STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-2, SUB 1300

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Duke Energy Progress, LLC	)	ORDER ACCEPTING
For Adjustment of Rates and Charges	)	STIPULATIONS, GRANTING
Applicable to Electric Service in North Carolina	)	PARTIAL RATE INCREASE, AND
and Performance Based Regulation	)	REQUIRING PUBLIC NOTICE

HEARD: Monday, March 6, 2023, at 7:00 p.m., Haywood County Courthouse, Courtroom 2-A, 285 N. Main Street, Waynesville, North Carolina

Monday, March 13, 2023, at 7:00 p.m., Person County Courthouse, Superior Courtroom, 105 S. Main Street, Roxboro, North Carolina

Tuesday, March 14, 2023, at 7:00 p.m., Commission Hearing Room 2115, Dobbs Building, 430 N. Salisbury Street, Raleigh, North Carolina

Monday, March 20, 2023, at 7:00 p.m., Greene County Courthouse, 301 N. Green Street, Courtroom 1, Snow Hill, North Carolina

Tuesday, March 21, 2023, at 7:00 p.m., Robeson County Courthouse, Courtroom B, 500 N. Elm Street, Lumberton, North Carolina

Thursday, April 20, 2023, at 6:00 p.m. via Videoconference, Commission Hearing Room 2115, Dobbs Building, 430 N. Salisbury Street, Raleigh, North Carolina

Thursday, May 4, 2023, at 2:00 p.m., Commission Hearing Room 2115, Dobbs Building, 430 N. Salisbury Street, Raleigh, North Carolina

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

APPEARANCES:

For Duke Energy Progress, LLC (DEP):

Jack E. Jirak, Deputy General Counsel, Kendrick C. Fentress, Associate General Counsel, Duke Energy Corporation, 410 South Wilmington Street, Raleigh, North Carolina 27602

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

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

Kiran H. Mehta, Partner and Melinda L. McGrath, Partner, Troutman Pepper Hamilton Sanders LLP, 301 South College Street, Suite 3400 Charlotte, North Carolina 28202

Brandon F. Marzo, Partner, Melissa Oellerich Butler, Associate, and Joshua Warren Combs, Associate, Troutman Pepper Hamilton Sanders LLP, 600 Peachtree Street, NE, Suite 3000, Atlanta, Georgia 30308

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

Christina D. Cress and Douglas E. Conant, Bailey & Dixon, LLP, 434 Fayetteville Street, Suite 2500, Post Office Box 1351, Raleigh, North Carolina 27602

Chris S. Edwards, Ward and Smith, P.A., Post Office Box 7068, Wilmington, North Carolina 28406

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

Marcus W. Trathen, Craig D. Schauer, Matthew Tynan, and Christopher B. Dodd, Brooks, Pierce McLendon, Humphrey & Leonard, LLP, 150 Fayetteville Street, Suite 1700, Raleigh, North Carolina 27601

For North Carolina Sustainable Energy Association (NCSEA):

Taylor M. Jones and Ethan Blumenthal, North Carolina Sustainable Energy Association, 4800 Six Forks Road, Suite 300, Raleigh, North Carolina 27609

For North Carolina League of Municipalities (NCLM):

Ben Snowden and Jonathan L. Taggart, Fox Rothschild LLP, 434 Fayetteville Street, Suite 2800, Raleigh, North Carolina, 27601

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

David L. Neal, Munashe Magarira, and Thomas Gooding, Southern Environmental Law Center, 601 West Rosemary Street, Suite 220, Chapel Hill, North Carolina 27516

For the United States Department of Defense and all other Federal Executive Agencies (DoD-FEA):

Kyle J. Smith, General Attorney, 9275 Gunston Road, Fort Belvoir, Virginia 22060

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., 3101 Glenwood Avenue, Suite 200, Raleigh, North Carolina 27612

For Kroger Co. and Harris Teeter LLC, a Division of Kroger Co. (Kroger Co. and 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 Carolinas Clean Energy Business Association (CCEBA):

John D. Burns, General Counsel, 811 Ninth Street, Suite 120-158, Durham, North Carolina 27705

For Fayetteville Public Works Commission (FPWC):

James P. West and Dustin K. Doty, Fayetteville Public Works Commission, 955 Old Wilmington Road, Fayetteville, North Carolina 28302

For Sierra Club:

Catherine Cralle Jones and Andrea C. Bonvecchio, Law Offices of F. Bryan Brice, Jr., 130 South Salisbury Street, Raleigh, North Carolina 27601

Justin Somelofske, The Sierra Club, 50 F. Street, Northwest, Washington, District of Columbia 20001

For Haywood Electric Membership Corporation (Haywood EMC):

Christina D. Cress, Bailey & Dixon, LLP, 434 Fayetteville Street, Suite 2500, Post Office Box 1351, Raleigh, North Carolina 27602

For the Using and Consuming Public:

Tirrill E. Moore, Assistant Attorney General, North Carolina Department of Justice, 114 West Edenton Street, Raleigh, North Carolina 27603

Lucy E. Edmondson, Robert B. Josey, Nadia L. Luhr, Anne M. Keyworth, William S.F. Freeman, William E.H. Creech, and Thomas Felling, the Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699

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BY THE COMMISSION: On June 8, 2022, pursuant to Rule R1-17B(c) of the Rules of Practice and Procedure of the North Carolina Utilities Commission, DEP filed its Request to Initiate Technical Conference Regarding the Projected Transmission and Distribution Projects to be Included in a Performance-Based Regulation (PBR) Application.

On September 6, 2022, pursuant to Commission Rule R1-17(a), DEP filed notice of its intent to file a general rate case application that includes a performance-based regulation application as authorized under N.C. Gen. Stat. § 62-133.16.

On October 6, 2022, DEP filed its Application to Adjust Retail Rates and for Performance-Based Regulations, and Request for an Accounting Order (the Application), supported by a Rate Case Information Report Commission Form E-1 (Form E-1), and direct testimony and exhibits. As required by N.C.G.S. § 62-133.16 and Commission Rule R1-17B, DEP's PBR Application included a residential decoupling rate-making mechanism, performance incentive mechanisms (PIMs) and tracking metrics, and a Multiyear Rate Plan (MYRP), including an earnings sharing mechanism (ESM).

PROCEDURAL HISTORY AND JURISDICTION

Procedural History

The following is a summary of the most pertinent filings by DEP, the parties, and procedural orders issued by the Commission.

Petitions to intervene were filed by CIGFUR on June 13, 2022, and CUCA on June 16, 2022. The Commission entered orders granting the petitions to CIGFUR on June 15, 2022, and CUCA on June 22, 2022.

On June 15, 2022, the Commission issued an Order Scheduling and Setting Procedures for the Technical Conference. The Commission's Order established that the Technical Conference would be held in person on July 25, 2022, that DEP should make its Transmission and Distribution (T&D) Information Filing by July 15, 2022, and that parties would be allowed to file written comments on DEP's T&D Information Filing on or before July 25, 2022.

Notice of intervention and of intent to participate in the Technical Conference was filed by the Attorney General's Office (AGO) on June 29, 2022.

Petitions to intervene and notices of intent to participate in the Technical Conference were filed by North Carolina Electric Membership Corporation (NCEMC) on June 30, 2022; NCJC, NCHC, SACE, and NCSEA on July 5, 2022; Vote Solar on July 11, 2022; and NRDC on July 11, 2022. The Commission entered orders granting the petitions of NCJC, NCHC, SACE, and NCSEA on July 7, 2022; Vote Solar on July 12, 2022; and NRDC on July 13, 2022. The Commission denied NCEMC's petition to intervene and granted NCEMC amicus curiae status on July 11, 2022.

CIGFUR also filed a notice of intent to participate in the Technical Conference on July 11, 2022. Notice of the Public Staff's intent to participate in the Technical Conference was filed by the Public Staff on July 11, 2022.

On July 15, 2022, DEP filed its T&D Information Filing. Comments in response to DEP's T&D Informational Filing were filed by the Public Staff, CIGFUR, NCSEA, and NCJC, et al. on July 25, 2022.

On July 25, 2022, a technical conference was held before the Commission with Chair Charlotte A. Mitchell, Presiding; and Commissioners ToNola D. Brown-Bland; Daniel G. Clodfelter; Kimberly W. Duffley; Jeffrey A. Hughes; Floyd B. McKissick, Jr.; and Karen M. Kemerait.

