (id. at 354) a comparison of authorized ROEs for other vertically integrated utilities from 2015 through January 2020 that shows that the intervenor witness recommendations[14] are far below the ROEs available to other such utilities:




[14] The chart prepared by witness D'Ascendis reflects witness Woolridge's original 9.00% ROE recommendation.

Witness D'Ascendis indicated that the "significant departure" represented by the recommendations of witnesses Baudino and O'Donnell raises two concerns:

> First, DE Progress must compete with other companies, including utilities, for the long-term capital needed to provide safe and reliable utility service. Given the choice between two similarly situated utilities, one with a return that falls far below industry averages and another with a return that more closely aligns with returns available to other utilities, investors will choose the latter. That is a particular concern for the Company, given its risk profile, its need to access external capital … If the Commission were to approve an ROE in the ranges recommended by [witnesses Baudino and O'Donnell], investors would receive a lower return with greater risk than would be available from other utilities. A likely outcome would be increasing reluctance on the part of investors to provide capital at reasonable costs and terms.
>
> Second, although no regulatory commission sets returns solely by reference to those authorized elsewhere, authorized returns do provide observable and measurable benchmarks against which return recommendations may be assessed. In my experience, regulatory commissions generally consider the same types of market, methodological, and risk factors at issue in this proceeding. They recognize that financial models are important tools in determining returns and appreciate that because all models are subject to assumptions, no one method is most reliable at all times, and under all conditions.
>
> As discussed throughout my Rebuttal Testimony, that holds true in this case. Even if we focus on a single method, it remains critically important to apply reasoned judgment to determine where the Cost of Equity falls within that model's range of results. Just as investors consider company-specific and general market factors, we should do the same. Those considerations, and that judgment, leads to the conclusion that [witnesses Baudino and O'Donnell's] ROE recommendations are unduly low.

(Id. at 354-55.)

Witness D'Ascendis criticized the growth rates witness Baudino applied to the Constant Growth DCF model and his reliance on the Constant Growth DCF model to determine the Company's ROE, the Market Risk Premium witness Baudino used in the CAPM, witness Baudino's statements concerning the relevance of the ECAPM analysis, as well as the reasonableness of his Bond Yield Plus Risk Premium analysis, among other factors. (Id. at 487.) Witness D'Ascendis testified that witness Baudino's reliance on dividend growth rates as a measure of expected growth for the Constant Growth DCF model is not appropriate; rather earnings growth is a more appropriate measure. (Id. at 496.) As witness D'Ascendis explained, earnings growth is the fundamental driver of the ability to pay dividends and investors tend to value common equity on the basis of price/earnings (P/E) ratios – earnings are the only growth rates statistically and positively related to the P/E ratio. (Id.) Thus, the cost of equity is a function of expected growth in earnings, not dividends. (Id.) Likewise, academic literature supports use of an earnings growth rate. (Id.)

Additionally, witness D'Ascendis disagrees with witness Baudino's CAPM approach to calculating the Market Risk Premium, which incorporates historical estimates of the Market Risk Premium. (Id. at 501.) Witness D'Ascendis explained that the Market Risk Premium is meant to be forward-looking. (Id. at 502.) He noted that witness Baudino included book value growth estimates in his Market Risk Premium analysis but not his proxy company DCF analysis – excluding book value growth increases witness Baudino's Market Risk Premium by approximately 63 basis points. (Id. at 501-02.) Witness D'Ascendis pointed out that witness Baudino argues that the ECAPM suggests Beta coefficients published by Value Line and Bloomberg are "incorrect and that investors should not rely on them." (Id. at 504.) However, witness D'Ascendis testifies that the ECAPM reflects published research findings that companies with lower Beta coefficients tend to have higher returns than those predicted by the CAPM, and those with higher Beta coefficients tend to have lower returns than expected. (Id.) He further argued that Beta coefficient adjustments like those used by Value Line address the tendency of "raw" Beta coefficients to regress toward the market mean of 1.00 over time. (Id.) Moreover, witness D'Ascendis noted that the two are different issues and are addressed with different methods. (Id.) Witness D'Ascendis also argued that the Bond Yield Plus Risk Premium analysis is a sound method of quantifying the relationship between the ROE and interest rates, disagreeing with witness Baudino's assertion that the Bond Yield Plus Risk Premium method is a "blunt instrument." (Id. at 511-12.) None of witness Baudino's arguments resulted in the revision of witness D'Ascendis's conclusions or recommendations. None of witness Baudino's arguments resulted in the revision of witness D'Ascendis's conclusions or recommendations.

Witness D'Ascendis challenged witness O'Donnell's application of the Constant Growth DCF and subsequent recommendation for an ROE of 8.75%. (Id. at 529.) Witness D'Ascendis explained that the reliance on historical growth rates by witnesses O'Donnell and Baudino as part of their Constant Growth DCF modeling does not adequately encapsulate how the model is a forward-looking measure of investors' expectations and there is support that future growth is superior to that of historically oriented growth measures. In response to Witness O'Donnell's contention that the DCF approach is "far superior to all the models now used by practitioners (Tr. vol. 3, 26), witness D'Ascendis contended that no support was offered for that assertion. In response to witness O'Donnell's use of the Retention Growth Model, witness D'Ascendis tested the relationship between retention ratios and future growth rates and demonstrated that earnings growth actually *decreased* as the retention ratio increased. (Tr. vol. 11, 540.) Witness D'Ascendis testified that the CAPM addresses comparable risk in a way that the DCF-based methods do not; the Beta coefficient reflects "systematic" risk, which provides a direct measure of relative risk. (Id. at 549.)

Additionally, witness D'Ascendis testifies that the intervenor witnesses fail to recognize the risks faced by the Company and their recommended ROEs do not appropriately reflect the evolving capital market environment. (Id. at 252.) To illustrate his point that an ROE in the range recommended by Baudino and O'Donnell would risk devaluing the Company's equity and, thus, ability to compete for capital, witness D'Ascendis provided an example of a recent rate decision for CenterPoint Energy Houston Electric in which the financial community responded negatively to an adverse regulatory outcome. (Id. at 527.)

*Supplemental Rebuttal Testimony Dylan W. D'Ascendis (DEP)*

Witness D'Ascendis also pre-filed Supplemental Rebuttal Testimony to update his ROE models and respond to the pre-filed Supplemental Direct Testimony of AG witness Baudino regarding current and expected capital markets and their effect on the cost of equity.

Witness D'Ascendis noted that even though the North Carolina and U.S. economies have contracted, economic conditions in North Carolina continue to be highly correlated to conditions nationally, and, therefore, continue to be reflected in the analyses used to determine the ROE. (Tr. vol. 11, 614.) In addition, evidence was presented that shows that the current level of volatility, which is 50% higher than normal levels, is expected to persist until at least the end of 2021. (Id. at 612.)

Witness D'Ascendis updated his ROE analyses based on market data as of June 30, 2020, resulting in a DCF ranging from 7.76% - 9.67%, a CAPM ranging from 10.19% - 15.70%, an ECAPM ranging from 10.94% - 15.70%, a Bond Yield Risk Premium ranging between 9.96% - 10.25%, and an Expected Earnings ranging between 5.50% - 13.56%. (Id. at 594-95; D'Ascendis Supplemental Rebuttal Ex.1-6.)

*Second Partial Stipulation and Other Intervenor Settlements*

As discussed above, in separate stipulations with CIGFUR, the Commercial Group, and Harris Teeter, the Company stipulated to an ROE of 9.75%, along with a number of other provisions representing substantial give and take between the parties. Subsequently, the Company and the Public Staff executed the Second Partial Stipulation, which among other things, provided for an ROE of 9.60%. These separate agreements represent substantial movement by these parties from the positions on return on common equity articulated in testimony. Thereafter, the other intervenor settlements were amended to provide that if the Commission enters a final order in this docket approving an ROE of 9.60% to be applied to a common equity component of the ratemaking capital structure consisting of 52.00% equity and 48.00% long-term debt, those parties would agree that the provisions of their settlement agreements concerning the ROE and capital structure have been fulfilled.

*Settlement Supporting Testimony of Dylan W. D'Ascendis (DEP)*

Witness D'Ascendis pre-filed Settlement Supporting Testimony, in which he supported the Second Partial Stipulation reached between the Public Staff and the Company, explaining that though the stipulated ROE of 9.60% is somewhat below his recommended range, he recognizes that the settlement represents negotiation by the parties of otherwise contested issues and that the Company believes that the Second Partial Stipulation's ROE and capital structure "would be viewed by the rating agencies as constructive and equitable." (Tr. vol. 11, 619-20.) Witness D'Ascendis also testified that economic conditions in North Carolina, which deteriorated in the first half of 2020 as a result of the COVID-19 pandemic, remain highly correlated to the overall conditions nationwide. (Id. at 626.) Witness D'Ascendis noted that "[f]rom January 2016 through June 2020, the average authorized ROE for vertically integrated electric utilities was 9.74 percent, 14 basis points above the Stipulated ROE. Of the 107 cases decided during that period, 64 (*i.e.*, nearly 60.00 percent) included authorized returns of 9.60 percent or higher." (Tr. vol. 11, 621.) He concluded that the 9.60% stipulated ROE is "a reasonable resolution of an otherwise contentious issue." (Id. at 620.)

*Settlement Testimony of J. Randall Woolridge (Public Staff)*

In his testimony supporting the Second Partial Stipulation, Public Staff witness Woolridge testified that he found the cost of capital components reasonable within the context of the overall settlements and in resolution of most of the issues in the proceeding. (Tr. vol. 15, 691-92.) He noted that the stipulated ROE was a compromise for each party, a reduction from the Company's last authorized ROE of 9.90%, below the 9.67% average authorized ROE for vertically integrated electric utilities during the first half of 2020, and the lowest ROE authorized for a vertically integrated investor-owned electric utility in North Carolina in at least the last 30 years. (Id. at 695.)

*Hearing Testimony of Dylan W. D'Ascendis (DEP)*

Under cross-examination by the AGO, witness D'Ascendis noted that measures of volatility had fallen since March, but still remained high and were expected to continue to remain high. (Tr. vol. 2, 43-44.) Witness D'Ascendis further testified that:

> … the virus and things like that, they don't know any borders, right, state borders, … the conditions that are going on across the whole country are also what's going on in North Carolina. So when it comes to … correlation and using … nationwide across-the-group data, you know, these companies' market data and things like that, that's still applicable to, say, the companies in this case.

(Tr. vol. 1, 125.)

Witness D'Ascendis also stated:

> … the unemployment rates for U.S. as a whole compared to North Carolina, even though both of them are not great, they're not ideal, obviously, from what's been going on, North Carolina's actually faring better than the country as a whole. Now, they've dropped … I think they only peaked out at 12.9 percent unemployment, and that was in April; and now they're -- in

> July, they're down to 8.5 percent as compared to the nation as a whole, which is 10.2 percent in July. So it's -- even though they're moving at the same rate, North Carolina fell less or had less unemployed percentage-wise and has recovered faster than the country as a whole. So, you know, it has hit, but North Carolina, even though everything is still very bad, and I'm not trying to say that it's not, they're less affected. But -- still affected, but less affected than what's been going on in the country.
>
> (Tr. vol. 1, 125-26.)

*Public Witness Testimony/Statements of Consumer Position*

The Commission also received numerous statements of consumer position with regard to this docket, many of which expressed concern about DEP's proposed rate increase. The Commission held five evening hearings throughout the Company's North Carolina service territory to receive public testimony. A total of 58 individuals testified and several testified that the rate increase was not affordable for many customers, including those on fixed incomes, the elderly, person with disabilities, the unemployed and underemployed, and the poor. Notably, a number of customers also expressed the view that the Company should be required to revise its current grid modernization plans in favor of energy efficiency and renewables. Likewise, many customers expressed that the Company should be required to pay for coal ash remediation entirely rather than recovering in rates.

*Law Governing the Commission's Decision on Return on Equity*

Rate of return on common equity is often one of the most contentious issues to be addressed in a rate case, even in a case such as this one in which the Second Partial Stipulation and the other intervenor settlements have been reached. In the absence of a settlement agreed to by all the parties, the law of North Carolina requires the Commission to exercise its independent judgment and arrive at its own independent conclusion as to the proper rate of return on common equity. *See, e.g., CUCA I,* 348 N.C. at 466, 500 S.E.2d at 707. In order to reach an appropriate independent conclusion regarding the rate of return on common equity, the Commission must evaluate the available evidence, particularly that presented by conflicting expert witnesses. *State ex rel. Utils. Comm'n v. Cooper*, 366 N.C. 484, 491-93, 739 S.E.2d 541, 546-47 (2013) (*Cooper I*). In this case, the expert witness evidence relating to the Company's cost of equity capital was presented by Company witness D'Ascendis, Public Staff witness Woolridge, AG witness Baudino, CIGFUR witness Phillips, Commercial Group witness Chriss, and CUCA witness O'Donnell.

The baseline for establishment of an appropriate rate of return on common equity is the constitutional constraints established by the decisions of the United States Supreme Court in *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n of W. Va.,* 262 U.S. 679 (1923) (*Bluefield*), and *Fed. Power Comm'n v. Hope Nat. Gas Co.,* 320 U.S. 591 (1944) (*Hope*), which establish that:

> To fix rates that do not allow a utility to recover its costs, including the cost of equity capital, would be an unconstitutional taking. In assessing the impact of changing economic conditions on customers in setting [a rate of return on common equity], the Commission must still provide the public utility with the opportunity, by sound management, to (1) produce a fair profit for its shareholders, in view of current economic conditions, (2) maintain its facilities and service, and (3) compete in the marketplace for capital.

(2018 DEC Rate Order, at 50); s*ee also State ex rel. Utils. Comm'n v. Gen. Tel. Co. of the Se.*, 281 N.C. 318, 370, 189 S.E.2d 705, 738 (1972) (*General Telephone*). As the North Carolina Supreme Court held in *General Telephone*, these factors constitute "the test of a fair rate of return declared" in *Bluefield* and *Hope*. (Id.)

It is also important for the Commission to keep in mind that the rate of return on equity is, in fact, a cost. The return that equity investors require represents the cost to the utility of equity capital. In his dissenting opinion in *Missouri ex rel. Southwestern Bell Telephone Co. v. Missouri Public Service Commission*, 262 U.S. 276 (1923), Justice Brandeis remarked upon the lack of any functional distinction between the rate of return on equity (which he referred to as a "capital charge") and other items ordinarily viewed as business costs, including operating expenses, depreciation, and taxes:

> Each is a part of the current cost of supplying the service; and each should be met from current income. When the capital charges are for interest on the floating debt paid at the current rate, this is readily seen. But it is no less true of a legal obligation to pay interest on long-term bonds . . . *and it is true also of the economic obligation to pay dividends on stock, preferred or common.*

Id. at 306. (Brandeis, J., dissenting) (emphasis added). Similarly, the United States Supreme Court observed in *Hope*, "[f]rom the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business . . . [which] include service on the debt and dividends on the stock." 320 U.S. at 591, 603.

Leading academic commentators also define rate of return on equity as the cost of equity capital. Professor Charles Phillips, for example, states that "the term 'cost of capital' may be defined as the annual percentage that a utility must receive to maintain its credit, to pay a return to the owners of the enterprise, and to ensure the attraction of capital in amounts adequate to meet future needs." Phillips, Charles F., Jr., *The Regulation of Public Utilities* 388 (Public Utilities Reports, Inc. 1993). Professor Roger Morin approaches the matter from the economist's viewpoint:

> While utilities enjoy varying degrees of monopoly in the sale of public utility services, they must compete with everyone else in the free open market for the input factors of production, whether it be labor, materials, machines, or capital. The prices of these inputs are set in the competitive marketplace by supply and demand, and it is these input prices which are incorporated in

> the cost of service computation. This is just as true for capital as for any other factor of production. Since utilities must go to the open capital market and sell their securities in competition with every other issuer, there is obviously a market price to pay for the capital they require, for example, the interest on capital debt, or the expected return on equity.
>
> [T]he cost of capital to the utility is synonymous with the investor's return, and the cost of capital is the earnings which must be generated by the investment of that capital in order to pay its price, that is, in order to meet the investor's required rate of return.

Morin, Roger A., *Utilities' Cost of Capital* 19-21 (Public Utilities Reports, Inc. 1984). Professor Morin adds:

> The important point is that the prices of debt capital and equity capital are set by supply and demand, and both are influenced by the relationship between the risk and return expected for those securities and the risks expected from the overall menu of available securities.

Id*.* at 20.

In addition, the Commission is and must always be mindful of the North Carolina Supreme Court's command that the Commission's task is to set rates as low as possible consistent with the dictates of the United States and North Carolina Constitutions. *State ex rel. Utils. Comm'n v. Pub. Staff-N. Carolina Utils. Comm'n*, 323 N.C. 481, 490, 374 S.E.2d 361, 370 (1988) (*Public Staff*). Indeed, in *Cooper I,* the Supreme Court emphasized "changing economic conditions" and their impact upon customers. *Cooper I*, 366 N.C. at 484, 739 S.E.2d at 548.

The Commission noted in its Order Granting General Rate Increase, Application of Carolina Power & Light Company, d/b/a Progress Energy Carolinas, Inc., for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina, No. E-2, Sub 1023, at 37 (N.C.U.C. May 30, 2013), aff'd, State ex rel. Utils. Comm'n v. Cooper, 367 N.C. 444, 761 S.E.2d 640 (2014) (2013 DEP Rate Case Order) that while there is no specific and discrete numerical basis for quantifying the impact of economic conditions on customers, the impact on customers of changing economic conditions is embedded in the rate of return on equity expert witnesses' analyses. The Commission further noted in the 2013 DEP Rate Case Order:

> This impact is essentially inherent in the ranges presented by the return on equity expert witnesses whose testimony plainly recognizes economic conditions — through the use of economic models — as a factor to be considered in setting rates of return.

(2013 DEP Rate Case Order, at 38.)

Finally, under long-standing decisions of the North Carolina Supreme Court, the Commission's subjective judgment is a necessary part of determining the authorized rate of return on common equity. *Public Staff*, 323 N.C. at 490, 374 S.E.2d at 369. As the Commission has previously noted:

> Indeed, of all the components of a utility's cost of service that must be determined in the ratemaking process the appropriate [rate of return on common equity] is the one requiring the greatest degree of subjective judgment by the Commission. Setting [a rate of return on common equity] for regulatory purposes is not simply a mathematical exercise, despite the quantitative models used by the expert witnesses. As explained in one prominent treatise,
>
>> Throughout all of its decisions, the [United States] Supreme Court has formulated no specific rules for determining a fair rate of return, but it has enumerated a number of guidelines. The Court has made it clear that confiscation of property must be avoided, that no one rate can be considered fair at all times and that regulation does not guarantee a fair return. The Court also has consistently stated that a necessary prerequisite for profitable operations is efficient and economical management. Beyond this is a list of several factors the commissions are supposed to consider in making their decisions, but no weights have been assigned.
>>
>> The relevant economic criteria enunciated by the Court are three: financial integrity, capital attraction and comparable earnings. Stated another way, the rate of return allowed a public utility should be high enough: (1) to maintain the financial integrity of the enterprise, (2) to enable the utility to attract the new capital it needs to serve the public, and (3) to provide a return on common equity that is commensurate with returns on investments in other enterprises of corresponding risk. These three economic criteria are interrelated and have been used widely for many years by regulatory commissions throughout the country in determining the rate of return allowed public utilities.
>>
>> In reality, the concept of a fair rate of return represents a "zone of reasonableness." As explained by the Pennsylvania commission:
>>
>>> There is a range of reasonableness within which earnings may properly fluctuate and still be deemed just and reasonable and not excessive or extortionate. It is bounded at one

> level by investor interest against confiscation and the need for averting any threat to the security for the capital embarked upon the enterprise. At the other level it is bounded by consumer interest against excessive and unreasonable charges for service.
>
> As long as the allowed return falls within this zone, therefore, it is just and reasonable. It is the task of the commissions to translate these generalizations into quantitative terms.

Charles F. Phillips, Jr., *The Regulation of Public Utilities,* 3d ed. 1993, 381-82. (Notes omitted.)

(2013 DEP Rate Case Order, at 35-36 (additions and omissions after the first quoted paragraph in original).)

Moreover, the North Carolina Supreme Court has interpreted N.C.G.S. § 62-133 as requiring the Commission to make findings regarding the impact of changing economic conditions on customers when determining the proper rate of return on equity for a public utility. *Cooper I*, 366 N.C. at 495, 739 S.E.2d at 548. The Commission must exercise its subjective judgment so as to balance two competing rate of return on equity-related factors—the economic conditions facing the Company's customers and the Company's need to attract equity financing in order to continue providing safe and reliable service. (2013 DEP Rate Case Order, at 35-36.)

In addition to adhering to the broad controlling legal principles on the allowed rate of return discussed above, the Commission must adhere to the multi-element formula set forth in N.C.G.S. § 62-133 when it sets rates. The rate of return on cost of property element of the formula in N.C.G.S. § 62-133(b)(4) is a significant, but not an independent element. Each element of the formula must be analyzed to determine the utility's cost of service and revenue requirement. The Commission must make many subjective decisions with respect to each element in the formula in establishing the rates it approves in a general rate case. The Commission must approve accounting and pro forma adjustments to comply with N.C.G.S. § 62-133(b)(3) and must approve depreciation rates pursuant to N.C.G.S. § 62-133(b)(1). The subjective decisions the Commission makes as to each of these elements have multiple and varied impacts on the decisions it makes on other rate- affecting elements, such as the decision it must make on the rate of return on common equity.

Pursuant to N.C.G.S. § 62-133(c), rates in North Carolina are set based on a modified historic test period. A component of cost of service equally important as the return on investment component is test year revenues. N.C.G.S. § 62-133(b)(3). The higher the level of test year revenues, the lower the need for a rate increase, all else remaining equal. Historically, and in this case, test year revenues are established through resort to regression analysis, using historic rates of revenue growth or decline to determine end of test year revenues. Economic conditions existing during the test year, at the time of the public hearings, and at the date of this Order will affect not only the ability of DEP's customers to pay electric rates, but also the ability of DEP to earn the authorized rate of return during the period rates will be in effect. Thus, in accordance with the above-discussed applicable law, the Commission's duty under N.C.G.S. § 62-133 is to set rates as low as reasonably possible without impairing the Company's ability to attract investors to raise the capital needed to provide reliable electric service and recover its cost of providing service.

In fixing rates, the Commission is also cognizant that when a utility's costs and expenses grow at a faster pace than revenues during the period when rates will be in effect, it will experience a decline in its realized rate of return on investment to a level below its authorized rate of return. Differences exist between the authorized return and the earned, or realized, return. Components of the cost of service must be paid from the rates the utility charges before the equity investors are paid their return on equity. Operating and administrative expenses must be paid, depreciation must be funded, taxes must be paid, and the utility must pay interest on the debt it incurs. To the extent revenues are insufficient to cover the entire cost of service, the shortfall reduces the return to the equity investor, last in line to be paid. When this occurs, the utility's realized, earned return is less than the authorized return, an occurrence commonly referred to as regulatory lag. In setting the rate of return, just as the Commission is constrained to address the impact of difficult economic times on customers' ability to pay for service by establishing a lower rate of return on equity in isolation from the many subjective determinations that must be made in a general rate case, it likewise is constrained to address the effect of regulatory lag on the Company by establishing a higher rate of return on equity. Instead, the Commission sets the rate of return considering both of these negative impacts in its ultimate decision fixing a utility's rates.

It is against this backdrop of overarching principles and law that the Commission turns to the evidence present in this case.

***Discussion and Application of Law to the Facts***

The Commission has examined the Company's Application and supporting testimony and exhibits and Form E-1 filings seeking to justify its requested increase. DEP's updated request prior to entering into the stipulations and including the May 2020 Updates was a retail revenue increase of approximately $569.7 million in annual revenues. The Public Staff, who in this docket represents all users and consumers of the Company's electric service, and DEP entered into a stipulation that resulted in reducing the retail revenue increase sought by the Company by $160.8 million. CIGFUR, the Commercial Group, and Harris Teeter each entered into a separate stipulation that as amended accepted a 9.60% rate of return on common equity, subject to certain conditions. As with all settlement agreements, each party to the stipulations gained some benefits that it deemed important and gave some concessions for those benefits. Based on DEP's Application, it is apparent that the stipulations tie the 9.60% rate of return on common equity to substantial agreed upon concessions made by DEP. As noted above, since the AG and CUCA, as well as other parties that did not provide testimony on ROE did not agree to the settlements, the Commission is required to examine the stipulations and exercise its independent judgment to arrive at its own independent conclusion as to the proper rate of return on common equity.

The starting point for an examination of what constitutes a reasonable rate of return on common equity begins with the various economic and financial analyses provided by the parties' expert witnesses. In this proceeding, those analyses were provided in the testimonies of six different witnesses: witness D'Ascendis for DEP; witness Woolridge for the Public Staff; witness Baudino for the AG; witness Chriss for the Commercial Group; witness Phillips for CIGFUR; and witness O'Donnell for CUCA. These testimonies, as summarized above, provide a relatively broad range of methods, inputs, and recommendations regarding the proper rate of return on common equity determination for DEP. For example, witness D'Ascendis relied in his direct testimony on four different analyses to arrive at his rate of return on common equity recommendation. These analyses were a Constant Growth DCF Analysis, a Capital Asset Pricing Model analysis, an Empirical Capital Asset Pricing Model, a Bond Yield Plus Risk Premium analysis, and an Expected Earnings analysis. By way of comparison, Public Staff witness Woolridge and AG witness Baudino relied upon DCF analyses and CAPM analyses in reaching their conclusions; however, the inputs utilized by these witnesses in their analyses are different from those utilized by witness D'Ascendis. Commercial Group witness Chriss recommended that the Commission look at the proposed ROE in light of recent ROEs approved by the Commission and by commissions nationwide. Similarly, CIGFUR witness Phillips looked at the average allowed rates of return on common equity for both vertically integrated and distribution-only electric utilities of 9.73% and recommended that average as a cap to the allowed rate of return on common equity. Finally, CUCA witness O'Donnell proposed an ROE of 8.75% using the DCF and CAPM methodologies, as well as a comparable earnings approach.

These varying analyses, as is typical, produced varying results. Witness D'Ascendis's analyses prompted him to propose a rate of return on common equity range of 10.00% to 11.00% with a specific rate of return on common equity recommendation of 10.50%. Witness Woolridge's analyses resulted in a recommended rate of return on common equity range of 6.70% to 8.40% with a primary recommendation of a 9.00% rate of return on common equity with a 50.00% common equity and 50.00% debt capital structure and a secondary recommendation of an 8.40% rate of return on common equity if DEP's proposed capital structure of 47.00% long-term debt and 57.00% common equity was approved. AG witness Baudino proposed an ROE of 9.00%. Finally, as noted above, witness O'Donnell recommended an ROE of 8.75%, and witness Phillips a cap on rate of return on common equity of 9.73%.

The Commission finds the cost of equity analyses helpful in reaching its conclusion on an appropriate rate of return on common equity for DEP, but notes that the ranges of the various analyses span a range from 6.70% to 15.70% and the specific rate of return on common equity (primary) recommendations of the witnesses span a range from 8.75% on the low end to 10.50%[15] on the high end.

The Commission finds that the updated DCF, Bond Yield Risk Premium, and Expected Earnings analyses of DEP witness D'Ascendis, the Second Partial Stipulation, and the other intervenor settlements are credible, probative, and entitled to substantial weight.

DEP witness D'Ascendis in his supplemental rebuttal testimony provided his constant growth DCF analyses, as shown on Supplemental Rebuttal Ex. DWD-1, pages 1 and 2 as follows: 30-day dividend yield high ROE mean 9.67%, median 9.42%; and 90-day dividend yield high ROE mean 9.57%. The Commission finds witness D'Ascendis’s constant growth DCF analyses mean and median rate of return on common equity results credible, probative, and entitled to substantial weight.

DEP witness D'Ascendis’s updated Bond Yield Plus Risk Premium, as shown on Supplemental Rebuttal Ex. DWD-5, using the current 30-year Treasury yield of 1.47%, the near term projected 30-year Treasury yield of 1.72%, and the long-term projected Treasury yield of 3.40% and applying it to the approved rates of return on common equity in 1,630 electric utility rate proceedings between January 1980 and June 30, 2020, results in rates of return on common equity of 10.25%, 10.08%, and 9.96%, respectively. While in the past, the Commission has generally approved the use of current interest rates rather than projected near-term or long-term interest rates, in this particular case, disequilibrium in the current markets as discussed by witness Woolridge give the Commission reason to look beyond the current Treasury yields and give some weight to projected rates. The Commission finds witness D'Ascendis’s updated Bond Yield Plus Risk Premium analyses using the current and projected 30-year Treasury yields to be credible, probative, and entitled to substantial weight.

DEP witness D'Ascendis's Expected Earnings approach produced a range from 5.50% to 13.56% with an average of 10.18% and a median of 10.55%. (Supplemental Rebuttal Ex. DWD-6.) In prior cases, the Commission has given weight to this methodology, which stands separate and apart from the market-based methodologies (e.g., the DCF or CAPM) also used by ROE experts. (*See, e.g*., 2013 DEC Rate Order at 36.) The Commission chooses to do so again in this case.

In this case, the Commission is greatly concerned that the low ROEs recommended by AG witness Baudino and CUCA witness O’Donnell, would, when translated into rates and holding all other things equal, fail the *Hope* “end results” test. This is shown graphically in Chart 1 of D’Ascendis’s Rebuttal Testimony. (Tr. vol. 11, 354, *infra*.) The Commission agrees with witness D'Ascendis that this could result in investors receiving a lower return with greater risk than would be available from other utilities,

[15] As noted *infra*, DEP witness D'Ascendis recommended an ROE of 10.50%, but DEP requested a lower ROE of 10.30% to mitigate the impact of the rate increase on customers.

thereby making it more costly to raise capital. The Commission agrees with witness D'Ascendis that the ROE recommendations of witnesses Baudino and O'Donnell are unduly low, places great weight upon this observation, and therefore finds the Baudino and O'Donnell ROE recommendations to be unpersuasive. In doing so, the Commission emphasizes that it is referencing the data concerning other authorized ROEs as a means to test the ROE recommendations of witnesses Baudino and O'Donnell, and not as a reference to or reliance upon the doctrine of "gradualism." *See Cooper II*, 367 N.C. at 443. (*See also* DNCP Remand Order, at 33-35.)

Witnesses Baudino and O'Donnell recommended ROEs of 9.00%, and 8.75%, respectively. These recommendations are far outside the band of authorized ROE results set out in D'Ascendis's Chart 1. These recommendations are also far below the stipulated 9.90% ROE from the Company's previous rate case or 10.20% from the rate case prior to that. The recommendations of witnesses Baudino and O'Donnell are also inconsistent with those recently authorized in North Carolina. The Commission has most recently authorized an ROE of 9.75% for Dominion Energy North Carolina; 9.90% for the Company and DEC in their prior rate cases, 9.70% for Piedmont Natural Gas and 9.40 for Aqua America. Witness D'Ascendis indicated, and the Commission agrees, that these witnesses' recommendations are far below the average and median ROE for vertically integrated electric utilities in jurisdictions rated in the top third by Regulatory Research Associates, which range from 9.37% to 10.55%. Witnesses Baudino and O'Donnell's recommendations are below those of other vertically integrated utilities similarly rated from 2015 – 2020, while witness D'Ascendis's recommended ROE of 10.50% and the settled ROE of 9.60% do fall within that ROE range.

In his direct testimony, witness Baudino testified that his 9.00% ROE recommendation was "reasonably close to recently allowed ROEs", using a 9.68% average ROE determination by commissions in 2017 as "recently allowed ROEs." Witness Baudino admitted on cross-examination that he "would say … [this 68 point differential] was reasonable." (Tr. vol. 2, 136.) The differential between the stipulated ROE (9.60%) and witness Baudino's 9.00% ROE recommendation is, of course, 60 basis points – less than the 68 basis points witness Baudino deemed "reasonable."

There are other aspects of these witnesses' analyses that the Commission finds troubling. For example, the Commission finds questionable witness Baudino's failure to adjust his ROE recommendation in his Supplemental Direct Testimony considering the recent volatility in the markets, increase in betas for the companies in the proxy group, and the higher DCF results in his supplemental testimony. Additionally, the Commission agrees with witness D'Ascendis's criticism of witness Baudino's growth rates applied to the Constant Growth DCF model, as well as his reliance on the Constant Growth DCF model to determine the Company's ROE, the Market Risk Premium used in the CAPM and relevance of the ECAPM analysis, as well as the reasonableness of his Bond Yield Plus Risk Premium analysis among other factors. The Commission further agrees with witness D'Ascendis that witness Baudino's reliance on dividend growth rates as a measure of expected growth for the Constant Growth DCF model is not appropriate. Finally, the Commission also gives no weight to witness Baudino's CAPM approach to calculating the Market Risk Premium, which incorporates historical estimates of the Market Risk Premium and is not forward-looking.

In regard to the ROE recommendation of CUCA witness O'Donnell, like with witness Baudino, his reliance on historical growth rates in his DCF analysis does not adequately encapsulate how the model is a forward-looking measure of investors' expectations. Further, the Commission finds compelling witness D'Ascendis's test of the relationship between retention ratios and future growth rates demonstrating that earnings growth actually *decreased* as the retention ratio increased, thereby undermining the premise underlying witness O'Donnell's use of the Retention Growth Model. As for witness O'Donnell's Comparable Earnings Approach, his forward-looking 2019 and 2022/2024 analysis yielding ROE estimates of 9.80% to 10.60% for his proxy group was similar to witness D'Ascendis's updated Expected Earnings analysis of 10.21% to 10.30%. Overall, it seems that witness O'Donnell's 8.75% ROE estimate is at odds with the data he presented.

Additionally, witness D'Ascendis testifies that the intervenor witnesses fail to recognize the risks faced by the Company and do not appropriately reflect the evolving capital market environment. (Id. at 148.) We agree. A significant departure from the authorized ROEs of other similarly situated utilities impacts the Company's ability to compete with other companies for long-term capital to provide safe and reliable utility service. The Commission notes the risk that an ROE in the range recommended by witnesses Baudino and O'Donnell could lead to a devaluation of the Company's equity and, thus, ability to compete for capital, as illustrated by witness D'Ascendis in his discussion of a recent rate decision in which the financial community responded negatively to an adverse regulatory outcome for CenterPoint Energy Houston Electric.

In sum, in light of all of the factors discussed in this Order, the Commission places minimal weight upon the ROE recommendations of witnesses O'Donnell and Baudino. Rather, we find the stipulated ROE to be reasonable and appropriate based on the evidence presented. As witness D'Ascendis notes in his Second Settlement Testimony, the average authorized ROE for vertically integrated electric utilities from 2016 to June 2020 was 9.74%, 14 basis points above the Stipulated ROE.

The Commission, of course, does not blindly follow ROE results allowed by other commissions. The Commission determines the appropriate ROE based upon the evidence in and particular circumstances of each case. However, the Commission believes that the ROE trends and decisions by other regulatory authorities deserve some weight, as (1) they provide a check or additional perspective on the case-specific circumstances, and (2) the Company must compete with other regulated utilities in the capital markets, meaning that an ROE significantly lower than that approved for other utilities of comparable risk would undermine the Company's ability to raise necessary capital, while an ROE significantly higher than other utilities of comparable risk would result in customers paying more than necessary. Both of those outcomes are undesirable, and would result in unjust and unreasonable rates. The fact that witness D'Ascendis's recommended range for his Expected Earnings falls within the average lends support to the Commission's approval.

DEP witness D'Ascendis in his Supplemental Rebuttal testimony provided his constant growth DCF analyses, as shown on Supplemental Rebuttal Ex. DWD-1, pages 1 and 2: 30-day dividend yield high ROE mean 9.67%, median 9.42%; and 90-day dividend yield high ROE mean 9.57%. Although the Commission, as stated in previous Commission general rate case orders, does not approve of witness D'Ascendis's sole use of analysts' predicted earnings per share to determine the DCF growth rate, the Commission finds witness D'Ascendis's constant growth DCF analyses mean and median rate of return on common equity results credible, probative, and entitled to substantial weight.

DEP witness D'Ascendis's updated Bond Yield Plus Risk Premium, as shown on Supplemental Rebuttal Ex. DWD-5, using the current 30-year Treasury yield of 1.47%, the near term projected 30-year Treasury yield of 1.72%, and the long-term projected Treasury yield of 3.40% and applying it to the approved rates of return on common equity in 1,630 electric utility rate proceedings between January 1980 and June 30, 2020, results in rates of return on common equity of 10.25%, 10.08%, and 9.96%, respectively. While in the past, the Commission has generally approved the use of current interest rates, rather than projected near-term or long-term interest rates, in this particular case, current disequilibrium in the market gives the Commission reason to look beyond the current Treasury yields and give some weight to projected rates. The Commission finds witness D'Ascendis's updated Bond Yield Plus Risk Premium analyses using the current and projected 30-year Treasury yields to be credible, probative, and entitled to substantial weight.