On August 3, 2022, DEP filed a letter advising that it would provide the additional information in response to Chair Mitchell's request that it identify "Red Zone" projects and associated cost-benefit analyses (CBAs) included in DEP's T&D Information Filing, as part of DEP's direct testimony to be filed on August 19, 2022, in Docket No. E-100, Sub 179.

On September 6, 2022, pursuant to Commission Rule R1-17(a), DEP filed notice of its intent to file a general rate case application that includes a performance-based regulation application as authorized under N.C.G.S. § 62-133.16.

On September 12, 2022, pursuant to N.C.G.S. § 62-69, DEP, Duke Energy Carolinas, LLC (DEC), the Public Staff, CIGFUR, and Carolina Industrial Group for Fair Utility Rates III (CIGFUR III), filed the Agreement and Stipulation of Partial Settlement regarding the cost of service study (COSS Stipulation) for consideration by the Commission in Docket Nos. E-2, Sub 1300 and E-7, Sub 1276. On September 13, 2022, a revision to the Stipulation was filed by the aforementioned parties attaching exhibits which were inadvertently omitted from the version filed the previous day.

On October 6, 2022, DEP filed its Application, Form E-1, and the direct testimony and exhibits of Stephen G. De May, North Carolina President, DEP, DEC, and Progress Energy, Inc.; Jonathan L. Byrd, Managing Director of Rate Design and Regulatory Solutions for Duke Energy Business Services, LLC (DEBS); [1] Brent C. Guyton, Director of Asset Management in Customer Delivery for DEP and DEC; Laura A. Bateman, Vice President of Carolinas Rates and Regulatory Strategy; Phillip O. Stillman, Managing Director of Load Forecasting and Corporate Strategic Regulatory Initiatives; LaWanda M. Jiggetts, Rates and Regulatory Strategy Manager for DEC; Retha Hunsicker Vice President, Customer Experience Design and Solutions for DEBS; Tim S. Hill, Vice President, Coal Combustion Products (CCP) Operations, Maintenance and Governance for DEBS; Bradley G. Harris, Rates and Regulatory Strategy Director for DEBS; Janice D. Hager, President of Janice Hager Consulting, LLC; Tom Ray, Senior

[1] DEBS provides various administrative and other services to DEP and other affiliated companies of Duke Energy Corporation (Duke Energy).

Vice President of Nuclear Operations for Duke Energy Corporation (Duke Energy); Lesley G. Quick, Vice President of Customer Technology, Advocacy, Regulatory and Business Support within Customer Services for Duke Energy; Karl W. Newlin, Senior Vice President, Corporate Development and Treasurer, DEBS; Dr. Roger A. Morin, Emeritus Professor of Finance at the Robinson College of Business and Professor of Finance for Regulated Industry at the Center for the Study of Regulated Industry, both at Georgia State University; Laurel M. Meeks, Director of Renewable Business Development for DEP; Evan W. Shearer, Principal Integrated Planning Coordinator for DEC; Daniel J. Maley, Director of Transmission Compliance Coordination for DEBS; Justin C. LaRoche, Director of Renewable Development for Duke Energy; Julie K. Turner, Vice President of Carolinas Coal Generation for Duke Energy; Kathryn S. Taylor, Rates and Regulatory Strategy Manager for DEC; Jacob J. Stewart, Director Health and Wellness for DEBS; Nicolas G. Speros, Director of Accounting for DEBS; John J. Spanos of Gannett Fleming Valuation and Rate Consultants, LLC (Gannett Fleming); and Teresa Reed, Director of Rates and Regulatory Planning for DEBS.

On October 31, 2022, the Commission issued an order which declared a general rate case, suspended the proposed new rates, established the test year period as ending December 31, 2021, and advised that an order scheduling hearings and requiring public notice would be issued at a later date.

Petitions to intervene were filed by Kroger Co. and Harris Teeter on November 4, 2022, and the Commercial Group on November 11, 2022. The Commission entered orders granting the petitions of the Commercial Group and Kroger Co. and Harris Teeter on November 15, 2022.

Petitions to intervene were filed by FPWC on November 23, 2022, and by the Sierra Club on December 14, 2022. The Commission entered orders granting the petitions of FPWC and the Sierra Club on January 10, 2023.

On December 16, 2022, the Commission issued an Order Scheduling Investigation and Hearings, Establishing Intervention and Testimony Due Dates and Discovery Guidelines, and Requiring Public Notice (Scheduling Order). The Order scheduled public witness hearings in Lumberton, Raleigh, Waynesville, Roxboro, and Snow Hill, North Carolina on February 21, February 27, March 6, March 13, and March 20, 2023, respectively. Further, the order set the relevant test period to be used by all parties as the twelve-month period ending December 31, 2021, with appropriate adjustments. The Commission directed, among other instructions, that DEP publish the Public Notice of Hearings on Rate Increase Application (Public Notice) attached to the order as Appendix A, once a week for two consecutive weeks and mail the Public Notice to its customers no later than 30 days in advance of the first set hearing. Subsequently, on December 21, 2022, the Commission issued its Order Rescheduling Public Witness Hearings, Revising Public Notice, and Revising Requirement for Mailing Public Notice (Second Scheduling Order) correcting public hearing location addresses for Lumberton and Raleigh; rescheduling the public witness hearing in Lumberton to March 21, 2023, and the public witness hearing in Raleigh to March 14, 2023; authorizing corresponding revisions to the Public Notice; and instructing DEP to mail each of its customers a copy of the Public Notice no later than 14 days in advance of the public witness hearing scheduled for March 6, 2023.

A petition to intervene was filed by DoD-FEA on January 30, 2023. The Commission entered an order granting DoD-FEA's petition on January 31, 2023.

On December 20, 2023, DEP filed a motion requesting leave to file direct testimony of Kendal C. Bowman adopting the direct testimony of Stephen G. De May, file the direct testimony and exhibits of Graham C. Tompson adopting the direct testimony of Laurel Meeks, and to amend the direct testimony of the Battery Energy Storage Panel. On January 10, 2023, the Commission entered an order granting DEP's motion filed December 20, 2023, and accepted the testimony and exhibits filed into the record.

A joint petition to intervene was filed by ElectriCities of North Carolina, Inc. (ElectriCities) and North Carolina Eastern Municipal Power Agency (NCEMPA) on February 1, 2023. The Commission entered an order denying Electricities' and NCEMPA's joint petition on February 10, 2023.

On February 13, 2023, DEP filed the supplemental direct testimony and exhibits of witnesses Jiggetts; LaRoche; Turner; Taylor; Martin M. Strasburger, Chief Security and Information Security Officer for Duke Energy; Reed; Ray; John R. Panizza, Director, Tax Operations for DEBS; Morin; Shearer; Graham C. Tompson, Business Development Manager for Duke Energy; Maley; Guyton; and Bateman.

On March 13, 2023, Haywood EMC filed a petition to intervene. On March 15, 2023, the Commission issued an order granting Haywood EMC's petition and establishing the scope of its intervention.

On March 14, 2023, the Commission issued its Order Scheduling Virtual Public Witness Hearing and Establishing Requirements for Notice of Virtual Public Witness Hearing (March 14, 2023 Scheduling Order). The March 14, 2023 Scheduling Order scheduled an additional virtual hearing for the purpose of receiving public witness testimony on DEP's Application for April 20, 2023.

On March 15, 2023, CCEBA filed a petition to intervene. On March 17, 2023, NCLM filed a Petition to Intervene. The Commission issued orders granting the petitions filed by CCEBA and NCLM on March 27, 2023.

In March, April, and May of 2023, the Commission held seven public hearings as scheduled by the Scheduling Order, Second Scheduling Order, and March 14, 2023 Scheduling Order for the purpose of receiving the testimony of public witnesses.

NCEMC filed a petition to intervene on March 17, 2023. The Commission issued an order denying NCEMC's Petition on March 28, 2023.