There is ample support for the stipulated ROE of 9.60%. First, that ROE falls within D'Ascendis's range under his constant growth DCF analyses. Second, the lower end of the range of witness D'Ascendis' updated Bond Yield Plus Risk Premium analyses fall 46 basis points above the stipulated ROE. Third, the stipulated ROE falls within the range for witness D'Ascendis's Expected Earnings Analysis, which is similar to the previously approved comparable earnings method, and supported by recent FERC Orders. In prior cases, the Commission has given weight to this methodology, which stands separate and apart from the market-based methodologies (*e.g.,* the DCF or CAPM) also used by ROE experts. (*See, e.g.*, 2013 DEC Rate Order at 36.) The Commission chooses to do so again in this case. An ROE of 9.60% is squarely within the range of all of the numerical results from the econometric models utilized by witness D'Ascendis in his Supplemental Rebuttal testimony. For one, the Expected Earnings approach produced a range from 5.50% to 13.56% with an average of 10.18% and a median of 10.55%. (Supplemental Rebuttal Ex. DWD-6.) As such, 9.60%, albeit on the lower end of the range, is within the "zone of reasonableness" that leading commentators and the North Carolina Supreme Court have indicated are presumptively just and reasonable. *See State ex rel. Utils. Comm'n v. Gen. Tel. Co. of the Southeast*, 285 N.C. 671, 681 (1974) (a "zone of reasonableness extending over a few hundredths of one percent" exists within which the Commission may appropriately exercise its discretion in choosing a proper ROE).

Finally, as the Supreme Court made clear in *CUCA I*, 348 N.C. at 466, and *CUCA II*, 351 N.C. at 231, the Commission should give full consideration to a non-unanimous stipulation itself, along with all evidence presented by other parties, in determining whether the stipulation's provisions should be accepted. In this case, insofar as expert ROE testimony is concerned, both witness D'Ascendis and witness Woolridge support an ROE at 9.60%. (Tr. vol. 11, 620 (D'Ascendis); Tr. vol. 15, 695-96 (Woolridge).) Only witness Baudino questioned the settlement ROE (Tr. vol. 2, 133; Tr. vol. 10, 125), but, as indicated above, the Commission places very little weight upon his ROE recommendation. Thus, the Commission finds and concludes that the Second Partial Stipulation itself, along with the expert testimony of witnesses D'Ascendis and Woolridge, is credible evidence of the appropriate ROE and is entitled to substantial weight in the Commission's ultimate determination of this issue. Moreover, the Commission also gives weight to the other intervenor settlements, as amended, that support the use of an ROE of 9.60%.

In summary, the Commission concludes there is substantial evidence supporting the reasonableness of a rate of return on common equity of 9.60%. First, that rate of return is well within the range of recommended returns by the economic experts in this docket of 8.75% to 10.50%. Second and third, it falls within the range of DEP witness D'Ascendis's DCF and Expected Earnings analyses. Fourth, it falls 46 basis points below the lower end of the range of DEP witness D'Ascendis's Bond Yield Plus Risk Premium analysis results. Fifth, it is slightly below the recommended range of DEP witness D'Ascendis (10.00% to 11.00%). Sixth, it falls squarely within the range and very close to the average of recent vertically-integrated electric utility allowed rates of return on common equity nationally.[16] Seventh, it is supported by credible filed settlement testimony by the cost of capital witnesses for DEP and the Public Staff. Finally, and without expressly adopting his methodology, it is consistent with witness Phillips' notion that DEP's return should be capped at the average rate of return on common equity approved by other state commissions for 2019. These factors lead the Commission to conclude that a 9.60% rate of return on common equity is supported by the substantial weight of the evidence in this proceeding. However, to meet its obligation in accord with the holding in *Cooper I*, the Commission will next address the impact of changing economic conditions on customers.

In this case, all parties had the opportunity to present the Commission with evidence concerning changing economic conditions as they affect customers. The testimony of witnesses D'Ascendis, Woolridge, and Baudino, which the Commission finds

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[16] The Commission determines the appropriate rate of return on common equity based upon the evidence and particular circumstances of each case. However, the Commission believes that the rate of return on common equity trends and decisions by other regulatory authorities, as well as other recent decisions of this Commission, deserve some weight, as (1) they provide a check or additional perspective on the case-specific circumstances, and (2) the Company must compete with other regulated utilities in the capital markets, meaning that a rate of return on common equity significantly lower than that approved for other utilities of comparable risk would undermine the Company's ability to raise necessary capital, while a rate of return on common equity significantly higher than other utilities of comparable risk would result in customers paying more than necessary.

entitled to substantial weight, addresses changing economic conditions at some length. Witness D'Ascendis provided detailed data concerning changing economic conditions in North Carolina, as well as nationally, and concluded that the North Carolina-specific conditions are “highly correlated” with conditions in the broader nationwide economy. As such, witness D'Ascendis testified that changing economic conditions, both nationally and specific to North Carolina, are reflected in his rate of return on common equity estimates.

Public Staff witness Woolridge agreed with DEP witness D'Ascendis that as of the time of the filing of his testimony, economic conditions had improved in North Carolina. He pointed out that at the time of the filing of his testimony that while the unemployment rates in North Carolina and DEP’s service territory have fallen since their peaks in the 2009-2010 period, they are both above the national average of 3.90%. Witness Woolridge also noted that while North Carolina’s residential electric rates are below the national average, its median household income is more than 10% below the U.S. norm.

However, since the filing of this case and as a result of the COVID-19 pandemic, economic conditions have deteriorated in North Carolina in the first half of 2020, as have economic conditions across the country. The Commission gives weight to the testimony of witness Baudino regarding the national decline of the GDP in the first quarter of 2020 by-5.0% as well as the testimony of witness D'Ascendis regarding the national and State unemployment rates in July of 10.2% and 8.5%, respectively.

As the Commission has noted, customer impact due to changing economic conditions is embedded in ROE expert witness analyses. Witness D’Ascendis’s analysis, which the Commission credits and to which the Commission gives weight, also indicates that even though the North Carolina and U.S. economies have contracted, economic conditions in North Carolina continue to be highly correlated to conditions nationally, and, therefore, continue to be reflected in the analyses used to determine the ROE.

The point is to see whether or not the econometric data relied upon by ROE expert witnesses may be used by the Commission to capture the effects and impacts of changing economic conditions upon customers and we find that based on the evidence presented in this case, it does.

Based upon the general state of the economy and the need for the continuing affordability of electric utility service, and after weighing and balancing factors affected by the changing economic conditions in making the subjective decisions required, the Commission concludes that the stipulated rate of return on common equity of 9.60% will not cause undue hardship to customers even though some will struggle to pay the increased rates resulting from the Second Partial Stipulation.

The many Commission-approved adjustments reduced the revenues to be recovered from customers and the return to be paid to equity investors. Some adjustments reduced the authorized rate of return on investment financed by equity investors. These adjustments have the effect of reducing rates and providing rate stability to consumers (and return to equity investors) in recognition of the difficulty some consumers will have paying increased rates in the current economic environment. While the equity investor's cost was calculated by resort to a rate of return on common equity of 9.60% instead of 10.30%, this is only one approved adjustment that reduced ratepayer responsibility and equity investor reward. Many other adjustments reduced the dollars the investors actually have the opportunity to receive. Therefore, nearly all of the adjustments reduce ratepayer responsibility and equity investor returns in compliance with the Commission's responsibility to establish rates as low as reasonably permissible without transgressing constitutional constraints, and thus, inure to the benefit of consumers' ability to pay their bills in this economic environment.[17]

For example, to the extent the Commission made downward adjustments to rate base, disallowed test year expenses, increased test year revenues, or reduced the equity capital structure component, the Commission reduced the rates consumers will pay during the future period when rates will be in effect. In this case, the Commission has ordered negative adjustments to many expenses sought to be included in the Company's revenue requirement. Because the compensation owed to investors for investing in the Company's provision of service to consumers takes the form of return on investment, downward adjustments to rate base, disallowances of test year expenses, increases to test year revenues, or reduction in the equity capital structure component will reduce investors' return on investment irrespective of the determination of rate of return on common equity.

The Commission has also approved herein an annual $2.5 million shareholder contribution to the Neighbor Energy Fund in 2021 and 2022, as provided in the Second Partial Stipulation, and an annual contribution of $3 million, in conjunction with DEC, to the Helping Home Fund in 2021 and 2020, for a total contribution of $11 million of the Company's shareholder funds for energy assistance to low-income customers the Company agreed to provide, in conjunction with DEC, an aggregate combined shareholder-funded contribution to the Helping Home Fund of $3 million per year for two years (for a total of $6 million). (NCSEA and NCJC et al. Stipulation, § IV.) These decisions directly benefit customers with the least ability to pay in the current economic environment. The Commission takes these facts into account in approving the 9.60% return on equity. Further, these contributions by the Company effectively reduce the authorized 9.60% rate of return on equity.

Considering the changing economic conditions and their effects on DEP's customers, the Commission recognizes the financial difficulty that an increase in DEP's rates may create for some of DEP's customers, especially low-income customers. As shown by the evidence, relatively small changes in the rate of return on common equity

[17] The Commission notes that consumers pay "rates," a charge in cents per kilowatt-hour (kWh) for the electricity they consume. They do not pay a "rate of return on common equity," though it is a component of the Company's cost of providing service, which is built into the charge per kWh. Investors are compensated by earning a return on the capital they invest in the business. Per the Commission determination of the rate of return on common equity in this matter, investors will have the opportunity to be paid in dollars for the dollars they invested at the rate of 9.60%.

have a substantial impact on a utility's base rates. Therefore, the Commission has carefully considered changing economic conditions and their effects on DEP's customers in reaching its decision regarding DEP's approved rate of return on common equity.

The Commission also recognizes that the Company is in a significant construction mode, and much of the associated investment is for generation, transmission, and distribution infrastructure to benefit DEP's customers, as well as in response to recent increases in environmental compliance costs and other operating expenses. The need to invest significant sums to serve its customers requires the Company to maintain its creditworthiness in order to compete for large sums of capital on reasonable terms. The Commission must weigh the impact of changing economic conditions on DEP's customers against the benefits that those customers derive from the Company's ability to provide safe, adequate, and reliable electric service. Safe, adequate, and reliable electric service is essential to the well-being of the people, businesses, institutions, and economy of North Carolina. Thus, the Commission finds and concludes that such capital investments by the Company provide significant benefits to all of DEP's customers.

The Commission concludes in the exercise of its independent judgment and discretion that a 9.60% rate of return on common equity is supported by the evidence and should be adopted. The hereby approved rate of return on common equity appropriately balances the benefits received by DEP's customers from DEP's provision of safe, adequate, and reliable electric service in support of the well-being of the people, businesses, institutions, and economy of North Carolina (which benefits are symbiotically linked to the Company's ability to compete in the equity capital market to access capital on reasonable terms that will be fair to ratepayers) with the difficulties that some of DEP's customers will experience in paying DEP's adjusted rates. The Commission further concludes that a 9.60% rate of return on common equity will allow DEP to compete in the market for equity capital, providing a fair return on investment to its investor-owners and, the lowering of the rate from the requested 10.30% to 9.60% has the effect of lowering the cost of service which forms the basis of the rates the ratepayers must pay for service. Accordingly, the Commission concludes, taking into account changing economic conditions and their impact on customers, that the approved rate of return on common equity will result in the lowest rates constitutionally permissible in this proceeding.

Finally, in approving the 9.60% rate of return on common equity, the Commission gives significant weight to the stipulations and the benefits that they provide to DEP's customers, which the Commission is obliged to consider as an independent piece of evidence under the Supreme Court's holding in *CUCA I*.

**Capital Structure**

In its Application, DEP witness Newlin proposed using a capital structure of 53.00% members' equity and 47.00% long-term debt. (Tr. vol. 11, 633.) Witness Newlin testified that the Company's "specific debt/equity ratio will vary over time, depending on a variety of factors, including among other things, the timing and size of capital investments and payments of large invoices, debt issuances, seasonality of earnings, and dividend payments to the parent company." (Tr. vol. 11, 395-96.) As of December 31, 2019, DEP’s capital structure was 52.00% common equity and 48.00% long-term debt. (Tr. vol. 11, 661.)

In his Direct Testimony, CUCA witness O’Donnell recommended that the Commission reject the Company’s capital structure proposal and instead advocated a capital structure of 50.00% members’ equity and 50.00% long-term debt. (Tr. vol. 14, 133.) Witness O’Donnell's analysis supporting his recommended capital structure was based on his comparison of capital structures of publicly traded holding companies, not operating utility companies. (Id. at 237-38.)

Public Staff witness Woolridge testified that the Company’s proposed capital structure included more common equity than the average of the proxy group he used in conducting his analysis. (Tr. vol. 15, 563.) He stated that it is appropriate to use the common equity ratios of the parent holding companies and that the high debt ratio and low equity ratio of DEP’s parent company, Duke Energy, is credit negative for DEP as evaluated by Moody’s. (Id. at 566-67.) He noted, however, that because DEP is a regulated business, it is exposed to less risk and can carry relatively more debt in its capital structure than most unregulated companies, like Duke Energy. (Id. at 569.) Witness Woolridge further testified that DEP should take advantage of its lower business risk to employ cheaper debt capital at a level that will benefit its customers through lower revenue requirements. (Id. at 569.) Therefore, witness Woolridge recommended a capital structure of 50.00% common equity and 50.00% debt based on a 9.00% rate of return on common equity. (Id. at 571.) Witness Woolridge also made an alternative capital structure recommendation of the Company’s proposed structure of 47.00% long-term debt and 53.00% common equity based on an 8.40% return on equity. (Id. at 572.)

AG witness Baudino recommended that the Commission reject the Company’s requested ratio and instead recommended the Commission approve the Company’s December 2018 capital structure, which includes a common equity of 51.50%. (Tr. vol. 13, 445, 511.) As noted, above, witness Baudino’s recommendation is lower than the Company’s recent actual capital structure of 48.00% long-term debt and 52.00% common equity.

In his Rebuttal Testimony, witness Newlin pointed out that CUCA witness O'Donnell utilized data showing capital structures that were inappropriate to use because they do not differentiate between various types of utility companies, which present radically different risk profiles. (Tr. vol. 11, 661.) Witness D'Ascendis pointed out that parent and operating companies do not necessarily have the same capital structures because financing at each level is driven by “the specific risks and funding requirements associated with their individual operations.” (Id. at 469.) He pointed to the Commission's previous rejection of the use of parent company structures as opposed to operating company structures in determining the operating utility’s appropriate equity/debt ratio. *See* Order Accepting Stipulation, Deciding Contested Issues and Granting Partial Rate Increase, Docket No. E-2, Sub 1142 (February 23, 2018) (2018 DEP Rate Order), at 87-88; Order Granting General Rate Increase and Approving Amended Stipulation, Docket No. E-7, Sub 909 (December 7, 2009) (2009 DEC Rate Order), at 27-28. Witness D'Ascendis pointed out that parent and operating companies simply do not necessarily have the same capital structures, because financing at each level is driven by “the specific risks and funding requirements associated with their individual operations.” (Id. at 244.)

In addition, witness D’Ascendis noted the use of the operating subsidiary’s actual capital structure – that is, the capital actually funding the utility operations that provide service to customers – is entirely consistent with precedent of the Federal Energy Regulatory Commission (FERC), so long as three criteria are met: the operating subsidiary (1) issues its own debt without guarantees; (2) has its own bond rating; and (3) has a capital structure within the range of capital structures for comparable utilities. (Id. at 483-84.) Witnesses Newlin and D’Ascendis testified that DEP, which issues its own debt and has its own bond rating, has a capital structure that is generally consistent with that of other operating companies, especially vertically integrated companies. (*See* id. at 673 (Newlin); and id. at 568 (D’Ascendis).) Further, in response to witness O’Donnell, witness D’Ascendis testified that by excluding equity ratios authorized in jurisdictions that include non-investor supplied capital in the capital structure, witness O’Donnell’s review demonstrated an average and median authorized equity ratio in 2019 of 52.08% and 52.00% for vertically integrated utilities. (Id. at 568.) Thus, he noted that the stipulated 52.00% equity ratio is consistent with authorized equity ratios. (Id. at 624.) DEP witness Newlin also pointed out that witness O’Donnell considers jurisdictions in which non-investor supplied capital is included in the capital structure, thus biasing his review. (Id. at 660.)

Subsequently, the Company reached several stipulations with a number of parties agreeing that the rates in this proceeding should be set using a capital structure of 52.00% equity and 48.00% debt. The 52/48 capital structure agreed to in the settlement agreements represent a compromise between the Company’s 53/47 position and the intervenors’ recommendations ranging from a 50/50 to a 51.5/48.5 capital structure. Both witness Woolridge (for the Public Staff) and witness Newlin (for the Company) support the agreed 52/48 ratio. (*See* Tr. vol. 15, 695 (Woolridge) (52/48 ratio reflects a reasonable compromise, “is reflective of each Company’s current equity ratio and is also consistent with their current authorized equity ratios”); Tr. vol. 11, 697 (Newlin).) Witness Newlin indicates that the stipulated capital structure “is reasonable and appropriate when viewed in the context of the overall Second Partial Settlement,” and that he believes its approval would be viewed by the ratings agencies as constructive and equitable. (Id. at 697.) Witness De May’s Second Settlement Testimony also supports the stipulated 52/48 capital structure. (Id. at 790.)

Under § III.B of the Second Partial Stipulation, DEP and the Public Staff proposed a capital structure of 52.00% common equity and 48.00% long-term debt. In their stipulation testimony, Company witness Newlin and Public Staff witness Woolridge testified that the capital structure reflected in the Second Partial Stipulation represents a compromise by both parties in an effort to reach agreement and is in the public interest.

The Company stipulated separately with CIGFUR, the Commercial Group, and Harris Teeter that it was appropriate to use a capital structure consisting of 52.00% equity and 48.00% long-term debt.

In evaluating the evidence on capital structure in this proceeding, the Commission first notes that the equity/debt ratios reflected in the Second Partial Stipulation and the Stipulations with CIGFUR, the Commercial Group, Harris Teeter, Vote Solar, NCSEA and NCJC et al. of 52.00% equity and 48.00% long-term debt are consistent with and well within the prior experience of the Commission.[18] These are not determinative factors from the Commission's perspective, but they do provide some context supporting the reasonableness of the stipulated capital structure.

Based upon its own review and independent analysis of the evidence, the Commission concludes that a capital structure of 52.00% equity and 48.00% long-term debt, as is reflected in § III.B. of the Second Partial Stipulation and the Stipulations with CIGFUR, the Commercial Group, Harris Teeter, Vote Solar, NCSEA and NCJC et al., is just and reasonable and appropriate for use in this proceeding on several grounds.

First, this capital structure is the same capital structure authorized for DEP in its last rate case. Second, this capital structure was accepted by the Public Staff, CIGFUR, the Commercial Group, and Harris Teeter in separate stipulations. Third, the Commission gives substantial weight to Company witness Newlin's testimony that the stipulated capital structure is reasonable and appropriate when viewed in the context of the overall Second Partial Stipulation. Fourth, the Commission places substantial weight as well on witness Woolridge's conclusion that the end result of the settlement is fair and reasonable with respect to both ratepayers and shareholders, and that customers will benefit from lower rates as a result of a negotiated settlement. Fifth, the Commission also gives weight to the Second Partial Stipulation and the benefits that it provides to DEP's customers, which the Commission is obliged to consider as an independent piece of evidence under *CUCA I* and *CUCA II*. Each party to the Second Partial Stipulation gained some benefits that it deemed important and gave some concessions for those benefits. Based on the Application and pre-filed testimony, it is apparent that the Second Partial Stipulation ties the 52/48 capital structure to substantial concessions the Company made to reduce its revenue requirement. Sixth, the Commission gives weight to the Stipulations with CIGFUR, the Commercial Group, Harris Teeter, Vote Solar, NCSEA and NCJC et al. as it did to the Second Partial Stipulation.

Accordingly, based on the matters set forth above, and in the exercise of its independent judgment, the Commission finds that the weight of the evidence in this proceeding favors using the stipulated capital structure pursuant to § III.B. of the Second Partial Stipulation and the Stipulations with CIGFUR, the Commercial Group, Harris

[18] *See* DENC Sub 532 Order (51.75% common equity and 48.25% debt); PSNC Sub 565 Order (52.0% common equity, 44.62% long-term debt, 3.38% short-term debt); PNG Sub 743 Order (52.00% equity, 47.15% long-term debt, 0.85% short-term debt); DEC Sub 1146 Order (52% common equity and 48% long-term debt); DEP Sub 1142 Order (52% common equity and 48% long-term debt); DENC Sub 562 Order (52% common equity and 48% long-term debt).

Teeter, Vote Solar, NCSEA and NCJC et al. and that such capital structure is just, reasonable, and appropriate for use in setting rates in this docket.

**Cost of Debt**

In his testimony, witness Newlin testified that the Company's long-term debt cost as of December 31, 2018, was 4.15%, which was the value used to determine the revenue requirement in the Company's Application. As part of § III.B. of the Second Partial Stipulation, DEP and the Public Staff agreed to use in determining the revenue requirement the May 2020 embedded cost of debt of 4.04%. The Commission finds for the reasons set forth herein that 4.04% cost of debt is just and reasonable.

In his Direct Testimony, Public Staff witness Woolridge initially proposed a cost of long-term debt of 4.11%, DEP's long-term debt cost as of December 31, 2019, and DEP thereafter updated its cost of debt to 4.11% in supplemental testimony filed July 10, 2020. (Tr. vol. 15, 696.) As part of the give and take negotiations involved in the settlement process, DEP and the Public Staff agreed to a cost of long-term debt of 4.04%, DEP's long-term debt cost updated through May 2020. (Id.)

No intervenor offered any evidence to contradict the use of 4.04% as the cost of debt. The Commission therefore finds and concludes that the use of a debt cost of 4.04% per the terms of § III.B. of the Second Partial Stipulation is just and reasonable to all parties in light of all the evidence presented.

**EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 33-35**

The evidence supporting these findings and conclusions is contained in the verified Application and Form E-1 of DEP; the testimony and exhibits of DEP witnesses Oliver and Smith; Public Staff witnesses D. and T. Williamson, Thomas, and Maness; CUCA witness O'Donnell; NC WARN witness Powers; CIGFUR witness Phillips; Commercial Group witness Chriss; NCSEA and NCJC et al. witnesses Alvarez and Stephens; Vote Solar witnesses Van Nostrand and Fitch; Harris Teeter witness Bieber; the Second Partial Stipulation; and the entire record in this proceeding.

**Summary of the Evidence**

***Company Testimony***

*GIP Overview*

DEP witness Oliver explained in his Direct Testimony that the Company has identified seven major trends that are driving the need to make improvements to DEP's transmission and distribution systems in North Carolina. (Tr. vol. 16, 127-28.) In his Direct Testimony, DEP witness Oliver denotes these trends as "Megatrends." (Id.) These seven Megatrends are: (1) concentrated population and business growth, especially in urban and suburban areas; (2) technological advances in renewables and DERs, resulting in new types of load and resources impacting the grid; (3) technological advances with devices and systems that manage the transmission and distribution (T&D) grids; (4) changing customer expectations and use of the grid; (5) increasing environmental commitments in DEP's service area; (6) increasing number, severity, and impact of weather events; and (7) increasingly sophisticated threats of physical and cyber-attacks on grid-infrastructure. (Id. at 611-12.)

Witness Oliver explained that the Company observed these Megatrends develop over the past several years. (Id. at 128.) During this process of identifying and validating the Megatrends, DEP collected information from its own operations in North Carolina and its sister companies that function in other jurisdictions. (Id. at 129.) The Company detected a commonality in the facts and information that evidenced the existence of these Megatrends in North Carolina, South Carolina, Florida, Kentucky, Ohio, and Indiana. (Id.) The Company then looked across the industry to see if other utilities and industry stakeholders were seeing the same Megatrends develop in their operations. (Id. at 128-29.) According to witness Oliver, he observed that the same Megatrends were developing nationally. (Id.)

To address the Megatrends, the Company determined that it needed to make strategic, data-driven improvements to power a smart-thinking grid that is more reliable, resilient, and built to meet the energy needs of customers today and into the future. (Id. at 111.) As such, the Company developed a comprehensive three-year Grid Improvement Plan (GIP) that will transform the grid and provide a new level of operation while providing benefits now and in the years to come. (Id.)

Components of the GIP operationally fall into one of three categories: (1) compliance-driven programs that *protect* the grid; (2) programs that leverage advanced technologies to *modernize* the grid; and (3) projects and programs that work to *optimize* the customer's experience. (Id. at 111-12.)

Compliance-driven programs in the GIP are efforts that need to be completed to reduce physical and cyber threats to the grid. (Id. at 133.) These programs may be required by an external law, rule, or regulation; a binding legal obligation such as a contract, agency order, or other legal document; or Operations Council approval of the work as being critical and imperative to the Company's operations. (Id.) Witness Oliver testified that work in this category is limited to rapidly evolving threats to the grid that outpace the scope and timing of standard compliance work. (Id. at 133-34.)

Rapid technology advancement work that modernizes 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 changes within the utility. (Id. at 135.) Work in this category often relates to system communication, automation, and intelligence and is essential for modern system operations. (Id.)

System optimization programs 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. (Id. at 136-37.) Witness Oliver testified that work in this category primarily includes a "bundled combination" of Self-Optimizing Grid (SOG) deployments, and advanced power systems that, when working together, provide optimum system performance for customers. (Id. at 137.)

Witness Oliver defined the 19 programs that make up the DEP GIP in Oliver Ex. 10 and described the components of each in Oliver Ex. 4. These programs are as follows:

*Programs that Protect the Grid*

1. Physical and Cyber Security

The Physical and Cyber Security program protects against the potential risks and impacts of attacks on the electric grid. (Oliver Ex. 4, 42.) The Physical and Cyber Security program includes in the following transmission subprograms: (1) Transmission Substation Physical Security; and (2) Windows-based Unit Change Outs. (Id.)

The Transmission Substation Physical Security subprogram is the largest of these programs, and enhances grid resiliency by installing high security perimeter fencing and lighting, intrusion detection technology, security enclosure buildings, and security cameras. (Id.) The Windows-based Unit Change Outs subprogram replaces older Windows-based relays that cannot be updated due to technology constraints. (Id.)

The Physical and Cyber Security program also includes subprograms at the distribution level. (Id. at 41.) At the distribution system level, much of the focus involves securing and improving risk mitigation of remotely controlled field equipment. (Id.) The distribution subprograms include: (1) Device Entry Alert System (DAES); (2) Secure Access and Device Management (SADM); and (3) Distribution Line Device Cyber Protection.

The DAES subprogram installs an entry door alarm head-end system and delivers processes to enhance physical and cyber security on the distribution systems' intelligence electronic devices. (Id. at 43.) This subprogram ensures that all physical access of intelligent electronic devices are being tracked and monitored. (Id.) The SADM subprogram provides a tool to remotely and securely perform device management activities and event record retrieval on the Company's entire device inventory. (Id.) The goal of the SADM subprogram is to improve the security of field devices and increase compliance with NERC CIP and other security requirements. (Id.) SADM also provides process and labor efficiencies associated with device management, and improves post-event resolution. (Id.) The Distribution Line Device Cyber Protection subprogram addresses physical and cyber security risks for thousands of line devices, such as regulators, capacitors, reclosers, etc. (Id.) This subprogram is focused on replacing legacy control equipment with new equipment that meets or exceeds Duke Energy Industrial Control System enterprise security requirements and provides a platform for future asset management enhancements. (Id.)

*Programs that Modernize the Grid*

1. Power Electronics for Volt/VAR

The Power Electronics for Volt/VAR (Power Electronics) pilot program integrates protection and control technology, which may help reduce power quality issues associated with high Distributed Energy Resource (DER) penetration, and ultimately improves reliability to customers. (Id. at 8.) DERs have intermittent power impacts that can change at rapid rates that are often faster than the legacy electromechanical voltage management equipment can handle. (Id.) As explained by witness Oliver, integrating advanced solid-state technologies like power electronics better equips the distribution system to manage power quality issues associated with increasing DER penetration. (Id.) This limited-scale deployment will help DEP validate the technology's capabilities and benefits.

2. Distribution System Automation

The Distribution System Automation (DA) program improves how the distribution system protects the public and itself from unsafe voltage and current levels and significantly reduces the impact experienced by customers due to grid [losses]. (Id. at 10.) The DA program consists of several subprograms that work in concert to support dynamic and growing distribution system loads in a more sustainable way while minimizing power quality issues that often accompany a large-scale transition to solar power. (Id.) These subprograms include: (1) Urban Underground System Automation; (2) Fuse Replacement; (3) Hydraulic to Electronic Recloser; and (4) System Intelligence and Monitoring.

The Urban Underground System Automation subprogram modernizes the protection and control of underground power systems that serve critical high-density areas, such as urban business districts and airports. (Id.) Specifically, the Urban Underground System Automation subprogram replaces manually operated underground switchgear with remotely operated automated switchgear and deploys advanced automation schemes in high-density areas. (Id. at 11.) The Fuse Replacement subprogram project focuses on replacing one-time use fuses with automatic operating devices capable of intelligently resetting themselves for reuse. (Id. at 10.) The Hydraulic to Electronic Recloser subprogram replaces obsolete oil-filled devices with modern, remotely operated reclosing devices that support continuous system health monitoring. (Id.) The System Intelligence and Monitoring pilot subprogram develops a database and system model that monitors electrical disturbances across the distribution system. (Id. at 11.) This subprogram helps engineers and technicians address electrical disturbances and improves customer experience. (Id. at 10.)

3. Integrated System Operations Planning

The Integrated System Operations Planning (ISOP) program is a planning tool that integrates utility planning for generation, transmission, distribution, and customer programs to improve the valuation and optimization of energy resources across the system. (Id. at 18.) The ISOP is a multi-year development program that will integrate and refine existing system planning tools and, in some cases, develop new analytical tools to assess characteristics that have not historically been captured or considered in long-term planning. (Id.)

4. Transmission System Intelligence

The Transmission System Intelligence program deploys transformational system monitoring and control equipment to enable faster response to outages and more intelligent analysis of issues on the grid. (Id. at 33.) Witness Oliver states that transmission grid automation improvements will reduce the duration and impacts associated with transmission system issues. (Id.) Additionally, improvements in transmission system device communication capabilities enable better protection and monitoring of system equipment. (Id.)

The Transmission System Intelligence program includes four subprograms: (1) Electromechanical to Digital Relays; (2) System Intelligence and Monitoring; (3) Remote Substation Monitoring; and (4) Remote Control Switches. (Id. at 34.) The Electromechanical to Digital Relays subprogram replaces non-communicating electromechanical and solid-state relays with remotely operated digital relays. (Id.) Witness Oliver testified that modern relay design with communications capabilities and microprocessor technology enables quicker recovery from events than the design of the existing electromechanical relays. (Id.) The System Intelligence and Monitoring subprogram determines when equipment maintenance or repair is needed through a machine-learning platform. (Id.) This subprogram allows asset managers to proactively address equipment issues before catastrophic equipment failures occur. (Id.) The Remote Substation subprogram enables operators to remotely monitor and control substations. (Id.) Witness Oliver explains that this subprogram is critical for programs like the IVVC program and DA program. (Id.) The Remote Control Switches subprogram replaces non-communicating switches with modern switches with communication and remote control capabilities. (Id.) This subprogram will support faster isolation of trouble spots on the transmission system and more rapid restoration following line faults. (Id.)

5. Enterprise Communications Advanced Systems

The Enterprise Communications Advanced Systems (Enterprise Communications) program modernizes and secures the critical communications between intelligent grid management systems, data and controls systems, and sensing and control devices. (Id. at 45.) This program addresses technology obsolescence, secures vulnerabilities, and provides new workforce-enabling capabilities. (Id.) Specifically, the Enterprise Communications program includes improvement and expansion of the entire communications network from the high-speed, high-capacity backbone fiber optic and microwave networks to the wireless connections at the edge of the grid. (Id.) The Enterprise Communications program consists of five subprograms that help build the secure communications required for the increasing number of smart components, sensors, and remotely activated devices on the transmission and distribution systems. (Id.) The five subprograms include: (1) Mission Critical Transport; (2) Business Wide Area

Network (Business WAN); (3) Grid-wide Area Network (Grid WAN); (4) Mission Critical Voice; and (5) Next Generation Cellular. (Id. at 46.)

The Mission Critical Transport subprogram implements the strategic advancements to the backbone of the communication network to ensure reliable, sustainable, interoperable communications for grid devices and personnel. (Id.) This subprogram replaces end-of-life fiber cable, optical systems, and microwave systems; strategically expands high-capacity fiber to new, targeted routes; and investigates alternatives for faster or more cost-effective fiber deployments. (Id.) The Business WAN subprogram updates data network architecture to improve reliability and performance of the core business. (Id.) The Grid WAN subprogram improves network reliability, performance, and security for grid control applications. (Id.) The Mission Critical Voice subprogram replaces radios used by field personnel to enhance communications between and within the field of operations. (Id.) This subprogram will deploy a common platform of radios that are compatible throughout all Duke Energy service areas. (Id.) The new radio system will allow field workers to communicate with and help other Duke jurisdictions during major storms. (Id.) The Next Generation Cellular subprogram replaces obsolete 2G/3G communication networks with current 4G/5G technology required for modern grid devices in the field. (Id.) This subprogram will replace existing network devices located on distribution line devices and substation equipment. (Id.)

6. Enterprise Applications

The Enterprise Applications program deploys the systems and upgrades needed to monitor the health and security of the grid and analyze data to enable grid automation and optimization technologies. (Id. at 48.) Within the program, there are two main components responsible for the delivery of enterprise technology solutions that support transmission, distribution, and other critical lines of business: (1) Enterprise Systems, and (2) Grid Analytics. (Id.)

Enterprise Systems focuses on delivering transformative, cross-functional technical solutions to the enterprise in non-disruptive ways. (Id.) There are two subprograms within Enterprise Systems: (1) the Integrated Tools for Outage Applications (iTOA), and (2) the Targeted Management Tool (TMT). (Id.) The iTOA works to drive standardization and coordination of grid control center tools. (Id.) The iTOA also upgrades and consolidates outage coordination as well as planned switching and logging applications for transmission and distribution control centers. (Id. at 49.) The TMT facilitates faster and more efficient workflows by integrating asset management and mapping system upgrades. (Id.)

The Grid Analytics component optimizes the electric system health and performance through two subprograms: (1) the Heath Risk Management (HRM) tool, and (2) the Enterprise Distribution System Health (EDSH) tool. (Id. at 48.) The HRM subprogram gathers and analyzes transmission system data for use in predictive and preventative maintenance efforts. (Id. at 49.) The EDSH subprogram improves asset performance on the transmission and distribution systems by using predictive and prescriptive analytics that allow the Company to take proactive steps to prevent or mitigate disruptive events. (Id.)

7. DER Dispatch Enterprise Tool

The DER Dispatch Enterprise Tool (DER Dispatch Tool) is a software-based solution that provides operators with the ability to monitor and manage both transmission and distribution connected DERs. (Id. at 51.) This program will coordinate with Distribution Management System and Energy Management System to improve the way DERs are integrated in the energy supply mix, both at the distribution and bulk power level. (Id.) The DER Dispatch Tool, if utilized to its full potential, will enable system operators to model, forecast, and dispatch a portfolio of DERs based on system conditions and real-time customer demand. (Id.) Witness Oliver testified that the DER Dispatch Tool provides operators with a more automated and refined toolset by eliminating the need for a dispatcher to place a call to DER sites to dispatch distribution connected to DERs. (Id.) Additionally, witness Oliver explained that the DER Dispatch Tool will help meet the need to match energy demand with supply, especially in emergency conditions. (Id.)

*Programs that Optimize Customer Experience*

1. DSDR Conversion to CVR Program

Oliver Exhibit 10 indicates that DEP already utilizes Integrated Volt/Var Control (IVVC) to reduce system voltages, as a means of lowering peak demand, during on-peak periods. The Distribution System Demand Response (DSDR) conversion to Conservation Voltage Reduction (CVR) project would allow, using IVVC technology, for a reduction in voltage demand during non-peak periods as well.

2. SOG

The SOG program, also known as the smart-thinking or self-healing grid, redesigns key portions of the distribution system to improve grid reliability and resiliency. (Id. at 7.) The SOG is designed to automatically reroute power around a problem area, like an outage caused by a tree on a power line, animal interference, or storm activity. (Id. at 6.) With this automation, the grid can self-identify problems and react to them by isolating affected areas and automatically rerouting power, thereby shortening or even eliminating outages for many customers. (Id.) The SOG program consists of the following subprograms: (1) Substation Bank Capacity; (2) Circuit Capacity and Connectivity; (3) SOG Segmentation and Automation; and (4) the Advanced Distribution Management System (ADMS). (Id. at 7.)

SOG Capacity projects focus on expanding substation and distribution line capacity to allow for two-way power flow. (Id. at 6.) SOG Connectivity projects create tie points between circuits. (Id.) SOG Segmentation and Automation projects provide intelligence and control capability for the SOG. (Id.) The SOG Segmentation and Automation subprogram focuses on segmenting circuits and equipping those segments with automated switching devices. (Id. at 7.) The ADMS subprogram is an enterprise-wide program that orchestrates and manages the SOG Segmentation and Automation projects. (Id.) The ADMS is a centralized software that leverages the intelligence captured from the grid to optimize power flow and reduce the impact of faults experienced by customers. (Id.)

According to Witness Oliver, the SOG programs could reduce outage impacts by as much as 75%. (Id. at 6.)

3. Long Duration Interruption/High Impact Sites

The Long Duration Interruption/High Impact Sites (LDI/HIS) program is designed to improve the reliability for parts of the grid where the duration of potential outages is expected to be much higher than average. (Id. at 16.) The LDI/HIS program is also designed to improve the reliability of high impact customers, such as airports and hospitals, and high-density areas that could require a variety of infrastructure solutions to improve quality and reliability. (Id.)

4. Targeted Undergrounding

The Targeted Undergrounding (TU) program identifies the most outage prone overhead power line sections and relocates them underground to reduce the number of outages experienced by customers. (Id. at 19.) According to witness Oliver, these segments drive a disproportionate amount of momentary interruptions and outage events that affect customers and burden grid assets with faults that shorten the life of equipment. (Id.) Witness Oliver testified that targeted undergrounding significantly reduces outages and momentary interruptions and will quicken restoration times after major events like storms. (Id.)

5. Distribution Transformer Retrofit

The Distribution Transformer Retrofit program retrofits existing overhead distribution transformers to minimize the number of customers impacted by fault or failure. (Id. at 21.) Witness Oliver testified the core activities of the Distribution Transformer Retrofit program include installing fused disconnect switches on the high-voltage side of every overhead transformer to protect upstream customers from a fault at or downstream of the transformer, and adding lightning arrestors and animal protection to reduce the risk of external factors. (Id.)

6. Distribution Hardening and Resiliency—Flood Hardening

Witness Oliver explained that the Distribution Hardening and Resiliency (H&R)—Flood Hardening program seeks to mitigate the effects to at-risk equipment from flooding. (Id. at 23.) The H&R—Flood Hardening program will target the hardest hit flood-prone areas from Hurricanes Matthew and Florence. (Id.) The H&R—Flood Hardening program includes the following: creating alternate power feeds for substations in flood-prone areas, and for radial power lines that cross into and through flood-prone areas; hardening river crossings where power lines are vulnerable to elevated water levels; and improving guying for at-risk structures within flood zones. (Id.)

7. Transmission H&R

The Transmission H&R program works to create a stronger and more resilient transmission grid capable of withstanding or quickly recovering from extreme external events. (Id. at 35.) The program consists of the following subprograms: (1) 44kV System Upgrade; (2) Targeted Line Rebuild for Extreme Weather; (3) Networking Radially Served Substations; (4) Substation Flooding Mitigation; and (5) Animal Mitigation. (Id.)

The 44kV System Upgrade subprogram rebuilds and upgrades targeted portions of the 44kV system to harden the system against extreme weather, position the system to support DER, and make the overall system more resilient. (Id. at 36.) The Targeted Line Rebuild for Extreme Weather subprogram protects transmission line assets from extreme weather by addressing vulnerable wooden structures. (Id. at 35.) The Networking Radially Served Substations subprogram increases resiliency of radially served substations where outage duration is higher than average. (Id. at 36.) The Substation Flooding Mitigation subprogram systematically reviews and prioritizes substations most vulnerable to flood damage to determine the proper mitigation solution. (Id. at 37.) Finally, the Animal Mitigation subprogram installs fences inside or around substations and devices on transmission poles and towers to prevent animal induced events from impacting customers directly through an outage or indirectly through a system perturbation such as a voltage depression. (Id. at 35.)

8. Transformer Bank Replacement

The Transformer Bank Replacement program is an acceleration of an existing predictive and proactive replacement program that leverages new system intelligence capabilities to target substation transformers before they fail. (Id. at 39.) The objective of the Transformer Bank Replacement program is to anticipate future transformer failures and replace those transformers in an orderly fashion. (Id.) Witness Oliver states that this program will significantly reduce the impacts and costs of replacement when compared to performing the same work following a catastrophic failure. (Id.)

9. Oil Breaker Replacement

The Oil Breaker Replacement program is an acceleration of an existing program that identifies and replaces oil-filled circuit breakers on the transmission and distribution systems with technology capable of two-way communications and remote operations. (Id. at 40.) Specifically, transmission level oil breakers will be replaced with sulfur hexafluoride gas circuit breaker technology. (Id.) Distribution level oil-filled breakers will be replaced with vacuum circuit breaker technology. (Id.) Witness Oliver testified that the communication and control capabilities of these technologies better position the transmission and distribution systems to work with grid automation systems to better respond to electric grid events. (Id.) Witness Oliver also noted that these breaker technologies are better suited for protecting circuits with higher solar and other variable energy resource penetration. (Id.)

10. Energy Storage[19]

The Energy Storage program implements energy storage technologies to defer, mitigate, or eliminate the need for traditional utility investments. (Id. at 13.) The program supports customer and utility initiatives through smart investments in storage for applications that deliver value to customers and the company. (Id.) These applications include microgrid projects for preventing outages, as well as long-duration outage projects for providing redundant power sources for rural and remote communities. (Id.) Projects within the Energy Storage program are designed on a case-by-case basis for the specific challenge being addressed. (Id.) The program also includes the development and deployment of the Energy Storage Control System to manage the fleet of energy storage resources. (Id. at 13.)

11. Electric Transportation[20]

The Electric Transportation pilot program establishes a foundational level of public fast-charging infrastructure to advance electric vehicle adoption in North Carolina and inform best practices for cost-effective integration of various electric vehicle types. (Id. at 28.) The Electric Transportation program consists of five components: (1) Residential EV Charging Rebates; (2) Commercial Customer Charging Rebate; (3) Electric School Bus Infrastructure Investments; (4) Electric Transit Bus Infrastructure Investments; and (5) DC Fast Charging Infrastructure. (Id.)

After describing the GIP programs, witness Oliver provided an overview of the benefits the Company anticipates will result from the initiative. (Tr. vol. 16, 139-40.) Witness Oliver explained that the GIP will provide two types of benefits: (1) primary (direct) benefits and (2) secondary (indirect) benefits. (Id.) Primary benefits consist of value that is directly captured by the Company and customers. (Id. at 139.) For example, primary benefits to the Company include things like avoided deployments of outage restoration crews, avoided equipment replacement costs, avoided operations and maintenance savings, and other costs that can be estimated and quantified. (Id.) Examples of primary benefits captured by customers include avoided lost wages, avoided lost product, avoided damaged equipment costs, and other expenses that cost customers money. (Id.) Witness Oliver testified that the GIP is justified in its entirety on primary benefits alone. (Id. at 140.) The GIP also provides secondary benefits to customers through risk reduction, value to third parties, and value to society as a whole. Witness Oliver stated that the Company estimated the indirect value of the GIP to third parties, but

[19] As explained below, although the Energy Storage program is part of the GIP, the program is not included in the Company's cost deferral request.

[20] As explained below, although the Electric Transportation program is part of the GIP, the program is not included in the Company's cost deferral request.

did not value the indirect benefits to society as a whole. (Id.) Therefore, the secondary benefits of the GIP are understated and are greater than what the Company has calculated. (Id.)

Witness Oliver testified that the Company performed cost benefit analyses (CBAs) that quantify the benefits for each of the GIP programs that are appropriate for such metrics. (Id.) Specifically, the CBAs detail, among other things, the amount of O&M savings the Company anticipates from the GIP; the amount of avoided capital costs the Company anticipates from the GIP; and the number of outages that each of the GIP programs are anticipated to avoid. (Id. at 140-41.) The detailed CBAs for the Company's proposed GIP programs were provided with witness Oliver's Direct Testimony as Oliver Ex. 7.

Witness Oliver explained that the GIP for North Carolina is identical to the South Carolina grid improvement plan in substance, so that the two plans can work together to benefit DEP customers. (Id. at 142.)

*Stakeholder Engagement*

DEP's Grid Improvement Plan is the successor program to a proposal made by the Company in Docket No. E-7, Sub 1146 denominated the Power Forward plan (Power Forward). Power Forward, which was a ten-year, $13 billion plan, with rider surcharges was widely opposed by intervenors to the Sub 1146 docket and ultimately rejected by the Commission. In rejecting Power Forward, however, the Commission suggested that the Company collaborate with stakeholders in developing any future grid improvement plan programs. (Id. at 143-44.) In response to the Commission's recommendation, the Company convened three in-person stakeholder workshops and a series of webinars addressing the Company's plans for grid improvement. (Id. at 145.) Witness Oliver stated that the Rocky Mountain Institute (RMI) acted as a neutral facilitator in each of the three workshops and prepared detailed, post-project reports that were filed with the Commission at the conclusion of each workshop. (Id. at 145-46.) Witness Oliver testified that because of these stakeholder engagements, the Company made significant changes to its portfolio of investments, provided cost benefit analysis and underlying data sources and work sheets for all applicable programs and projects to stakeholders, and responded to questions concerning distributed renewable energy resources. (Id. at 146-47.)

Additionally, a series of webinars focused on deep dives into the analysis behind the Company's GIP. (Id. at 148.) Specifically, the webinars focused on cost benefit analysis of the SOG, TU, and Transmission H&R projects. (Id.) During each of the webinars, experts were on hand to guide participants through cost benefit analysis scenarios and address questions regarding the implementation, improvements, and progress of the programs. (Id.) The workshops and webinars are explained, documented, and discussed in detail in Oliver Ex. 11 – 18.

*Cost Recovery*

The Company has requested regulatory asset/deferral accounting treatment for costs related to its GIP programs and cost recovery consideration in future general rate cases. (Tr. vol. 13, 158.) The Company requested authorization to begin deferring incremental costs not included in this proceeding beginning January 1, 2020 (id.), which was later modified to June 1, 2020 based upon updates to the Company's rate base through May 31, 2020 (id. at 239).

Witness Smith stated that the Company is requesting deferral of North Carolina's retail share of the following types of GIP costs: depreciation of capital investments; return on capital investments (net of accumulated depreciation) at the Company's weighted average cost of capital; O&M expenses related to the installation of equipment, property tax related to the capital investments; and a return of the balance of costs deferred at the Company's weighted average cost of capital. (Id. at 158-59.)

Witness Smith explained that for purposes of determining amounts to be deferred for future cost recovery from North Carolina retail customers, consideration is given to the nature of the expenditures, i.e., whether the expenditures are related to improvement of the distribution system, transmission system, or communications systems. (Id. at 159.) Witness Smith testified that distribution expenditures made to improve North Carolina distribution infrastructure would be fully assigned to North Carolina retail customers. (Id.) In contrast, because expenditures made to improve transmission infrastructure benefit both wholesale and retail customers, an appropriate share of the costs would be allocated to North Carolina retail customers. (Id.) For the same reasons, expenditures made to improve communications systems would be allocated among both retail and wholesale customers. (Id.)

Witness Smith testified that the Company's request for deferral accounting treatment satisfies the Commission's traditional test for cost deferral. (Id.) Witness Smith stated that the GIP expenditures are not simple, regularly occurring, inconsequential investments but instead are major non-routine investments that produce substantial customer benefits. (Id. at 159-60.) In the 2018 DEC Rate Order, the Commission noted that it would consider a request for deferral outside the test year "were the Company to demonstrate that the costs can be properly classified as . . . grid modernization [and not customary spend]." (2018 DEC Rate Order, at 148.) The Commission indicated that a list of projects arising from a collaborative stakeholder process would aid it in the examination of a deferral request. (Id. at 161.) As described above, witness Oliver testified that the projects for which the Company seeks deferral arise from a robust stakeholder process. (Id.)

Additionally, witness Smith testified that the Commission has consistently demonstrated that deferral is not a rigid concept and can be flexibly applied. (Id. at 160.) In the 2018 DEC Rate Order, the Commission declared that it could authorize deferral of "demonstrated" grid modernization costs incurred prior to the test year with "reliance on leniency in imposing the 'extraordinary expenditure' test." (2018 DEC Rate Order, at 149.) For example, in the Northbrook Hydro proceeding in Docket No. E-7, Sub 1181, the

Commission allowed DEC to defer losses experienced due to the sale of DEC's hydroelectric generation assets. (Id. at 161.) The Commission noted that the benefits accruing to the Company's customers due to the sale were substantial and the costs that customers would have to bear in the future were relatively small. (Id. at 161-62.)

Witness Smith testified that without cost deferral the Company will experience a significant adverse earnings impact. (Id. at 160.) Specifically, the earnings degradation is expected to grow to over 100 basis points by 2022, the third year of the GIP. (Id.) Witness Smith asserted that these effects are material to the Company's financial standing and could adversely impact the Company's financial strength and flexibility, thereby impairing reliable access to capital on reasonable terms. (Id.)

Witness Oliver testified that deferral accounting treatment is necessary to mitigate the debilitating effect that regulatory lag will have on the GIP without a deferral. (Tr. vol. 16, 150-51.) Witness Smith stated that the Commission has previously recognized that regulatory lag is always present in an integrated, investor-owned market such as North Carolina. (Tr. vol. 13, 160.) This is especially so in a jurisdiction (such as North Carolina) that uses a historical test year to set rates. (Id.)

Witness Oliver noted that if the Commission does not approve regulatory asset treatment for the Company's GIP investment, the Company would be required to reassess its ability to implement the GIP. (Tr. vol. 16, 152-53.) In such situation, the Company would have to try to perform small pieces of the GIP over a much longer period with its existing revenues, which would delay important benefits and potentially essential improvements for customers. (Id. at 153.)

***Public Staff Testimony***

Public Staff witness Maness testified that in many situations, the Commission will only approve deferral accounting if both prongs of a two-prong test are met. (Tr. vol. 15, 1593.) First, the costs must be very unusual, even "extraordinary in type." (Id.) Second, the costs must be very significant, even extraordinary, in magnitude; significant enough that the Commission can reasonably conclude that they are not being recovered in current customer rates. (Id. at 1593-94.)

Accordingly, the Public Staff assessed the Company's accounting deferral request in two steps. (Id. at 364.) First, Public Staff witnesses D. Williamson and T. Williamson reviewed the Company's proposals to assess which, if any, GIP programs in the request should be considered extraordinary in type and outside the scope of DEP's ordinary course of business. (Id.) Second, Public Staff witness Maness assessed the costs associated with any identified extraordinary by type programs to determine whether the costs of that program are of a magnitude that justifies deferral. (Id.) Public Staff witnesses D. Williamson and T. Williamson also noted that, separate from DEP's forward-looking GIP proposal, DEP had requested recovery in this proceeding of over $242 million of GIP related programs. (Id. at 377.)

Additionally, Public Staff witness Thomas analyzed the CBAs supporting the Company's GIP and provided his results and recommendations regarding the reasonableness of the GIP CBAs to the Commission. (Id. at 435.)

*Public Staff's Evaluation of the GIP*

The Public Staff generally agreed with the Megatrends identified by the Company but took the position that some of these trends were not new, novel or outside the scope of normal business. (Id. at 385.) Additionally, the Public Staff agreed that the Company should continue to address these trends by making the necessary grid infrastructure investments. (Id.)

The Public Staff developed a matrix analysis for reviewing the GIP to determine if certain programs or subprograms should be considered as extraordinary by type. (Id. at 404.) While this matrix analysis provided an increased level of objectivity to a very subjective topic, witnesses T. Williamson and D. Williamson acknowledged that their evaluation of the GIP programs necessarily contained some level of subjectivity. (Id. at 392.) Witnesses T. Williamson and D. Williamson employed a two-step approach to evaluate the GIP programs. (Id.) First, witnesses T. Williamson and D. Williamson reviewed each GIP program to determine whether it exhibited characteristics of a grid modernization program. (Id.) Second, witnesses T. Williamson and D. Williamson created an evaluation matrix that was used to rank each GIP program proposal on metrics considered important in defining grid modernization. (Id.; T&D Williamson Ex. 4.) The results of these two review processes were used to inform a final determination as to whether each GIP program met the "extraordinary in type" test. (Id. at 392-93.)

In determining whether each GIP program should be considered grid modernization, witnesses D. Williamson and T. Williamson sought to identify programs that would "bring the current grid up to new standards of operation and reliability." (Id. at 393.) Witnesses D. Williamson and T. Williamson also relied upon several information sources, such as the U.S. Department of Energy's Modern Distribution Grid Project and the California Public Utilities Commission Staff White Paper on Grid Modernization, to help guide their evaluation of the GIP programs. (Id. at 394-97.) Based upon this evaluation, witnesses D. Williamson and T. Williamson determined that the following GIP programs failed to meet the definition of grid modernization: (1) Distribution H&R; (2) Transmission H&R; (3) Transformer Bank Replacements; (4) TU; and (5) LDI/HIS. (Id. at 397.) Witnesses D. Williamson and T. Williamson explained that these programs were customary grid investments and not of an extraordinary type. (Id. at 397-98.)

In creating and applying an evaluation matrix, witnesses D. Williamson and T. Williamson determined a set of metrics on which to evaluate each GIP program based on their experience with grid modernization in North Carolina and their research into grid modernization efforts across the country. (Id. at 398.) Witnesses D. Williamson and T. Williamson considered three primary metrics: (1) the transformative impact of the program; (2) timing of the deployment; and (3) how the program fits in grid modernization architecture. (Id.) Each GIP program was then given a score by metric, with the available scores ranging from one (the lowest) to three (the highest). (Id.) Finally, a weighted score was calculated based upon the weights for each metric. (Id. at 399.) The "transformative" metric was assigned a weight of 2.0, while the "timing" and "grid architecture" metrics were each assigned a weight of 1.0. (Id. at 399-401.) The higher the overall score, the more likely witnesses D. Williamson and T. Williamson viewed the program as an "extraordinary type." (Id. at 399.)

Witnesses D. Williamson and T. Williamson testified that the "transformative" metric was the primary driver for determining whether a GIP program has characteristics of grid modernization. (Id.) Witnesses D. Williamson and T. Williamson explained that the "transformative" metric is designed to reflect whether the Company is proposing programs that will bring the grid up to new standards of operation and reliability rather than providing for investments that are needed to maintain or restore the grid to historic levels of operation and reliability. (Id. at 399-00.) The "timing" metric evaluates whether the program is ongoing or new work, and whether the implementation timeline is critical to grid operations. (Id. at 400.) Lastly, the "grid architecture" metric is based upon the concept of an overarching grid architecture. (Id.) Specifically, the "grid architecture" metric ranks GIP programs based on whether the program is a standalone program, dependent on core components, or a core component of grid modernization. (Id. at 400-01.)

Based on the evaluation matrix described above, witnesses D. Williamson and T. Williamson recognized the following GIP programs and/or subprograms as "extraordinary in type" and qualified for deferral accounting treatment consideration: (1) ISOP; (2) SOG Segmentation and Automation; (3) Transmission System Intelligence; (4) SOG ADMS; and (5) Urban Underground System Automation. (Id. at 405-08.) Witnesses T. Williamson and D. Williamson noted that in the "transformative" metric, all five programs classified as "extraordinary in type" were considered to provide significant new capabilities to the grid. (Id. at 404.) Additionally, in the "grid architecture" metric, all five of the programs were considered a core component of grid modernization. (Id.) Finally, in the "timing" metric, four of the five programs were determined to be programs that could begin implementation, but that the three-year timeline proposed by the Company was not critical to grid operations. (Id. at 405.)

*Public Staff Cost Recovery Testimony*

Public Staff witness Maness assessed the costs associated with the five GIP programs witnesses Williamson and Williamson identified as "extraordinary in type" to determine whether such costs were of sufficient magnitude to justify deferral. (Id. at 1595-96.) Witness Maness testified that the Public Staff's analysis focused on the basis point impact on earned ROE of the investment, plus certain estimated O&M, depreciation, and property tax expenses over the three-year GIP period. (Id. at 1596.) As such, witness Maness explained that the rate base analysis also included impacts of estimated Accumulated Deferred Income Tax (ADIT) changes to the rate base, as well as annual changes in gross plant in service investment, all calculated using a 13-month average to reflect average investment during each year. (Id. at 1596-97.) The baseline for witness Maness's basis point impact analysis was the Public Staff's recommended capital structure, cost rates (including ROE), rate base, and net operating income in this proceeding. (Id. at 1597.)

Witness Maness noted that normally, in conducting an analysis of this type, the Public Staff would consider the actual earnings of the Company during the year, as compared to the most recent Commission-approved ROE. (Id.) However, since the Company is requesting an accounting deferral right out of a general rate case, witness Maness stated that he did not attempt to project the Company's actual earnings over the 2020-2022 proceeding and has instead used the Public Staff's recommended earnings and ROE as a proxy for actual earnings during the three-year deferral period. (Id.) Additionally, witness Maness testified that he believes it is reasonable to consider deferral of the applicable amounts during the entire three-year period. (Id.) Witness Maness emphasized, however, that the prudence and reasonableness of actual amounts spent and deferred should remain subject to Commission review in future rate cases. (Id. at 1598.)

Witness Maness expressed that under normal circumstances, the Public Staff would not recommend deferral of an investment with basis point impacts as small as the amount of the total investment associated with the five GIP programs identified as extraordinary in type by witnesses T. Williamson and D. Williamson. (Id.) However, witness Maness explained that the Public Staff took special notice of language in the Commission's DEC 2018 Rate Order that appears to suggest leniency regarding the magnitude of costs or financial impacts necessary to justify deferral. (Id. at 1598-99.) Witness Maness testified that for this reason, the Public Staff did not object to allowing deferral of the capital costs of the five GIP programs, along with associated incremental expenses, incurred from March 2020, through December 2022, as long as the Commission determines that the estimated amount of basis point impacts falls within the range of leniency that it is willing to grant in this particular case. (Id. at 1600-01.) Witness Maness recommended that any deferral the Commission approves in this proceeding be considered specific only to this case, and not precedential with regard to any future general rate case proceeding or deferral request. (Id. at 1601.)

Witness Maness also recommended that the Commission apply the following restrictions to any deferral request granted in this proceeding: (1) deferral should be restricted to incremental capital costs related to plant in service and incremental expenses (offset by incremental operating benefits) incurred between March 1, 2020, and the earlier of December 31, 2022, or the effective date of the rates set in the Company's next general rate case; (2) no allocated overheads or administrative and general costs should be included in the allowable deferred amount; (3) the prudence and reasonableness of all costs incurred should remain subject to review in the Company's next general rate case; and (4) the Company should make annual reports setting forth the cost amounts incurred and deferred by GIP program and subprogram, with a description of each significant cost amount included in plant in service or expenses. (Id. at 1601-02.)

*Public Staff CBA Testimony*

Public Staff witness Thomas provided an analysis of the CBAs supporting the GIP programs and provided to the Commission the results and recommendations of the Public Staff's investigation into the reasonableness of the GIP CBAs. (Id. at 435.) Specifically, witness Thomas highlighted the Public Staff's concerns with the CBAs, presented sensitivity analyses, and presented the Public Staff's conclusion regarding the cost-effectiveness of the GIP programs. (Id. at 435-36.) Witness Thomas did not recommend that any GIP programs be rejected based upon their CBAs. (Id. at 436.)

Witness Thomas expressed several concerns regarding the CBAs. (Id. at 443-44.) Witness Thomas stated that direct benefits from the GIP are largely customer reliability benefits, which are difficult to quantify and verify. (Id. at 443.) As such, witness Thomas noted that the CBAs may not accurately reflect customer reliability benefits. (Id.) Specifically, witness Thomas took issue with how the Company quantified the reduction in outages as a result of the GIP. (Id. at 456.) Witness Thomas stated that his concerns centered around the fact that the interruption cost estimates are not certain enough, not region-specific enough, and are not sufficiently verifiable to be considered in a prudence evaluation of proposed GIP investments. (Id. at 472.) For example, witness Thomas stated that the Company used the LBNL Report to estimate the value of longer outages, despite cautions against such practice. (Id. at 473-74.) Therefore, witness Thomas cautioned that the methodology used by the Company to estimate the costs of outages of a sustained duration may overstate the costs to customers. (Id. at 477.)

Additionally, witness Thomas argued that the customer reliability benefits were heavily skewed towards Commercial and Industrial (C&I) customers. (Id. at 482.) Witness Thomas observed that where reliability benefits were broken out by customer class, approximately 97% were attributed to C&I customers, with the remaining 3% attributed to residential customers. (Id. at 483-84.) Witness Thomas stated that the allocation of GIP reliability benefits raises serious questions about equity in the Company's cost allocation and rate design. (Id. at 483.)

Further, witness Thomas observed that no sensitivity analyses of any key variables were conducted as part of the Company's CBA process. (Id. at 447.) Witness Thomas stated that the lack of sensitivity analyses in the CBAs masks the significant uncertainty in key underlying assumptions. (Id.)

Lastly, witness Thomas testified that some CBAs ignored or minimized the unfavorable effects of momentary outages, as well as future investments in traditional grid maintenance programs. (Id. at 444.) Specifically, witness Thomas argued that the SOG CBA ignores the costs of increased momentary outages during SOG events. (Id. at 458.) Witness Thomas stated that the SOG CBA should reflect that for some customers, sustained outages are not eliminated entirely, but rather become momentary outages. (Id. at 468.) Additionally, witness Thomas noted that certain CBAs lack consideration of the impacts of vegetation management. (Id. at 458.) Witness Thomas opined that the Company's vegetation management plan will reduce the number of avoided outages that the Company is currently projecting from its GIP programs. (Id. at 459.) Witness Thomas explained that if the outage rates decline over the next five years due to increased vegetation management, then the baseline used in the GIP CBAs will be overstated, causing the projected customer interruptions reduction, and the estimated benefits, to similarly be overstated. (Id.) Witness Thomas noted that while the Company accounted for this in some of the CBAs, certain CBAs did not include the impact of future vegetation management improvements. (Id. at 459-60, 516-18.)

Accordingly, witness Thomas recommended several changes to the CBAs and suggested that the Company take steps to improve its interruption cost estimates. (Id. at 438-40.) Witness Thomas recommended that the Company: (1) track and annually report the progress of the GIP implementation throughout the three-year plan and beyond; (2) perform CBAs for some GIP programs that were not evaluated for cost-effectiveness, such as the DA program and DER Dispatch Tool; (3) perform and file sensitivity analyses of its CBAs; (4) conduct an interruption cost study in the Carolinas or otherwise update interruption costs used in the Interruption Cost Estimate (ICE) tool; (5) remove or modify certain benefits from its CBAs, including long-term reliability benefits, and $CO_2$ emission savings; (6) revise SOG CBAs to include the effect of momentary outages; (7) revise SOG CBAs to account for increased vegetation management activity; (8) consider the impact of GIP programs on costs not considered and factor those impacts into its CBAs; (9) reduce the scope of the DSDR to CVR Conversion; (10) review its Transformer Bank Replacement and Oil Breaker Replacement programs; (11) include the cost of repairing faults on underground lines in its TUG CBA; (12) consider if changes to GIP cost allocations are warranted; and (13) defer no more than $23.7 million over the next three years if the Commission determines that the Transmission System Intelligence program should be granted deferral. (Id. at 438-40.)

On September 15, 2020, witness T. Williamson filed Supplemental Testimony in response to the Company's May 2020 Updates filing. In his Supplemental Testimony, witness T. Williamson noted some delays being experienced by DEP in achieving full enablement of SOG capabilities on circuits where hardware installation was complete, and noted that delays between project completion and benefit realization may pose challenges in assessing the cost effectiveness of GIP programs and adjusting the overall course of the GIP in an ongoing manner. (Tr. vol. 16, 65-66.) Witness T. Williamson also stated that traditional concepts of "used and useful" do not fully account for all the issues that must be considered when evaluating GIP investments and programs, but indicated the Public Staff's belief that the SOG equipment in question was, nonetheless, used and useful in providing utility service to the Public and, therefore, appropriate for inclusion in DEP's rate base. (Id.)

***Intervenor Testimony***

NCSEA and NCJC et al. witness Alvarez testified that the Company underestimated costs to ratepayers for its GIP by billions of dollars. (Tr. vol. 15, 272.) Specifically, witness Alvarez asserted that the GIP will cost ratepayers $8.6 billion over 30 years, compared to $2.3 billion presented by the Company. (Id. at 264.) Witness Alvarez contended that the $2.3 billion North Carolina capital budget in the GIP understated costs to ratepayers by 50% because: (1) $424.5 million in capital is detailed in GIP CBAs but not included in the GIP capital schedule; (2) $192.5 million in capital for Energy Storage and Electric Transportation programs are not included in GIP capital schedule totals; (3) $1.1 billion in software and communications network replacement costs are not included in capital budgets or CBAs; and (4) $4.5 billion in carrying charges ratepayers will have to pay on GIP investments are not included in ratepayer costs. (Id. at 264-65.)

Witness Alvarez also argued that the GIP overstates benefits to customers by billions of dollars. (Id. at 265.) First, witness Alvarez testified that aggressive and unsupported assumptions were used to calculate many program-specific reliability improvement estimates. (Id.) Witness Alvarez stated that the Transmission H&R, TU, LDI/HIS, Transformer Bank Replacement, and Oil-Filled Breaker Replacement programs all had overstated reliability improvement estimates. (Id. at 285-86.) Second, witness Alvarez also contested the Company's use of the ICE calculator to translate reliability improvement estimates into economic benefits. (Id. at 301-02.) Witness Alvarez alleged the following issues with the Company's estimates of economic impact per CI or CMI by rate class: the estimates are based on a limited number of surveys of manufacturing and retail ratepayers only, conducted decades ago; the definition of "large" C&I ratepayer is very small, increasing the large C&I ratepayer count to which avoided cost estimates are multiplied; and there is no consistency in how survey respondents took back up generation and uninterruptible power supplies into account when completing surveys. (Id. at 295.) Witness Alvarez also argued that the Company's aggregation of individual service outage impacts is inappropriate and leads to exaggerated overall avoided cost benefit estimates. (Id. at 298.) Third, witness Alvarez testified that the Company inappropriately relied on the IMPLAN model to estimate secondary, economic-development benefits of reliability improvements it attributed to the GIP. (Id. at 284.) Witness Alvarez claimed that the Company used dramatically overstated primary GIP ratepayer benefits as inputs into the IMPLAN software. (Id. at 306.) Fourth, witness Alvarez stated that he was concerned with the Company's failure to estimate the detrimental impact of GIP rate increases. (Id.)

Witness Alvarez concluded that the GIP is, at best, a break-even proposition for the Company's ratepayers overall, and dramatically negative for residential ratepayers. (Id. at 309-10.) As such, witness Alvarez recommended that the Commission reject the Company's GIP and establish a separate proceeding to develop a transparent, stakeholder-engaged distribution planning and capital budgeting process. (Id. at 321.) Alternatively, witness Alvarez recommended that the Commission adopt the program-specific recommendations witness Stephens describes as secondary recommendations in his testimony. (Id.) Lastly, witness Alvarez recommended that the Commission reject deferral accounting cost recovery on the basis that it encourages suboptimal capital investment. (Id.)

NCSEA and NCJC et al. witness Stephens also recommended that the Commission reject the Company's GIP and establish a separate grid modernization proceeding led by the Commission with stakeholder participation. (Id. at 476.) Witness Stephens noted that witness Alvarez's testimony provides an outline for such process and additional justification for the same recommendation. (Id.) Alternatively, witness Stephens recommended that the Commission evaluate each GIP program separately. (Id. at 476.) Witness Stephens then proceeded to categorize the GIP programs into the following "merit groupings": (1) merits approval with conditions; (2) merits approval with material modifications and conditions; (3) merits rejection; and (4) merits rejection pending further evaluation. (Id. at 476-77.) Additionally, for each GIP program approved, witness Stephens recommended that the Commission apply three conditions. (Id. at 480.) First, witness Stephens stated that the Commission should require ongoing performance measurement against pre-GIP baselines. (Id.) Witness Stephens explained that performance measurement is critical to ensure that ratepayer benefits are being maximized and increased over time, and to inform potential future expansions or curtailments of GIP programs. (Id. at 490-91.) Second, witness Stephens opined that the Commission should establish capital cost caps for every GIP program or subprogram it approves, as well as specifications for the program-specific extents of capabilities it expects to be operational within the cost cap. (Id. at 480.) Witness Stephens stated that these cost caps should include all capital for each GIP program, including capital spent prior to the end of the test year in the instant rate case. (Id. at 490.) Third, witness Stephens asserted that the Commission should require operating audits, with appropriate use of random sampling, to validate the functionality and geographic scope of any approved GIP program or subprogram. (Id.) Witness Stephens contended that this will help prevent a utility from reducing functionality or geographic scope in order to remain under any cost caps. (Id.) Lastly, witness Stephens recommended that deferral accounting for the GIP programs and subprograms be rejected. (Id. at 481-82.) Witness Stephens explained that deferral accounting treatment leads to excessive capital spending on sub-optimal projects. (Id. at 482.) Witness Stephens argued that the grid investments the Company has been making in recent years do not appear to be achieving the intended results and, therefore, approval of the Company's request for deferral accounting treatment will serve to increase the likelihood that DEP will earn or exceed its authorized ROE, thereby increasing the Company's already-adequate incentive to invest into the grid. (Id. at 481.)

Witness Stephens acknowledged that some GIP programs warrant Commission approval. (Id. at 477-78.) However, witness Stephens suggested that the following GIP programs and/or subprograms only be approved with conditions: (1) the IVVC program; (2) the flood and animal mitigation subprogram of the Transmission H&R program; (3) the LDI/HIS program; (4) foundational software, including Enterprise Applications, ISOP, and DER dispatch; (5) Cybersecurity (excluding substation physical security); and (6) Enterprise Communications (excluding mission critical voice and data network investments). (Id. at 477-78.) Witness Stephens explained that all of the GIP programs under this merit grouping satisfy one or more of the following criteria: they represent standard industry practice; they consist of software needed to optimize grid assets or operations, or improve cybersecurity; they are likely to deliver benefits to ratepayers in excess of costs to ratepayers; and they are critical to stakeholders' value that cannot otherwise be secured. (Id. at 488.)

Finally, witness Stephens recommended that some programs and/or subprograms be rejected pending further evaluation. (Dec. 2, 2020 Errata, Tr. vol. 15, Stephens Pre-Filed Testimony at 38.) Witness Stephens stated that in all of these programs, critical evaluations are missing that will require extensive effort beyond the scope of this proceeding. (Id.) Witness Stephens suggested that the Commission reject the following GIP programs and/or subprograms pending a more thorough evaluation: (1) Enterprise Communications Mission Critical Voice; (2) Distribution Automation; and (3) Transmission System Intelligence. (Id.) Witness Stephens argued that Enterprise Communications Mission Critical Voice should be rejected because the Company did not evaluate alternatives to its proposal to build proprietary voice and data communication networks. (Id.) Witness Stephens also contended that the Distribution Automation and Transmission System Intelligence programs should be rejected because the Company did not provide CBAs for either program. (Id. at 39-40.)

CUCA witness O'Donnell testified that the GIP will result in massive rate hikes for customers and is likely to harm the North Carolina economy. (Tr. vol. 14, 140.) Witness O'Donnell stated that he believes that the Company's objective is to drive earnings through grid investments and that the Company is not considering how these cost increases will negatively impact the North Carolina economy or how consumers may respond. (Id. at 139-40.) Additionally, Witness O'Donnell asserted that the GIP is simply a re-packaged Power Forward proposal. (Id. at 147.) Witness O'Donnell claimed that the Company has not been forthcoming to the public concerning costs associated with the GIP and that the Company has not scaled back its grid investment plans since the Commission's rejection of Power Forward. (Id.)

Witness O'Donnell also discussed several issues he had with the Company's CBAs. (Id. at 158-61.) First, witness O'Donnell disagreed with witness Oliver's assertion that some GIP projects could not be measured in a CBA. (Id. at 160-61.) Second, witness O'Donnell argued that if an independent project's assets will be used in multiple grid projects, the cost of the independent project should be apportioned in the various grid projects. (Id. at 161) Otherwise, excluding the cost of the independent project will skew the results of the CBA and not give the Commission an accurate view of the real costs of the grid projects. (Id.) Third, witness O'Donnell asserted that witness Oliver should have tested his assumptions with a sensitivity analysis. (Id.)

Witness O'Donnell provided two recommendations for how the Commission should address the Company's application for cost recovery of grid modernization assets. (Id. at 161-62.) First, to the extent the Company did not provide a CBA for a specific project, witness O'Donnell suggested that the requested project be denied. (Id. at 162.) If the project that is denied is critical to the CBA of a project that the Company has deemed economically feasible, witness O'Donnell stated that both projects should be denied. (Id.) Additionally, witness O'Donnell recommended that if the Commission rejects a GIP project, that the Company be permitted to re-file its GIP without prejudice and be required to include all costs in the GIP and apply a contingency factor of +/- 25% on various inputs into the model. (Id.) Second, witness O'Donnell suggested that the Commission make cost recovery of the grid modernization assets contingent upon the Company meeting the reliability targets as set forth by DEP in its CBAs. (Id.) Specifically, witness O'Donnell recommended that the Company be granted cost recovery if and only if the reliability targets are reached every year. (Id.)

NC WARN witness Powers testified that the Commission should reject the Company's GIP as unreasonable. (Tr. vol. 15, 864.) Witness Powers noted that many of the GIP capital projects are indistinguishable from traditional spend T&D projects, with no formal applications or associated evidentiary process to evaluate the reasonableness or potential alternatives for these proposed expenditures. (Id. at 864-66.) Witness Powers contended that the stakeholder workshops used to develop the GIP were essentially sales presentations by the Company that did not adequately review the scope and cost of the GIP. (Id. at 866.) Additionally, witness Powers stated that the Company's traditional T&D expenditures, without the GIP, are adequate to provide safe and reliable service. (Id. at 867.) Therefore, witness Powers recommends that the Commission reject the Company's GIP. (Id. at 864.)

CIGFUR witness Phillips testified that the Commission should not approve the accounting deferral request for several reasons. (Tr. vol. 14, 311-14.) First, witness Phillips contended that deferral accounting for GIP costs would shift regulatory risk from investors to customers by providing investors with an almost guaranteed recovery of specific expense items. (Id.) Second, witness Phillips stated that use of the GIP deferral would allow the Company to pursue single-issue ratemaking. (Id.) Witness Phillips explained that the accounting deferral could allow the Company to defer cost increases of its revenue requirement outside of a rate case but ignore cost decreases. (Id.) Third, witness Phillips argued that use of the GIP cost deferral would compromise the Company's incentive to be diligent and efficient in its procurement and operations in-between rate cases. (Id.) Finally, witness Phillips stated that the GIP costs the Company proposes to defer are not unpredictable or outside of the Company's control. (Id.) Accordingly, witness Phillips stated that the Company has not demonstrated the need to defer its GIP costs and, as such, the accounting deferral should be rejected. (Id.) In the alternative, if the Commission approves the GIP cost deferral, witness Phillips asserted that the Company's allowed ROE should be reduced to reflect the reduced business risk that investors will face. (Id. at 312.)