On March 27, 2023, the Commercial Group filed the direct testimony and exhibits of Steve W. Chriss, Director, Energy Services, Walmart; DoD-FEA filed the direct testimony and exhibits of Maureen L. Reno, Founder and Principal Consultant of Reno Energy Consulting Services, LLC, and Larry Blank, Principal of TAHOEconomics, LLC; NCLM filed the direct testimony of Terry Mann, Mayor of the City of Whiteville, North Carolina, and Bill Saffo, Mayor of the City of Wilmington, North Carolina; The Sierra Club filed the direct testimony and exhibits of Roger D. Colton, Co-Founder, Fisher, Sheehan, and Colton, Public Finance and General Economics and Michael Goggin, Vice President, Grid Strategies, LLC; NCJC, et al. filed the direct testimony and exhibits of John Howat, Senior Policy Analyst, National Consumer Law Center, Mark E. Ellis, independent consultant and testifying expert, David B. Posner, Manger, RMI and the joint direct testimony of David G. Hill, Managing Consultant at Energy Futures Group, Inc. and Jake Duncan, a Southeast Regulatory Director for Vote Solar; FPWC filed the direct testimony and exhibits of Laurie A. Tomczyk, Senior Manager, NewGen Strategies and Solutions, LLC; CIGFUR filed the direct testimony and exhibits of Michael P. Gorman, Managing Principal, Brubaker & Associates, Inc. and Nicholas Phillips, Jr., Principal, Brubaker & Associates, Inc.; Kroger Co. and Harris Teeter filed the direct testimony and exhibits of Justin Bieber, Principal, Energy Strategies, LLC; CUCA filed the direct testimony of Charles Heilig, President, Parkdale Mills, and Kevin W. O'Donnell, President, Nova Energy Consultants, Inc.; the AGO filed the direct testimony and exhibits of Edward Burgess, Senior Director of Integrated Resource Planning, Strategen Consulting, and Ron Nelson, Senior Director, Strategen Consulting.

Also on March 27, 2023, the Public Staff filed the direct testimony and exhibits of James S. McLawhorn, Director of the Energy Division of the Public Staff; Evan D. Lawrence, Engineer with the Energy Division of the Public Staff; Roxie McCullar, Consultant, William Dunkel and Associates; John W. Chiles, Principal, GDS Transmission Services group at GDS Associates, Inc.; Thomas C. Williamson, Engineer with the Energy Division of the Public Staff; Christopher C. Walters, Associate, Brubaker & Associates, Inc.; Blaise C. Michna, Engineer with the Energy Division of the Public Staff; Jay B. Lucas, Manager of the Electric Section, Operations and Planning in the Energy Division of the Public Staff; Jordan A. Nader, Engineer with the Energy Division of the Public Staff; Jeff Thomas, Engineer with the Energy Division of the Public Staff; David M. Williamson, Engineer with the Energy Division of the Public Staff; Dustin Metz, Engineer with the Energy Division of the Public Staff, the joint testimony and exhibits of Fenge Zhang, Financial Manager, Electric Section with the Accounting Division of the Public Staff, and Michelle Boswell, Director of Accounting for the Accounting Division of the Public Staff, and the joint testimony and exhibits of David M. Williamson and Jeff T. Thomas, Engineers with the Energy Division of the Public Staff.

On April 3, 2023, DEP filed a motion seeking to substitute Melissa B. Abernathy as the sponsor of the direct testimony and exhibits prefiled by Kathryn S. Taylor. On April 20, 2023, the Commission issued its Order Granting DEP's Motion for Substitution of Witness and Adoption of Testimony.

On April 14, 2023, DEP filed the rebuttal testimony and exhibits of DEP's witnesses Maley; Kevin A. Murray, Vice President of the Project Management and Construction Organization for DEBS; Morin; Bowman, President of Duke Energy's Utility Operations in North Carolina; Donna T. Council, Senior Vice President, Corporate Real Estate, Aviation, and Business Services for DEBS; LaRoche; Ray; Turner; Guyton; Panizza; Newlin; Quick; Speros; Spanos; Jiggetts; Melissa B. Abernathy, Director of Rates and Regulatory Planning for DEC; Stewart; and joint rebuttal testimony of witnesses Bowman, Quick, Abernathy, and Speros; Bateman and Stillman; Tompson and Shearer; Conitsha B. Barnes, Director of Energy Policy Management for DEC, Harris, and Quick; and Byrd and Reed.

On April 17, 2023, DEP filed amended rebuttal testimony of witness Morin.

On April 18, 2023, DEP filed second supplemental direct testimony of witness Reed and third supplemental direct testimony of witnesses Abernathy and Jiggetts.

On April 25, 2023, the Public Staff filed a motion to withdraw portions of witness Thomas' testimony. On May 1, 2023, the Public Staff filed a motion to withdraw portions of witness T. Williamson's testimony. On May 8, 2023, the Commission issued its order granting the Public Staff's motions to withdraw portions of testimony filed by witnesses T. Williamson and Thomas.

On April 26, 2023, the Public Staff and DEP filed an Agreement and Stipulation of Partial Settlement (April 26, 2023 Partial Settlement).

On April 27, 2023, the Commission issued its Order Continuing Hearing and Modifying Dates for Additional Hearing Procedures. Pursuant to the order, the expert witness hearing was rescheduled to commence on May 4, 2023. Also on April 27, 2023, the AGO filed its motion to substitute Ron Nelson as the sponsor of the testimony and exhibits filed by AGO witness Burgess. On May 8, 2023, the Commission issued its order granting the AGO's motion.

Also on April 27, 2023, the Public Staff filed a Transmission Cost Allocation Agreement and Stipulation of Settlement between DEP, DEC, and the Public Staff (TCA Stipulation).

On April 28, 2023, DEP filed settlement testimony of witness Bateman to support the TCA Stipulation. Also on April 28, 2023, DEP filed the settlement testimony and exhibits of witnesses Abernathy, Jiggetts, and Bowman in support of the April 26, 2023 Partial Settlement.

On May 1, 2023, DEP, the Public Staff, and CIGFUR filed an Agreement and Stipulation of Settlement on Performance Incentive Mechanisms, Tracking Metrics and Decoupling Mechanism (the PIMS Stipulation). Also on May 1, 2023, DEP and CIGFUR filed a separate Agreement and Stipulation of Settlement (the Power Quality Stipulation).

Additionally, on May 1, 2023, the Public Staff filed the supplemental and settlement joint testimony and exhibits of witnesses Zhang and Boswell; the supplemental testimony of witnesses Metz and Williamson; and the settlement testimony of witnesses Metz and McLawhorn in support of April 26, 2023 Partial Settlement.

On May 2, 2023, CIGFUR filed supplemental direct testimony of witness Phillips, Jr. in support of the Power Quality Stipulation. Also on May 2, 2023, DEP, the Public Staff, and CIGFUR filed an Amended Agreement and Stipulation of Partial Settlement that amended the April 26, 2023 Partial Settlement, including through the inclusion of CIGFUR as a party (as amended, the Revenue Requirement Stipulation). Also on May 2, 2023, the Public Staff filed the joint testimony of witnesses Thomas and D. Williamson and DEP filed the joint settlement testimony of witnesses Bateman and Stillman supporting the PIMS Stipulation.

On May 4, 2023, DEP, Sierra Club, NCJC, et al., and the Public Staff filed an Agreement and Stipulation of Partial Settlement Regarding Low-Income/Affordability Performance Incentive Mechanism and Affordability Issues (the Affordability Stipulation). On May 5, 2023, DEP filed the settlement testimony of witnesses Barnes, Harris, and Quick and the Public Staff filed testimony of witness D. Williamson in support of the Affordability Stipulation.

On May 4, 2023, the expert witness hearing commenced.

From May 5, 2023, through June 6, 2023, DEP filed 18 Late-Filed Exhibits, and the Public Staff filed Late-Filed Exhibit Nos. 1 and 2.

On May 10, 2023, DEP, the Commercial Group, and Kroger and Harris Teeter filed an Agreement and Stipulation of Settlement (MGS Partial Rate Design Stipulation).

On May 16, 2023, DEP filed a Notice of Intent to Place Temporary Rates into Effect and Request for Expedited Approval of Notice of Undertaking, as well as a revised Appendix A, and on May 17, 2023, a second revised Appendix A. Also on May 17, 2023, the Commission filed an Order Approving Public Notice of Temporary Rates Subject to Refund and Financial Undertaking and Expiration of EDIT-3 Rider.

On May 23, 2023, DEP filed its Temporary Rates Compliance Filing.

On May 26, 2023, the Public Staff filed a Motion to Strike Portions of DEP's Late-Filed Exhibits 9 and 10, which DEP filed a response to on May 30, 2023. On June 2, 2023, the Commission issued an Order Denying the Public Staff's Motion to Strike Portions of DEP's Late-Filed Exhibits 9 and 10.