Vote Solar witnesses Van Nostrand and Fitch testified that they reviewed the GIP in light of grid modernization best practices, Vote Solar's participation in the stakeholder engagement process, the emergence of climate-related risks, and recent policy development in North Carolina since the Company's last rate case. (Tr. vol.15, 116-19.) Witnesses Van Nostrand and Fitch concluded that the Company's GIP does not assess or respond to climate-related risks, nor does it adhere to grid modernization best practices. (Id. at 120-72.) As a result, witnesses Van Nostrand and Fitch contended that the Company's GIP does not provide enough information to indicate that the GIP programs and subprograms are prudent investments. (Id. at 117.) Additionally, witnesses Van Nostrand and Fitch asserted that the stakeholder process the Company conducted did not adhere to best practices or a reasonable expectation of engagement and collaboration. (Id. at 129.) Further, witnesses Van Nostrand and Fitch expressed concern with the Company's request for deferred accounting treatment of GIP investments. (Id. at 196.) Witnesses Van Nostrand and Fitch stated that deferred accounting is an extraordinary ratemaking tool and it would be a departure from customary ratemaking practices to use deferred accounting in these particular instances. (Id.) Witnesses Van Nostrand and Fitch asserted that using deferral accounting for GIP expenditures shifts risks to ratepayers because it reduces the regulatory oversight that results from the general rate case process and largely eliminates the economic incentive from regulatory lag for a utility to hold down costs. (Id. at 204.)

Accordingly, witnesses Van Nostrand and Fitch made several recommendations to the Commission. (Id. at 220-21.) First, witnesses Van Nostrand and Fitch recommended that the Commission direct the Company to assess and manage climate-related risk across its operations assets and in accordance with prudent utility practice, and make clear that it will apply this standard to the GIP investments. (Id. at 221.) Second, witnesses Van Nostrand and Fitch recommended that the Commission direct the Company to participate in ongoing Department of Environmental Quality stakeholder processes around grid modernization and integrate data, findings, and recommendations into its grid modernization investments. (Id.) Further, the Company should be required to file a report by December 31, 2020, identifying any gaps in knowledge that need to be filled through further collaboration. (Id.) Third, witnesses Van Nostrand and Fitch suggested that going forward, the Commission should require the Company to develop large distribution investments such as the GIP through an integrated distribution planning or ISOP process. (Id.) Fourth, to the extent that the Company is permitted to defer GIP costs, witnesses Van Nostrand and Fitch recommended that the Commission impose performance-based conditions on the recovery of such deferred amounts in rates, such as through adjustments to the weighted average cost of capital applied to the unauthorized balance of deferred amounts. (Id.)

Harris Teeter witness Bieber testified that the accounting deferral is unnecessary and that the creation of a regulatory asset to recover deferred GIP costs would amount to single-issue ratemaking. (Tr. vol. 15, 229.) Witness Bieber stated that absent a compelling public interest, single-issue ratemaking is not sound regulatory practice. (Id. at 249.) Witness Bieber explained that a single-issue cost recovery mechanism is warranted only if it meets the following criteria: (1) the anticipated costs or revenues are subject to significant volatility from year-to-year; (2) the anticipated costs or revenues are not reasonably controllable by management; and (3) the anticipated costs or revenues are substantial enough to have a material impact on the utility's revenue requirement and financial health between rate cases. (Id. at 250.) Witness Bieber stated that the Company's GIP costs do not meet all three of these criteria. (Id. at 251.) Specifically, the GIP costs do not appear to be volatile in nature or outside the control of the Company. (Id.) Accordingly, witness Bieber recommended that the Commission reject the Company's proposal for deferred accounting treatment for GIP costs. (Id. at 251-52.) Instead, witness Bieber opined that the Company's costs associated with the GIP should be considered within the context of a general rate case. (Id.)

***DEP Rebuttal Testimony***

*Oliver*

1. <u>GIP Program and Subprogram Analysis</u>

In his Rebuttal Testimony, witness Oliver responded to the issues raised by witnesses D. Williamson and T. Williamson, Thomas, Alvarez, Stephens, O'Donnell, Bieber, Phillips, and Van Nostrand and Fitch.

Witness Oliver testified that he agreed with the Public Staff's assessment of the five GIP programs and subprograms recognized as "extraordinary in type" and deserving of consideration for deferral accounting treatment. (Tr. vol. 16, 159.) Further, witness Oliver asserted that notwithstanding the Company's position that all of the programs and subprograms in the GIP should be eligible for deferral accounting treatment, the Company believes that several other GIP programs and subprograms should also qualify for deferral treatment as "extraordinary in type" using the Public Staff's evaluation methodology. (<u>Id</u>.) Witness Oliver contended that using the Public Staff's own methodology, the following programs and/or subprograms should be considered "extraordinary in type" and were deserving of deferral treatment using the Public Staff's analytical framework: (1) SOG Capacity and SOG Connectivity; (2) DSDR Conversion to CVR; (3) DA; (4) Power Electronics; (5) DER Dispatch Tool; and (6) Cyber Security. (<u>Id</u>. at 159-60.)

Witness Oliver explained all of the major components of the SOG program work together to fundamentally redesign key portions of the distribution system and transform it into a dynamic, smart-thinking, self-healing grid. (<u>Id</u>. at 160-61.) As such, witness Oliver stated that the benefits outlined in the SOG CBA could not be achieved by leaving out the SOG Capacity and SOG Connectivity subprograms. (<u>Id</u>.) Additionally, witness Oliver argued that the DSDR Conversion to CVR should be classified as "extraordinary in type" because the conversion will enable greater application of DER resources on DEP's system. (<u>Id</u>. at 161.) Witness Oliver also stated that all three DA subprograms – Hydraulic to Electronic Recloser, System Intelligence and Monitoring, and Fuse Replacement – should qualify as "extraordinary in type." (<u>Id</u>. at 161-64.) First, under the Hydraulic to Electronic Recloser subprogram, witness Oliver explained that the Company is shifting from reclosers to new industry standard electronic reclosers. (<u>Id</u>. at 162.) Witness Oliver noted that these new devices allow for remote operation and provide ongoing and continuous monitoring of the health of the distribution system, both of which are transformative capabilities not available using current equipment. (<u>Id</u>.) Second, witness Oliver explained that the System Intelligence and Monitoring subprogram adds significant new digital and analytical capabilities for devices on the grid and therefore results in greater transformative grid intelligence capabilities that allow the Company to proactively understand grid events. (<u>Id</u>. at 163.) Third, witness Oliver asserted that the Fuse Replacement subprogram is truly a leap forward in capability not previously available to the electric industry and bringing this new capability to the grid has the ability to further increase reliability from day one of install. (<u>Id</u>. at 163-64.) Regarding the Power

Electronics program, witness Oliver testified that the program meets the “extraordinary in type” test because it enhances the transformative capability of the distribution system to manage power quality issues associated with increasing DER penetration. (Id. at 164-65.) Witness Oliver also asserted that the DER Dispatch Tool should be considered “extraordinary in type” because 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. (Id. at 165.) Finally, witness Oliver stated that the Cyber Security program meets the “extraordinary in type” test because purposeful threats to the electric grid are on the rise and attacks on electric utilities can have significant geopolitical, humanitarian, and economic impact. (Id. at 165-66.) As such, additional transformative and architectural measures must be taken to address new risks and the changing landscape. (Id.at 166.)

Witness Oliver also testified that the GIP programs and subprograms the Public Staff did not score as “extraordinary” are nevertheless appropriate for the GIP. (Id. at 169.) Witness Oliver contended that while the Public Staff’s approach to evaluate the GIP programs and subprograms is rational, it is also somewhat subjective and not the only way to evaluate those programs. (Id.) Notably, witness Oliver observed that the Public Staff is not recommending any of the GIP programs not be implemented. (Id.) Instead, witness Oliver explained that the Public Staff only takes issue with the requested deferral accounting for programs and subprograms that did not meet their standard of “extraordinary.” (Id.)

In response to claims that several GIP programs and/or subprograms are not “extraordinary” in nature, witness Oliver explained why these GIP programs and subprograms should be included in the GIP. (Id. at 200-07.) Specifically, witness Oliver rebutted contentions by several parties that the following programs and/or subprograms were not “extraordinary”: Distribution Transformer Retrofit; Transmission H&R; TU; LDI/HIS; Transformer Bank Replacement; Oil Breaker Replacement; Transmission Substation Physical Security; Enterprise Communications; and Enterprise Applications. (Id.)

At the outset, in response to several intervenors who claimed that Distribution Transformer Retrofit, Transmission H&R, TU, Transformer Bank Replacement, and Oil Breaker Replacement programs are all base maintenance work that should not be included in the GIP, witness Oliver stated that a critical point is being missed. (Id. at 200.) Witness Oliver acknowledged that with the exception of TU, all of the above-listed programs and/or subprograms have been performed in base work in the past. (Id.) However, witness Oliver argued that the increased pace of change required by the changing landscape of the electric industry demands that the Company accelerate the historical pace to better the position the Company to deal with future requirements. (Id.)

Regarding the TU program, witness Oliver testified that the Company included it in its GIP because it has an immediate and direct positive impact on customer satisfaction. (Id. at 201.) Witness Oliver stated that the scope of the TU program was scaled back by approximately 90% to address stakeholder concerns and the portion that remains is highly cost beneficial. (Id.) Witness Oliver stated the TU program uses a refreshed approach and now focuses on laterals that experience the highest outage events per year in a sustained pattern, correlated with significant age, high percentages of facilities inaccessible to trucks, and high vegetation management expenses. (Id.) Witness Oliver asserted that this approach greatly increases the benefit to cost ratio from the statistics cited by witness Stephens. (Id.) Additionally, witness Oliver disagreed with witness Stephens' assertion that the TU program was not standard industry practice. (Id. at 201-02.) Witness Oliver noted that both Dominion in Virginia and Florida Power & Light in Florida have active targeted undergrounding programs. (Id.) Witness Oliver explained that both programs have been further encouraged by legislation within each state. (Id. at 202.)

Witness Oliver testified that the Company included the LDI/HIS program in its GIP because the program is designed to address the extreme weather events and concentrated population growth Megatrends. (Id. at 202.) Specifically, the LDI/HIS program is designed to improve reliability: (1) in parts of the grid where duration of outages is much higher than average due to their accessibility; and (2) of high-impact customers like airports and hospitals, and high-density areas that require a variety of solutions to improve power quality and reliability. (Id.)

Witness Oliver testified that the Company included the Transformer Bank Replacement program in the GIP because the GIP accelerates the historical pace of replacements to better position the Company to deal with future requirements. (Id. at 203.) In response to witness Stephen's contention that the Company is proposing to replace substation transformers in the absence of oil testing results, witness Oliver explained that it is in fact 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. (Id.) Additionally, witness Oliver asserted that witness Alvarez's transformer failure rate calculations discussed by witness Stephens were flawed and inaccurate. (Id.) Witness Alvarez stated that the Company's reliability benefits are based on an estimate that 45 of the 101 transformer banks to be replaced would fail between now and 2036. (Id.) Witness Oliver clarified that while the Transformer Bank Replacement CBA does indeed account for 45 potential transformer bank failures, this is out of a population of approximately 700 banks. (Id.) Accordingly, witness Oliver testified that the failure rate would be 45/700, not 45/101. (Id.)

Similarly, witness Oliver testified that the Company included the Oil Breaker Replacement program in the GIP to accelerate the historical pace of replacements. (Id. at 203-04.) Witness Oliver stated that the Company agrees with witness Stephens' assertion that circuit breakers should be identified for replacement based on test results and operating counts. (Id.) Witness Oliver clarified that the Company does inspect and test substation circuit breakers to determine their health and maintenance needs, and noted that all oil circuit breakers proposed for replacement in the GIP have been selected based on these criteria. (Id.) Witness Oliver also rebutted witness Alvarez's breaker failure rate calculation discussed by witness Stephens. (Id.) Witness Alvarez stated that of the 370 oil-filled circuit breakers proposed for prospective replacement, 456, or 123%, would have failed by 2032. (Id.) Witness Oliver clarified that while the Oil Breaker Replacement CBA does account for 456 potential breaker failures through 2032, this is out of a population of approximately 2,700 oil circuit breakers. (Id.) As such, the correct annual failure rate is approximately 1%. (Id.)

Witness Oliver testified that it was important to include the Transmission Substation Physical Security subprogram in the GIP because threats to grid infrastructure is one of the top Megatrends that has shaped the GIP. (Id. at 205-06.) Witness Oliver noted that this threat is widely accepted as valid throughout the utility industry. (Id.) In response to witness Stephens' observation that the Company has never recorded a single incident of unauthorized substation intrusion, witness Oliver states that the Company is proud of this record and intends to maintain this record through implementation of the Transmission Substation Physical Security subprogram. (Id.)

Witness Oliver testified that it was important to include the Enterprise Communications program in the GIP because a strong, secure, updated, and robust communications system is a foundational pillar to any intelligent grid. (Id. at 206-07.) Witness Oliver explained that as the Company places additional intelligent two-way communicating devices on the grid, having a robust communications platform is a necessity. (Id.) In fact, witness Oliver agreed with some industry experts who consider the expanding high-speed communications networks to be the third grid. (Id.)

Finally, witness Oliver testified that it was important to include the Enterprise Applications program in the GIP because the program focuses on delivering transformative, cross-functional solutions to the enterprise in non-disruptive ways. (Id. at 207.)

2. CBAs

Witness Oliver also rebutted Public Staff and intervenor concerns regarding the CBAs that support the GIP. (Id. at 171.) Specifically, witness Oliver responded to the issues raised by witnesses Thomas, Alvarez, and O'Donnell.

In response to witnesses Thomas and O'Donnell's assertions that the Company should have performed sensitivity analyses around its CBAs, witness Oliver testified that the concept of the AACE estimate classes associated with a GIP program or subprogram provide a reasonable measure of the expected cost estimate accuracy. (Id. at 173.) Regarding the benefit component, witness Oliver stated that the amount of combined operational and customer benefits for most GIP programs and subprograms provided assurance that the GIP program or subprogram was a positive benefit to customers. (Id.)

In response to witnesses Thomas and Alvarez's concerns pertaining to reliability benefits, witness Oliver testified that it was appropriate for the Company to use the ICE model to estimate the benefit of its GIP programs and subprograms. (Id. at 174-75.) Witness Oliver stated that the underlying data supporting the ICE model is based on extensive utility customer surveys and has been validated multiple times through ongoing updates by LBL/Nexant. (Id. at 175.) Additionally, witness Oliver noted that all economic benefits calculated are estimates. (Id.) As such, witness Oliver stated these estimates should be considered statistically valid having been generated through the use of well-established and well-respected industry modeling techniques. (Id.) Further, witness Oliver asserted that it is inappropriate to compare the Company's GIP reliability benefits against the GDP of North Carolina. (Id. at 176.) Witness Oliver acknowledged that from a purely mathematical perspective, the $6 billion figure is approximately 1% of the 2018 North Carolina GDP. (Id.) However, witness Oliver stated that any correlation of these two figures beyond that math exercise is pure speculation. (Id.) For instance, witness Oliver explained that the $6 billion figure is the net present value of 25-30 years of annual benefit streams. (Id.) Therefore, witness Oliver stated that it would be more appropriate to speculate on the impact each annual period could have on the state GDP, which is a much smaller portion. (Id.) Moreover, witness Oliver stated that the economic impact to North Carolina resulting from increases or decreases in reliability benefits cannot be measured by simply examining changes in state-level GDP growth over time. (Id.) Witness Oliver explained that 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. (Id.)

In response to witness Thomas' recommendation that the Company conduct direct customer surveys, witness Oliver testified that there would likely only be marginal value in conducting an independent survey of customers in North Carolina for the purposes of evaluating customer savings associated with GIP reliability improvements. (Id. at 177.) Witness Oliver explained 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. (Id.) Therefore, witness Oliver stated that the significant cost, resources, and time requirements of conducting such a study without a guarantee of greater statistical value seems unwarranted at this time. (Id.)

In response to witness Alvarez's allegation that the GIP will cost ratepayers $8.6 billion over 30 years, compared to the $2.3 billion presented by the Company in Ex. 10, witness Oliver testified that witness Alvarez's cost estimate is unsubstantiated and not useful for the Commission's determination of GIP deferral eligibility. (Id. at 189.) Witness Oliver stated that attempting to reconcile the values from the CBAs to the values from Ex. 10 relative to the 2020-2022 period is not an accurate comparison because each set of values serves a valid but different purpose. (Id.) Specifically, witness Oliver stated that the CBAs assist in validating the benefit-to-cost ratio for select GIP programs and subprograms whereas the Ex. 10 amounts are budgetary in nature. (Id.)

In response to witnesses Alvarez and O'Donnell's assertions that the Company did not estimate the detrimental impacts to GIP benefits that would come from GIP-related rate increases, witness Oliver testified that incorporating additional factors into its calculation of the primary economic benefits and secondary economic benefits fell outside of the scope of the IMPLAN analysis. (Id. at 194-95.) Witness Oliver stated that the purpose of the IMPLAN analysis was to estimate the aggregated benefit stream from the GIP that will accrue to the Company's customer base as a whole. (Id.)

### 3. Performance Metrics

In response to witness Thomas and witness Stephens' assertions that the GIP should have quantifiable targets and metrics to measure performance, witness Oliver testified that the Company agreed. (Id. at 197.) Witness Oliver explained that the CBAs provided metrics for the GIP programs and subprograms, as appropriate. (Id. at 197-98.) Specifically, witness Oliver stated that the CBAs detail, among other things, the amount of O&M savings the Company anticipates for the GIP; the amount of avoided capital costs the Company anticipates from the GIP; and the number of outages that each of the programs and subprograms within the GIP are anticipated to avoid. (Id.) Additionally, witness Oliver asserted that the Company intends to track deployment metrics for the GIP. (Id. at 198.) In particular, witness Oliver stated that the Company intends to track GIP program and subprogram scope, schedule, cost, and benefits as appropriate during implementation. (Id.)

Witness Oliver testified that since the Company has quantifiable metrics and targets built into its GIP, witness Stephens' suggestion that the Commission implement cost caps and audits is unnecessary. (Id. at 198-99.) Witness Oliver explained that the Company's performance is subject to prudence reviews that are already inherent in the regulatory process. (Id.) Therefore, witness Oliver stated that if customers do not get the value they pay for under the GIP, the Company remains at risk for a prudence disallowance unless it can provide reasonable and prudent reasons as to why customers did not get their deserved value. (Id.)

In response to witness Stephens' conclusion that DEC's and DEP's investments in recent years do not appear to be achieving the intended results, witness Oliver explained that while the previous level of expenditures has maintained system performance, since 2013 the Company has seen a worsening trend in the SAIFI and SAIDI statistics due to an increase in number of outage events and several other factors. (Id. at 199.) Witness Oliver stated that the analysis and Megatrends utilized to inform the GIP resulted in programs that were designed specifically to address these worsening trends. (Id.) However, witness Oliver asserted that in 2019, the Company saw SAIDI and SAIFI improvements. (Id.)

### 4. Stakeholder Engagement/Power Forward

In response to allegations from witness Alvarez and witnesses Van Nostrand and Fitch that the Company's stakeholder engagement efforts were "superficial" and/or "inadequate," witness Oliver testified that the Company's stakeholder engagement efforts not only allowed for increased collaboration with stakeholders but also enhanced transparency of the development of the GIP. (Id. at 208.) As accurately noted by witnesses T. Williamson and D. Williamson, witness Oliver averred that a "global consensus" was not reached on all topics addressed during the stakeholder engagement process. (Id.) However, witness Oliver asserted that 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. (Id.) Further, witness Oliver stated that before the Company filed its GIP with Commission, the additional CBAs conducted by the Company along with other meeting materials were published in an online data room for stakeholder review. (Id.)

In response to critiques that the GIP is in many ways a repackaged Power Forward plan, witness Oliver testified that there are clear differences in the purpose, scope, and level of stakeholder engagement between Power Forward and the GIP. (Id.) First, witness Oliver asserted that the GIP is a 3-year plan whereas Power Forward was a 10-year plan. (Id.at 209.) Witness Oliver stated that there is currently no "Phase 2" of the GIP, and any future plan would be built based on collaboration with stakeholders. (Id.) Second, witness Oliver observed that the scopes of the two plans are dramatically different. (Id.) For example, witness Oliver noted that Distribution H&R and TU made up 64% of Power Forward. (Id.) In contrast, witness Oliver stated that these programs make up only 11% of the GIP. (Id.) Additionally, witness Oliver declared that large new programs, such as IVVC and Physical and Cyber-Security, exist in the 3-year GIP. (Id.) Moreover, witness Oliver stated that SOG, a program generally supported by all stakeholders, made up less than 10% of Power Forward. (Id.) Witness Oliver noted that it is the largest program in the GIP. (Id.)

In response to concerns that the GIP does not address DER accommodation as discussed during the stakeholder engagement process, witness Oliver agreed that the GIP does not address third party owned DER accommodation in North Carolina. (Id. at 211.) Witness Oliver explained that this is because that is not what the GIP is designed to do. (Id.) Witness Oliver testified that state and federal rules and policies dictate how these interconnection issues are addressed, and discussions regarding these issues are currently ongoing in North and South Carolina. (Id.) As such, witness Oliver contended that the Company cannot and should not attempt to get ahead of federal and state rules and evolving policy issues regarding interconnection in the GIP. (Id.)

Witness Oliver recommended that the Commission reject witness Alvarez's primary recommendation to reject the Company's GIP and instead establish a separate proceeding to develop a stakeholder-engaged distribution planning and capital budgeting process. (Id. at 212.) Witness Oliver stated that the Commission should ignore witness Alvarez's primary recommendation for several reasons. (Id.) First, witness Oliver argued that if the Commission were to reject the GIP, it could result in negative impacts. (Id.) Second, witness Oliver testified that contrary to witness Alvarez's allegation, the Company undertook an extensive and transparent stakeholder engaged planning process when it was deciding on which programs to include in the GIP. (Id.) Witness Oliver asserted that rejecting the GIP would undermine not only the efforts of the Company but also each stakeholder involved in the stakeholder engagement process. (Id.) Third, witness Oliver contended that if the Commission were to reject the GIP, the work in the GIP would have to be sub-optimized, delayed, diminished in scope and effectiveness, and potentially not conducted at all. (Id.) Witness Oliver explained that in such situation, the Company would have to try to perform small pieces of the GIP over a much longer period of time using its existing revenues, delaying important benefits and potentially essential improvements for customers. (Id.) Witness Oliver also testified that he did not recall witness Alvarez being an active participant in the GIP stakeholder proceeding. (Id. at 211.) Therefore, witness Oliver stated that witness Alvarez's critique of a process in which he had virtually no involvement is confusing. (Id.)

In response to arguments that the GIP should be delayed until an IDP or ISOP process is developed and conducted, witness Oliver testified that he disagreed. (Id. at 213.) Witness Oliver asserted that certain GIP programs and subprograms, such as SOG, IVVC, 44kV System Upgrade, Transmission System Intelligence, and DA, would only improve the success of ISOP once implemented. (Id.) Witness Oliver stated that delaying these programs and subprograms could in fact hinder the ability of ISOP to deliver its intended benefits. (Id.) Moreover, witness Oliver explained as the ISOP process is currently being developed, the Company cannot reasonably be criticized for not having this tool in place now. (Id. at 214.)

*Smith*

In her Rebuttal Testimony, witness Smith responded to the issues raised by witnesses O'Donnell, Stephens, Alvarez, Phillips, Maness, and Bieber.

Witness Smith testified that the type of investments, the level of costs, and the overall scale of the GIP led the Company to request deferral of the associated revenue requirements. (Id. at 216.) Witness Smith explained that authorization to defer costs allows the Company the opportunity to avoid adverse financial impacts of regulatory lag, but only to the extent the Commission ultimately allows recovery of the deferred cost in a future rate case. (Id.) Witness Smith clarified that if allowed to defer GIP costs, the Company still bears the risk of recovering the costs in a future rate proceeding. (Id.) Therefore, despite intervenor testimony to the contrary, cost deferral is not pre-approval of cost recovery. (Id. at 220.) Rather, witness Smith explained that deferred revenue requirements will be considered for recovery in a future general rate case proceeding in conjunction with all other electric costs subject to consideration. (Id.) Further, witness Smith testified that contrary to witness Alvarez's assertions, when deferred costs are presented in future rate proceedings for recovery, the costs will not be ambiguous. (Id. at 220-21.) Witness Smith explained that if the Commission authorizes deferral of GIP costs, the Company will initially record the expenditures for all GIP programs and subprograms according to FERC accounting requirements. (Id.) Therefore, all GIP expenditures will be classified functionally and recorded to the appropriate FERC account as if no deferral exists. (Id. at 551.) The Company will then record special journal entries to reclassify the costs that it is authorized to defer into a regulatory asset account. (Id.) As such, witness Smith stated that when the Company requests cost recovery of the deferred amounts in a future general rate case, the details of the deferred amounts will be known. (Id. at 221.)

Additionally, witness Smith testified that contrary to what is implied in some intervenor testimony, the Company is not requesting deferral of its capital expenditures. (Id. at 216.) Instead, the Company is requesting to defer the traditional revenue requirement amounts associated with the GIP capital expenditures. (Id.) As such, witness Smith explained that the cost to be deferred will be the depreciation and return on investment for the completed plant in service, and the financing costs related to the amounts that are unrecovered during the period between the in-service date of the asset and when the Company rates are updated to include cost recovery of the assets. (Id. at 216-17.)

In response to witness Stephens' characterization of deferred accounting authorization as granting the Company "a pot of money it can invest as it wishes," witness Smith stated that this characterization incorrectly infers that the investments for which the Company is granted authorization for cost deferral are not subject to Commission review and scrutiny and a finding of reasonableness and prudency. (Id. at 221-22.) Witness Smith asserted that the implication is that the Company bears no risk with regard to amounts that the Company spends and thus is incentivized to spend indiscriminately. (Id. at 222.) To the contrary, witness Smith reiterated that GIP expenditures, like all expenditures, are at risk for recovery because authorization to defer does not guarantee recovery of the costs. (Id. at 222-23.) As explained earlier, witness Smith stated that approval to defer costs only allows the Company to identify the costs for deferral and record them as a regulatory asset for *potential* future recovery through future rate adjustments. (Id.) Additionally, witness Smith clarified that while the estimated amounts of GIP expenditures are provided in the testimony and exhibits of this proceeding, it is the actual costs incurred that are ultimately deferred and then brought forward for potential cost recovery. (Id.) Therefore, witness Smith stated that recovery is ultimately based on actual costs, not estimated costs, nor an estimated total amount for the GIP. (Id.)

Witness Smith also disputed witness O'Donnell's comments regarding customer rate impacts of grid modernization. (Id. at 223.) Witness Smith asserted that the grid modernization rate impact presented by witness O'Donnell is related to the Power Forward program, not the GIP. (Id.) Witness Smith noted that witness O'Donnell used information from February 2017 that he previously presented in this direct testimony filed in the Sub 1146 proceeding. (Id.) Moreover, witness Smith stated that not only is the Power Forward program data presented by witness O'Donnell outdated, but the GIP is drastically different in scope than the Power Forward program. (Id. at 223.)

In response to intervenor concerns that customers bear the risk of cost overruns or GIP program scope shortcomings that could be addressed by the imposition of spending caps, witness Smith noted that the Commission, at present, has full authority to address cost overruns or scope issues in a future rate proceeding when the deferred costs are presented for recovery. (Id. at 222-23.) Witness Smith stated that in the future rate case, the Company bears the risk of any disallowances the Commission could choose to impose. (Id.)

In response to witness Phillips and witness Bieber's concerns that deferral accounting is an example of single-issue ratemaking, witness Smith restated that deferral accounting is not ratemaking at all. (Id. at 220.) Witness Smith testified that cost recovery is a separate and distinct process from cost deferral. (Id. at 215.) As such, witness Smith stated that customer rates are not impacted by the Commission's decision to permit cost deferral. (Id.)

Witness Smith also testified that she does not agree with the cost deferral restrictions recommended by witness Maness. (Id. at 217.) Witness Smith stated that it was inappropriate to exclude costs that are directly related to the GIP programs for which the Company is requesting deferral. (Id.) Witness Smith noted that witness Maness's proposal to exclude deferral of a return on the balance of deferred incremental capital costs and incremental expenses will exclude financing costs incurred by the Company between the time the GIP costs are incurred and the time such costs are approved for recovery in future rates. (Id.) Witness Smith explained that many programs and subprograms within the GIP have short construction periods and therefore will be placed into service quickly. (Id. at 218.) Given the length of time to complete a general rate case, witness Smith noted that even if the Company had a rate case every year, the delay in cost recovery from the month that the GIP program or subprogram is placed in service to the month that the costs are reflected in the Company's new base rates could be significant. (Id.) If rate cases do not occur every year, then the lag in cost recovery is multiplied. (Id.) Witness Smith stated that the impact of regulatory lag for the GIP is substantial and, therefore, the Company should be given the opportunity to recover all prudently incurred GIP costs through future rate adjustments by being allowed to defer all of the costs associated with the GIP. (Id.)

Finally, witness Smith observed that the Public Staff's analysis of the estimated impact on the Company's ROE if GIP cost deferral is not approved differs, in some respects, from the analysis prepared by the Company. (Id. at 219-20.) Witness Smith noted that the main difference is that the Public Staff's analysis is based on the five GIP programs identified by witnesses Williamson and Williamson as "extraordinary in type" and, consequently, a considerably smaller amount of capital expenditures. (Id.) Witness Smith stated that witness Oliver's rebuttal testimony provides substantial support for authorization of deferral for all GIP amounts. (Id.) As such, witness Smith contended that the ROE impact presented in her direct testimony is the appropriate impact for the Commission to consider in making its cost deferral determination. (Id.)

*Oliver/Smith Joint Testimony*

On August 5, 2020, in compliance with the Commission's July 23, 2020, Order Requiring Duke Energy Carolinas, LLC and Duke Energy Progress, LLC to file Additional Testimony on Grid Improvement Plans and Coal Combustion Residual Costs, DEP witnesses Oliver and Smith filed Joint Testimony on GIP related issues specified by the Commission. Specifically, this testimony provided information to the Commission regarding the revenue requirement and customer rate impacts of two hypothetical scenarios – one where the Company's GIP deferral request was granted in its entirety and one where its deferral request was denied in its entirety. Because DEP had recently entered into a settlement with the Public Staff (which occurred after the date of the Commission's Order directing the additional testimony), the Joint Testimony of witnesses Oliver and Smith also provided revenue requirement and rate impact information illustrative of the effects of the Second Partial Stipulation.

In their Joint Testimony, witness Oliver and Smith provided the data requested by the Commission but made it clear that in the case of a total denial of the requested deferral, the data was unavoidably based on hypothetical assumptions about decisions and actions that the Company might take with regard to GIP programs in the absence of a deferral, which could not be known at present. (Tr. vol. 13, 266-72.) The analysis provided by witness Oliver and Smith showed a cumulative five-year increase in rates of 4.5% resulting from a full deferral of the Company's filed GIP proposals and a negligible cumulative impact on rates from a full denial of the Company's filed GIP proposals. The cumulative impact from a deferral of the GIP programs agreed to in the Second Partial Stipulation was 1.9% over the first five years. (Oliver/Smith Ex. 1 – 3.)

*Oliver Supplemental Rebuttal Testimony*

On September 22, 2020, witness Oliver filed Supplemental Rebuttal Testimony in response to Public Staff witness T. Williamson's September 15, 2020, Supplemental Testimony. Witness Oliver's Supplemental Rebuttal Testimony confirmed witness T. Williamson's conclusion that full enablement of SOG capabilities by the Company was currently proceeding more slowly than the Company would like and discussed the reasons for this temporary phenomenon, which included the impacts of the COVID-19 pandemic on hiring and training. (Tr. vol. 16, 216-19.) Witness Oliver also confirmed that the installed SOG equipment included in the Company's May Updates was, nevertheless, fully used and useful in providing utility service to DEP's customers. (Id.) Witness Oliver also discussed the steps the Company was taking to accelerate SOG enablement, as well as the steps DEP would take if the Commission approved the accelerated SOG installations that would result from approval of the Second Partial Stipulation. (Id.)

***Second Partial Stipulation***

On July 31, 2020, DEP and the Public Staff filed the Second Partial Stipulation. In pertinent part, the Second Partial Stipulation provided for the Public Staff's agreement to support deferral accounting treatment for the following GIP programs specified in Oliver Ex. 10, limited to the three-year capital budget period of 2020-2022: (1) Self-Optimizing Grid (all programs including Capacity and Connectivity, ADMS, and Segmentation and Automation); (2) DSDR Conversion to CVR; (3) Integrated System and Operations Planning; (4) Transmission System Intelligence; (5) Distribution Automation; (6) Power Electronics; (7) DER Dispatch Tool; and (8) Cyber Security. The budgeted amount for these settled GIP programs is approximately $1.25 billion over a three year period.[21] In return for this agreement by the Public Staff to support deferral accounting treatment for the specified GIP programs during the proposed three-year term for such programs, DEP agreed to withdraw its deferral accounting request in this docket for the other GIP programs specified in Oliver Ex. 10. The parties also reached agreement as to the types of costs eligible for deferral and preserved the Public Staff's rights to review such costs for prudence and reasonableness. The parties also agreed to jointly develop metrics to monitor the implementation and measure the effectiveness of the agreed GIP programs

[21] Consisting of approximately $800 million for DEC and $400 million for DEP. (Tr. vol. 4, 128.)

and DEP agreed to report such metrics, including cost-effectiveness, for each of the agreed programs on a regular basis beginning with expenditures made during the last six months of 2020.

On September 16, 2020, Public Staff witness Maness filed his Second Supplemental Coal Ash Testimony in this proceeding, in which he addressed certain aspects of the Joint Testimony filed by witnesses Oliver and Smith on August 5, 2020. Witness Maness testified that the exhibits filed by witnesses Oliver and Smith did not appear to reflect the impact of any accumulated deferred income taxes (ADIT) related to incremental GIP investment. In witness Maness's opinion, the impacts of ADIT on rate base should be included in order to present a complete picture of the impacts of GIP investment on the revenue requirement, witness Maness also reiterated his earlier testimony that no amortization period for deferred GIP costs be decided in this case, stating that it makes better sense to wait to decide on the reasonable period until the facts and circumstances surrounding eventual GIP costs are clearer. (Tr. vol. 15, 1624-25.)

The Second Partial Stipulation, considered together with the settlements reached between DEP and other intervenors, resolved GIP-related issues between DEP and the majority of intervenors that filed testimony relating to GIP issues. Because of the scope and nature of the settlements, the current GIP program proposal before the Commission for consideration is that reflected in the Second Partial Stipulation with the Public Staff. The only parties whose active opposition to GIP in the form of filed testimony were not resolved through these settlements are NC WARN and CUCA.

***Expert Witness Hearing***

At the expert witness hearing on this matter, the prefiled direct and rebuttal testimony described previously was admitted into the record and the witnesses who appeared for the hearing were cross-examined and subjected to questions from the Commission.[22] In particular, DEP witnesses Oliver and Smith, Public Staff witnesses D. Williamson and T. Williamson, Thomas, and Maness, CUCA witness O'Donnell, and NCSEA and NCJC et al. witnesses Stephens and Alvarez all appeared and testified at the expert witness hearing regarding GIP related issues. No witnesses materially altered their prefiled testimony at the hearing of this matter; however, each of the settling parties' witnesses who appeared agreed that the settlements reached by their clients with DEP were a fair resolution of the GIP issues and indicated that they supported their individual settlements notwithstanding their prefiled testimonies and that the settlements were not inconsistent with their prefiled testimonies. (Tr. vol. 8, 63-64, 66, 96-97.)

In the expert witness hearing, several Commissioners raised questions about whether approving deferral accounting for the settled GIP programs would effectively tie

[22] The following GIP witnesses did not appear at the expert witness hearing but their prefiled testimony was admitted into the record pursuant to the agreement of the parties: (1) Van Nostrand and Fitch (Vote Solar); (2) William Powers (NC WARN); and (3) Justin Bieber (Harris Teeter).

the Commission's hands in a subsequent rate case when recoverability of the deferred costs was examined. Public Staff witness Maness provided the following testimony on this issue:

> Q. If the Commission accepts this provision, and then the day comes when the Company asks to include GIP program costs it has incurred in rates, what will there be then for me to decide as a Commission at that point? What is left for me to decide at that point?
>
> A. I think what is left for you to decide is exactly the same as if there had been no deferral request. In other words, the prudence --- the reasonableness and prudence of the costs that have been incurred, plus going forward in time, the decision to actually defer those costs. . . The only thing that this order that we would be doing here is saying we think there is enough of a general conclusion that this – at this point in time, that these are good projects to go forward with, that we think deferral is justified as a regulatory accounting adjustment. It's not a ratemaking decision, and the ultimate ratemaking decision is going to be left to be subject to the same evidence and deliberations of the Commission as if there had never been deferral approved.

(Tr. vol. 7, 53-54.) Witness Maness affirmed this analysis again on redirect. (Tr. vol. 8, 40.)

In the expert witness hearing, a number of issues were also raised on cross-examination and questions from the Commission, regarding scope and variability inherent in the settled GIP program proposals and how the Commission could be assured both initially and on an ongoing basis that the programs were properly scoped, budgeted, and implemented appropriately, and producing the projected benefits. Questions were also raised regarding how the programs might be adjusted if they were not performing as projected. Both DEP witnesses and Public Staff witnesses testified on these points.

On the point regarding how does the Commission know what it is approving if it goes forward with the eight settled GIP programs, Public Staff witness Thomas testified:

> Jay Oliver's testimony, he does present fairly detailed summaries of each program. We've obviously investigated each program. I focused on costs and benefits, so I do know what ratepayers are getting, in terms of fuel savings and reduced operational costs associated with outage restoration, reduced vegetation management expenses. So I know about at least those operational benefits that have been estimated by Duke. And also I have an idea of the type of reliability improvements that customers might see.

(Tr. vol. 7, 69.) For his part, in his redirect testimony, witness Oliver indicated that under the intervenor settlements, DEP intended to implement the eight settled GIP programs as described in his Direct Testimony and Exhibits. (Tr. vol. 9, 55.) Witness Oliver also testified extensively on his confidence in the cost estimates underlying the GIP proposals.

(Id. at 65-66; Tr. vol.10, 23-24, 42.) And that DEP has a process called “check and adjust” to react to projects that are not performing as anticipated and to make appropriate changes and that DEP would use those processes to adjust the settled GIP programs, in conjunction with the Public Staff, if they do not perform as anticipated. (Tr. vol.10, 25-28, 44-46, 49.) Finally, witness Oliver reiterated on redirect, the obligations undertaken to work with the Public Staff to ensure that the GIP programs are monitored and reported on in the Second Partial Stipulation. (Id. at 56-58.)

On the issue of how the Commission can be assured that the Company has correctly anticipated the benefits of the settled programs, witness Oliver testified to DEP’s experience with the two largest settled programs:

> So the IVVC programs, we have a great pilot. It’s called the DSDR program in DEP. We know exactly how to do this work. We know exactly what it costs. We know exactly how to operate it. The difference is just operating it on a different timeframe. We’re going to operate it the majority of the hours of the year versus just peak shaving. The technology is no different. . .
>
> For self-optimizing grid, now, this is a tried and true technology. I will, again, point to Ohio. As part of the Smart Grid Rider in Ohio we implemented a significant self-optimizing grid program and are able to track the benefits of that program very closely, and it’s been operational for several years.

(Tr. vol. 9, 52-53.)

On the issue of how will the Commission know if the settled GIP programs are being implemented properly, Public Staff witness T. Williamson testified:

> [E]very six months we are going to see through reporting what the Company is doing. And as witness Thomas indicated, we’re going to be, you know, assessing all along the way what that value is, and at any point, should the Company, you know, either accelerate or stop a particular program. . . I think we put some provisions in place to allow us to assess the value that the using and consuming public is going to be receiving along the way.

(Tr. vol. 7, 71.) Witness Oliver testified, after explaining that DEP was already tracking GIP performance in South Carolina, that:

> We are going to work with the Public Staff to design a reporting package I want to say that’s pretty similar to . . . [South Carolina], and it will track cost, it will track benefits, it will track schedule, and it will track scope.

(Tr. vol. 9, 56-57.) witness Oliver also testified extensively to the internal processes and procedures utilized by the Company to monitor the scope, progress, budget, spending, and benefits associated with capital projects and the applicability of those processes to the settled GIP programs should the Commission authorize deferral accounting for those projects. (Tr. vol. 10, 14-18, 20-21.)

On the issue of whether DEP will be able to measure the benefits and performance of the settled GIP programs, witness Oliver was unequivocal:

> We certainly have ways to measure the specific reliability improvements in these programs. We also have ways to measure specific voltage reduction that we're going to get from IVVC. So yes, I'm confident we can measure the effects [of the settled GIP programs].
>
> (Tr. vol. 6, 71.)
>
> I know that we can track the reliability of the CI and CI savings . . . I know that we can track the voltage reduction as we implement the IVVC program. We can do that now. There are a few other programs. There's one in particular that we have agreed as part of the settlement with the Public Staff to do a cost-benefit analyses for as part of our distribution automation program.

(Tr. vol. 6, 37.) When asked if he believed that DEP had the tools necessary to engage in a higher-level evaluation of GIP performance going forward if deferral were granted, witness Oliver testified:

> I do. I believe we have what is needed to evaluate. We have laid out the defined scope, we have laid out the defined budget, we have laid out costs, and we've laid out benefits associated with the work, and the cost-benefit analysis.

(Id. at 64.) Witness Oliver also noted that the settlement with the Public Staff provided for performance reporting and that he had no issue sharing those reports with the Commission. (Id. at 76.) Public Staff witness Thomas also indicated comfort with the parties' ability to measure GIP program performance and confirmed the Public Staff's intention to monitor GIP program performance closely. (Id. at 151.) Witness Thomas also testified to his expectation that the reports on GIP performance produced by DEP under the Second Partial Stipulation would be filed with the Commission. (Tr. vol. 7, 73.)

In the expert witness hearings, the issue of potential future allocation of costs versus allocation of benefits was discussed at length. On questions from the Commission, Public Staff witness Thomas confirmed his direct testimony statement that under the Company's cost-benefit analyses results, 97% of the economic benefit of reliability improvements resulting from the GIP programs under the Companies CBAs flowed to C&I customers but that this figure was applicable to only the SOG and IVVC programs. (Id. at 63; Tr. vol. 8, 32.) On redirect, witness Thomas clarified that:

> A big reason for the skew between residential and commercial/industrial is because the underlying study that quantifies those benefits from Lawrence Berkeley National Lab assigns a very small value, in the $5 or $10 per outage for residential customers, and it's very large for

> commercial/industrial customers, sometimes reaching into the hundreds of thousands.

(Id. at 37.) Witness Thomas' point was also confirmed by witness Oliver on redirect who also noted that this disparity in presumed benefits between residential and commercial/industrial customers was nothing new – i.e. it is not unique to GIP programs but is a constant with regard to any activity that reduces outages. (Tr. vol. 9, 60.) Witness Oliver later clarified these statistics by noting that 37% of benefits under the GIP programs are not reliability benefits and that all customers benefitted from those. (Id. at 58.) Of the remaining 63% of reliability benefits, most of them are attributable to the SOG program, which reduces outages for all customers. According to witness Oliver, approximately 92% of customers on each of DEP's circuits subject to the SOG program are residential customers and they would benefit from enhanced reliability every time SOG avoided an outage. (Id. at 59.) Witness Oliver also made the point that other reliability enhancing programs such as pole replacement and vegetation management, also yielded "economic benefit" results similar to the SOG CBA but that, as is the case with SOG, the vast majority of customers whose outages are reduced by those programs are residential customers. (Id. at 60-61.) Finally, witness Oliver testified that in addition to reliability benefits, "all customers benefit from modernizing the grid to proactively address the Megatrends, to start building the two-way power flow model." (Id. at 58.)

In terms of deciding cost allocation in this case, both Public Staff witness Maness and DEP witness Oliver indicated that no party was requesting that the Commission make that determination in this proceeding and that it should be properly reserved for the cost recovery proceeding, which would be DEP's next general rate case. (Tr. vol. 8, 39-40; Tr. vol. 9, 44-45, 64.)

Finally, questions regarding the similarity of GIP to Power Forward and whether GIP really was just normal maintenance dressed up for special rate treatment were also raised at the expert witness hearing. Witness Oliver testified directly that this was not the case:

> Q. Would you agree with me that there is a substantial overlap between the programs described in Duke Energy Carolinas' prior Power Forward program and the currently proposed grid improvement plan.
>
> A. I would not.
>
> (Tr. vol. 5, 19.)
>
> The $1.25 billion that we have in the deferral agreement, . . . all of it, provides new technology that is required to move the grid to deal with what is coming in the future. To deal with the growth in private renewables, to deal with growth in solar . . ., to deal with the growth in electric vehicles we are seeing.
>
> (Tr. vol. 4, 140.)

> [t]he programs we are postulating now in this three-year plan are simply foundational: having the ability for two-way power flow, switching from the one-way grid of today; moving from managing the grid in circuits to managing the grid in segments, which is really the core of two-way power flow; the core of being able to fully leverage private distributed energy sources, that's simply foundational to no matter what the future is.
>
> (Tr. vol. 5, 40.)

No one rebutted these assertions at the hearing of this matter.

**Discussion and Conclusions**

Before beginning our analysis of and conclusions regarding GIP related matters in this proceeding, the Commission would note that the prefiled and live testimony and exhibits of witnesses representing more than a dozen parties make up the record on GIP in this proceeding. This record is thousands of pages long. Much of this evidence is summarized above. The Commission has reviewed and considered all of the evidence in reaching its conclusions below, but it is not practicably possible to recount or specifically address in this order each and every contention, fact, or assertion regarding GIP made by every party in this proceeding. To the extent the Commission does not specifically and expressly address a particular fact, contention, or assertion made by a party, it is because the Commission found that fact, contention, or assertion either immaterial or insufficiently probative of the appropriate outcome on GIP deferral related matters in this proceeding to merit separate discussion.

DEP's GIP proposals in this proceeding have their genesis in DEC's Power Forward proposals in Docket No. E-7, Sub 1146. In that case, DEC proposed a multi-program, ten-year, $13 billion plan and requested a surcharge mechanism (and/or a deferral) to assist in its ability to recover the costs of this program. Power Forward was strongly contested by many intervenors and ultimately rejected by the Commission. In rejecting Power Forward, however, the Commission left the door open for a more refined program reflecting stakeholder review and input.

Following the DEC 2018 Rate Order decision, the evidence is clear that DEC and DEP followed the Commission's direction and conducted a significant effort at involving interested parties in its refinement and modification of the Power Forward initiative into what is now its GIP proposal in this docket. Not unexpectedly, some parties are dissatisfied with the GIP proposal made in this docket and with the process by which DEP developed those proposals, including its stakeholder engagement process.

DEP's GIP proposals, as filed, consisted of 19 programs (many with subprograms) for which regulatory asset treatment/deferral of costs was sought. It is clear from the record that except for those costs related to GIP projects placed in service prior to the end of the updated test year in this case, DEP is not seeking prospective cost-recovery approval from the Commission with respect to its GIP costs included in its three year plan at this time, but simply authorization to defer GIP costs until a future rate case, at which time the reasonableness and prudence of those costs will be reviewed and those costs potentially amortized for future recovery from customers. The Commission acknowledges, as does DEP and the Public Staff, that authorization to defer GIP costs carries with it at least an implication that, based upon the evidence before the Commission, it is reasonable for DEP to begin implementation of its settled GIP programs to the extent deferral of costs is authorized (Second Partial Stipulation, § III.C.), although not to continue incurring such costs should such continuation cease to be justified in the context of costs and benefits.

The original 19 programs proposed for cost deferral have now been reduced through negotiations between DEP and the Public Staff to eight programs with a total projected budget of approximately $1.25 billion (for both DEP and DEC) between the effective date of this order and the end of 2022. In the Second Partial Stipulation, and contingent upon approval of that settlement, DEP agreed to withdraw its deferral request with regard to costs incurred for the other 11 GIP programs. The net impact of the intervenor settlements, which are supported, at least in part, by the vast majority of parties filing testimony on GIP, is to roughly cut in half the number of programs and projected spend on the Grid Improvement Plan over the next 30 months. This is the proposal now before the Commission for consideration.

The Commission has carefully reviewed the evidence on DEP's GIP proposal in this docket and concludes that approval of the Second Partial Stipulation's provisions between the Public Staff with DEP on the subject of program cost deferral is appropriate and supported by the preponderance of evidence and that the deferral of GIP costs thereunder is just and reasonable and consistent with the public interest. The facts, analysis, and discussion supporting the Commission's conclusion in this regard are set forth below.

***Review of Second Partial Stipulation***

Under North Carolina law, a stipulation entered into by less than all parties in a contested case proceeding under Chapter 62 "should be accorded full consideration and weighed by the Commission with all other evidence presented by any of the parties in the proceeding." *State ex rel. Utilities Comm'n v. Carolina Utility Customers Association*, 348 N.C. 452, 466 (1998). Further, "[t]he Commission may even adopt the recommendations or provisions of the nonunanimous stipulation as long as the Commission sets forth its reasoning and makes 'its own independent conclusion' supported by substantial evidence on the record that the proposal is just and reasonable to all parties in light of all the evidence presented." (Id.)

In this case, relative to GIP proposals, the Company has reached stipulations with 15 parties: (1) the Public Staff; (2) Vote Solar; (3) Harris Teeter; (4) BJ's Wholesale Club; (5) Ingles Markets; (6) Walmart; (7) Food Lion, (8) JC Penney; (9) Macy's; (10) CIGFUR; (11) NCSEA; (12) NCJC; (13) NCHC; (14) SACE; and (15) NRDC.

Because of the structure and scope of the GIP stipulations reached with the various settling parties, the active GIP program proposals before the Commission for consideration are those contained in the aforementioned Second Partial Stipulation with the Public Staff, which is more detailed in nature than the other stipulations but which also includes a commitment by DEP to withdraw its request for deferral accounting treatment for individual GIP programs that are not specifically supported by the Second Partial Stipulation. The agreed-on programs in the Second Partial Stipulation represent eight of the original 19 GIP program proposals put forth by DEP.

The settlements with the other intervenors either provide express support for or non-objection to the deferral of costs associated with the programs specifically agreed to in the Second Partial Stipulation.

Consistent with Finding of Fact No. 10, the Commission concludes that the Second Partial Stipulation represents material evidence of the appropriate resolution of this proceeding with regard to the GIP-related issues.

***Megatrends***

As part of its development of its GIP programs in this proceeding, DEP analyzed so-called Megatrends impacting the retail transmission and distribution of electricity in North Carolina and based its GIP proposals on those Megatrends. According to DEP, these Megatrends included:

1. Threats to Grid Infrastructure
2. Technology Advancements – Renewables and DER
3. Environmental Trends
4. Impact of Weather Events
5. Grid Improvement
6. Concentrated Population Growth
7. Customer Expectations

They are identified and discussed in witness Oliver's prefiled direct testimony and further examined in Oliver Ex. 2. The implications of the Megatrends are further identified and discussed in Oliver Ex. 3.

No party took serious issue with DEP's analysis that these identified trends are in fact real and occurring. Several parties did provide or elicit testimony that the Megatrends were not unique to DEP or North Carolina, that one or more of them may have been in existence for some period of time or might exist indefinitely (Tr. vol. 8, 104), or that addressing these trends was not outside the scope of normal business (Tr. vol. 15, 317.) None of the Megatrends were substantively challenged as to their existence or the fact that they were impacting the ability of DEP to provide electric service to end-use customers in North Carolina.

With regard to the Power Forward proposal, the Commission concluded in the DEC 2018 Rate Order that "the reasons DEC says underlie the need for Power Forward are not unique or extraordinary to DEC, nor are they unique or extraordinary to North Carolina. Weather, customer disruption, physical and cyber security, DER, and aging assets are all issues the Company (and all utilities) have to confront in the normal course of providing electric service." (DEC 2018 Rate Order, at 146.) In this proceeding, the Commission accepts the reasonableness of witness Oliver's conclusion that DEP must adjust its provision of electric service to end use customers in North Carolina to address these trends.

***Identity of GIP and Power Forward***

Several intervenor witnesses indicated a belief that the GIP was simply a repackaged Power Forward program, which the Commission had previously rejected in Docket No. E-7, Sub 1146. While the Commission acknowledges a clear historical link between Power Forward and the GIP, the evidence demonstrates that the two programs are sufficiently distinct to consider GIP on its own merits.

Power Forward was a 10-year $13 billion dollar proposal raised by DEC in Docket No. E-7, Sub 1146 and rejected by the Commission. GIP, as originally proposed by DEP, was a three-year $2.3 billion dollar program. As proposed in the Second Partial Stipulation, it is now a three-year, $1.25 billion program. Power Forward sought primarily to implement a rider surcharge mechanism to collect Power Forward program costs from ratepayers on an intra-rate case basis. Under the GIP, DEP proposes a more limited deferral of costs between rate cases subject to a subsequent prudence review and amortization in a potential future rate case. Thus, with respect to scope, duration and requested relief, there are clear distinctions between GIP and Power Forward.

It is also clear from the evidence that the two programs, particularly as the GIP has been modified under the Second Partial Stipulation, are distinct from each other. The most obvious evidence of this fact was provided in Public Staff witnesses T. Williamson and D. Williamson's Direct Testimony, in Table 3, which provides a graphic comparison of DEP's filed GIP proposals and the Power Forward proposals in Docket No. E-7, Sub 1146. Recognizing that GIP and Power Forward were proposed for different durations, that table shows that nine Power Forward programs were included among the originally filed 19 GIP programs, and that those nine programs were funded at different levels between Power Forward and GIP. A comparison of the Second Partial Stipulation and Table 3 of the Williamsons' testimony reveals that of the eight settled GIP programs, only two – SOG and Distribution System Automation - are common to Power Forward.

And while several intervenor witnesses attempted to demonstrate consistency between Power Forward and GIP, in particular CUCA witness O'Donnell, their comparisons were substantially subjective in nature and do not stand up to the analysis put forward by DEP and discussed above. Accordingly, we give the testimony of witnesses who raised these arguments, no weight. We find GIP, particularly in the form presented by the intervenor settlements, to be sufficiently distinct from DEP's previous

Power Forward proposals that GIP should be judged on its own merits and not summarily rejected on the basis of alleged similarity with Power Forward.

CUCA witness O'Donnell further argued that GIP was an incremental first step towards the same result anticipated by Power Forward and cited to statements made by Duke Energy's CEO Lynn Good to the effect that the holding company's long-term capital investment goals had not directionally changed as a result of the Commission's 2018 DEP Rate Order. The Commission does not generally regulate capital investment goals for regulated utility holding companies. That is a function for management. We do regulate rates and services of regulated utilities and in some circumstances review and approve (or reject) individual utility capital projects consistent with the provisions of Chapter 62 of the General Statutes.

Our ruling in this Docket is very limited in scope. In essence, it simply allows DEP to treat costs incurred in pursuing the settled GIP programs as regulatory assets pending a prudence and reasonableness determination in a later rate case. DEP remains fully at risk for the reasonableness and prudence determination of its GIP costs and for their ultimate recovery from ratepayers as would be the case if DEP simply undertook these programs without a deferral and then sought recovery of the costs in a rate case. The only difference here is that deferral of these costs allows certain between-rate-case earnings impacts of these costs to be held on the books of DEP as a regulatory asset and preserves them for possible future recovery if they are determined by the Commission, in a future proceeding, to be just and reasonable, prudently incurred, and otherwise eligible for recovery from ratepayers. The Commission retains complete control over the recovery of these deferred costs from ratepayers utilizing the same prudence and reasonableness standards applicable to any DEP capital investment and the rights of all parties to oppose or support such ultimate recovery are preserved as well.

***Adequacy of Stakeholder Process***

Several intervenor witnesses challenged the adequacy of the stakeholder process conducted by DEP and described, and documented, in the Direct Testimony of witness Oliver. The criticisms ranged from assertions that the programs that resulted were not the product of participant consensus to the implication that the process was more window dressing than substance.

The Commission directed DEP to engage in a process with interested stakeholders coming out of the Sub 1146 rate case and the Company did that. The process consisted of three day-long workshops and multiple webinars and the sharing of analytical data about the proposed GIP programs, including detailed CBAs for those programs. Each workshop conducted by DEP was facilitated by a third-party entity – the Rocky Mountain Institute – who provided written summaries of the workshops. All were also preceded by the distribution of read ahead materials. All were well-attended, and the attendees documented and polled on the effectiveness of the workshops. Significantly, the Company's proposals were modified over the course of the workshops based upon stakeholder input.

We find that DEP's efforts at establishing and implementing a stakeholder process to be a good faith effort to comply with our prior directive and we do not find any basis in that process to challenge our decision to approve the limited GIP deferral provided for in the Second Partial Stipulation between DEP and the Public Staff.

***Cost Benefit Evidence/Cost Allocation***

The evidence presented in this case, particularly at the expert witness hearing, establishes that utilizing standard nationwide data to forecast economic benefit from reliability improvements/outage reduction disproportionally favors commercial and industrial customers. This is because the presumptive benefits are dramatically higher for commercial and industrial customers in comparison to residential customers on a per outage basis. This statement is equally applicable to any increase in system reliability whether caused by vegetation management programs, pole replacement programs, or as in this case grid modernization and improvement programs.

In the Commission's view, these GIP programs will have the effect of increasing reliability on DEP's system, which benefits all customers who avoid outages as a result. This includes the roughly 92% of DEP customers who are residential customers that will directly benefit from the SOG program. And notwithstanding the economic analyses showing disproportionate economic benefits to commercial and residential customers, we believe that the impacts of avoided outages are more nuanced than that and are highly dependent on factors such as the duration of outages and the circumstances of individual customers when an outage occurs.

For example, as testified to by DEP witness Oliver, a residential customer who is dependent on electricity to run life-sustaining medical equipment may value continuous electric service beyond any economic measure. Similarly, a residential customer who is operating a business from her home during the pandemic may be impacted in a far greater amount than the $5 or $10 assumed in the standard model testified to by Public Staff witness Thomas.

As the Public Staff did, we find the CBAs to be a good faith effort to estimate some of the future benefits of implementing the eight settled GIP programs and we accept them subject to their limitations. We are also cognizant of the fact and expressly find that the reasons justifying the deferral of costs associated with the eight settled GIP programs go beyond the CBA results reflected and discussed in the testimony of DEP witness Oliver, Public Staff witness Thomas, and other witnesses.

The Commission does recognize, however, that for the programs justified on the basis of their cost benefit analysis, the underlying reliability improvements, as discussed by Public Staff witness Thomas, do provide a reasonable indicator of success for individual programs. The Commission views the biannual reporting requirements as a method by which the Company can assess the benefits of individual GIP programs on an ongoing basis, and adjust the scope and direction if actual benefits are falling short of estimated benefits. The Commission expects that any significant shortfall in realized benefits exposed in the biannual reports should be accompanied by a reasonable explanation of the cause of such shortfall and appropriate responsive action when DEP seeks cost recovery of those programs.

With regard to the appropriate allocations of GIP costs in this proceeding, as Public Staff witness Maness pointed out, it is not customary to address cost recovery in deferral orders and it would, in fact, be contrary to normal ratemaking and cost recovery processes to do so in this case. Nothing about the Commission's Order in this case predetermines how GIP- related costs may be allocated or recovered in a future rate proceeding and the rights of all parties with regard to that subject are preserved.[23]

In sum, the Commission finds that the evidence in this case supports the deferral of costs associated with the eight settled GIP programs and that all issues related to cost allocation or cost recovery related to such costs shall be preserved for any future proceedings in which the Company may seek recovery of such costs.

***Potential Variability/Uncertainty in Implementation of GIP Programs***

Concerns over what will occur should the Commission approve deferral of the costs for the eight settled GIP programs in this docket as proposed and supported by the Second Partial Stipulation showed up in several forms during the hearing of this matter. Several witnesses indicated a belief that some sort of pilot program should be initiated because of the lack of experience with these programs. Other witnesses and Commissioners expressed concern with the scope of the programs for which deferral is sought and the possibility that such scope would be changed during the period of the deferral. Other witnesses and Commissioners expressed concern with the Commission's relative visibility over the implementation of the underlying GIP programs and how the Commission could be reassured that the Company was proceeding appropriately with implementing the programs, particularly in circumstances where the programs might not produce the expected results or experience dictated a change in scope or approach to particular programs.

As is discussed in some detail in the portion of this order addressing evidence provided during the Expert Witness Hearing portion of this proceeding, the Company and Public Staff witnesses provided significant reassurance to the Commission that the eight settled GIP programs are well-defined on the record as to scope, implementation, and budgets as an initial matter, that the Company has significant experience in implementing similar programs in many cases, and that rigorous project management and evaluation mechanisms will be utilized by the Company in implementing and monitoring these

[23] The Commission recognizes that DEP has agreed in the Commercial Customer Settlement to file for cost recovery of GIP costs in a future case using a particular cost allocation methodology and has also agreed in several of the Intervenor Settlements to collect GIP related costs allocable to OPT-V customers using demand rates but those agreements are voluntary in nature and do not bind the Commission or any other party or otherwise dictate how GIP costs may be ultimately allocated in a future rate case.

programs. These mechanisms will include reporting to the Commission at six-month intervals on the progress of such implementation as anticipated in the Second Partial Stipulation.

Against this backdrop and in light of the fact that the Commission has the ultimate authority to deny recovery of imprudently incurred or unreasonable costs – even if they have been previously deferred – the Commission finds that adequate protections against risks inherent in the design, budgeting, implementation and monitoring for the eight settled GIP programs are adequately addressed in the record and in the Second Partial Stipulation.

***Satisfaction of Commission Standard for Deferral of GIP Costs***

As was recited in the testimony of Public Staff witness Maness, the fundamental test historically utilized by the Commission in assessing the propriety of a proposal for cost deferral is whether the costs proposed for deferral are extraordinary in type and extraordinary in magnitude. This test is not the exclusive basis upon which the Commission has previously allowed, or indicated it would allow, deferral of costs incurred by utilities. For example, as witness Maness further noted, the Commission's discussion of the Power Forward proposal in the 2018 DEC Rate Order in the Sub 1146 proceeding stated that the Commission can authorize a test for approving a deferral within a general rate case with parameters different from those to be applied in other contexts and "authorize[d] expedited consideration, and to the extent permissible, reliance on leniency in imposing the 'extraordinary expenditure' test." (2018 DEC Rate Order, at 149.) In her testimony, in addition to indicating the belief that DEP's GIP proposals satisfied the Commission's historical test, DEP witness Smith also cited to the Commission's prior decision in the *Northbrook Hydro* proceeding in Docket No. E-7, Sub 1181, where the Commission allowed DEC to defer losses associated with the sale of the Company's hydrogeneration assets where the benefits to customers were significant and costs were modest. (Tr. vol. 13, 159-62.)

With regard to the Commission's historical test, Public Staff witnesses T. Williamson and D. Williamson found a number of the programs and subprograms proposed by the Company to be extraordinary in type in their direct testimony. Specifically, they found the ISOP program, the Transmission System Intelligence program, and SOG subprograms Automation and Control and ADMS, and UG automation to be extraordinary in type. (Tr. vol. 15, 404.) In his Rebuttal Testimony, witness Oliver expanded that list – using the Public Staff's analysis matrix – to include the remaining subprograms under SOG and Distribution Automation (on the grounds that all subprograms needed to be utilized together to reap the benefits of those programs), Power Electronics, CVR conversion, DER Dispatch Tool, and Cyber Security. Each of these additional programs/subprograms was ultimately included in the list of programs supported by the Public Staff for deferral accounting treatment in the Second Partial Stipulation.

As recited above, witness Oliver testified that the eight settled GIP programs will establish the basis for two-way power on the DEP distribution system to prepare for future demands, will allow greater control over prevailing voltages on a year-round basis, will divide the distribution grid up on a segmented (instead of a circuit) basis, will allow remote and automated operation of those segments to reduce customer outages, will enhance ISOP operations, will provide additional protection against advanced cyber threats, and will allow for more effective management of DER generation.

Several witnesses made the argument that a number of DEP's original proposed GIP programs constituted normal transmission and distribution maintenance and operations expense, but the majority of those programs have been dropped from DEP's current GIP request pursuant to the Second Partial Stipulation.

With regard to the extraordinary magnitude prong of the test, the primary evidence on this was provided by Public Staff witness Maness and Company witness Smith. Witness Maness testified in his direct testimony that the five programs and subprograms initially found by the Public Staff to be extraordinary by type would not normally be recommended by the Public Staff to be deferred on the basis of magnitude, but that the Public Staff would not object to deferral if the Commission determined that the leniency it had mentioned in the DEP 2018 Rate Order should be granted in this case with regard to those programs. At the expert witness hearing, witness Maness agreed that the enlarged scope of GIP programs included in the Second Partial Stipulation would result in a larger and more material impact on the Company, \$445 million versus \$1.25 billion (in aggregate for both DEC and DEP) in investment. In response to questions from the Company regarding whether the amount to be deferred under the Second Partial Stipulation represents a material impact to the Company's earnings, witness Maness stated that he had not completed an analysis of whether the impact of the additional programs would be extraordinary in amount. (Tr. vol. 7, 89-90.) Witness Smith testified in her direct testimony that the Company's proposed GIP expenditures met the Commission's traditional test for deferral.

From the recitation of the evidence above, it is clear that opinions differed among the various witnesses as to the degree to which DEP's original GIP proposals satisfied the Commission's historic deferral test. That record has in large part now been overcome by the various settlements entered into by DEP, and most notably the Second Partial Stipulation with the Public Staff, which uniformly support deferral of the costs of the eight GIP programs specified in the Second Partial Stipulation.

The Commission concludes that the parties have compromised significantly to reach agreement, as evidenced by the Second Partial Stipulation, and deferral treatment for the settled programs is reasonable and in the public interest in light of Commission precedent. The Commission recognizes that the Company has undertaken stakeholder engagement efforts since the last rate case and has made considerable efforts to narrow its grid improvement request through negotiations. The accounting deferral request, as modified by the Second Partial Stipulation with the Public Staff, and supported by other intervenor settlement agreements, represents a set of programs that can be classified as grid modernization, along with reporting requirements that will ensure collaboration and transparency.

***Overall Conclusion on GIP-Related Matters***

In evaluating the Company's GIP-related proposals in this proceeding, it is important to be clear about what the Company has requested and what the Commission is approving. The Company's request at this point, which is supported by fifteen distinct intervenors, is for authorization to record the earnings impacts of a three-year, approximately $1.25 billion,[24] eight program GIP as agreed to in the Second Partial Stipulation as a regulatory asset on its balance sheet for a defined period of time. This is a significant request, and the Commission treats it as such, but it is not a request for the Commission to find that these programs are just and reasonable or a request to find that the costs that will be recorded under the deferral are prudently incurred or properly recoverable from ratepayers. Those questions are reserved for future proceedings. The Commission recognizes that some degree of authorization to proceed with the settled GIP programs is implicit in its authorization to defer costs but as multiple witnesses have testified, actual cost recovery will be decided at a future date in a different proceeding where all intervening parties will have the right to present whatever evidence they wish on cost allocation and cost recovery including evidence that the deferred costs should not be recovered from customers.

We would also note that much of the evidence on the Company's GIP deferral request has been more in the nature of a critique of the need for and likely efficacy of the underlying grid improvement plan programs. We would note that the direct testimony of witnesses for settling parties such as Alvarez, Stephens, Van Nostrand, Fitch, Bieber, and Phillips has been superseded by settlements entered into by their clients. Accordingly, we give their direct testimony no weight in our ultimate decision on GIP deferral out of deference to the positions of their clients set forth in the Customer Group Stipulations, Vote Solar Stipulation, and NCSEA and NCJC et al. Stipulation. We are unpersuaded by the testimony of witnesses like O'Donnell, and Powers, in part because much of their testimony is aimed at collateral considerations about how each GIP program is designed, or was evaluated, or will operate, or should be tested, or should be modified or conditioned. Our task here is not to determine and design the perfect grid modernization program for the Company but instead to determine whether the Company has presented evidence sufficient to support the public interest in proceeding ahead with the programs they have designed (with input from stakeholders) and whether the expenses of those programs qualify for deferral. We conclude that they have met that burden in this case.

Based on the totality of the evidence presented, and recognizing the limited nature of the Commission's ruling in this docket, the Commission authorizes DEP to defer the earnings impacts of engaging in the GIP programs identified in the Second Partial Stipulation with the Public Staff subject to the conditions of that settlement and in

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[24] Of the total $1.25 billion, approximately $800 million applies to DEC GIP programs and $400 million applies to DEP GIP programs.

conformance with the representations the Company has made about how it will implement, monitor, manage, and report on those programs as they proceed.

## EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 36-40

The evidence supporting these findings and conclusions is contained in the Company's verified Application and Form E-1; the testimony and exhibits of DEP witness Hager, Public Staff witnesses Floyd and McLawhorn, NCJC et al. witness Wallach, CUCA witness O'Donnell, Commercial Group witness Chriss, and CIGFUR witness Phillips; the Second Partial Stipulation; and the entire record in this proceeding.

In her testimony, Company witness Hager described the purpose of cost of service studies and how costs are assigned in those studies. She explained that utilities use cost of service studies to spread to customer classes the revenue requirements identified by the Company for recovery. (Tr. vol. 11, 1072.) Using the principle of cost causation, expenses and rate base costs are assigned to the specific jurisdictions and customer classes that "caused" such costs to be incurred. (Id. at 1029.) Costs are first grouped according to their function. (Id. at 1031.) Functions include production (generation), transmission, distribution, and customer service, billing, and sales. (Id.) Functionalized costs are then classified based on the utility operation or service being provided and the related causation of the costs. (Id.) Typical classifications include demand, energy, and customer-related costs. (Id.) Finally, the functionalized and classified costs are allocated or directly assigned to the proper jurisdiction and customer class based on the way the costs are incurred (i.e., based on cost causation principles). (Id.)

Witness Hager further explained that before any allocations occur, cost components identified as having a direct relationship to a jurisdiction or customer class are directly assigned to that jurisdiction or class. (Id. at 1033.) For these costs and for the remaining unassigned costs, specific allocation factors are developed that relate to the (1) demand, (2) energy, and (3) customer-related classifications described below. (Id.)

Regarding demand-related costs, witness Hager stated that they are costs incurred that vary in direct relationship to the kilowatts (kW) of demand that customers place on the various segments of the system. (Id. at 1032.) Costs that are classified as demand-related include major portions of the Company's investment and related expenses in its production and transmission facilities and a significant portion of the investment and related expenses of its distribution system. (Id.) These costs – often referred to as "fixed costs" – tend to remain constant over the short run and do not change based on the amount of energy consumed. (Id.) Energy-related costs – often referred to as "variable costs" – are costs incurred that vary in direct relationship to the amount of energy or kilowatt-hours (kWh) generated and delivered. (Id.) Customer-related costs are costs incurred as a result of the number of customers being served. (Id.) Customer costs do not vary with the customers' volume of usage but are related to the number of customers. (Id.)

Witness Hager described how the Company's cost of service study allocated costs in this case. DEP allocated demand-related production and transmission costs to jurisdictions and customer classes based on the summer coincident peak method. (Id. at 1033.) Distribution plant investments are directly assigned to jurisdictions. (Id.) The Company then allocates demand-related distribution costs to customer classes based on the non-coincident peak method. (Id. at 1033-34.) With respect to energy-related costs, such as fuel costs and variable production costs incurred at generating stations, DEP uses the kWh sales information during the test period, adjusted for the level of losses attributable to each class and jurisdiction, to derive the level of kWh at the generator attributable to that class or jurisdiction. (Id. at 1037.) The Company uses customer allocators to allocate customer-related costs such as meter reading, billing and collection, and customer information and services. (Id.) In addition, DEP included in this category a portion of distribution costs that the Company identified as customer-related, based on the minimum system method. (Id. at 1037-40.)

**Use of Summer Coincident Peak**

DEP based its filing in this case on the summer coincident peak (SCP) methodology for allocating demand-related production and transmission costs among jurisdictions and among customer classes. While Public Staff witness McLawhorn initially testified in support of the use of the Summer/Winter Peak and Average (SWPA) methodology, in the Second Partial Stipulation, the Public Staff agreed to the use of the SCP methodology for purposes of settlement. CUCA witness O'Donnell testified that the proper allocation methodology for DEP to use in this case is SCP. CIGFUR witness Phillips supports a coincident peak methodology, but recommended that DEP be required to use the winter peak instead of the summer peak in its demand allocation factor.

Company witness Hager testified in support of the SCP methodology for allocation among jurisdictions and among customer classes. She explained that a coincident peak allocator assigns the fixed demand-related costs to the jurisdictions and customer classes in proportion to their respective contribution to the system's peak hourly demand during the test period. (Tr. vol. 11, 1034.) Each jurisdiction's and customer class' cost responsibility (i.e., the percentage of the fixed portion of production and transmission demand costs assigned to each jurisdiction and customer class) is equal to the ratio of their respective demand in relation to the total demand placed on the system. (Id.) The cost of service study supporting the Company's proposed rate design in this proceeding allocates the fixed portion of production and transmission demand-related costs based upon a jurisdiction's and customer class's coincident peak responsibility occurring during the summer. (Id.)

The peak generation and transmission demand used in the Company's cost of service study for the test year occurred on June 19, 2018, at the hour ending at 5:00 p.m. (Id.) DEP's peak system demand for the test year, however, occurred during the winter on January 7, 2018, at the hour ending at 8:00 a.m. (Id. at 1035.) Witness Hager explained that in 14 of the last 25 years, the Company's coincident peak occurred in the months of June through August. (Id.) She noted that the test year summer peak is within the range of these past occurrences, and it is therefore appropriate to assign fixed demand-related costs to the Company's jurisdictions and customer classes based upon the SCP. (Id.)

Witness Hager testified that despite the fact that the test year peak occurred in the winter, the Company has determined that SCP continues to be the most appropriate allocation methodology. (*See, e.g.,* id. at 1035, 1048-49, 1054-55, 1057.) While both summer and winter peaks are important in the planning process, witness Hager noted that the assets for which the Company seeks cost recovery in this case are largely the result of an emphasis on summer peak planning. (Id. at 1035, 1049, 1054-55.) Moreover, summer peaks continue to be strong in DEP's service territory. (Id. at 1058-59.) She noted that in the test year, three of the four highest monthly peaks occurred in the summer. (Id. at 1059.)