On June 7, 2023, DEP and CIGFUR filed an Agreement and Stipulation of Settlement (the LGS Partial Rate Design Stipulation).

On June 27, 2023, the Public Staff filed the second supplemental testimony of witnesses Zhang and Boswell, the second supplemental testimony of witness D. Williamson, and the supplemental testimony of witness Thomas. On that same date, DEP and the Public Staff filed an Agreement and Stipulation of Settlement (the Supplemental Revenue Requirement Stipulation) and the Public Staff filed the supplemental settlement testimony of Metz, Zhang, and Boswell.

On June 27, 2023, the Public Staff filed a Motion for Leave to File Testimony on the June 7, 2023 Stipulation filed between DEP and CIGFUR.

On June 28, 2023, the Public Staff filed the corrected second supplemental exhibits of witness D. Williamson.

On July 3, 2023, CIGFUR filed a motion to strike the second supplemental testimony and corrected second supplemental exhibits of Public Staff witness D. Williamson. On that same date, CIGFUR filed in opposition to the Public Staff's motion for leave to file testimony on the June 7, 2023 Stipulation.

On July 3 and 5, 2023, DEP, NCLM, and the Public Staff filed responses to the July 3, 2023 CIGFUR filings.

On July 6, 2023, the Commission issued an Order on Post-Hearing Motions and Reconvening Hearing which denied CIGFUR's motion to strike the second supplemental testimony and corrected second supplemental exhibits of Public Staff witness D. Williamson, denied the motion for leave of the Public Staff to file testimony on the June 7, 2023 Stipulation, and reconvened the expert witness hearing for limited purposes.

On July 24, 2023, the expert witness hearing was reconvened.

Jurisdiction

No party has contested the fact that DEP is a public utility subject to the Commission's jurisdiction pursuant to the Public Utilities Act (Act), Chapter 62 of the North Carolina General Statutes. The Commission concludes that it has personal jurisdiction over DEP and subject matter jurisdiction over the matters presented in DEP's Application.

Application

In summary, DEP requested in its Application and initial direct testimony and exhibits, a base rate increase of approximately $227.6 million, or 5.9%, in its annual electric sales, offset by a rate reduction of $8.5 million to refund certain tax benefits, for a net revenue increase of $219.2 million, or 5.7% from its North Carolina retail electric operations, including a rate of return on common equity of 10.2% and a capital structure consisting of 47.0% debt and 53.0% equity. DEP's Application and initial direct testimony and exhibits also sought approval of PBR and a series of rate increases based on DEP's proposed three-year MYRP, and other mechanisms required as part of PBR, with the first rate increase effective November 5, 2022. DEP sought increases to the revenue requirement of $106.6 million, $150.8 million, and $138.3 million in Rate Year 1, Rate Year 2, and Rate Year 3, respectively.

DEP submitted evidence in this case with respect to revenue, expenses, and rate base using a test period consisting of the 12 months ending on December 31, 2021, adjusted for certain known changes in revenue, expenses, and rate base through March 31, 2023[2].

DEP, by its supplemental direct testimony and exhibits, revised its requested base revenue requirement increase to approximately $283.5 million, offset by a rate reduction of $8.5 million to refund certain tax benefits, for a net revenue increase of $275 million, including an increase to the rate of return on common equity to 10.4% and an increase to the cost of debt to 3.88% based on the average embedded cost of debt financing as of December 31, 2022. DEP also revised its series of rate increases based on DEP's proposed three-year MYRP. DEP's updated MYRP revenue requirements were $104 million, $133.4 million, and $147.5 million in Rate Year 1, Rate Year 2, and Rate Year 3, respectively.

DEP, by its second supplemental direct testimony and exhibits, revised its requested base revenue requirement increase to approximately $308.8 million, offset by a rate reduction of $8.5 million to refund certain tax benefits, for a net revenue increase of $300.3 million including an increase to the cost of debt to 3.9% based on the average embedded cost of debt financing as of February 28, 2023. DEP also revised its series of rate increases based on DEP's proposed three-year MYRP. DEP's updated MYRP revenue requirements were $104.1 million, $133.5 million, and $147.6 million in Rate Year 1, Rate Year 2, and Rate Year 3, respectively.

DEP, by its March 2023 supplemental direct testimony and exhibits, revised its requested base revenue requirement increase to approximately $314.6 million, offset by a rate reduction of $8.5 million to refund certain tax benefits, for a net revenue increase of $306.1 million, including an increase to the cost of debt to 4.03% based on the average embedded cost of debt financing as of March 31, 2023. DEP also revised its series of rate increases based on DEP's proposed three-year MYRP. DEP's updated MYRP revenue requirements were $104.5 million, $133.5 million, and $148.2 million in Rate Year 1, Rate Year 2, and Rate Year 3, respectively.

[2] DEP's Application initially proposed a capital cut-off date of April 31, 2023; however, upon further discussion and agreement with the Public Staff, the parties agreed to, and the Commission's Scheduling Order established, a capital cut-off date of March 31, 2023. The change in capital cut-off was reflected in DEP's supplemental filings.

Whole Record

The Commission held public witness hearings as noted above. The following public witnesses appeared and testified:

Waynesville:	Les Cochran, Charles Guyton, Andrew Jarbeau, Porter Hughes, Gray Jernigan, Rob Denton, Mary Curry, Walker Spruill, Delisa Ensley, Ken Brame, Judy Mattox, Abby Frye, and Angelica Cote.
Raleigh:	William Terry, Criss Berke, Amelia Covington, Divine Earth-Dowd, Jennifer Eison, Stacey Campbell, Paul Baer, Lisa Brewer, Peter Thomas, Agnes Foucha, Ashleigh Armstrong, Ziyad Habash, Ebony McKinnan, Cathy Buckley, Deborah Ford, Ernestine Ledbetter, Matthew Muse, Eleanor Weston, Kaitlyne Sheehan, and Brenda Jackson.
Snow Hill:	Gwen Johnson, David Barnes, Phyllis Merritt-James, Brianna Howard, Jaylind Lampa, Larry James, Glenda Thomas, Vicky Bailey, Barbara Dantonio, Don Cavellini, Beatrice Jones, Syene Jasmin, Bobby Jones, and Constance Coram.
Lumberton:	Debra David, Robert Macy, Jaquline Banks; Les Cochran; Sallie McLean; Lauren Martin; Samantha Sirabian; Daniel Dimaria, Hannah Jeffries, Esther Murphy, Ryua Hishikawa, Georgette Hunt, Mac Legerton, Ricky Johnson, Felicia Bethea, Carol T. Richardson, Frankie Hall, and William Fairley.
Virtual Hearing:	Michael Righi, Reagan McGuinn, Ruby Bell, Kay Reibold, Steven Norris, Sean Lewis.

In summary, almost all the public witnesses stated their opposition to DEP's proposed rate increase. *See generally*, Tr. vols. 2-6. Many witnesses testified that they were on fixed incomes and about the poverty in some of the counties served by DEP. Moreover, public witnesses testified to their concern regarding DEP's use of fossil fuels, including coal and natural gas power plants, fracking, and DEP not adequately increasing the use of clean energy and renewables. Finally, some public witnesses voiced their view that DEP's executive compensation and shareholder dividends are excessive.

In addition to the public witness testimony, the Commission received a number of consumer statements of position, all of which were filed in the docket. *See generally*, Docket No. E-2, Sub 1300CS. The public witness testimony and consumer statements of position have been considered by the Commission in its deliberations on DEP's rate case Application.

The testimony and exhibits in this proceeding are voluminous. The Commission has carefully considered all the evidence and the record as a whole. However, the Commission has not attempted to recount every statement of every witness in this Order.

Rather, the Commission has summarized the evidence that is in the record. Likewise, while the Commission has read and fully considered the parties' post-hearing briefs, it has not in this Order attempted expressly to summarize or discuss every contention advanced or authority cited in the briefs.

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

FINDINGS OF FACT

Stipulations

1. On April 26, 2023, DEP and the Public Staff filed the Revenue Requirement Stipulation, which resolved a portion of the base period and MYRP revenue requirement issues in this proceeding. On May 2, 2023, DEP and the Public Staff amended the Revenue Requirement Stipulation, adding CIGFUR as a party and resolving an additional revenue requirement issue.