Public Staff witness McLawhorn recommended using the SWPA methodology for allocating production plant and production plant-related costs. (Tr. vol. 15, 895.) Witness McLawhorn explained that under the SWPA methodology, the fixed costs of production plant and production plant-related costs are allocated among jurisdictions and customer classes based on a formula that contains two components. (Id. at 898.) The first component, the "summer/winter peak" component, is based on the demands of the jurisdictions or customer classes in question at the time of the utility's summer and winter peak demands. (Id.) This component takes into account the hour when the load on the system is highest during both the summer months and the winter months. (Id.) The second component, the "average" demand component, considers the energy consumed during all hours of the year and is calculated by dividing the total kWh sales for the year by the number of hours in a year to arrive at the average demand. (Id. at 898-99.) According to witness McLawhorn, this component recognizes that load is being served by the system during all hours of the year, not just during one single hour of the year. (Id. at 899.) Witness McLawhorn argued that the SWPA methodology more accurately reflects actual generation planning (i.e. the Integrated Resource Planning process, or IRP) and customer usage than the SCP methodology. (Id. at 911-16.) He testified that decisions leading to the identification of specific least cost combinations of plant in the IRP are not based solely on the one hour highest peak in the summer, and the amount of annual energy that these resources will be required to provide to the system is a major consideration in resource selection. (Id. at 903, 912-16.) Witness McLawhorn testified that a cost allocation methodology that focuses on one single peak hour, such as SCP, can result in certain customer classes, such as the lighting classes in this case, not being allocated any production plant costs, despite consuming significant amounts of energy from the Company's generating plants during other hours of the year. (Id. at 904.) Witness McLawhorn testified that SWPA addresses both the peaks a utility must meet during the summer and winter seasons and the energy required to supply customers during the remaining hours of the years. (Id. at 903.)

CUCA witness O'Donnell testified that because DEP built its generation fleet to meet peak demand, the proper methodology to use in this case is SCP. (Tr. vol. 14, 244.) According to witness O'Donnell, fixed costs, such as generation, should be allocated on peak and not any mix of demand and energy. (Id. at 245.)

CIGFUR witness Phillips testified that because DEP has transitioned from a summer peaking to a winter peaking utility over the last several years, the winter coincident peak (WCP) methodology should be used in this case. (Id. at 301.) Witness Phillips also disagreed with the SWPA methodology and explained that the Commission rejected SWPA in its Order[25] issued in DEP's rate case in Docket No. E-2, Sub 1023. (Id. at 302-03.)

In her rebuttal testimony, witness Hager responded to witness McLawhorn's and witness Phillips' arguments for alternative cost allocation methodologies. With respect to SWPA, witness Hager disagreed with allocating fixed demand costs using an energy allocator. (Tr. vol. 11, 1050-54.) She also clarified that the Company's cost of service methodology does not ignore energy-related production costs; in fact, the Company treats $2 billion of production costs (e.g., fuel, purchased power, and O&M) as variable, and allocates these costs to the jurisdiction and customer classes using an energy allocator. (Id. at 1051.) In response to the argument that DEP should switch to WCP in this case, witness Hager expressed concern about the volatility of the winter peak and the resulting volatility that using a single winter peak could introduce into customer rates. (Id. at 1058.) She also emphasized the importance of a consistent cost allocation methodology among DEP's jurisdictions so that the Company does not under- or over-recover its costs. (Id. at 1049, 1057.) Witness Hager concluded that the Company will continue monitoring system peak information and the key drivers for and the amount of investments in production plant in order to identify when and if a different allocation method should be proposed in future rate cases. (Id. at 1059.)

In § III.I. of the Second Partial Stipulation, the Public Staff accepted, for this case only, the Company's proposal to calculate and allocate the Company's cost of service based on the SCP cost of service allocation methodology. The Company agreed that it will not cite Commission approval of the Second Partial Stipulation as support for approval of the SCP methodology in future proceedings. (Second Partial Stipulation, § IV.B.) In his testimony filed in support of the Second Partial Stipulation, witness McLawhorn noted that this acceptance of the SCP cost of service allocation methodology does not constitute precedent and should have no impact on the rate design study proposed by Public Staff witness Floyd and endorsed by DEP. (Tr. vol. 15, 934.)

Section IV.B. of the Second Partial Stipulation provides that prior to the filing of its next general rate case, the Company shall undertake an analysis of additional cost of service studies subject to the following conditions:

1) The Company agrees to analyze and develop cost of service studies based on each of the following methodologies:

a. Single Summer Coincident Peak;

b. Single Winter Coincident Peak;

[25] Order Granting General Rate Increase, Docket No. E-2, Sub 1023 (May 31, 2013), at 14.

c. One that utilizes the four highest monthly system peaks (two monthly peaks in summer and two monthly peaks in winter);

d. SWPA;

e. Base Intermediate and Peak (as described in the Regulatory Assistance Project (RAP) "Electric Cost Allocation for a New Era" Manual, published January 2020); since the Company's accounting systems do not have the data developed to produce such a study, this method may be analyzed by looking at how it has been used at another utility or with a higher level hypothetical analysis;

f. One that utilizes the twelve highest monthly system peaks in the test year; and

g. Any other identified relevant methodologies.

To the extent cost of service studies were developed in the current rate cases for these methodologies, those studies may be used for the analysis, and to the extent cost of service studies for a methodology have not already been developed, the underlying adjusted cost of service data from the current rate cases may be used to develop the studies.

2) Each methodology studied will include an evaluation of the allocation of the functions of utility service (production plant, transmission plant, distribution plant, and customer costs), including an identification of which cost components associated with these functions of utility service are fixed, and which are variable costs of service. The above methodologies only impact production and transmission allocations; however, the cost of service studies will show the allocation of all functions. For purposes of these studies, all demand and customer classified costs can be designated as fixed and all energy classified costs can be designated as variable.

3) Each methodology studied will include an evaluation of its strengths and weaknesses on both a jurisdictional and class allocation basis.

4) Included in the studies shall be a discussion of how the allocation of fuel and other variable operations and maintenance (O&M) expenses align with system planning.

5) The Company shall consult with the Public Staff and any other interested parties throughout the study process.

The Commission finds and concludes that SCP is the appropriate cost allocation methodology for purposes of this proceeding, subject to the provisions of the Second Partial Stipulation. While the Company and the Public Staff have disagreed as to the appropriate allocation methodology the Company should use to allocate the costs of production plant, it is not unreasonable for them to have agreed, as part of their overall settlement of certain contested issues that the allocation of production plant costs based on the SCP methodology is reasonable for purposes of this proceeding. Upon consideration of all of the evidence in this proceeding, including the Second Partial Stipulation that the Commission accepts in its entirety and upon which the Commission places great weight, the Commission approves of the use of the SCP cost allocation methodology to set the Company's base rates in this proceeding. However, the Commission's acceptance of the SCP methodology for cost allocation between jurisdictions and among customer classes in this proceeding shall not be a precedent for and may be contested in future general rate case proceedings. The Commission notes, as it held in its Order in Docket No. E-100, Sub 133, that "evidence regarding the appropriate cost allocation methodology is specific to each case." (Order Denying Rulemaking Petition, Docket No. E-100, Sub 133 (Oct. 30, 2012), at 10.) Accordingly, even in the absence of the Company's agreement in the Second Partial Stipulation that the Commission's decision herein "shall not be a precedent," the decision in fact is not precedent as to how the Commission might rule on cost allocation issues in a future case.

In arriving at its conclusion that SCP is appropriate for purposes of this case, the Commission gives weight to the testimony of Company witness Hager that the Company continues to experience a strong summer peak. Having the necessary generation and transmission resources to meet this summer peak (plus an appropriate reserve margin) is an important planning criterion of the Company's system. Under cost causation principles, therefore, all customer classes should share equitably in the fixed production and transmission costs of the system in relation to the demands they place on the system at the peak.

Furthermore, the Second Partial Stipulation requires that the Company analyze and develop cost of service studies based on the following alternative methodologies, including those recommended by the Public Staff and CIGFUR: single summer coincident peak; single winter coincident peak; one utilizing the four highest monthly system peaks (two summer monthly peaks and two winter peaks); SWPA; and Base Intermediate and Peak. The Company has also agreed with CIGFUR to analyze and develop a cost of service study based upon the Summer Winter Coincident Peak method. The Commission acknowledges that no single cost allocation methodology is perfect. In future rate proceedings, this Commission expects that the Company will consider and analyze these methodologies and propose cost allocation methodologies that appropriately reflect the nature of system demands, as well as being reflective of the Company's annual integrated resource planning process. The Second Partial Stipulation reflects this compromise among the parties in this proceeding and the Commission finds that compromise reasonable and appropriate.

**Energy Allocations within MGS Sub-Classes**

Commercial Group witness Chriss recommended that DEP re-run the whole cost of service study using corrected energy allocators within the MGS rate classes. (*See* Tr. vol. 14, 95-96.) Witness Hager acknowledged that the Company did inadvertently transpose energy billing determinants used to calculate energy unit costs between the

SGS-TOU and other MGS rate classes. (Tr. vol. 11, 1069.) However, as the Company clarified in response to the Commercial Group's data request noting this error, this transposition was isolated to the calculation of billing determinants and did not impact the Company's cost of service allocations or its filings under E-1, Item 45, which reflected the correct allocators for those classes. (Id.) Witness Hager also noted that those energy billing determinants were not used by witness Pirro in rate design. (Id.) Since the error noted by witness Chriss does not impact the Company's cost of service allocations, rate design, or filings in this case, the Commission will not require DEP to re-run its cost of service study as recommended by witness Chriss.

**Minimum System**

The Company uses a minimum system study to classify certain distribution costs as customer-related. CIGFUR also recommended that the Commission accept the minimum system approach in the allocation of distribution costs as used by DEP in this proceeding. The Public Staff did not oppose the Company's use of the minimum system method in this case. The NCJC, et al. group of intervenors is the only party that objected to the Company's use of the minimum system concept in allocating distribution costs.

Witness Hager testified that the Company classifies meter reading, billing and collection, and customer information and services as customer-related costs. (Tr. vol. 11, 1037.) In addition, DEP has included in this category a portion of distribution costs that the Company has identified as customer-related, including the costs of the service drop and meter (FERC Accounts 369-370) and a portion of the costs for distribution lines, poles, and transformers (FERC Accounts 364-368). (Id. at 1037-38.) She explained that DEP's minimum system study allowed DEP to classify the distribution system into the portion that is customer-related (driven by number of customers) and the portion that is demand-related (driven by customer peak demand levels). (Id. at 1039.) The methodology behind the Company's minimum system study allows DEP to assess how much of its distribution system is installed simply to ensure that electricity can be delivered to each customer, regardless of the customer's frequency of use. (Id. at 1061.) Witness Hager testified that "[w]ithout the minimum system, low use customers could easily avoid paying for the infrastructure necessary to provide service to them which is counter to cost causation principles." (Id. at 1040.) She further explained that the methodology used by the Company is consistent with the guidance regarding allocation of distribution costs provided in the National Association of Regulatory Utility Commissioners (NARUC) Electric Utility Cost Allocation Manual (CAM). (Id. at 1038.)

Witness Hager also noted that the Public Staff endorsed the minimum system method in its Report on the Minimum System Methodology in Docket No. E-100, Sub 162.[26] (Id. at 1041.) The Public Staff concluded that the NARUC CAM "continues to be

[26] Report of the Public Staff on the Minimum System Methodology of North Carolina Electric Public Utilities, Docket No. E-100, Sub 162 (March 28, 2019). (Hager DEC Redirect Ex. 1.) Hager DEC Redirect Ex. 1 was admitted into evidence in the DEP proceeding pursuant to the Joint Stipulation of Live Testimony

considered an important resource for the calculation and allocation of electric utility cost of service for regulatory commissions, consumer advocates, and parties before the Commission testifying on issues of cost-of-service and rate design." (Id.)

NCJC et al. witness Wallach opposed the minimum system method and recommended instead that the Commission require that DEP adopt the basic customer method for classifying distribution costs in the cost of service study. (Tr. vol. 14, 408.) Unlike the minimum system method, which classifies a portion of the costs for distribution lines, poles, and transformers (FERC Accounts 364-368) as customer-related, the basic customer method classifies 100% of all poles, wires, and line transformers as demand-related costs. (*See* Tr. vol. 11, 1040.) Witness Wallach urged that the Commission "give no weight" to the Public Staff's endorsement of the minimum system classification method as he believes that the Public Staff based its recommendations on an "unsubstantiated belief that there is a minimum portion of the cost of the distribution grid which is incurred regardless of demand." (Tr. vol. 14, 455.) According to witness Wallach, customer demand, rather than the number of customers, drives distribution costs. (Id. at 410, 416.)

CIGFUR witness Phillips recommended that the Commission accept the minimum system approach for allocating distribution costs. (Id. at 303.) Witness Phillips explained that classifying Accounts 364 to 368 entirely on a demand basis contradicts cost causation and generally accepted costing methodology. (Id.) The minimum system method accounts for the portion of total distribution costs a utility must incur to connect a customer to the system. (Id. at 304.) Witness Phillips asserted that "this minimum or 'skeleton' distribution system can be considered as customer-related costs since it depends primarily on the number of customers, rather than on demand or energy usage." (Id. at 305.)

In her rebuttal testimony, witness Hager responded to witness Wallach's recommendations regarding the minimum system method. Witness Hager testified that the NARUC CAM includes "two methods of allocating embedded distribution costs, both of which identify a portion of FERC distribution asset accounts 364 to 368 as customer-related and a portion as demand-related." (Tr. vol. 11, 1062-63.) Therefore, witness Wallach's proposal that the Company adopt the basic customer method and all of Accounts 364 to 368 should be allocated based on demand contradicts NARUC CAM guidance. (Id. at 1063.)

Witness Hager testified that the minimum system method comports with the practical reality that a utility incurs certain minimum costs "to ensure that if a customer wants to flip a light - - flip on a light switch, that power is there, you know, conductors, transformers, poles." (Id. at 1246.) According to witness Hager, the theory behind the use of a minimum system study is sound and consistent with cost causation, which is the

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and Exhibits of Certain Rate Design and Cost Allocation Witnesses entered into by the Public Staff, CIGFUR, DEP, Harris Teeter, Vote Solar, NCSEA, NCJC, et al., CUCA, and the Commercial Group, which was filed in this docket on September 24, 2020. (Tr. vol. 11, 1303.)

bedrock of cost of service studies. (Id. at 1060.) Every customer requires some minimum amount of wires, poles, transformers, etc., to receive service; therefore, every customer "caused" DEP to install some amount of such distribution assets. (Id. at 1060-61.) The concept DEP used to develop its minimum system study was to consider what distribution assets would be required if every customer had only some minimum level of usage (e.g., one light bulb). (Id. at 1061.)

During the evidentiary hearing, witness Floyd testified the Public Staff believes that distribution costs have a demand-related component and a customer-related component, and that the minimum system method is a reasonable approach to distinguishing what portions are demand-related and what portions are customer-related. (Tr. vol. 15, 1045.)

Upon consideration of all the evidence in this proceeding, the Commission approves of the use of the minimum system methodology to determine the customer-related portion of distribution costs in this proceeding. The Commission places significant weight on the testimony of Company witness Hager regarding the minimum system method's alignment with established cost causation principles and authoritative sources such as the NARUC CAM and Dr. Bonbright. (*See, e.g.,* Tr. vol. 11, 1038, 1041, 1062-63, 1065-66, 1202, 1300.) In addition, the Commission gives significant weight to the conclusions of the Public Staff in its Report on the Minimum System Methodology in Docket No. E-100, Sub 162. The Commission finds that the Company's use of the minimum system method is just and reasonable to all parties in light of all the evidence presented.

**Non-Coincident Peak Demand Allocators for Distribution Costs**

As discussed above, the Company used a minimum system study to classify certain distribution costs as customer-related. Witness Hager testified that distribution costs that are not deemed to be customer-related, are designated as demand-related and demand-related distribution costs are allocated to the customer classes based on non-coincident peak (NCP) demand allocators. (Tr. vol. 11, 1036.) She explained that the NCP allocators are developed by taking the ratio of the non-simultaneous peak demands of the customers in each class whenever that peak occurred during the test period and comparing that to the sum of all customers' non-simultaneous peak demands. (Id.) She noted that the Company develops several different NCP allocators to account for the different levels of the distribution system where customers may take service (primary, secondary, etc.). (Id.) For example, only the NCP demand of customers taking service at secondary voltage are included in the development of the NCP allocator used to allocate secondary distribution lines and poles. (Id.)

Witness Wallach recommended that the Commission reject the Company's use of the NCP demand allocator to allocate distribution costs. (*See* Tr. vol. 14, 422-28.) According to Wallach, the NCP allocator fails to accurately reflect usage patterns of residential customers and causes distribution costs to be over-allocated to the residential classes. (Id. at 423.) He concluded that in order to reasonably account for the effect of load diversity on distribution equipment sizing and cost, demand-related distribution costs should be allocated to rate classes based on each class's diversified peak demand. (Id. at 428.)

Witness Hager explained that distribution facilities serve individual neighborhoods, rural areas, and commercial districts. (Tr. vol. 11, 1036.) They do not function as a single integrated system in meeting system peak demand. (Id.) Instead, the distribution system serving each neighborhood, rural area, or commercial district must be able to meet the localized peak demand in the area it serves whenever that peak occurs. (*See* id. at 1036-37.) Accordingly, witness Hager reasoned that contribution to NCP is the appropriate measure of determining customers' responsibility for these costs because it best measures the factors that drive investment to support that part of the system. (Id. at 1037.)

Aside from witness Wallach, no intervenor contested the Company's use of NCP demand allocators for allocating demand-related distribution investments. In light of the evidence presented, including the testimony of witness Hager, the Commission finds and concludes that the Company's use of NCP demand allocators to assign costs to the respective rate classes is reasonable and appropriate.

**Allocation of Coal Ash Compliance Costs**

CUCA witness O'Donnell recommended that the Commission use the same cost allocation method approved by the Commission in the Company's last fuel case, which is an equal percentage change for all customer classes, for the allocation of the coal ash costs in this case and in future cases. (Tr. vol. 14, 178.) He noted that in times of fuel cost increases, this allocation methodology has benefited large consumers, and in times of fuel cost decreases, this allocation methodology has benefited small consumers. (Id. at 179.) He concluded that what has been deemed appropriate for fuel cases for many years should also be appropriate for the allocation of coal ash costs. (Id.)

Company witness Hager testified that DEP does not support witness O'Donnell's proposed allocation of coal ash compliance costs. (Tr. vol. 11, 1068.) She explained that DEP used an energy allocation factor in compliance with the 2018 DEP Rate Order. (*See* id.) The method proposed by witness O'Donnell is not consistent with that Order, nor does it follow cost causation principles, according to witness Hager. (Id.) She noted that costs are not "caused" by the relative impact of rates on classes of customers. (Id.)

In DEP's last rate case, the proper allocation of CCR costs was a litigated issue, and the Commission found that it is reasonable and appropriate to allocate all CCR expenditures by an energy allocation factor, rather than a demand-related production plant allocation factor. (*See* 2018 DEP Rate Order, at 222-24.) Aside from CUCA, no intervenor has challenged the allocation of the Company's coal ash compliance costs in this rate case. While the Commission did not expressly address the argument raised by witness O'Donnell – that CCR costs should be allocated using a fixed equal percent share method – in the 2018 DEP Rate Case, no one, including witness O'Donnell (who appears to base his position solely on the impact to large consumers), has introduced any evidence in this proceeding that supports disturbing the Commission's finding that the appropriate and reasonable course of action is to allocate CCR costs by the energy allocation factor. As the Commission reasoned in DEP's last rate case, CCR is a residual of the burning of coal in order to produce electricity. (*See* 2018 DEP Rate Order, at 224.) For every kWh of electricity that is produced by coal-fired generation, there are CCRs produced that must be properly handled and stored. (Id.) As such, the quantity of CCRs and the cost of storing them are energy-driven. (Id.) The Commission also gives weight to witness Hager's testimony in this case that allocating costs based on the relative impact to customer classes is not supported by the principles of cost causation. (*See* Tr. vol. 11, 1068.) Accordingly, we decline to adopt witness O'Donnell's recommendation and find and conclude that the Company should continue to use an energy allocator with respect to the CCR costs for which it seeks recovery in this case.

**EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 41-44**

The evidence supporting these findings and conclusions is contained in the Company's verified Application and Form E-1; the testimony and exhibits of DEP witnesses Hager and Pirro; Public Staff witness Floyd; NCJC et al. witnesses Howat and Wallach; CUCA witness O'Donnell, and Hornwood witness Coughlan; the Second Partial Stipulation; and the entire record in this proceeding.

In his Direct Testimony, Company witness Pirro provided an overview of the Company's proposed rate design. He testified that in establishing the rate design in this case, he considered current rates and their structure, impacts upon customers, equitable pricing structures, simplicity of the rate design, administrative complexity, and rate and revenue stability. (Tr. vol. 11, 1086.) He explained that the base rate increase has been allocated to the rate classes on the basis of rate base. (Id. at 1088.) This allocation methodology distributes the increase equitably to the classes while gradually moving each class's deficiency or surplus contribution to return to the retail average rate of return (ROR), within a band of reasonableness of plus or minus 10%, if possible. (Id.) He explained that the unit cost study from the cost of service study provides customer, demand, and energy related unit costs that are important in establishing cost-based rates. (Id.) According to witness Pirro, setting rates that are aligned with unit cost minimizes cross-subsidization within a rate class and provides appropriate price signals to customers. (Id.) He noted that in moving rate schedules and riders closer to a more cost-justified basis, it is important to consider the impact upon customers and employ the principle of gradualism. (Id. at 1089.) He testified that this principle was applied in this case to update price relationships and levelize the percentage change in revenues on participants within the rate class while still moving towards a more equitable pricing structure. (Id. at 1089-90.)

While the Company's unit cost study justifies an increase to the monthly Basic Customer Charges to better reflect customer-related costs and minimize customer cross-subsidization, witness Pirro testified that the Company is not proposing to raise the Basic Customer Charges in this proceeding due to concerns raised by low income and other advocates. (Id. at 1086, 1088-89.) Pirro Exhibit 7 illustrates the Basic Customer Charges for the major customer classes.

Witness Pirro testified that the Company has proposed to adjust its residential rate schedules (RES, R-TOUD, R-TOU) to recover the revised revenue requirement, but has not proposed any major structural changes to its residential rates. (*See* id. at 1093-94, 1149.) Similarly, the Company has not proposed to alter the overall structure of its small general service (SGS and SGS-TOUE), small general service – constant load (SGS-TOU-CLR), medium general service (MGS, SGS-TOU, GS-TES, APH-TES, CH-TOUE, CSE, CSG), large general service (LGS, LGS-TOU, LGS-RTP), seasonal and intermittent service (SI), sports field lighting service (SFLS), and traffic signal service (TFS and TSS) rates. (*See* id. at 1095-1103.) Witness Pirro explained that these schedules were revised to collect the allocated revenue requirement and that certain schedules were adjusted to gradually move all rate schedules closer to a more equitable pricing structure. (*See* id. at 1095-1103, 1149.) With respect to Schedule SFLS, witness Pirro noted that the Company is requesting to decrease the charge applicable for disconnection of service after less than one month from $17.00 to $9.14 to match the Service Charge requested in the service regulations, as described below. (Id. at 1102-03.)

Witness Pirro also described proposed changes to the Company's service riders, which are offered to modify standard service to meet unique or special customer requirements, to better reflect cost of service. (Id. at 1108.) First, the Company is requesting to increase the Customer Charge in the Large Load Curtailable Rider LLC, Dispatched Power Rider No. 68, Incremental Power Service Rider IPS, and Supplementary and Non-Firm Standby Service Rider NFS from $50.00 to $65.00 to recover the current costs associated with the customer notification system that is necessary to alert customers to curtailment events. (Id.) Second, the Company is requesting to increase the Discount Rate for curtailable load under the Large Load Curtailable Rider LLC from $5.40 to $5.60 per kW of non-firm demand to better reflect the current avoided cost benefit, with a corresponding increase to the charge for use of Premium Demand during a Level 1 Curtailment event from $2.70 to 2.80. (Id. at 1109.) Third, the Company is proposing to adjust the Non-Firm Standby Service Delivery Charges for the Supplementary Non-Firm Standby Service Rider NFS to reflect the unit cost of service for service from distribution and transmission facilities. (Id.) Fourth, the Company is proposing to update the Generation Reservation and Standby Service Delivery Charges for Rider SS to reflect current cost of service. (Id.) Fifth, the Company is requesting to update the TotalMeter and NonStandard Metering Rates under the Meter-Related Optional Programs Rider (Rider MROP) to better reflect current cost estimates. (Id.) Finally, the Company is requesting to revise the Manually Read Meter (MRM) provision of Rider MROP to allow the MRM option for all Schedule SGS customers. (Id.)

Witness Pirro also described the Company's proposed revision to the Line Extension Plan to clarify that conduit must be properly installed by the customer, and if not, the customer would be responsible for any added cost the Company may incur to extend electric service. (Id. at 1110.)

Witness Pirro testified that the Company has proposed changes to several charges contained in its service regulations to better reflect current cost studies along with the benefits of Smart Meter implementation, including: a decrease in the Service Charge from

$17.00 to $9.14; a decrease in the Landlord Service Charge from $5.35 to $2.00; a decrease in the Reconnect Charge during normal business hours from $19.00 to $12.94; a decrease in the Reconnect Charge outside of normal business hours from $55.00 to $19.48; an increase in the charge for a customer-requested duplicate meter test for non-demand meters from $40.00 to $45.00; an increase in the charge for a customer-requested duplicate meter test for demand meters from $50.00 to $57.00; a reduction in the monthly facilities charge associated with Extra Facilities under the contributory option from 0.4 percent to 0.3 percent; and a reduction in the monthly facilities charge applicable to interconnection facilities installed pursuant to the Terms and Conditions for the Purchase of Electric Power under a Purchase Power Agreement executed under the Purchased Power Schedule PP from 0.4 percent to 0.3 percent. (Id. at 1092-93.) In addition, the Company is proposing to change when bills are considered past due and delinquent for nonresidential customers from 15 to 25 days to match the current requirement for residential customers. (Id. at 1093.)

Witness Pirro also testified in support of the Company's proposed changes to its outdoor lighting schedules (SLS, SLR, ALS). As noted by witness Pirro, the Company's initiative to align the rates of public and private lighting is finished except for three areas (pricing for wood, metal/fiberglass, and system metal pole/post rates), which if approved, will complete this initiative. (Id. at 1103-04.) Witness Pirro described the Company's requested changes to its Street Lighting Service Schedule (SLS) as follows: increasing the pole/post rates by twice the percentage increase in fixture rates in order to better reflect marginal cost; increasing the SLS rates for wood, metal/fiberglass, and system metal poles/posts slightly more than other pole/posts to achieve the same percentage increase in rates under both ALS and SLS; and increasing the one-time charge for underground service from $521 to $580 to better reflect the cost to extend underground service to a fixture. (Id. at 1105.) With respect to Street Lighting Service (Residential Subdivisions) Schedule (SLR), he noted that monthly rates were adjusted by the same percentage to realize the same percentage increase in revenues under SLR as realized for schedules ALS and SLS. (Id.) Witness Pirro also described proposed changes to the Company's Area Lighting Service Schedule (ALS), including increasing the one-time charge for underground service from $521 to $580 consistent with the requested change to Schedule SLS. (Id. at 1106.) In addition, the Company proposes to no longer offer the LED 205 Site Lighter for new installations under Schedules SLS and ALS, and instead proposes to offer a new LED 220 Shoe Box fixture at a fixed monthly rate. (Id. at 1106-07.)

In addition to changes to specific lighting rates, the Company is also requesting approval to: (1) eliminate high pressure sodium (HPS) lighting options for new installations under each lighting schedule, and offer LED lighting for those installations; (2) require replacement of existing mercury vapor (MV) lighting and related fixtures by the end of 2023; (3) modify the term for lighting contracts from one to three years; and (4) make Schedule SLR subject to the Company's Outdoor Lighting Service Regulations. (Id. at 1104-06.) Witness Pirro indicated that the Company is emphasizing LED technology by ending the availability of HPS vapor fixtures in all three lighting schedules and noted the improved energy efficiency, color, and light provided by LED technology. (Id. at 1104-05.)

In his Direct Testimony, Public Staff witness Floyd testified that he reviewed the Company's rate designs, schedules, and revenue assignments and concluded that the Company's proposed modifications to its rate schedules are reasonable for purposes of this proceeding. (*See* Tr. vol. 15, 958, 1008.) He also discussed the Public Staff's revenue assignment principles that should be used to apportion any revenue increase approved in this proceeding. (Id. at 949, 952.) Those principles include maintaining the class RORs on rate base within plus or minus 10% of the overall ROR resulting from this case, moving all customer classes closer to the North Carolina retail jurisdictional return, limiting any increase to a particular customer class to no more than two percentage points greater than the jurisdictional increase approved in this proceeding, and minimizing any subsidization amount the customer classes. (Id.) However, in the event the Commission orders a decrease in the revenue requirement, he believes it is more appropriate to focus on addressing disparities in the class RORs; however, he noted that any revenue decreases assigned to individual customer classes should be limited such that no other customer class sees an increase simply to address a disparity in RORs. (Id. at 955.)

Witness Floyd also testified that he is supportive of the Company's proposed changes to its service regulations. (*See* id. at 958). He noted that customers will receive a benefit from the deployment of AMI meters in this case through lower connection and reconnection fees. (Id. at 966.) These reductions are due to savings resulting from the Company no longer having to dispatch its personnel to the customer's location to perform connections and reconnections. (Id.) Witness Floyd reviewed the Company's calculations of these proposed rates and found them to be reasonable. (Id.)

With respect to the Company's lighting schedules, witness Floyd indicated that he reviewed the cost data provided by the Company regarding the proposed changes to individual rates under each lighting schedule and believes the changes in rates and the related lighting services are reasonable and should be approved. (Id. at 963.) With respect to the contract terms and the application of the lighting service regulations to Schedule SLR, he concluded that both changes are reasonable attempts to consolidate the terms and conditions applicable to lighting services and each lighting rate schedule. (Id.)

In § IV.C. of the Second Partial Stipulation, the Company agreed, consistent with the rate design principles articulated by witness Floyd, that any proposed revenue change will be apportioned to the customer classes such that: (1) any revenue increase assigned to any customer class is limited to no more than two percentage points greater than the overall jurisdictional revenue percentage increase, thus avoiding rate shock; (2) class RORs are maintained within a band of reasonableness of plus or minus 10% relative to the overall North Carolina retail ROR, and for class RORs currently above the band of reasonableness, the Company will gradually move class RORs closer to the band of reasonableness; (3) all class RORs move closer to parity with the North Carolina ROR; and (4) subsidization among the customer classes is minimized.

In § IV.D. of the Second Partial Stipulation, DEP and the Public Staff agreed, as indicated by witness Floyd, that the proposed modifications to the Company's rate schedules are reasonable for purposes of this proceeding. Having considered the testimony and exhibits of all of the witnesses and the entire record in this proceeding, the Commission finds and concludes that §§ IV.C. and IV.D. of the Second Partial Stipulation are just and reasonable to all parties.

In addition, based on the testimony of witnesses Pirro and Floyd, which is undisputed, the Commission finds and concludes that the proposed amendments to DEP's service regulations are just and reasonable, serve the public interest, and should be approved.

The Commission also finds that DEP's proposed modifications of certain outdoor lighting fees and schedules to help modernize the Company's outdoor lighting products and services to reflect the continued adoption of LED technology, which were also supported by the Public Staff and not opposed by any party, are just and reasonable to all parties in light of the evidence presented and should be approved.

The Commission makes its findings and conclusions on each of the rate design issues raised by intervenors (aside from those addressed in the Company's settlements with Harris Teeter, the Commercial Group, and CIGFUR),[27] as set forth below.

**Basic Customer Charges**

Witness Pirro testified the Company generally supports setting the Basic Customer Charges to recover approximately 50% of the difference between the current rate and the full customer-related unit cost incurred to serve these customer groups as current rates significantly understate the current unit cost of service related to the customer component of cost. (Tr. vol. 11, 1089, 1121-22.) However, the Company has decided in this case to leave the Basic Customer Charges at their current rates due to concerns raised in the past by low-income and other advocates with respect to the level of the charges. (Id. at 1089, 1122.) Instead, the Company supports a collaborative stakeholder process to discuss opportunities to address low-income, fixed income, and low-usage customer concerns. (Id.) Witness Pirro indicated that once the Company has had the benefit of that collaborative process, the Company will address Basic Customer Charges in future proceedings so that it will better reflect equitable cost-based rates that provide accurate price signals to DEP's customers. (Id.)

Witness Floyd testified that the Public Staff does not object to the Company's proposal to leave Basic Customer Charges at current levels for purposes of this proceeding and indicated that the Public Staff supports convening a stakeholder process

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[27] The Harris Teeter, Commercial Group, and CIGFUR Stipulations are addressed separately in Evidence and Conclusions for Findings of Fact Nos. ___.

to address affordability issues, including the appropriate amount of the Basic Customer Charges. (Tr. vol. 15, 959.)

NCJC, et al. was the only party that disputed the Company's proposal to leave the Basic Customer Charges at current rates, and in particular, it challenged the Company's proposal to maintain the current residential Basic Customer Charge at $14.00 per month. Instead, NCJC, et al. witness Wallach supported use of the basic customer method and recommended a residential basic customer charge of $9.63 per month based on the unit cost of only the costs for meters, service drops, and customer services other than uncollectible accounts. (Tr. vol. 14, 409, 435, 437.) He argued that without his recommended reduction to the current Basic Customer Charge, residential customers with below-average usage will continue to subsidize larger customers. (Id. at 409.) According to witness Wallach, residential customers will also receive inaccurate price signals, which dampen incentives to conserve energy or invest in energy efficiency or distributed renewable generation. (Id. at 431.) He also took issue with the Public Staff's Minimum System Report and the conclusion that it is generally reasonable to use the results of a minimum system approach for setting the maximum allowable amount that could be recovered in a basic customer charge. (Id. at 410, 446-455.)

NCJC, et al. witness Howat testified that elevated basic customer charges disproportionately impact low-volume, low-income customers and discourage energy efficiency. (Id. at 372-73, 394-401.) Witness Howat testified that low-income households, and particularly low-income households of color, are disproportionate harmed by elevated basic customer charges, which exacerbate pre-existing problems with electric utility affordability and home energy security faced by many of these households. (*See* id.)

In his rebuttal testimony, witness Pirro disagreed with NCJC, et al.'s position that the current residential Basic Customer Charge should be reduced and maintained that the Company's current residential Basic Customer Charge should remain in effect in this proceeding. (Tr. vol. 11, 1122.) He reiterated that despite the fact that an increase to the residential Basic Customer Charge is warranted to reduce cross-subsidization, DEP has proposed no change to the current residential Basic Customer Charge of $14.00 that was approved in the Company's last rate case. (*See* id. at 1121-22.)

Witness Pirro rebutted witness Wallach's argument that costs identified by the minimum system methodology are not customer costs and should not be included in the Basic Customer Charge. (Id. at 1122.) He explained that the rates and rate design supported by his testimony are based upon the cost of service study, including the minimum system study, performed by the Company, accepted by Public Staff, and approved in previous rate cases by the Commission. (Id.) The Company's cost of service studies indicate that these costs are customer costs and therefore the Basic Customer Charge was designed to recover them. (Id.)

Schedule RES, the Company's primary residential rate schedule, does not have a demand component; rather it only has a Basic Customer Charge and a volumetric per kilowatt-hour (kWh) charge. (Id. at 1123.) Witness Pirro testified that it would be inappropriate to shift some of the costs currently included in the Basic Customer Charge to a volumetric rate. (Id.) He noted that witnesses Howat and Wallach acknowledge that metering, service drops, and billing costs are appropriate costs to recover through a per customer charge. (Id.) Witness Pirro testified that the distribution costs in question represent poles, conductors, conduit, and transformers, which are also fixed in nature and do not vary with customer consumption. (Id.) Importantly, these costs are unlike variable operations and maintenance (O&M) costs and fuel costs, which vary directly with energy consumption and are properly recovered via the volumetric kWh rate. (Id.) Thus, according to witness Pirro, recovering such costs via a kWh charge would provide an incorrect pricing signal. (Id.)

Similarly, witness Hager explained why it is appropriate to include uncollectible costs in the customer classification for inclusion in the Basic Customer Charge. (Id. at 1067.) In particular, she testified that witness Wallach's claim that uncollectible costs "tend to vary with revenues and thus with usage" is unsupported. (Id.) In addition, DEP has historically treated these as a customer cost in the same category as other FERC Customer Accounting Accounts, which is a reasonable assumption in witness Hager's opinion. (Id.)

Witness Pirro also disagreed with NCJC, et al.'s contention that the current Basic Customer Charge discourages distributed generation and energy efficiency. (Id. at 1123.) He argued that failing to properly recover customer-related costs via a fixed monthly charge would provide an inappropriate price signal to customers and would fail to adequately reflect cost causation. (Id.) Shifting customer-related costs to a volumetric per kWh rate further exacerbates this concern and overcompensates energy efficiency and distributed generation for the cost avoided by their actions, thereby skewing the market for such measures. (Id. at 1123-24.)

In response to witness Howat's argument that the current residential Basic Customer Charge disproportionately harms low-income customers, witness Pirro noted that the Company is mindful of the impact of any rate increase on its customers, particularly low-income customers; however, the Company does not design rates based upon customer incomes, but rather applies cost causation principles to the extent practical. (Id. at 1124.) He testified that there are other means of addressing the financial needs of low-income customers, such as Company, state, and local programs, which are more effective than biasing the rate design. (Id.) In any event, concerns raised in the past by NCJC and other low-income advocates are precisely why the Company did not propose to increase the Basic Customer Charge in this case, and instead proposes a collaborative to address issues facing low-income customers. (*See* id. at 1089, 1122.)