2. On September 13, 2022, DEP, DEC, the Public Staff, CIGFUR, and CIGFUR III (the COSS Stipulating Parties) filed the COSS Stipulation. The COSS Stipulation provides that DEP will first allocate production and transmission demand costs to the North Carolina retail jurisdiction using the Twelve Coincident Peak (12 CP) method and will allocate production demand costs among the North Carolina retail rate classes using the modified Average and Excess (A&E) Demand Method (the Modified A&E Method).

3. On April 27, 2023, DEP, DEC, and the Public Staff filed the TCA Stipulation. The TCA Stipulation provides for a pro forma adjustment of approximately $20 million to increase the revenue requirement in DEC's pending rate case proceeding in Docket No. E-7, Sub 1276 (DEC Rate Case) and to decrease the revenue requirement in the instant proceeding.

4. On May 1, 2023, DEP, the Public Staff, and CIGFUR filed the PIMs Stipulation.

5. On May 1, 2023, DEP and CIGFUR filed the Power Quality Stipulation.

6. On May 4, 2023, DEP, DEC, Sierra Club, NCJC, et al., and the Public Staff filed the Affordability Stipulation.

7. On May 10, 2023, DEP, the Commercial Group, and Kroger Co. and Harris Teeter filed the MGS Partial Rate Design Stipulation.

8. On June 7, 2023, DEP and CIGFUR filed the LGS Partial Rate Design Stipulation.

9. On June 27, 2023, DEP and the Public Staff filed the Supplemental Revenue Requirement Stipulation.

10. The Revenue Requirement Stipulation, the COSS Stipulation, the TCA Stipulation, the PIMs Stipulation, the Power Quality Stipulation, the Affordability Stipulation, the MGS Partial Rate Design Stipulation, the LGS Partial Rate Design Stipulation, and the Supplemental Revenue Requirement Stipulation are the product of give-and-take settlement negotiations between the respective stipulating parties.

Depreciation

11. The depreciation rates proposed by DEP, which reflect the accelerated retirement of DEP's coal units, as amended by the Revenue Requirement Stipulation to reflect 20-year amortization periods for General Plant FERC accounts 391 and 397 and a 70-year life for Transmission FERC account 356, are reasonable.

12. The deferral of 75.0% of the impact of accelerating the depreciation of DEP's Mayo and Roxboro Units 3 and 4 from the current retirement dates to a regulatory asset as agreed upon in the Revenue Requirement Stipulation is reasonable.

13. Any portion of net book value upon the retirement of DEP's subcritical coal-fired plants that will not be recovered through securitization will be recovered with a return over an amortization period to be determined by the Commission in a future rate case proceeding.

Base Period Plant-Related Items

14. DEP's plant-related capital investments during the test year in its transmission, distribution, fossil/hydro, nuclear, solar, and storage assets, as adjusted by the Revenue Requirement Stipulation, were prudently and reasonably made and should be reflected in the revenue requirement.

Grid Improvement Plan Costs

15. Since DEP's last general rate case, DEP has deferred incremental operation and maintenance expense, depreciation and property taxes associated with its three-year grid improvement plan (GIP), as well as the carrying cost on the investment and the deferred costs at DEP's weighted average cost of capital.

16. DEP proposes to amortize the GIP deferral of $36.4 million, associated with the GIP investment of $196.7 million on a North Carolina retail basis, over an amortization period of three years, which results in an annual amortization expense of $12.9 million.

17. Section III, Paragraph 11 of the Revenue Requirement Stipulation provides that DEP should be permitted to recover the full balance of its GIP deferral over an amortization period of 18 years, with a debt-only return during the deferral period and rate

base treatment during the amortization period.

Coal Ash

18. DEP's request to amortize costs associated with its coal combustion residual (CCR) obligations incurred through March 31, 2023, over a five-year period and to continue the deferral of any CCR costs incurred subsequent to March 31, 2023, is reasonable.

19. The over-amortization of CCR recovery in the amount of $8.5 million should be applied against the Coal Ash CCR Asset Retirement Obligations (ARO) deferral.

Harris Land Sales

20. Section III, Paragraph 22 of the Revenue Requirement Stipulation provides for a flowback period of three years for the liability related to the gains on Harris land sales and provides that DEP will include the unamortized balance in rate base.

21. It is appropriate for DEP to continue to defer any gains on Harris land sales to be returned to customers in a future general rate case proceeding.

Roxboro Wastewater Treatment Regulatory Asset

22. DEP's request for an accounting order to establish a regulatory asset upon the retirement of the Roxboro Wastewater Treatment Plant in which to defer the unrecovered remaining net book value of the plant and costs related to obsolete inventory, net of salvage was approved in the Commission's Order in DEP's last general rate case proceeding in Docket No. E-2, Sub 1219 (the 2019 Rate Case).

23. Section III, Paragraph 24 of the Revenue Requirement Stipulation establishes an amortization period of 12 years for the recovery of the deferred balance associated with the Roxboro Wastewater Treatment Facility and that the unamortized balance will be included in rate base.

Storm Securitization Over Collections

24. Per DEP's Agreement and Stipulation of Partial Settlement with the Public Staff in Docket No. E-2, Sub 1262, DEP agreed to establish regulatory asset or regulatory liability accounts for the purpose of tracking up-front financing costs and servicing and administration fees related to storm securitization.

25. The amortization over three years of the regulatory liability for the over-recovered balance of $0.9 million for storm securitization over collections is just and reasonable.

Cost of Debt

26. The embedded cost of debt of 4.03% as set forth in Section III, Paragraph 1 of the Revenue Requirement Stipulation is reasonable and appropriate for use by DEP in this case.

Accounting Adjustments

27. The accounting adjustments set forth in the Revenue Requirement Stipulation, as further described in detail in Jiggetts Partial Settlement Exhibit 2 and the Public Staff Accounting Supplemental and Settlement Exhibit 1, Schedule 1, are the reasonable product of give-and-take negotiations among the parties.

28. The accounting adjustments set forth in the Supplemental Revenue Requirement Stipulation, as further described in detail in Supplemental Revenue Requirement Stipulation Exhibit 1, are the reasonable product of give-and-take negotiations between the stipulating parties.

MYRP Capital Investments

29. DEP's proposed MYRP capital investments, reflecting the projected costs associated with the transmission, distribution, fossil/hydro, nuclear, cybersecurity, solar, and storage capital investments, as adjusted in the Revenue Requirement Stipulation, are just and reasonable to all parties in light of the evidence the parties presented, consistent with statutory and regulatory requirements, and appropriate for approval as part of DEP's overall Application in this proceeding.

Reporting Requirements

30. Section IV of the Revenue Requirement Stipulation establishes several reporting obligations of DEP.

Storm Normalization

31. The adjustment to DEP's revenue requirement, calculated using the method approved by the Commission in Docket Nos. E-2, Sub 1023, E-2, Sub 1142, and E-2, Sub 1219 to account for anticipated storm expenses based upon a 10-year average of storm costs after removing costs associated with major storms, is approximately $22.243 million.

DSDR

32. DEP has requested approval to recover the future costs associated with its Distribution System Demand Response (DSDR) energy efficiency program through base rates in lieu of the Demand-Side Management/Energy Efficiency (DSM/EE) rider, beginning with the rates established in this proceeding.

Payment Navigator

33. DEP has requested approval for its Payment Navigator program, which is designed to provide support to customers in need of assistance with managing payment of their electric bills, and the request is reasonable.

Customer Connect

34. DEP has proposed to recover approximately $60 million associated with the implementation of the Customer Connect platform, which is DEP's customer engagement platform, and the Customer Information System (CIS).

COSS Stipulation

35. The COSS Stipulation between DEP, DEC, CIGFUR, and the Public Staff, requires DEP to allocate production demand and transmission demand costs by using the 12 CP allocation method for jurisdictional allocations and the Modified A&E method among North Carolina retail customer classes.

Transmission Cost Allocation Stipulation

36. The TCA Stipulation establishes a pro forma adjustment to increase the revenue requirement for DEC in the DEC Rate Case by approximately $20 million on a North Carolina retail basis as well as a corresponding decrease to the revenue requirement for DEP in the instant proceeding.

PIMs Stipulation

37. On May 1, 2023, DEP, the Public Staff, and CIGFUR filed the PIMs Stipulation.

38. The PIMs Stipulation consists of the following three PIMs: Time Differentiated and Dynamic Rate Enrollment PIM, Reliability PIM, and the Renewables Integration and Encouragement PIM (consisting of Metrics A, B, and C) (collectively, the Settled PIMs). The PIMs Stipulation also provides for three tracking metrics – customer service, beneficial electrification from incremental load of EVs, and reporting and analyzing the 10 worst performing circuits (collectively, the Settled Tracking Metrics) – and provides a process for DEP to work with the Public Staff to develop tariffs and programs to estimate and update revenue associated with EV sales.

Power Quality Stipulation

39. DEP and CIGFUR filed the Power Quality Stipulation, which has the objective of enabling DEP to analyze power quality issues.

Affordability Stipulation

40. On May 4, 2023, DEP, DEC, Sierra Club, NCJC, et al., and the Public Staff filed the Affordability Stipulation, pursuant to which DEP and DEC agreed to make shareholder financial contributions totaling $16 million over three years to benefit eligible customers.

41. The Affordability Stipulation supports the Customer Assistance Program (CAP) and the corresponding tariffs associated with the CAP.

Rate Design

42. The objective of DEP's proposed rate design is to recover the revenue requirement while aligning the cost to serve customers within the customer classes and reflecting the costs a customer causes DEP to incur. DEP's proposed rate design allocates the revenue increase between customer classes by rate base amounts.

43. DEP's rate design involves adjustments that are intended to achieve DEP's rate design objective, including a subsidy reduction, a customer migration adjustment, and customer growth and weather normalization adjustments.

44. DEP proposes changes to residential rate schedules, the small general service (SGS) rate schedules, the medium general service (MGS) rate schedules, the large general service (LGS) rate schedules, the seasonal and intermittent rate schedules, the lighting rate schedules, and the traffic signal rate schedules.

45. DEP proposes changes to its service riders, which are offered to reflect the cost of meeting unique or special customer requirements.

46. DEP proposes updated and aligned TOU periods across its rate schedules that include time-differentiated pricing for residential and non-residential customers.

47. The MGS Partial Rate Design Stipulation, entered into by DEP, the Commercial Group, and Kroger Co. and Harris Teeter, provides that 75.0% of the reduction in revenue requirement, as determined by final Commission order, applicable to rate schedule MGS-TOU should be applied to energy rates.

48. LGS Partial Rate Design Stipulation, entered into by and between DEP and CIGFUR, provides that any increase in energy charges resulting from an increase in DEP's revenue requirement, which to be recovered from the LGS, LGS-TOU, and LGS-Real Time Pricing (RTP) rate schedules, as determined by final Commission order, shall be limited to a percentage that is less than half of the approved overall increase percentage to the LGS, LGS-TOU, and LGS-RTP classes, respectively, exclusive of any decrements for the LGS, LGS-TOU, and LGS-RTP rate schedules.

Capital Structure, Cost of Equity and Overall Rate of Return

49. DEP proposed a rate of return on common equity of 10.4%, with a capital structure consisting of 53.0% common equity and 47.0% debt.

50. The overall rate of return and rate of return on common equity must be supported by competent, material, and substantial record evidence; consistent with the requirements of N.C.G.S. § 62-133 considering changing economic conditions; and must balance DEP's need to maintain the safety, adequacy, and reliability of its service with the benefits to DEP's customers to receive from safe, adequate, and reliable electric service.

51. Ultimately, the capital structure, rate of return on common equity, and overall rate of return set by this Order must result in just and reasonable rates.

COVID Deferral Recovery

52. The Commission's December 21, 2021 Order in Docket No. E-2, Sub 1253 (Deferral Order) approved DEP's request to create a regulatory asset into which to defer incremental COVID-19 pandemic-related costs.

53. In this proceeding, DEP seeks to recover the deferred balance, including accrued carrying costs, of approximately $107 million related to: (1) customer fees waived; (2) bad debt charge-offs; (3) employee stipends to cover unplanned expenses associated with the COVID pandemic; (4) costs related to employee safety; (5) costs related to remote work; and (6) miscellaneous costs, such as employee overtime.

54. DEP identified and calculated two categories of COVID-related savings in the amount of approximately $4.5 million on a North Carolina retail basis related to: (1) reduced printing and postage costs due to the moratorium on customer disconnections; and (2) reduced travel expenses. DEP benefited from certain measures taken by the federal government to assist employers during the pandemic, including federal employee retention credits (ERCs) and the delay of payment obligation of the employer portion of social security tax.

55. DEP seeks to recover the deferred balance over a three-year period.

56. DEP requests to continue the deferral of the incremental bad debt, for future recovery.

Inflation Adjustment

57. DEP's calculation of the increase in Non-Labor and Non-Fuel Operating and Maintenance (O&M) costs due to the effect of inflation relies on the same method proposed and approved by the Commission in DEP's last three general rate cases.

Rate Case Expense

58. DEP proposes to recover additional rate case expense leftover from the 2019 Rate Case in this proceeding.

59. DEP proposes to recover rate case expenses, incurred in this proceeding over a three-year period.

60. DEP proposes to include the unamortized balance of rate case expense in rate base.

Over-Amortizations

61. DEP's approach to over-amortization of Commission-approved regulatory assets is to apply the amount of over-amortization for recovery of like kind expenses.

Storm Balancing Account and Winter Storm Izzy

62. DEP requested deferral of approximately $15 million in O&M costs associated with system restoration necessitated by Winter Storm Izzy, which occurred in January 2022.

63. DEP spent $87.126 million on a North Carolina retail jurisdictional basis in 2022 on annual storm costs (inclusive of both Winter Storm Izzy and Hurricane Ian, among other storms), which is beyond the normal range of fluctuation of storm costs of $27.4 million.

64. DEP and the Public Staff agree on the amount of $15 million of O&M costs to be recovered for Winter Storm Izzy but do not agree on the method of recovery.

65. DEP proposes to recover 2022 incremental Winter Storm Izzy costs by applying a portion of the $17 million over-amortization of Hurricane Matthew costs from the DEP's general rate case proceeding from 2017 in Docket No. E-2, Sub 1142 (the 2017 Rate Case).

66. DEP proposes to create a storm balancing account that would, in essence, operate as a rider or tracker. DEP proposes to use the remaining amount of over-amortization of Hurricane Matthew costs, approximately $2 million, to establish the storm balancing account.

Other Deferrals

67. DEP requests to defer the estimated tax benefits, net of costs, associated with the Inflation Reduction Act (IRA) and Infrastructure Investment Job Act (IIJA).

68. DEP has proposed three customer programs for approval by the Commission, the CAP, the Payment Navigator Program, and the Tariffed On-Bill Program.

69. DEP expects to incur incremental O&M costs related to the implementation of the CAP the Payment Navigator Program, and the Tariffed On-Bill Program, and implementation of the PIMs, including the required PIMs dashboard, and proposes to defer its incremental O&M costs associated with the implementation of the customer programs and PIMs.

Interconnection CIAC Regulatory Liability Recommendation

70. The Public Staff has identified an issue with respect to DEP's recording of contributions in aid of construction (CIAC) in the context of interconnection agreements (IA) between DEP and third party interconnection customers and proposed that a regulatory liability be established to record any instances in which DEP incorrectly recovered costs associated with interconnection agreements (IAs) from ratepayers.

Quality of Service

71. DEP and the Public Staff presented evidence as to the adequacy of electric service provided by DEP.

Tax-Related Items

72. DEP proposes revision to its previously approved North Carolina excess deferred income taxes (EDIT) rider (EDIT-4) to reflect additional amounts due to customers.

73. The levelized return rate should reflect a capital structure consisting of 47.0% long-term debt and 53.0% equity, a 4.03% embedded cost of debt, and a rate of return on equity of 9.8%.

Base Fuel and Fuel-Related Factors and Fuel Cost Allocation

74. DEP proposes to continue its use of the equal percentage fuel adjustment allocation methodology.

75. DEP proposes to allocate purchased power capacity costs to North Carolina retail and across North Carolina retail customer classes based on production demand.

Residential Decoupling Mechanism and Earnings Sharing Mechanism

76. DEP's PBR Application includes a residential decoupling mechanism, a rate-making mechanism intended to break the link between DEP's revenue and the level of consumption of electricity on a per customer basis by its residential customers, as required by N.C.G.S. § 62-133.16(c) and Commission Rule R1-17B.

77. DEP proposes as a component of the MYRP an ESM, an annual rate-making mechanism that shares surplus earnings between DEP and its customers over

the period of time covered by a MYRP, as required by N.C.G.S. § 62-133.16(c) and Commission Rule R1-17B.