With respect to the Public Staff's Report on Minimum System,[28] witness Floyd testified that the Public Staff believes that distribution costs have a demand-related

[28] Report of the Public Staff on the Minimum System Methodology of North Carolina Electric Public Utilities, Docket No. E-100, Sub 162 (March 28, 2019). (Hager DEC Redirect Ex. 1; *see* footnote 26, above.)

component and a customer-related component, and that the minimum system method is a reasonable approach to distinguishing what portions are demand-related and what portions are customer-related. (Tr. vol. 15, 1045-46.) He also explained that from the Public Staff's perspective, the minimum system method establishes the maximum boundary for a basic customer charge, the basic customer method establishes the minimum, and that "somewhere in between lies the answer." (*See* id. at 1045-47.) He also clarified that in setting the Basic Customer Charge, "it has been my experience in the half a dozen cases I've looked at that the Company has never used the maximum that was determined through the minimum system approach in their cost of service," and confirmed that in this case, DEP is not seeking any increase in the Basic Customer Charge. (*See* id. at 1095-96.)

In light of the parties' testimony and all of the evidence presented, the Commission finds and concludes that the Company's proposal to maintain the current Basic Customer Charges for all customer classes, including residential, to be just and reasonable. In arriving at its conclusion, the Commission notes that it has approved the use of the minimum system methodology in the Company's cost of service study to determine the customer-related portion of distribution costs in this proceeding, and finds persuasive the Public Staff's testimony that it is generally appropriate to use the minimum system study to set the maximum allowable amount for the fixed basic customer charge. Even so, the Commission further notes that the Company is not asking for the Basic Customer Charge to be set at the maximum amount under the minimum system method (which would result in Basic Customer Charge for residential rate schedules of $31.75), nor is the Company following its standard approach of taking a 50% step toward the theoretical minimum system Basic Customer Charges (which would result in a Basic Customer Charge for each residential rate schedule of nearly $23.00). (*See* Pirro Ex. 7.) Instead, the Company has proposed to maintain its current Basic Customer Charges, including a residential Basic Customer Charge of $14.00. This is the same Basic Customer Charge the Commission approved in the Company's last rate case, finding that it strikes an appropriate balance that provides rates that more clearly reflect actual cost causation and thus minimize subsidization and provide proper price signals to customers in the rate class, while also moderating the impact of such increase on low-usage customers. (*See* 2018 DEP Rate Order, 117.) Moreover, the Company has agreed to discuss issues impacting low-income and low-usage customers, including the Basic Customer Charge, in the collaborative stakeholder process discussed in Evidence and Conclusions for Finding of Fact No. 45 herein. Accordingly, the Commission finds and concludes that the Basic Customer Charges as set forth in Pirro Exhibit 7 are just and reasonable and are therefore approved by the Commission.

**Schedule LGS-RTP**

Schedule LGS-RTP (Real Time Pricing) is a voluntary rate option that offers the Company's large general service customers the opportunity to purchase incremental energy differing from a baseline load at rates that more closely match the Company's incremental cost of providing the kWh in the given hour. (*See* Tr. vol. 11, 1138.) The rate is available for up to 85 nonresidential customers with a contract demand requirement of

1,000 kW or greater and allows usage above or below a baseline amount to be billed at a rate that varies each hour to reflect the Company's marginal cost. (Id. at 1138, 1141.) Baseline usage is billed under an applicable standard tariff selected by the customer, while the incremental use is billed at the hourly rate. (Id. at 1138.) Hourly rates are provided to participants on the prior business day and include the expected marginal production costs including line losses and other directly-related costs. (Id.)

***Hourly Pricing Rates***

Witness Pirro explained that the hourly rates under LGS-RTP are calculated based upon the marginal or dispatch cost of the generator that is expected to serve the next kWh of system load based upon all available generating plants. (Id. at 1138-39.) Hourly rates are based on variable production cost data from an industry standard production cost model, which is updated daily to reflect the latest available information such as weather and load forecast, unit availability, heat rates, and variable commodity and emission costs. (Id. at 1139.) Hourly rates derived from the production cost model data reflect the change in the Company's fuel and other directly related variable costs that would be anticipated if the customer decides to exceed or reduce load from their baseline load. (Id.)

CUCA witness O'Donnell recommended that DEP be required to set hourly pricing rates based on the lower of the Company's marginal costs or costs found in the competitive wholesale power markets as adjusted for transmission costs and line losses. (Tr. vol. 14, 133, 179-81.) He argued that manufacturers need every option available to help mitigate rate increases and asserted that because his recommendation would not cost DEP any funds, the Company should be indifferent to making this change. (*See* id. at 180-81.) He concluded that because his recommendation helps manufacturers save on their power bills, he sees no reason that the Company should not set hourly pricing rates at the lower of the Company's marginal cost or the price as set by the open wholesale power market, as adjusted for transmission costs and line losses. (*See* id.)

In his rebuttal testimony, witness Pirro disagreed with witness O'Donnell's recommendation that the hourly rate be set at the lower of the Company's marginal cost or wholesale market rate. (Tr. vol. 11, 1140.) Witness Pirro testified that the Schedule LGS-RTP hourly rates are fundamentally based on the Company's system production costs and are not designed to represent or be a proxy for market-based pricing. (Id.) The rate is designed to afford customers the opportunity and flexibility to respond directly, through usage, to short term system costs. (Id.) Customers can increase usage as befits their process during periods of low system costs or decrease their usage during periods of higher system costs. (Id.) DEP actively participates in the wholesale energy market to the practical limitations of system reliability, transmission availability, and market liquidity, and customers benefit in the aggregate from those market purchases. (Id.) Witness Pirro explained that the RTP product is not a market product and was never intended to provide some customers with optionality beyond the ability of the Company to provide appropriately priced service. (Id.) He testified that applying hourly rates that are lower than the Company's marginal system cost would result in other customers subsidizing RTP customers. (Id.) According to witness Pirro, the current methodology best reflects the Company's expected fuel cost and is therefore the appropriate basis under which to set hourly rates. (Id.)

The Commission agrees with witness Pirro that it would be inappropriate to make the change to hourly pricing recommended by witness O'Donnell and finds and concludes that the Company's proposed structure and pricing for Schedule LGS-RTP, as modified by the Commission's final determination of revenue requirement, should be approved.

***Availability***

Hornwood witness Brian Coughlan advocated for expanding the availability of DEP's LGS-RTP rate by eliminating the cap of 85 customers and reducing the minimum demand requirement from 1,000 kW to 75 kW. (Tr. vol. 14, 550-51, 581.) He noted that RTP was established as an experimental rate in 1996, and was initially offered to a maximum of 25 customers. (Id. at 551-52.) In 1998, the customer limitation was increased from 25 to 85 customers. (Id. at 553.) Witness Coughlan testified that the 85 customers currently served under RTP enjoy an unfair advantage. (Id. at 555-56.) He testified that the changes he recommends are reasonable, fair, equitable and easy to implement with existing metering and billing technology. (Id. at 581.) He concluded that the relief being requested by Hornwood will provide pricing flexibility to customers, help attract new businesses and jobs and help retain existing businesses and jobs. (Id.)

In his rebuttal testimony, witness Pirro testified that a change in the rate design of the LGS-RTP tariff as suggested by witness Coughlan would require significant analysis and stakeholder engagement and suggested that this discussion should be a part of the comprehensive rate design study. (Tr. vol. 11, 1141.)

During the evidentiary hearing, witness Pirro explained why the LGS-RTP rate is capped at 85 customers and limited to customers with demand greater than 1,000 kW. (Tr. vol. 11, 1318-32.) He testified that RTP is "a very complex rate" intended for large, sophisticated customers who have the ability to plan their operations and respond to price signals. (Id. at 1319.) He noted that 'this type of rate is not for everyone," and based on his 30 years of experience in the industry, small or medium general service customers do not respond to day-ahead pricing signals as they generally do not have the ability to fluctuate their business operations like large general service customers do. (*See* id. at 1320-21, 1324, 1332.) He also clarified that participants do not receive "preferential pricing," but rather the opportunity to modify their operations to respond to price signals, which carries a risk – "[i]f they don't respond, they will be paying more during those hours." (*See* id. at 1321.)

Witness Pirro explained that it takes full-time personnel to manage this program, and with the onset of Customer Connect on the horizon, it does not make sense to increase the number of employees administering the program. (*See* id. at 1319, 1322-23.) He testified that participants in this LGS-RTP rate "require much more attention than a standard tariff customer" and that there is "a lot of front-end work that goes with administering" the program. (Id. at 1323, 1329.) For example, RTP requires creation of a customer's baseline load and calendar mapping that would reflect the customer's operation. (Id. at 1323.) He concluded that "it would be extremely difficult to manage a large population of greater than 85 at this time." (Id.) He said that lowering the kW threshold would open up the program to 45,000 small/medium general service customers, and the way the rate is currently designed would not be appropriate for mass scale. (*See* id. at 1329.) He reiterated that expansion of the availability of RTP would be a topic better suited for the comprehensive rate design study: "the design itself may not be appropriate on a grand scale. So that it what I think needs to be reviewed further." (Id. at 1325.)

Witness Floyd also cited the administrative burden of manually billing and calculating the RTP bill for customers being a basis for DEP not expanding participation. (Tr. vol. 15, 1131-32.) He noted that the administrative burden component would merit further study once DEP's new Customer Connect billing system is implemented. (*See* id.) In addition, he acknowledged that the existing RTP was not designed for small customers, but opportunities for expansion of the RTP rate, as well as time-of-use (TOU) opportunities for customers from 75 kW to 1 MW, should be included in the rate design study. (Id. at 1132, 1134-35.) Witness Floyd cautioned against changing the demand threshold or opening the rate up to additional LGS customers in this case, noting that "we need to look at things in concert with one another." (*See* id. at 1136.) In particular, he explained that the RTP rate schedule is a marginal rate schedule, and that while marginal capacity is not assigned fixed costs, the Company does need to plan to serve that load – that is why, when the system needs capacity, RTP customers are encouraged to curtail or pay a penalty. (Id. at 1137.) He testified that the Company does not need too much marginal load on its system because otherwise, the Company will be paying credits for incremental load that it does not need to call. (Id.) Accordingly, he concluded that an economic analysis would need to be done as part of the comprehensive rate design study. (*See* id.)

On October 5, 2020, DEP, the Public Staff, and Hornwood filed a Joint Stipulation of Facts clarifying several factual matters relating to Hornwood (Hornwood Stipulation).[29] Hornwood has four active accounts with DEP, one of which is billed under the Large General Service (LGS) rate schedule. (Hornwood Stipulation, at 1.) In his Direct Testimony filed in May 2020, witness Coughlan testified that Hornwood had requested to be served under LGS-RTP and was told the rate was fully subscribed. (*See* Tr. vol. 14, 553.) During the evidentiary hearing in October 2020, DEP reviewed again the number of customers enrolled in its LGS-RTP Schedule and determined that there was one available customer slot within the 85-customer cap. (*See* Hornwood Stipulation, at 1.) Hornwood was next in the queue and elected to enroll its LGS account in the Company's LGS-RTP Schedule. (Id.) As of October 5, 2020, there were no available slots under the 85-customer LGS-RTP cap. (Id.)

[29] The Hornwood Stipulation was accepted by the Commission during the evidentiary hearing on October 6, 2020. (Tr. vol. 20, 35-36.)

The Commission declines to adopt witness Coughlan's recommended changes to expand the availability the LGS-RTP rate schedule in this case. Witnesses Pirro and Floyd both offered convincing testimony that while this issue warrants additional study, it would be inappropriate to open the LGS-RTP rate to additional customers at this time. In particular, the Commission gives weight to their testimony relating to the burden of administering the rate, the fact that the original rate was designed for large customers, and importance of examining the greater economic implications. The Commission agrees it would be more appropriate to reevaluate this rate schedule in the broader context of examining RTP and TOU opportunities during the comprehensive rate design study, and in view of the implementation of Customer Connect. Further, the Commission disagrees with Hornwood's argument that the LGS-RTP rate is discriminatory because it limits participation and affords participants preferential pricing and therefore finds that the existing LGS-RTP eligibility requirements are not discriminatory. As witness Pirro pointed out, the LGS-RTP rate simply provides the opportunity for participants to modify their operations to respond to price signals, and as witness Floyd noted, they are penalized by higher prices if they do not. This does not confer an unreasonable preference or advantage on participants, and, as discussed above, the eligibility requirements are reasonable.

**Multi-Site Aggregate Commercial Rate**

Harris Teeter witness Bieber recommended that the Company study the feasibility of a multi-site aggregate commercial rate and propose a pilot program in its next rate case. (Tr. vol. 15, 229-30, 252-55.) Company witness Huber testified that without having studied such a rate offering, DEP believes it is premature for the Commission to order the Company to propose a multi-site aggregation pilot in its next rate case; however, the Company is willing to consider witness Bieber's proposal in the context of the comprehensive rate design study. (Tr. vol. 11, 1160.) The Commission agrees that it is appropriate that a multi-site aggregate commercial offering be considered in the comprehensive rate design study, including the purpose of the aggregation, the impact on cost of service, the potential for revenue realignments, and the implications for other aspects of utility service outside of base revenues (i.e., increased DSM/EE opt-outs due to aggregation and impact on administrative and other fixed cost recovery).

**EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 45**

The evidence supporting this finding and conclusion is contained in the Company's verified Application and Form E-1; the testimony and exhibits of DEP witnesses Huber and Pirro, and Public Staff witness Floyd; the Second Partial Stipulation; and the entire record in this proceeding.

In his testimony regarding the Company's proposed changes to its rates, Public Staff witness Floyd testified that the Company made very few modifications to its rate schedules other than to increase individual rate elements to achieve the revenue increase assigned to each customer class. (Tr. vol. 15, 957.) He noted that the current rates had not yet been updated to incorporate new AMI data analytics. (Id. at 957, 966-67.) Witness Floyd also indicated that there were no proposed changes to the basic facilities charges in any of the Company's rate schedules. (Id. at 959.) Witness Floyd concluded by stating his general support for the few proposed changes to rate schedules and service regulations as discussed by Company witnesses Pirro. (Id. at 958.)

Witness Floyd also testified that the Public Staff believes the Company should undertake a comprehensive rate design study prior to the filing of its next rate case and should allow stakeholders the opportunity to participate in the discussion. (Id. at 968.) According to witness Floyd, the study should (a) analyze each rate schedule to determine whether the schedule remains pertinent to current utility service, and if so, whether it should be modified or be replaced; (b) address the potential for new schedules to address the changes affecting utility service; and (c) explore providing more rate design choices for customers. (*See* id.)

Witness Floyd articulated six broad principles for future rate designs:

1. Be forward-looking and reflect long-run marginal costs.

2. Be focused on the usage components of service that are the most cost- and price-sensitive.

3. Be simple and understandable.

4. Recover system costs in proportion to how much electricity consumers use, and when they use it.

5. Give consumers appropriate information and the opportunity to respond to that information by adjusting their usage.

6. Be dynamic where possible.

(Id. at 968-69.)

Witness Floyd provided several examples of utility services that justify the need for a comprehensive study, including net metering and other distributed generation resources, microgrids, energy storage, and electric vehicles (EVs). (Id. at 969-70.) He also discussed a number of other items that warrant consideration in a rate design study, such as review of the Company's time-of-use (TOU) rates; the firmness of utility service (i.e., whether customers want firm utility service 24 hours, seven days a week, or whether they want non-firm, standby service that provides electric service when customer-owned generation is unavailable); and the unbundling of average rates into generation, transmission, distribution, and customer component costs. (*See* id. at 970-71.) Witness Floyd also noted that it has been almost eight years since the merger of DEC and DEP, yet their rate design structures remain very different in many ways, which can be confusing to customers. (Id. at 972.) He opined that a rate study could assist in a transition to consolidation of the rate designs of the two utilities. (Id.)

With respect to the timeframe for completing a comprehensive review of the Company's rate designs, witness Floyd explained that this study would be "no trivial matter" and would be a serious and lengthy undertaking involving many stakeholders. (Id.) By way of example, he noted that DEC's Schedule OPT resulted from an 18-month process that brought business and industry together to formulate a TOU rate design with broad support. (Id.) Witness Floyd testified that the proposed rate study would likely require a significant amount of time to develop new rates, as well as to implement them. (Id.) He also noted that any significant transition to new rates would be likely to produce "winners and losers," and therefore, a gradual implementation would be necessary to minimize any adverse impacts. (Id.)

In his Rebuttal Testimony, DEP witness Huber agreed that the Company should conduct a comprehensive rate design study. (Tr. vol. 11, 1156.) He stated that while historically, DEP's rate offerings have adequately served customers, changes in customer interests, public policy goals, and regulatory priorities, as well as increasing adoption of new technologies, demand a rethinking of DEP's rate designs. (*See* id.) Witness Huber testified that the Company agrees with witness Floyd's recommended components of a rate design study, and in particular, the six guiding principles he articulated in his direct testimony. (*See* id. at 1156-57.) Witness Huber also agreed with witness Floyd's comments that such a study should seek to harmonize the rate design structures of DEC and DEP. (Id. at 1157.)

Witness Huber noted that DEP is already collecting data that will be beneficial for a comprehensive rate design study. (Id. at 1159.) For example, DEC started providing service under nine new dynamic pricing pilots effective October 1, 2019, and DEP plans to incorporate the lessons gleaned from these pilots to better inform future rate design proposals. (Id.) In addition, deployment of smart meters throughout DEP's territory is nearly complete, offering an additional level of insight and data that will be used to design refreshed rates. (Id. at 1158.)

In response to witness Floyd's testimony regarding the suggested timeframe for such a study, witness Huber explained that DEP does not currently know the timing of its next rate case, but, in any event, the Company cannot cost-effectively implement any rate design changes until the new Customer Connect billing system is in use. (Id.) Customer Connect is scheduled to be implemented by DEP in November 2021. (Id. at 1158, 1170) Once the new Customer Connect system is fully deployed and post-deployment stabilization is achieved approximately six months later, the Company will be ready to begin implementing new rate designs. (Id. at 1158.) DEP strongly favors utilizing the time prior to implementation to analyze data, convene stakeholders, and refine its proposals. (Id.)

DEP initially proposed to complete the comprehensive rate design study by the end of the second quarter of 2021, which would have given the Company a year to engage stakeholders and complete the study had the hearing in this case proceeded as originally scheduled. (Id. at 1158, 1170, 1172.) In light of the delays caused by the unprecedented events of 2020, the Company proposes to complete the study within 12 months from the date of the final order in this proceeding. (Id. at 1170, 1172.) According to witness Huber, this timeline should allow the new rate designs to be implemented after the Company's new Customer Connect billing system is ready to support any proposed changes. (Id. at 1158, 1170, 1172.)

In the Second Partial Stipulation, DEP and the Public Staff memorialized their agreement that the Commission should order a comprehensive rate design study. (*See* Second Partial Stipulation, § IV.E.) They agreed that this study should address rate design questions related to, among other things: (1) firm and non-firm utility service, and the degree of customer-owned generation receiving both types of service; (2) various types of end-uses, such as EVs, microgrids, energy storage, and distributed energy resources; (3) the formats of future rate schedules (basic customer charges, demand charges, energy charges, etc.); (4) marginal cost versus average cost rate designs and pricing; (5) unbundling of average rates into the various functions of utility service (i.e., production, transmission, distribution, customer, general/administrative, etc.); and (6) socialization of costs versus categorization of specific costs and corresponding impact on rates/revenues. (Id.)

In the Supplemental Rebuttal Testimony filed jointly with DEP witness Pirro, witness Huber testified that while the Company has agreed to consider and prepare cost of service studies using a number of methodologies in its settlements, these cost of service studies are distinct from the comprehensive rate design study for a good reason. (Tr. vol. 11, 1167.) He indicated that a stakeholder process would not achieve unanimity with respect to which class cost of service study should be used and attempting to include this discussion in the rate design study could grind the collaborative stakeholder process to a halt before it really even begins. (Id.) Therefore, he recommended that cost allocation methods, such as cost of service allocators, not be included in the rate design study to ensure the parameters of the study are reasonable enough to produce focused results. (Id. at 1167-68.) Nevertheless, witness Huber noted that one of the key approaches to judge a rate design is by its impacts and alignment with both embedded cost to serve metrics as well as marginal cost to serve evaluations, and he testified that he intends to bring both of these lenses to the rate design study, balanced with other criteria such as understandability and stability. (Id. at 1168.)

Witness Huber also clarified that the Company envisions the review and implementation of new rate designs as an iterative process, with a focus for the first year on creating a detailed actionable roadmap and prioritization for tariff changes over time, including emerging end-use considerations. (Id.) He testified that where feasible and supported by broad consensus, pilots, research, or other improvements can and should be pursued during the process, even in advance of future rate cases. (Id. at 1169.) In addition to the implementation roadmap at the end of one year, the Company supports periodic updates to the Commission detailing progress, challenges, and implications for subsequent phases and topics. (Id.) He concluded that Commission guardrails covering scope, sequencing, and timelines would provide clarity for all stakeholders and support a focused and efficient study overall. (Id.)

During the evidentiary hearing, witness Huber emphasized that this rate design study is an ambitious undertaking that would require much work, but that he wants to move quickly to modernize the Company's pricing and rate offerings. (*See* id. at 1273-

74.) He also noted that the Company is in the process of procuring a state-of-the-art analytics platform that will enable the Company to leverage actual customer data from AMI and run various scenarios and load analysis more quickly. (*See* id. at 1270-72.) Witness Huber stressed that this is a stakeholder and data driven process, and his goal is to reach an outcome that is "tailored to North Carolina on-the-ground realities and goals." (Id. at 1272.) He also indicated that the Company is open to a third-party facilitator for the stakeholder portion of the process. (*See* id. at 1212.)

In terms of timing, witness Huber testified that he proposes to have a comprehensive roadmap and report a year after the final order in this case. (Id. at 1273.) He explained that there may be "low-hanging fruit" items that stakeholders might be able to reach consensus on in less than a year's time that could be "quick wins" prior to the conclusion of the study, whereas other items could take more time and require follow-up studies. (*See* id. at 1273-74.)

Witness Huber confirmed that if the Commission were to order a comprehensive rate design study, the Company would view it as a blank slate and an opportunity to take a fresh look at all of its rate designs:

> You know, this is how I view it, a data-driven collaborative process where everything is on the table, right? And when I say that, I don't want it to seem like this is going to get crushed by its own weight by any means. I think, you know, we would start out by obtaining goals from the different stakeholders, prioritization, mapping, and then diving into low-hanging fruit issues that we can, you know, work on right away. And that might be electric vehicles. It could be some other things.

(Id. at 1241-42.)

Witness Huber also provided his view on how cost of service would factor into the rate design study, stating that rate design translates both embedded and marginal costs. (*See* id. at 1256.) He explained that the comprehensive rate design study is "primarily going to be focused on rate design" and while the study will look at how efficiently a rate design aligns with the underlying cost to serve, it will not be examining whether "we should change this allocator or look at that allocator." (*See* id. at 1256-57.)

Finally, in response to Commission questions, witness Huber confirmed that the issue of the rates and charges for services for net metering customers would be a part of the comprehensive rate design study. (Id. at 1264, 1282-83.)

During the evidentiary hearing, witness Floyd reiterated that "we're facing a new utility paradigm that I believe requires a new study, new data, new research." (Tr. vol. 15, 1027.) He testified that "I can't stress enough that I believe a comprehensive approach with all the stakeholders is really what's necessary at this time." (Id. at 1028.)

When asked about the parameters of the study, witness Floyd testified that:

my testimony outlines some very basic principles, and there's a reason you don't see a lot of meat on those bones, is because I think a lot of folks would have a lot of different ways to interpret those half a dozen or so principles. But rate design – I don't think the Commission should take this as a static endeavor. This is something that future Commissions are going to have to constantly deal with in every rate case.

(Id. at 1106.)

Witness Floyd went on to say while he thinks it would be beneficial for the Commission to provide the parties with some guidance as to the parameters and timing of the study, he is not suggesting that the Commission put "a stake in the ground" and hopes that the Commission "gives the parties some latitude to have an open debate." (*See* id. at 1107, 1114-17.) As witness Floyd testified, "It cannot happen overnight; it needs to involve a bunch of stakeholders; and there's going to be a lot of argument. And there's certainly the high potential for disagreement." (Id. at 1107.) Accordingly, he recommended there be should be defined objectives and a timeframe for the study even if there is "disagreement at the end of the day." (*See* id. at 1116.)

The Commission first and foremost finds that the Company's proposed portfolio of rate designs as modified by this Order are just and reasonable for purposes of this proceeding. Nonetheless, as the Company and customers adopt new technologies, it is vital for rates to evolve to provide opportunities to maximize the efficiency and effectiveness of these technologies. The Commission recognizes the impact the results of a comprehensive rate study may have on future utility services, customers, and the economy of the State. That said, the Commission finds and concludes that it is in the public interest to order a comprehensive rate design study as outlined in the Second Partial Stipulation and further described in the testimony of witnesses Floyd and Huber, and as expanded upon herein. The Public Staff welcomed Commission guidance on scope and timeline of the study to keep the parties focused, but also asked for enough flexibility to allow for a robust discussion among stakeholders. Based on the evidence in the record, the Commission provides the following guidance.

In terms of the topics to be addressed by the rate design study, the Second Partial Stipulation already provides a detailed list of the categories of rate design issues that will be discussed during the study, including firm and non-firm utility services, various types of end uses (EVs, microgrids, energy storage, and distributed energy resources), the formats of future rate schedules, marginal cost versus average cost rate designs and pricing, unbundling of average rates into the various functions of utility services, and socialization of costs versus categorization of specific costs. (Second Partial Stipulation, § IV.E.) While of course the discussion need not be limited to items listed in these six categories, the Commission finds and concludes that the topics outlined in § IV.E. of the Second Partial Stipulation provide a good framework for the issues that should be covered in the comprehensive rate design study.

While both witness Floyd and witness Huber provided testimony about how cost of service informs and translates into rate design, the comprehensive rate design study as contemplated by the Company and the Public Staff in § IV.E. of the Second Partial

Stipulation does not encompass discussion of which cost allocation methodology the Company should propose in its next rate case. While the Company has agreed to consider and prepare cost of service studies using a number of methodologies in its settlements with CIGFUR and the Public Staff, these cost of service studies are separate and apart from the comprehensive rate design study. As described by witnesses Floyd and Huber, the comprehensive rate design study is designed to be a stakeholder process, and given the different perspectives of intervenors with respect to the appropriate cost of service methodology, it is unlikely that the interested stakeholders would reach consensus on the cost of service methodology; attempting to include this discussion in the rate design study could hinder the productivity of the stakeholder process. While a rate design study would necessarily include analysis and discussion of how rate designs align with different cost of service metrics, the Commission agrees that stakeholder discussion of the appropriate allocation methods (e.g., cost of service allocators) need not be included in the rate design study. Instead the focus of the comprehensive rate design study should remain on "rate design questions," as outlined in the Second Partial Stipulation with the Public Staff and in the testimony of witnesses Floyd and Huber.

The Commission recognizes that the comprehensive rate design study and the low-income collaborative discussed in Evidence and Conclusions for Finding of Fact No. 46 are separate but parallel stakeholder processes. As indicated below, to the extent the parties participating in the low-income collaborative recommend the design of new rates to offer to low-income customers, the parties should present those recommendations to the rate design study participants for consideration. Additionally, the Commission does not intend for the stakeholder processes for affordability and comprehensive rate design to be mutually exclusive or contingent upon the completion of either stakeholder process.

In terms of process, both witnesses Floyd and Huber emphasized the importance of engaging stakeholders. Understanding that the parties may not achieve consensus on all rate design items the Company ultimately proposes, the Commission agrees that robust stakeholder participation is vitally important to a meaningful rate design study and encourages the Company and the Public Staff to solicit input and feedback from interested parties throughout the process.

With respect to timing, ideally the study would conclude prior to the filing of the Company's next general rate case; however, because this is likely to be an ambitious and lengthy undertaking, and it is uncertain when the Company will file its next case, the Commission is hesitant to tie the completion of the study to the timing of a rate proceeding. Witness Huber indicated that he believes that the process could yield a detailed "roadmap" within a year, but indicated that while certain items could be agreed upon and perhaps even filed earlier in the process, others might take additional time and warrant additional study beyond that 12-month timeframe. (*See* Tr. vol. 11, 1168-69, 1241-43, 1273-74.) Accordingly, in connection with this study, the Commission finds and concludes that the Company should file a final report, including a comprehensive roadmap and timeline for proposing new rate designs and identifying areas for additional study, within 12 months of the Commission's subsequent order discussed below, unless a different timeframe is set in that subsequent order.

Finally, the Commission requests that parties that wish to participate in the study provide for the Commission's consideration a list of proposed topics, objectives, and issues that should comprise a comprehensive rate study within 30 days of this Order. The Commission will consider these filings and will issue a subsequent order detailing the objectives

**EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 46**

The evidence supporting this finding and conclusion is contained in the testimony and exhibits of DEP witnesses De May and C. Barnes; Public Staff witness Floyd; NCJC et al. witness Howat; and the entire record in this proceeding.

Company witnesses De May and C. Barnes addressed the issue of affordability. According to witness De May, DEP is committed to helping customers who struggle to pay for basic needs with programs and options to assist them during times of financial hardship. (Tr. vol. 11, 756.) The assistance programs that the Company offers, such as the Energy Neighbor Fund, and the Company's portfolio of demand-side management (DSM) and energy efficiency (EE) programs have helped many of the Company's customers reduce energy costs, pay home energy bills, manage fluctuations in their monthly bills, and manage through the difficulty of paying their entire bills by the due date. (Id.) Witness De May stated that the Company has several ideas for low-income programs that could help accomplish this goal. He provided several examples including a low-income bill credit on the BCC, a bill round-up program, and a Supplemental Security Income (SSI) price discount similar to that offered by DEC. (Id. at 757-58.) Witness De May stated that before seeking to implement these programs, a stakeholder process is necessary to adequately consider these and other programs to develop an appropriate suite of effective options for the Commission to consider for approval. (Id.) Accordingly, witness De May proposed that as part of its Order in this case, the Commission direct the Company to host, and the Public Staff to participate in, a collaborative workshop with interested stakeholders to address the establishment of new low-income programs at DEP and require that the Company and/or the Public Staff to file a final report with the Commission outlining the feedback and recommendations obtained in that workshop. (Id.) Per witness De May, the Company proposes to use the feedback and recommendations it receives from participants in such a workshop to develop proposals to file with the Commission for approval of new low-income programs. (Id.)

Public Staff witness Floyd also provided testimony on the issue of affordability.[30] He stated that affordability is an important issue for all customers. (Tr. vol. 15, 989.) However, witness Floyd emphasized that rates must first be designed using cost-causation principles, and then public policy as directed by the Commission or General

[30] On January 22, 2020, the Commission issued an order directing the Public Staff "to investigate [the Company's] analysis of affordability of electricity within its service territory as well as programs available to [the Company's] customers that address affordability with a particular focus on residential energy customers." Witness Floyd's testimony, in part, also addresses the directives included in that order.

Assembly, such as providing discounts to low-income customers, could be applied in designing final rates. (Id.) According to witness Floyd, any rate discount for low-income customers would be recovered from other customers and the amount of this shift or subsidization must be thoroughly understood in terms of its effect on other customers' rates. (Id. at 990.) He noted that the Public Staff believes the stakeholder process is the most appropriate venue to discuss issues of affordability of electric service and recommends the following parameters for a stakeholder process: (1) set a timeline for the process, including a deadline for the filing of recommendations to the Commission (deeming one year as being reasonable); (2) define "affordability in terms of electric utility service and investigate how it has changed over time; (3) investigate the success of existing rates, assistance and energy efficiency programs in addressing affordability; (4) analyze the data related to load, cost, and revenue profiles of low-income customers and the residential class in general, cost-causation, impact to cost-of-service, potential for subsidization, impact on revenues and rates for all customers, program eligibility, extent of assistance needed to be meaningful, definition of a "successful program"; and (5) require periodic reporting to the Commission on the status of the process. (Id. a 989-90.) In response to Commission questions, witness Floyd testified that the Company, the Public Staff, and all other parties need guidance from the Commission prior to beginning the low-income collaborative. (Tr. vol. 10, 100-01).

NCJC et al. witness Howat addressed issues related to affordability of electric service for lower income residential customers and programs and policies designed to mitigate affordability challenges faced by those customers. Witness Howat summarized data provided by the Company showing, according to witness Howat, significant affordability problems faced by customers. (Tr. vol. 14, 373-77.) According to witness Howat, over the past two years the number of non-pay disconnections increased for the Company and the payment of late charges, receipt of disconnection notices and involuntary loss of electric service reflect signs that residential customers are experiencing trouble affording their electric bill. (Id. at 375-76.) To address affordability issues, witness Howat recommended consideration of a new low-income rate design and an arrearage management program. (Id. at 401.) In addition, witness Howat recommended that new affordability program offerings be developed through a collaborative process overseen by the Commission, with parties being allowed to file comments regarding the findings and recommendations of the stakeholder process. (Id.) Witness Howat also recommended that the Company expand the Helping Home Fund or other similar comprehensive low-income energy efficiency programs as an important complement to affordable rate design. (Id. at 402.) He further noted that the Company's partial settlement and stipulation reached with NCSEA and NCJC et al. are welcome steps towards implementing his recommendations. (Tr. vol. 10, 133.)

In response to witness Floyd and Howat's testimony, DEP witness C. Barnes restated the need for a stakeholder process, with guidance from the Commission, would provide the most effective forum to discuss these issues, propose and evaluate options, and make recommendations to the Commission in a future docket. (Tr. vol. 11, 176.) Further, she stated that the Company agreed with the Public Staff's recommendations regarding the parameters for a stakeholder process set forth in witness Floyd's testimony. (Id. at 176-77.)

The Commission echoes the parties' sentiments that the affordability of electricity is an important issue. Many of the Company's customers have difficulty paying their energy bill and the Commission believes that a study of ways to make electric service more affordable for DEP's low income customers has great merit. The Commission agrees with the Company, the Public Staff, and NCJC et al. that a collaborative of interested parties should be established to propose ideas and present to the Commission a list of recommendations to be implemented to address this issue. Accordingly, within 90 days of the date of this Order, the Company shall convene a collaborative to hold workshops with the Public Staff and interested stakeholders to address the affordability of electric service for low income customers.

Both Company and intervenor witnesses highlighted the need for direction from the Commission in establishing the goals and parameters of the stakeholder process. Starting with witness Floyd's framework, the Commission directs that the collaborative should as part of its work:

(1) Describe the character and demographics of the Company's residential customer base.

- Provide some analysis of demographics of residential customers in terms of the members per household, types of households (single family or multi-family), the age, racial and gender makeup of households, household income data, and other data that would describe the types of residential customers the Company now serves.
- Estimate the number of customers who fall within households at or less than 150% of the federal poverty guidelines (FPG), and those who are at or less than 200% of the FPG.

(2) Investigate how "affordability" has changed over time and seek to define it for purposes of utility service today.

- What does "affordability" mean in other jurisdictions similar to North Carolina (vertically integrated investor-owned utilities)?
- Absent a statutory requirement, how best should the Commission consider "affordability" and define it?
- What customer qualifications (both qualitatively and quantitatively) should the Commission consider when determining who would be eligible for an affordability program?
- Review existing funding sources, and the ability of the utility to work with other agencies and bodies to coordinate delivery of program objectives. Using a graduated scale of 10% to 100% of need, what resources (dollars and manpower) would it take to successfully respond to each level of need?

(3) Investigate the success of existing rates, assistance and energy efficiency programs to address affordability.

- Evaluate the enrollment, eligibility, and ability to reduce the energy burden or bill as a percentage of residential customers who qualify for existing programs. In other words, is the program or rate accessed or accessible by 1% or 50% of eligible customers, and does it provide a meaningful reduction in energy burden?
- Review existing funding sources, and ability of utility to work with other agencies and organizations to coordinate delivery of program objectives. Using a graduated scale of 10% to 100% of need, what would it take to successfully respond each level of need?
- Should the program be maintained or replaced? If maintained, should any changes be made to improve performance? If replaced, what, if anything, would replace it?

(4) Analyze the data related to load, energy consumption, cost, and revenue profiles of low-income customers and the residential class in general, cost-causation, impact to cost-of-service, potential for subsidization, impact on revenues and rates for all customers, program eligibility.

- What defines a “successful program?”
- What policies should be considered to implement affordability programs?
- Review affordability program funding mechanisms.
- Provide a list of program options for consideration.

The Commission does not intend this list of objectives to be exhaustive or limiting in any manner. The Commission will look to the stakeholder process to provide information, guidance, and recommendations on the existing programs, future programs, and the mechanisms for funding that would be needed.

Within 12 months of the date of the first workshop, the Company and the Public Staff should file a joint final report outlining the feedback and recommendations obtained in the collaborative, including any new programs, rate schedules, and funding mechanisms that develop from a consensus of stakeholders. The Commission will then allow for interested parties to file comments on the joint final report. Additionally, to the extent the parties recommend the design of new rates to offer to low-income customers, the parties should present those recommendations to the rate design study participants for consideration. Additionally, the Commission does not intend for the stakeholder processes for affordability and comprehensive rate design to be mutually exclusive or contingent upon the completion of either stakeholder process. If consensus is achieved on particular issues surrounding affordability, proposals may be brought forward for consideration as soon as practicable.

## EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 47

The evidence supporting this finding and conclusion is contained in the Company's verified Application and Form E-1; the testimony and exhibits of DEP witness Huber, Public Staff witness Floyd, and NCSEA witness J. Barnes; the Second Partial Stipulation; and the entire record in this proceeding.