Performance-Based Regulation

78. DEP filed its first PBR Application in accord with N.C.G.S. § 62-133.16 and with Commission Rule R1-17B.

Revenue Requirement

79. After giving effect to the portions of the stipulations approved herein and the Commission's decision on contested issues, the annual revenue requirement for DEP for Rate Years 1, 2, and 3 will allow DEP a reasonable opportunity to recover its operating costs and earn the overall rate of return on its rate base that the Commission has found just and reasonable upon consideration of the findings in this Order.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-10

The evidence supporting these findings of fact is contained in DEP's verified Application and Form E-1; the stipulations between DEP and the other parties; the testimony and exhibits of DEP witnesses Bowman, Abernathy, Hager, Bateman, Stillman, Barnes, Harris, Quick and Jiggetts; Public Staff witnesses Zhang, Boswell, McLawhorn, D. Williamson, Thomas, and Metz; CIGFUR witness Phillips; and the entire record in this proceeding.

Revenue Requirement Stipulation

On April 26, 2023, the Public Staff and DEP filed the Revenue Requirement Stipulation resolving a portion of the revenue requirement issues between the parties. On May 2, 2023, DEP and the Public Staff amended the stipulation to include CIGFUR as a party and resolve among themselves an additional issue pertaining to vegetation management.

Witness Bowman testified that the stipulation resolves most of the revenue requirement issues between DEP and the Public Staff. She stated that the parties fully resolved the recovery of capital projects and related costs to be included in DEP's MYRP. Tr. vol. 7, 53-54. Witness Bowman also testified that the parties reached agreement on the inclusion of plant in service and depreciation rates and agreed to revenue requirement adjustments for the following items: cost of debt; executive compensation; board of directors expenses; rent expenses; lobbying; sponsorships and donations; incentive compensation; reliability assurance operations and maintenance (O&M) spend; aviation expenses; non-residential credit card fees; end of life nuclear reserve; coal inventory; salaries and wages; gain on Harris land sales; production O&M; and the treatment of various deferrals DEP is requesting to recover. *Id.* She explained that the Revenue Requirement Stipulation shows these accounting and ratemaking adjustments and the resulting effect on the revenue requirement. Witness Bowman also testified to DEP's commitment to perform a lead-lag study before its next rate case application and agreement to various reporting obligations. *Id*. Witness Bowman further testified that the stipulation represents a balanced settlement between the stipulating parties on the settled issues, is in the public interest, and should be approved by the Commission. *Id.*

Public Staff witnesses McLawhorn, Metz, Zhang, and Boswell testified that, from the Public Staff's perspective, the most important benefits the stipulation provides are: (1) an aggregated reduction in DEP's proposed revenue increase resulting from the agreed-upon adjustments; and (2) the avoidance of protracted litigation between DEP and the Public Staff before the Commission and possibly the appellate courts on the settled issues and the associated increased rate case expense recovery from customers. Tr. vol. 16, 514; Tr. vol. 19, 87. Based on these ratepayer benefits, and other provisions of the stipulation, the Public Staff believes the stipulation is in the public interest and that the Commission should approve it. *Id.*

Sections III and IV of the Revenue Requirement Stipulation outline several accounting and ratemaking adjustments, as well as reporting obligations, to which DEP, the Public Staff, and CIGFUR agree. The Commission fully discusses these agreed-upon issues later in this Order.

COSS Stipulation

On September 13, 2022, the COSS Stipulating Parties filed the COSS Stipulation with the Commission. Tr. vol. 11, 80. The COSS Stipulation provides that DEP will first allocate production and transmission demand costs to the North Carolina retail jurisdiction using the 12 CP method and then will allocate production demand costs among North Carolina retail customer classes using the Modified A&E method. *Id.* Because transmission demand does not have average or excess energy components, the transmission demand factors at the customer class level are equivalent to the 12 CP calculation. *Id.* The COSS Stipulation also provides that, for purposes of allocating production demand costs on a jurisdictional basis as well as to North Carolina retail rate classes, DEP will make an adjustment to exclude certain curtailable/interruptible loads if they were not curtailed at the twelve system peak hours during the test year. *Id.* The COSS Stipulation only applies in the current rate case, and the COSS Stipulating Parties are free to advocate for different methodologies in future DEP cases. *Id.* DEP witness Hager testified that the stipulation is reasonable and that the Commission should approve it, noting that it was the result of give-and-take negotiations of parties with diverse views on the appropriate methodologies reaching a settlement. *Id.* at 80-81.

TCA Stipulation

On April 27, 2023, DEP, DEC, and the Public Staff filed the TCA Stipulation. The TCA Stipulation sets forth the agreement of the parties thereto to a pro forma adjustment of approximately $20 million to increase the revenue requirement in the pending DEC Rate Case and to decrease the revenue requirement in the instant proceeding.

The TCA Stipulation calculates a pro forma amount of transmission expense for DEC and transmission revenue for DEP by multiplying the net transfers from DEP to DEC which occurred in 2022 pursuant to the joint dispatch agreement (JDA)[3]by the DEP non-firm transmission rate established in the FERC-approved Joint Open Access Transmission Tariff (OATT) of DEP, DEC, and Duke Energy Florida, LLC.[4] The stipulation also provides that the adjustment is for North Carolina ratemaking purposes only and will not change the terms or conditions of the JDA or result in any accounting entries for DEP or DEC. The TCA Stipulation provides that the adjustment will become effective on

[3] The JDA is the framework by which DEC and DEP manage and utilize their electric generation assets jointly to serve their respective retail customers with the most efficient generating plants available on a daily basis and was approved by the Commission as a part of the 2012 merger of DEP and DEC. Order Approving Merger Subject to Regulatory Conditions and Code of Conduct, Docket Nos. E-7, Sub 986, and E-2, Sub 998, June 30, 2012.

[4] DEC OATT Transmission Rate Formula Template Using Form 1-Data Utilizing Cost Data for (Historic Years) with Year-End Average Balances Development of Revenue Requirement OATT, p. 3 of 7 (328 of 1170); DEP OATT Transmission Non-Levelized Rate Formula Template Using Form-1 Data Development of Revenue Requirement, p. 3 of 5 (510 of 1170).

October 31, 2023 for both DEP and DEC, and will terminate at the sooner of the effective date of rates in DEP's or DEC's next general rate case or the effective date of a full merger of DEP and DEC, unless the Commission orders otherwise.

DEP witness Bateman testified in support of the TCA Stipulation. Tr. vol 14, 146. She explained that the TCA Stipulation is the result of substantial discovery and extensive negotiation among the stipulating parties and that it reflects a constructive near-term approach to addressing rate disparity concerns arising from the increasing net transfers of energy from DEP to DEC under the JDA. *Id.* Public Staff witness Metz also testified in support of the TCA Stipulation. Tr. vol. 16, 517-18. Witness Metz testified that the TCA Stipulation addresses the growing level of net transfers and the subsequent rate disparity between DEP and DEC in North Carolina and explained that the adjustment will compensate DEP and DEC ratepayers for the use and annual maintenance of each utility's transmission system for energy transfers under the JDA. *Id.*

PIMs Stipulation

On May 1, 2023, the DEP, the Public Staff, and CIGFUR filed the PIMs Stipulation. The PIMS Stipulation reflects an agreement between the parties regarding certain of the PIMs, tracking metrics, and the electric vehicle (EV) adjustment to DEP's decoupling mechanism.

DEP's PBR Policy Panel provided testimony in support of the PIMs Stipulation. Tr. vol. 14, 131. The PBR Policy Panel testified that the resolution reached among the parties to the stipulation represents a balanced approach to achieving policy goals in DEP's first PBR Application. Tr. vol. 15, 17, 70. DEP witness Stillman testified that the settled PIMs originated from the North Carolina Energy Regulatory Process (NERP) PBR Working Group,[5] were informed by DEP's pre-filing PIM stakeholder process, and evolved over discussions among the parties in the instant proceeding. Tr. vol. 14, 132-33. DEP witness Bateman testified that the Commission must examine the PIMs in the context of the entire MYRP. Tr. vol. 15, 15. Witness Bateman testified that DEP took a conservative approach in this first PBR Application in order for DEP, customers, and the Commission to gain experience with the operation and implementation of PIMs. *Id.* at 69. DEP witness Stillman explained DEP's approach to designing the PIMs around the 1.0% cap set forth in N.C. Gen. Stat. § 62-133 and stated that DEP was deliberate in choosing to propose only a select number of PIMs that meet the maximum number of policy goals. *Id.* at 65.