NCSEA witness J. Barnes proposed that the Commission direct the Company to establish EV-specific rates – i.e., rate options that apply to separately metered EV charging loads – for both home and commercial charging applications. (Tr. vol. 14, 463.) He outlined a number of characteristics for a proposed residential EV-specific rate, as well as parameters for a proposed non-residential EV-specific rate, including a requirement that such a rate remain available to participants for at least 10 years following enrollment. (Id. at 465-66.) He recommended that: (1) the Commission direct DEP to file separate, targeted EV-specific tariffs dedicated to EV charging for both residential and non-residential customers within 60 days of a final order in this docket; (2) the Commission establish an investigatory docket to receive further information and permit further discussion of EV-specific rates; and (3) any EV-specific rates established remain available, at a minimum, until successor or replacement rates are adopted. (Id. at 463-64.)

Public Staff witness Floyd testified that he believes it is appropriate for the Company to begin working on new EV rate designs and to discuss those designs with stakeholders as they are considered and developed. (Tr. vol. 15, 958.) He noted that electric vehicles are a prime example of a use that both provides benefits to the grid and imposes costs on the utility that justifies the need for a broader rate study. (*See* id. at 969.) Therefore, he recommended that the Commission require DEP to develop and propose EV rate designs as part of the comprehensive rate design study recommended in his testimony. (Id. at 958.)

Company witness Huber testified that DEP understands that increasing the adoption of electric vehicles is a state policy goal that could provide significant system benefits. (Tr. vol. 11, 1159.) He added that the study of rate designs that facilitate the adoption of electric vehicles that provide system benefits for all customers will be a part of the comprehensive rate design study. (Id.) He explained that in the context of a comprehensive study, any new or altered offerings can be crafted to work in concert with the other components of DEP's rate designs. (Id.)

In § IV.G. of the Second Partial Stipulation, the Public Staff and the Company agreed that DEP will develop and propose EV rate designs as part of the rate design study outlined in the Second Partial Stipulation.

When asked by NCSEA's counsel whether the Commission should open a separate docket to examine EV-specific rates, Company witness Huber recommended that EV rates be considered in the broader context of the comprehensive rate design study to ensure that there was a consistent ideology as it pertains to rates. (Tr. vol. 11, 1211.) Moreover, during questioning by the counsel for NCSEA, it was clear that witness

Huber disagreed with several of witness J. Barnes' recommendations as to the specific parameters for EV rate design, or at the very least, thought that further study was warranted before a determination could be made. (*See, e.g.,* id. at 1212-14.)

While NCSEA witness J. Barnes suggested that further study would not be required prior to implementing his recommended EV-specific rates (Tr. vol. 14, 471), his responses to questioning from counsel for the Public Staff indicated that there could be ratemaking implications and impacts to other customers resulting from his proposal that he had not fully considered. (*See* id. at 529-33.)

The Commission agrees that EV rate design is an important issue that should be addressed by the Company. Indeed, the Commission in its November 24, 2020 Order Approving Electric Transportation Pilot, in Part in Docket Nos. E-2, Sub 1197, and E-7, Sub 1195, stated that it would be beneficial for DEC and DEP to offer experimental EV rates through a pilot to encourage or support EV use, but noted that the limited pilot should not negatively impact the proposed rate design study that would include consideration of EV rates.

Accordingly, the Commission finds that it would be premature for the Company to propose and implement the EV-specific rate designs recommended by NCSEA witness J. Barnes. Rather, this topic would benefit from additional discussion and study as there appear to be areas of disagreement. Further, the Commission agrees with DEP witness Huber and Public Staff witness Floyd that the comprehensive rate design study would be the most appropriate venue for discussions and development of EV rate designs. Accordingly, the Commission finds and concludes that the provision of the Second Partial Stipulation requiring DEP to develop and propose EV rate designs as part of the rate design study is reasonable and in the public interest. Therefore, DEP shall develop and propose EV rate designs as part of the rate design study outlined in the Second Partial Stipulation. The Commission's conclusions herein do not preclude the Company from proposing an EV rate developed through the rate design study before the entire study is complete. Further, the Commission encourages the parties to prioritize the evaluation of EV rates as part of the rate design study.

**EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 48**

The evidence supporting this finding and conclusion is contained in the Company's verified Application and Form E-1; the testimony and exhibits of DEP witness Pirro and Public Staff witness Floyd; the Second Partial Stipulation; and the entire record in this proceeding.

Rider MROP is the Company's tariff for Meter-Related Optional Programs, which are available upon request and on a voluntary basis to eligible customers, subject to the availability of appropriate metering and meter-related equipment. (Tr. vol. 11, 1129.) Residential customers served under Schedules RES, R-TOU, or R-TOUD and certain non-residential customers served under Schedule SGS may request to participate in the MRM option under Rider MROP. (Id.) Participating customers are provided metering equipment that does not utilize radio frequency (RF) communications to transmit data.

(Id.) The initial set-up fee for the MRM option is $170.00 and the monthly rate is $14.75. (Id.) However, the initial set-up fee and monthly rate are waived for customers providing certified medical documentation of their need to avoid RF emissions. (*See* id. at 1129-30.)

In his Direct Testimony, DEP witness Pirro explained that, as directed by the Commission in its January 23, 2019 Order issued in Docket No. E-2, Sub 834, the Company recalculated the costs associated with the MRM option. (Id. at 1110.) The Company's analysis supports an initial set up fee of $180.52 and a recurring monthly charge of $20.75. (Id.) However, this optional service has been in effect less than one year, and DEP believes adjusting the fees associated with manual meter reading is premature. (Id.) Accordingly, the Company is not proposing to adjust the MRM charges. (Id.)

Witness Floyd provided a summary of the deployment of AMI and subscriptions to the AMI opt-out option (i.e., MRM) in the Company's North Carolina service territory and noted that through August 2019, 1,105 residential and small general service customers have enrolled in the MRM option, with 667 successfully qualifying for the medical waiver of fees in Rider MROP. (Tr. vol. 15, 964-65.)

Witness Floyd testified that he reviewed the Company's confidential calculations of the rider fees as compared to those originally filed in E-2, Sub 834. (Id. at 965.) He noted that these calculations have been updated with new cost inputs related to this proceeding and new projections of MRM participants. (Id.) The updated inputs and the decrease in the number of likely participants result in a 6% increase in the one-time fee and a 41% increase in the monthly fee using the same methodology by which the original fees were calculated. (Id.)

Witness Floyd concluded that although the increased fees are cost justified, the Public Staff is not recommending a change at this time. (*See* id.) He testified that the Public Staff believes that any costs associated with the MRM option not recovered by the rider itself should be socialized and recovered from all customers; otherwise, the increased costs to a customer exercising the AMI opt-out option could become overly burdensome if that customer did not receive a waiver of MRM fees. (Id.) According to witness Floyd, the current charges provide a reasonable hurdle to discourage a customer from opting out of AMI metering without a legitimate reason. (Id. at 966.)

In his Rebuttal Testimony, witness Pirro indicated that the Company would prefer to wait and see if the next cost study produced prior to a rate case shows a similar pattern in terms of a significant increase in MRM rates before determining whether costs not covered by Rider MROP should be socialized and recovered from all customers. (Tr. vol. 11, 1130.)

In § IV.H. of the Second Partial Stipulation, DEP and the Public Staff agreed that any costs associated with the MRM option in Rider MROP not recovered by the rider itself should be socialized and recovered from all customers. In this provision, the Stipulating Parties also agree that the current charges provide a reasonable hurdle to discourage a customer from opting out of AMI metering without a legitimate reason. (*See* Second Partial Stipulation, § IV.H.) No other party addressed or took any position with respect to the costs associated with the MRM option in Rider MROP or this provision of the Second Partial Stipulation. The Commission agrees with witnesses Pirro and Floyd that no adjustment to the current MRM fees in Rider MROP is warranted at this time and finds and concludes that this provision of the Second Partial Stipulation, which provides for socialization of any costs associated with the MRM option not recovered by Rider MROP, is just and reasonable to all parties in light of the evidence presented.

**EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 49-53**

The evidence supporting these findings and conclusions is contained in the Company's verified Application and Form E-1; testimony and exhibits of DEP witnesses De May, Henderson, Oliver, and Turner; and Public Staff witnesses Dorgan, Metz, D. Williamson, and T. Williamson; the Second Partial Stipulation; and the entire record in this proceeding.

Public Staff witness Metz testified that the Public Staff and Commission must be able to fully evaluate the Company's decisions to make significant capital investments in its electric system, including the consideration of alternative investments considered and not chosen. Witness Metz recommended that, to improve efficiency in requesting and reviewing project specific documentation going forward, the Commission order the Company to begin collaboration with the Public Staff within three months following conclusion of the rate case to clarify expectations for project evaluation and selection and document creation and retention. (Tr. vol. 15, 829.) Witness Metz also recommended that the Company have an independent third party perform a review and audit of M&S inventory for at least one nuclear station, one fossil station, and one hydro station by the time of its next general rate case filing, or within the next three years, whichever is sooner, and establish a long term schedule for a continuous independent audit cycle (e.g., a three to five year rotational cycle.) (Id. at 844-45.)

Additionally, Public Staff witness Dorgan noted that in the process of the Public Staff's investigation, the Company appeared to have a backlog in unitizing plant projects to the appropriate plant account for depreciation. (Tr. vol. 15, 732-33.) Witness Dorgan further testified that, according to the Public Staff, the unitization of plant occurs within three to nine months upon completion of plant, with larger plants comprising the longer time period to unitize. (Id. at 733.) Witness Dorgan testified that the Company stated it was working with an accounting firm to develop a plan for both the generation and power delivery plant categories to address the backlog. (Id.) Accordingly, he recommended that the Company file with the Commission its plans to reduce the backlog, within 90 days of the Commission's Order in this case, and implement the proposed plans and procedures to decrease the lag in unitization. (Id.)

Company witnesses Henderson and Turner testified on rebuttal that DEP does not oppose witness Metz's recommendations with respect to project collaboration and auditing. (Tr. vol. 11, 151-53; Tr. vol. 11, 986-87.) Regarding the audit recommendation, witnesses Henderson and Turner stated that the Company should utilize Duke Energy's own independent Corporate Audit Services department to meet this recommendation. They explained that the Corporate Audit Services department is required to maintain independence and objectivity in its work, and that it reports to the Audit Committee of the Board of Directors and to Duke Energy's senior ethics and compliance officer. They stated that the department is authorized to have full, unrestricted access to all Duke Energy functions, records, property, and personnel, and to obtain the necessary assistance of personnel in audited units, as well as other specialized services from within or outside the Duke Energy enterprise. (Id.)

Public Staff witnesses D. Williamson and T. Williamson testified that the Commission should direct the Company to begin filing semi-annual vegetation management reports in the same manner as DEC files under the Commission's directives in Docket Nos. E-7, Subs 1146 and 1182. (Id. at 354, 362.) They explained that there have not been any changes to the Vegetation Management compliance filing since the Company's March 22, 2016 filing, which are required to be filed with the Commission in Docket No. E-2, Sub 1010. (Id. at 358.)

Finally, Public Staff witnesses T. Williamson and D. Williamson testified that in addition to the two reliability indices that electric utilities have traditionally used to evaluate its reliability performance, SAIDI and SAIFI, the Company has begun to utilize the CEMI-6 index over the last few years. (Tr. vol. 15, 386-87.) Witnesses D. Williamson and T. Williamson stated that this scoring metric represents the percentage of customers experiencing six or more sustained interruptions in a 12-month period and is a good indicator of the worst performing circuits, which would allow for better targeting of resources to the most critical needs. (Id.) In accordance with Commission Rule R8-40A(d), the Company files twelve-month trailing reliability scores for both SAIDI and SAIFI, on a quarterly basis in Docket No. E-100, Sub 138A. (Id.) Witnesses D. Williamson and T. Williamson stated that the Company does not report CEMI-6 scores and the individual categories that make up the total SAIDI and SAIFI scores to the Commission. (Id.) Witnesses D. Williamson and T. Williamson recommended that if the Company is going to utilize additional indices to analyze its level of reliability, the Commission should require the Company to update the filing requirements of Sub 138A to include these new indices. (Id.) Additionally, witnesses D. Williamson and T. Williamson recommended that the Commission require the Company to file the full breakdown of individual categories for all index calculations, so that the Public Staff and Commission are aware of the drivers of both positive and negative contributors to reliability. (Id.)

Section IV.I. of the Second Partial Stipulation provides that the Company agrees to work with the Public Staff on document retention, project reporting, and other reasonably applicable matters to better assist the Public Staff in future audits of plant within 90 days after the Commission issues its final order in this rate case. Section IV.J. of the Second Partial Stipulation provides that the Company agrees to conduct an independent review/audit of its M&S inventory to be performed by the Company's Internal Audit Services, and that the terms of the audit should, at a minimum, meet those recommended in the Direct Testimony of Public Staff witness Metz. Section IV.K. of the Second Partial Stipulation provides that the Company and the Public Staff agree to schedule a meeting to discuss the Company's plant unitization policies and reach agreement on reporting obligations. Section IV.L. of the Second Partial Stipulation provides that DEP and the Public Staff agree that the Commission should require the Company to file an annual report of its Vegetation Management performance similar to the DEC's report format filed in Docket Nos. E-7, Sub 1146 and 1182. Section IV.M. provides that both DEP and the Public Staff agree that the Commission should update the requirements for service reliability index reporting in Docket No. E-100, Sub 138A to include new indices utilized by the North Carolina electric utilities along with the support data for all indices.

No other party offered any evidence addressing these issues. Accordingly, the Commission finds and concludes it to be just and reasonable to all parties in light of all the evidence presented, for purposes of this proceeding, that the Company work with the Public Staff on document retention, project reporting, and other reasonably applicable matters within 90 days after the Commission issues its final order in this rate case. The Commission also finds and concludes that the Company shall conduct an independent review/audit of its M&S inventory to be performed by the Company's internal Corporate Audit Services department, and that the terms of the audit should, at a minimum, meet those recommended in the Direct Testimony of Public Staff witness Metz. The Commission directs the Company and the Public Staff to meet to discuss the Company's plant unitization policies and reach agreement on reporting obligations. The Commission also directs the Company to file an annual report of its Vegetation Management performance similar to the DEC's report format filed in Docket Nos. E-7, Sub 1146 and 1182. Finally, the Commission agrees to update the filing requirements for service reliability index reporting in Docket No. E-100, Sub 138A to include the reporting of the individual categories that make up the total System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) and include the Customers Experiencing Multiple Interruptions (CEMI-6) index.

## EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 54

The evidence supporting this finding and conclusion is contained in the verified Application and Form E-1 of DEP, the testimony and exhibits of DEP witness Hatcher; Public Staff witnesses D. Williamson and T. Williamson; the Second Partial Stipulation, and the entire record in this proceeding.

DEP witness Hatcher provided testimony relating to the Company's service quality and ways in which the Company is working to enhance the customer experience. (Tr. vol. 11, 840, 858.) Witness Hatcher noted that customer satisfaction (CSAT) is a key focus area for DEP. (Id. at 841.) He explained that using data and analytics, the Company is executing a long-term, customer-focused strategy designed to deliver greater value to its customers. (Id.) The Company's CSAT program includes both national benchmarking studies and proprietary transaction and relationship CSAT studies. (Id. at 849-50.) Witness Hatcher explained that the Company analyzes the results from these studies in vigorous monthly data review sessions, with findings driving improvements to processes, technology and behaviors – all to continuously improve the customer experience. (Id. at

850.) Specifically, he explained that DEP measures overall customer satisfaction and perceptions about the Company via its proprietary relationship survey, the "Customer Experience Monitor Survey" (CX Monitor Survey). (Id. at 841.) Surveys are taken from residential, small/medium business customers, and large business customers, to measure customer loyalty and the ongoing perceptions of the customer experience. (Id. at 850.) The CX Monitor Survey data is used to measure the Company's Net Promoter Score (NPS), a top metric used by companies across industries to measure customer advocacy. (Id. at 841-42.) He indicated that, since 2018, the Company has seen a significant increase in its Net Promoter Score (NPS), with some of the Company's highest NPS scores occurring between the months of September and December of 2018 was severely impacted by major storms. (Id. at 851.)

As explained by witness Hatcher, in addition to its relationship study, DEP utilizes Fastrack 2.0, the Company's proprietary, post-transaction measurement program, to measure overall customer satisfaction with the Company's operational performance (i.e., responding to and resolving customer service requests). (Id.) Fastrack 2.0 was intentionally designed to complement the CX Monitor survey and provide greater insight into experiences that matter to its customers and near real time feedback to our front line, customer-facing employees. (Id. at 851-52.) The survey questions cover the customer's experience about completed field work such as requests to begin and end electric service, outdoor lighting repairs and new construction service requests. (Id. at 852.) Witness Hatcher explained that analysis of these ratings helps to identify specific service strengths and opportunities that drive overall satisfaction and to provide guidance for the implementation of process and performance improvement efforts. (Id.) Through 2018, roughly 85% of DEP residential customers expressed high levels of satisfaction with key service interactions: Start/Transfer Service, Outage/Restoration, and Street Light Repair. (Id.) Witness Hatcher indicated that the Company has also implemented 'Reflect', a post-contact survey that will gather customers' immediate feedback after contacting Duke Energy by web, text, call to automated system or live agent. (Id.) Per Witness Hatcher, as data is collected, this tool provides critical feedback to improve all channels customers use to interact with Duke Energy. (Id.)

Witness Hatcher further explained that the Company is working hard across its business to further improve the customer experience by making strategic, value-based investments for the benefit of customers. (Id. at 858.) Two examples witness Hatcher provided are enhancements to the Company's integrated voice response (IVR) system and the deployment of Customer Connect. (Id.) Finally, witness Hatcher explained that the Company's efforts to improve customer service based on customer expectation and feedback is why the Company is seeking approval to eliminate convenience fees for credit and debit card payments made by residential customers (Id. at 862-63.) and to extend the due date for non-residential to pay their bills from 15 days to 25 days to match the current requirement for residential customers. (Id.)

Public Staff witnesses T. Williamson and D. Williamson also provided joint testimony regarding DEP's quality of service. (Tr. vol. 15, 356-58.) In evaluating the Company's overall quality of service, they reviewed the System Average Interruption

Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) reliability scores filed by DEP with the Commission in Docket No. E-100, Sub 138A; informal complaints and inquiries from DEP customers received by the Public Staff's Consumer Services Division; the Consumer Statements of Position filed in Docket No. E-2, Sub 1219CS; and the Public Staff's own interactions with DEP and its customers. (Id.) They noted that for the period 2010 through 2019, Company reports show the non-Major Event Days for the SAIDI index have been slowly and moderately worsening over time but staying stable for the SAIFI index. (Id.) While witnesses D. Williamson and T. Williamson concluded that the quality of service provided by DEP to its North Carolina retail customers is adequate, DEP and the Public Staff agreed in § IV.N. of the Second Partial Stipulation that the Company's quality of service is good.

No intervenor offered any evidence contradicting the agreement in the Second Partial Stipulation that the quality of DEP's service is good. Therefore, consistent with § IV.N. of the Second Partial Stipulation, the Commission finds and concludes that the overall quality of electric service provided by DEP is good.

**EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 55**

The evidence supporting these findings and conclusions is contained in the Second Partial Stipulation, the verified Application and Form E-1 of DEP, the testimony and exhibits of DEP witnesses McGee and Smith; Public Staff witnesses Metz and Maness, and the entire record in this proceeding.

In her Direct Testimony, Company witness McGee supported the fuel component of proposed base rates for all customer classes and the fuel pro forma adjustments to the test year operating expenses contained in Smith Exhibit 1. (Tr. vol. 11, 50-51.) Witness McGee proposed to use the total prospective fuel and fuel-related cost factors approved in Docket No. E-2, Sub 1173, and implemented December 1, 2018. (Id. at 50.) Witness McGee explained that these factors represented the fuel-related amounts DEP expected to collect from its North Carolina retail customers through its approved rates in the next billing period, and that DEP's intent in using the fuel-related factors that represent expected future rates as a component of its proposed new rates was to make it clear that the Company is requesting a rate increase that relates to non-fuel revenues only. (Id. at 50-51.)

In his Direct Testimony, Public Staff witness Metz testified that the base fuel factor in DEP's application was appropriate for the Company's initial filing as it reflected the rates in effect at the time of the filing. Witness Metz stated that since the approved base fuel rate in Docket No. E-2, Sub 1204, DEP's previous annual fuel proceeding, went into effect December 1, 2019, the Sub 1204 rates would have to be refined in future Public Staff filings in this case. Witness Metz also stated that a future update would need to reflect the refinement of catalyst depreciation being shifted from fuel rates to base rates. (Tr. vol. 15, 852-53.)

In her supplemental testimony, witness McGee supported a revised base fuel factor to conform to the fuel rates approved in Sub 1204, and updated DEP's fuel costs based on revised weather and customer growth adjustments. (Tr. vol. 11, 55-56.) In her supplemental testimony, Company witness Smith presented an adjustment to update fuel costs to the Sub 1204 approved rates, and explained that the adjustment was also revised to reflect removal of catalyst depreciation from fuel clause recovery. Witness Smith explained that after discussion with the Public Staff, DEP concluded that recovery of this expense in base rates is the most reasonable cost recovery approach. (Tr. vol. 13, 172.)

The Company filed its subsequent fuel factor adjustment case in Docket No. E-2, Sub 1250 on June 9, 2020. Section IV.O. of the Second Partial Stipulation provided that should a final Commission order be issued in DEP's then ongoing annual fuel rider proceeding, Docket No. E-2, Sub 1250, prior to the date the proposed orders are due in this general rate case proceeding, the total of the approved base fuel and fuel related cost factors, by customer class, will be the sum of the respective base fuel and fuel-related cost factors set in Docket No. E-2, Sub 1142 and the annual non-EMF fuel and fuel-related cost riders approved by the Commission in Sub 1250. Company witness Smith (Tr. vol. 13, 260-61) and Public Staff witness Maness (Tr. vol. 16, 34) supported the provision for the total approved base fuel and fuel related cost factors through their testimony in support of the Second Partial Stipulation.

The Commission issued a final order in the Sub 1250 fuel rider proceeding on November 30, 2020. In the Sub 1250 order, the Commission concluded that, effective for service rendered on and after December 1, 2020, DEP shall adjust the base fuel and fuel-related costs in its North Carolina retail rates as approved in Sub 1142 of 1.993 cents/kWh, 2.088 cents/kWh, 2.431 cents/kWh, 2.253 cents/kWh, and 0.596 cents/kWh for the Residential, Small General Service, Medium General Service, Large General Service, and Lighting classes, respectively (all excluding regulatory fee), by amounts equal to 0.087 cents/kWh, 0.038 cents/kWh, (0.203) cents/kWh, (0.049 cents/kWh), and 0.796 cents/kWh, respectively (also excluding regulatory fee). This results in total non-EMF fuel and fuel-related factors of 2.080 cents/kWh for the Residential class, 2.126 cents/kWh for the Small General Service class, 2.228 cents/kWh for the Medium General Service class, 2.204 cents/kWh for the Large General Service class, and 1.392 cents/kWh for the Lighting class, excluding the regulatory fee. Pursuant to § IV.O. of the Second Partial Stipulation, these total non-EMF fuel and fuel-related cost factors would become the base fuel and fuel-related cost factors approved in this general rate case.

According to witness McGee, the Company will continue to bill customers the fuel rates authorized by the Commission in its annual fuel proceedings. (Tr. vol. 11, 52, 57.) As such, there will be no change in customers' bills as a result of including these fuel cost factors in the proposed base rates. (Id.)

No intervenor offered any evidence contesting the testimony of Company and Public Staff witnesses that support the base fuel and fuel-related cost factors therein or the Second Stipulation provision for the Company's base fuel and fuel related cost factors. Accordingly, the Commission finds and concludes it to be just and reasonable to all parties in light of all the evidence presented, for purposes of this proceeding, that the approved base fuel and fuel related cost factors, by customer class, will be the sum of the respective base fuel and fuel-related cost factors set in Docket No. E-2, Sub 1142 and the annual non-EMF fuel and fuel-related cost riders approved by the Commission in Sub 1250, namely 2.080 cents/kWh for the Residential class, 2.126 cents/kWh for the Small General Service class, 2.228 cents/kWh for the Medium General Service class, 2.204 cents/kWh for the Large General Service class, and 1.392 cents/kWh for the Lighting class, excluding the regulatory fee. Consistent with this change in the base factors, the Sub 1250 prospective per class rider amounts of 0.087 cents/kWh, 0.038 cents/kWh, (0.203) cents/kWh, (0.049 cents/kWh), and 0.796 cents/kWh will be reset to zero as of the effective date of the rates set in this proceeding.

## EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 56

The evidence supporting this finding and conclusion is contained in DEP's verified Application and Form E-1, the testimony and exhibits of DEP witness De May, the Second Partial Stipulation, and the entire record in this proceeding.

DEP witness De May testified that DEP is committed to helping customers who struggle to pay for basic needs with programs and options to assist them during times of financial hardship. (Tr. vol. 11, 756.) He further testified that the assistance programs that DEP offers, such as the Energy Neighbor Fund, have helped many of the Company's customers pay their home energy bills. (Id.)

As part of the Second Partial Stipulation, the Company agreed to make an annual $2.5 million shareholder contribution to the Energy Neighbor Fund in 2021, and 2022, for a total contribution of $5 million. (Second Partial Stipulation § IV.P.) No intervenors took issue with this provision of the Second Partial Stipulation. Accordingly, the Commission finds and concludes that this provision is just and reasonable to all parties in light of all the evidence presented.

## EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 57

The evidence supporting this finding and conclusion is contained in the verified Application and Form E-1 of DEP, the testimony and exhibits of DEP witnesses Schneider and Hatcher; Public Staff witness Floyd; NCJC et al. witness Wallach; and the entire record in this proceeding.

Company witness Schneider described the Company's implementation of AMI technology in the DEP North Carolina service territory. Witness Schneider explained that AMI meters, often referred to as "smart meters," have advanced features and capabilities beyond traditional electricity meters, including the capability for two-way communications, interval usage measurement, tamper detection, voltage and reactive power measurement, net metering capability, and an internal remotely operable disconnect switch. (Tr. vol. 11, 946-47.) Witness Schneider explained how AMI technology also provides greater convenience to customers, including through the Pick Your Due Date option program, which allows eligible customers to select their desired billing due date. (Id. at 948-49.) Witness Schneider stated that AMI allows customers more control over their energy usage, including through the Usage Alerts program, which alerts eligible customers at the midpoint of their billing cycle of their accumulated charges and a forecast of their month-end bill. Witness Schneider noted that more than 399,000 DEP customers are enrolled in Usage Alerts. (Id. at 949-50.) Witness Schneider also described how AMI offers increased transparency and communication with customers, through the Duke Energy customer portal and a new program through which customers would be able to download usage data in a format consistent with the Green Button "Download My Data" standard. Witness Schneider also noted the Commission's approval in Docket Nos. E-7, Sub 1209 and E-2, Sub 1213 of the Company's joint application with DEC for a smart meter usage application pilot to provide customers access to real-time energy usage on their smart devices. (Id. at 950-51.) Witness Schneider explained how the Company is utilizing AMI to increase communications with customers during storm outages and restoration. (Id. at 951-52.)

Witness Schneider stated that as of August 2019, DEP installed about 723,000 smart meters in its North Carolina service territory, and planned to continue implementation through early 2021 for the remaining approximately 694,000 DEP meters. (Id. at 947.) Witness Schneider noted that since DEP's last rate case through June 30, 2019, the Company invested $158.3 million on new AMI meters across the system in North and South Carolina, and that the Company projected to invest an additional $53.3 million across the system between July 1, 2019 through February 29, 2020. (Id. at 948.)

Witness Schneider testified that the Commission approved DEP's request to revise the Meter Related Optional Programs Rider MROP to include a Manually Read Metering option on January 23, 2019. Witness Schneider stated that the Company began enrolling customers in the opt-out program in April 2019, and had enrolled 0.16% of its customers through August 2019. (Id. at 947-48.)

Public Staff witness Floyd described his investigation of the status of the Company's deployment of AMI technology and subscriptions to the AMI opt-out option permitted by Rider MROP. (Tr. vol. 15, 963-67.) Witness Floyd stated that the Company is close to completing its deployment of smart meters, which has allowed DEP to reduce its connection and reconnection charges. (Id. at 1009.) Witness Floyd did not oppose the Company's request for recovery of AMI meter costs in this case.

NCJC et al. witness Wallach did not take a position on the Company's recovery of AMI costs in this case, but contended in the context of discussing the basic customer charge that while all residential customers will contribute the same amount for recovery of AMI costs, all residential customers probably will not share equally in the benefits. (Tr. vol. 14, at 441-42.)

At the hearing, Company witness Hatcher testified in response to questioning by counsel for the AGO and redirect from DEP counsel regarding the prudence of the Company's investments in AMI and the benefits of AMI technology, including providing customers more insight and control over their energy usage, opportunities to pick due dates and to receive usage alerts, and benefits related to storm response. (Tr. vol. 11, 875-83, 905-07.)

**Discussion and Conclusions**

In light of the evidence presented, the Commission finds and concludes that the costs included in this case associated with the Company's AMI project were reasonably and prudently incurred and should properly be included in the Company's rate base in this proceeding. The AMI project costs included in this case represent the costs incurred to significantly advance DEP's AMI meter deployment through its North Carolina service territory. Company witness Schneider presented substantial evidence regarding the progress the Company has made in that regard, the value of AMI to the Company's customers, and the programs that AMI technology has permitted DEP to create. Company witness Hatcher's live testimony further supported the costs incurred for the AMI project.

The Public Staff did not oppose the Company's recovery of AMI project costs in this case, and acknowledged the value of AMI technology for allowing the Company to reduce its connection and reconnection charges. The Public Staff's testimony regarding Rider MROP is addressed in the Evidence and Conclusions for Finding of Fact No. 48. NCJC et al. also did not oppose DEP's recovery of AMI project costs in this case, and the basic customer charge is addressed in the Evidence and Conclusions for Findings of Fact Nos. 41-44.

In *State ex rel. Utils. Comm'n v. Intervenor Residents*, 305 N.C. 62, 75-77, 286, S.E.2d 770, 778-79 (1982), the North Carolina Supreme Court held that the uncontested evidence of a public utility regarding the reasonableness of its costs can be accepted by the Commission as satisfying the utility's burden of proof on the question of cost recovery. As a result, the Commission finds and concludes that DEP has met its burden of showing that its AMI costs were reasonable. The Commission finds and concludes that the evidence received in this proceeding adequately supports the Company's deployment of AMI meters, and demonstrates the many benefits customers receive and will continue to receive from DEP's AMI program. The Commission therefore finds and concludes that the Company's requested recovery of costs associated with its AMI project is just and reasonable to all parties in light of the evidence presented.

**EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 58**

The evidence supporting this finding and conclusion is contained in the verified Application and Form E-1 of DEP, the testimony and exhibits of DEP witness Smith and the entire record in this proceeding.

In its Application and the direct testimony of DEP witness Smith, the Company requested an accounting order to establish a regulatory asset to defer the unrecovered net book value of its Roxboro Wastewater Treatment Plant at the time of the plant's anticipated early retirement in 2021. (Application at 19, Tr. vol. 13, 165.) The Company requested to amortize the costs, the remaining net book value of the plant at the time of its retirement, at the level presented in the proposed depreciation study until rates can be adjusted in the Company's next rate case. (Id.) The Company also requested permission to defer to this regulatory asset any costs related to obsolete inventory, net of salvage, at the time of retirement. (Id.)

No party contested the Company's request for an accounting order. The Commission finds that the Company's request for an accounting order for the Roxboro Wastewater Treatment Plant is reasonable and approved and the Company is authorized to amortize the costs at the level approved by the Commission in this proceeding for the applicable depreciable plant in service accounts, and subject to further changes in the Company's next general rate case.

IT IS, THEREFORE, ORDERED as follows:

1. That the Public Staff Partial Stipulations filed by DEP and the Public Staff are hereby approved in their entirety;

2. That the Company's revised Lead-Lag Study filed as Angers Supplemental Ex. 3. is approved for purposes of calculating the cash working capital amounts to be included in the revised rates;

3. That DEP's request for an accounting order for approval to establish a regulatory asset to defer the North Carolina retail portion of incremental O&M expenses associated with the Company's severance program, as modified by the terms of the First Partial Stipulation, shall be, and is hereby approved;

4. That the Company's Storm Costs are reasonable and prudent and that the terms of the Public Staff Partial Stipulations regarding the Storm Costs are approved;

5. That per the terms of the First Partial Stipulation, a Storm Cost Recovery Rider shall be established and shall initially be set to collect $0;

6. That DEP's request to defer the Storm Costs in a regulatory asset account until the date storm recovery bonds are issued pursuant to an approved financing order in accordance with N.C.G.S. § 62-172, or the Company seeks recovery of the storm costs through an alternative method of cost recovery, is hereby approved;

7. That the Company's request to defer the costs related to the Asheville CC Project, as modified by the terms of the First Partial Stipulation, is approved;

8. That DEP shall reduce the annual funding for the Company's Nuclear Decommissioning Trust Fund by $8.7 million;

9. That the proposed RAL-1 Rider is approved and shall be implemented;

10. That the proposed revision to the existing EDIT-1 Rider is approved and shall be implemented;

11. That the proposed EDIT Rider,[31] as modified by the terms of the Public Staff Partial Stipulations, is approved and shall be implemented and that the protected federal EDIT will be removed from the EDIT Rider and returned to customers through base rates;

12. That DEP's request to establish a regulatory asset for deferral of incremental capital costs (return, property tax, and depreciation) related to plant in service and incremental installation expenses (offset by incremental operating benefits) for plant placed in service between June 1, 2020 and December 31, 2022, and a return on the deferred balance, for the eight GIP programs specified in § III.C. of the Second Partial Stipulation, for cost recovery consideration in a future rate case shall be, and is hereby approved;

13. That the Public Staff and the Company shall work together to establish biannual reporting requirements to track the deferred GIP expenditures per the terms of the Second Partial Stipulation;

14. That within 90 days of the date of this Order, the Company shall convene a collaborative to hold workshops with the Public Staff and interested stakeholders to address the affordability of electric service for low income customers as provided herein;

15. That within 12 months of the date of the first workshop, the Company and the Public Staff shall file a joint final report with the Commission outlining the feedback and recommendations obtained in the collaborative, including any new programs, rate schedules, and funding mechanisms that develop from a consensus of stakeholders;

16. That the aspects of rate design agreed upon in the Second Partial Stipulation are approved and shall be implemented;

17. That the proposed amendments to DEP's Service Regulations are hereby approved;

18. That the Company's proposed modifications of certain outdoor lighting fees and schedules are approved;

19. That within 30 days of this Order, parties that wish to participate in the Comprehensive Rate Design Study shall file for the Commission's consideration a list of proposed topics, objectives, and issues that should be considered in the study. Parties are encouraged to work jointly to the extent possible. The Commission will consider these filings, and will issue a subsequent order detailing the objectives, timeframe, and subject matter of the comprehensive rate study, including the topics listed in the Second Partial

[31] The proposed EDIT rider was originally designated "EDIT-2." Because the Company has already implemented an EDIT-2 Rider as part of its temporary rates, the new EDIT rider approved herein will be designated EDIT-3 (which reflects the two-year levelized rider resulting from the Public Staff Partial Stipulations) and EDIT-4 (which reflects the five-year levelized rider resulting from the Public Staff Partial Stipulations).

Stipulation. The Company shall file a final report, including a comprehensive roadmap and timeline for proposing new rate designs and identifying areas for additional study, within 12 months of the Commission's subsequent order discussed above, unless a different timeframe is set in that subsequent order;

20. That no adjustment to the current MRM fees in Rider MROP shall be made at this time and that any costs associated with the MRM option in Rider MROP not recovered by the rider itself shall be socialized;

21. That the Company shall conduct an independent review and audit of its M&S inventory, to be performed by the Company's internal Corporate Audit Services department, and as further described in the Second Partial Stipulation;

22. That within 90 days of this Order, the Company and the Public Staff shall begin collaborations on document retention, project reporting, and other reasonably applicable matters to better assist the Public Staff in future audits of plant;

23. That the Company and the Public Staff shall meet to discuss the Company's plant unitization policies and reporting obligations;

24. That the Company shall file an annual report of its Vegetation Management performance similar to the DEC's report format provided in Docket Nos. E-7, Subs 1146 and 1182;

25. That per the terms of the Second Partial Stipulation, the approved total non-EMF fuel and fuel-related cost factors by customer class (excluding the regulatory fee), are as follows: 2.080 cents/kWh for the Residential class, 2.126 cents/kWh for the Small General Service class, 2.228 cents/kWh for the Medium General Service class, 2.204 cents/kWh for the Large General Service class, and 1.392 cents/kWh for the Lighting class.

26. That the Shareholder Contribution to the Energy Neighbor Fund as agreed to by DEP and the Public Staff in the Second Partial Stipulation is approved;

27. That DEP's request for an accounting order to establish a regulatory asset to defer the remaining net book value of the Roxboro Wastewater Treatment Plant, at the time of the plant's anticipated early retirement in 2021, and costs related to obsolete inventory, net of salvage, at the time of retirement is approved and the Company may continue amortizing the costs at the level approved by the Commission in this proceeding for the applicable plant in service accounts, and subject to further changes in the Company's next general rate case;

**CERTIFICATE OF SERVICE**

DOCKET NO. E-2, SUB 1219
DOCKET NO. E-2, SUB 1193

I hereby certify that a copy of the foregoing **JOINT PROPOSED ORDER OF DUKE ENERGY PROGRESS, LLC AND THE PUBLIC STAFF** was served electronically or by depositing a copy in United States Mail, first class postage prepaid, properly addressed to the parties of record.

This the 4th day of December 2020.

*/s/ Camal O. Robinson*
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