Public Staff witnesses D. Williamson and Thomas provided testimony in support of the PIMs Stipulation. Tr. vol. 18, 424-25. Witnesses D. Williamson and Thomas testified that the PIMs Stipulation benefits ratepayers by providing improved compliance with N.C.G.S. § 62-133 and that each PIM in the stipulation appropriately targets a specific policy goal set forth in N.C.G.S. § 62-133. They further testified that the PIMs Stipulation

[5] The NERP was a stakeholder process to examine ways to align utility regulation with the 2019 Clean Energy Plan initiated by Governor Roy Cooper. Tr. vol. 14, 74.

will benefit ratepayers through improved operational efficiencies, cost savings, and reliability of electric service over the course of the MYRP. *Id*.

Power Quality Stipulation

On May 1, 2023, DEP and CIGFUR filed the Power Quality Stipulation. The Power Quality Stipulation provides that DEP and CIGFUR will work together to identify up to 13 industrial customer premises with DEP-owned transmission-to-distribution retail substations exclusively or primarily dedicated to the respective customer (Eligible Premises). Subject to a feasibility review, DEP will install power quality monitoring technology at each of the Eligible Premises and meet with the identified customer at least once annually to review the data from the power quality monitoring technology.

In his testimony supporting the Power Quality Stipulation, CIGFUR witness Nicholas Phillips stated that the stipulation will help ensure that DEP will satisfy the requirement to maintain or improve reliability as North Carolina implements the Carbon Plan. Tr. vol. 21, 495. He testified that the reliability risks posed by inverter-based resources are well-documented and that the Commission has recognized those risks. *Id*. at 496-97.

Witness Phillips explained in his testimony that the power quality pilot program would allow DEP to mitigate the reliability risks associated with inverter-based resources. *Id*. at 497-98. Specifically, he testified that it would allow DEP to: (1) proactively monitor power quality during implementation of the Carbon Plan; (2) gather and share data analytics with the Public Staff and the Commission; (3) determine whether power quality incidents are the result of an individual circuit or customer problem, or potentially part of a larger trend; (4) diagnose potential power quality issues and, pursuant to review, implement solutions to address any such issues; and (5) take a proactive approach to customer service and service quality. *Id.*

Regarding the cost of the pilot program, DEP witness Stillman testified on cross examination that the Power Quality Stipulation does not expressly limit the amount to be spent on the program. Tr. vol. 15, 76. He testified that the cost of installing the power quality monitoring technology would be approximately $10,000 to $25,000 per meter and that the total number of meters necessary for this pilot program is unknown. *Id.* at 75. He further testified that the cost of implementing solutions to any problems identified through the pilot program, as contemplated in the Power Quality Stipulation, will depend on the cause of the specific power quality issue for each premise. He added that the lessons learned from the pilot program will help the whole system, because the more meters that DEP installs, the more DEP will learn about the source of the power quality issues. In acknowledging that DEP intends to seek cost recovery on a cost-of-service basis, witness Stillman testified that the pilot program will help DEP better understand power quality issues, which, ultimately, will be to the benefit of all customers. Tr. vol. 21, 474-76.

Affordability Stipulation

On May 4, 2023, DEP, DEC, Sierra Club, NCJC, et al., and the Public Staff filed the Affordability Stipulation. The Affordability Stipulation obligates DEP to withdraw the affordability PIM proposed in this proceeding. In lieu of the affordability PIM, $16 million of shareholder funds will be dedicated over the next three years to address affordability concerns as follows: $10 million will be contributed to support health and safety repairs that would allow for energy efficiency and weatherization upgrades to homes; and $6 million will be contributed to the Share the Light Fund, which offers customers bill payment assistance. Tr. vol. 22, 99-100. In addition, the stipulation obligates DEP to collect and report annually, in Docket No. M-100, Sub 179, the monthly payments ratio, which is the number of residential payments remitted divided by the number of active residential accounts. Finally, the stipulation obligates DEP to establish its CAP as a three-year pilot program and convene a stakeholder engagement process to consider CAP data, metrics, and future CAP program features.

MGS Partial Rate Design Stipulation

On May 10, 2023, DEP, the Commercial Group, and Kroger Co. and Harris Teeter filed the MGS Partial Rate Design Stipulation, which resolves some of the issues in this proceeding among the parties. The MGS Partial Rate Design Stipulation provides that 75.0% of any reduction in revenue requirement, as determined by final Commission order, applicable to rate schedule MGS-time-of-use (TOU), should be applied to energy rates. The MGS Partial Rate Design Stipulation also obligates Kroger Co. and Harris Teeter to withdraw their proposal related to a multi-site aggregate commercial rate. Finally, the MGS Partial Rate Design Stipulation provides that Kroger Co. and Harris Teeter do not oppose the Revenue Requirement Stipulation or the PIMs Stipulation.

LGS Partial Rate Design

On June 7, 2023, DEP and CIGFUR filed the LGS Partial Rate Design Stipulation, which provides that any increase in energy charges resulting from any increase in DEP's revenue requirement to be recovered from the LGS, LGS-TOU, and LGS-Real Time Pricing (RTP) rate schedules, as determined by final Commission order, shall be limited to a percentage that is less than half of the approved overall increase percentage to the LGS, LGS-TOU, and LGS-RTP classes, respectively, exclusive of any decrements for the LGS, LGS-TOU, and LGS-RTP rate schedules. By its terms, the LGS Partial Rate Design Stipulation would apply to any customer currently taking service under an LGS, LGS-TOU, or LGS-RTP rate schedule who proceeds to take service under either the High Load Factor tariff or Hourly Pricing (HP) tariff, in the event the Commission approves such tariffs in this proceeding.

Supplemental Revenue Requirement Stipulation

On June 27, 2023, DEP and the Public Staff filed the Supplemental Revenue Requirement Stipulation which resolves issues related to the Public Staff audit of DEP's third and final update. On that same date the Public Staff filed the joint supplemental testimony of witness Metz, Zhang, and Boswell in support of the stipulation. DEP also filed testimony in support of the stipulation.

Discussion and Conclusions

Because not all parties to this docket have adopted the stipulations outlined above, 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, 500 S.E.2d 693 (1998) (*CUCA I*), and *State ex rel. Utils. Comm'n v. Carolina Util. Customers Ass'n, Inc.*, 351 N.C. 223, 524 S.E.2d 10 (200) (*CUCA II*) govern the Commission's acceptance of the stipulations. 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.

CUCA I, 348 N.C. at 466, 500 S.E.2d at 703.

However, as the Court made clear in *CUCA II*, the fact that not all 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. *CUCA II*, 351 N.C. at 231, 524 S.E.2d at 16. 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, 524 S.E.2d at 16.

The Commission concludes that the Revenue Requirement Stipulation, the COSS Stipulation, the TCA Stipulation, the PIMs Stipulation, the Power Quality Stipulation, the Affordability Stipulation, the MGS Partial Rate Design Stipulation, the LGS Partial Rate Design Stipulation, and the Supplemental Revenue Requirement Stipulation result from the give-and-take negotiations between the stipulating parties and represent compromises that are fair and adequate to each party. The Commission has fully evaluated the provisions of these stipulations, the testimony proffered by parties in support of these stipulations cited above, the dearth of evidence in the record opposing any of these stipulations, and concludes, exercising its independent judgment, that it should accept in part and reject in part the provisions of the stipulations, consistent with the specific discussion and resolution of the issues set forth below.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 11-13

Depreciation

The evidence supporting these findings of fact is included in DEP's verified Application and Form E-1; the testimony and exhibits of DEP witnesses Spanos and Jiggetts, Public Staff witnesses Zhang and Boswell, Lucas, and McCullar, FPWC witness Tomcyzk, and CIGFUR witness Gorman; and the entire record in this proceeding.

Spanos Direct Exhibit 1 to DEP witness Spanos's direct testimony is the 2021 DEP Depreciation Study prepared by Gannett Fleming (2021 Depreciation Study). Tr. Ex. vol. 10. Witness Spanos testified that the purpose of the 2021 Depreciation Study was to estimate the most current annual depreciation accruals related to electric plant in service for ratemaking purposes and to determine appropriate average service lives and net salvage percentages for each plant account. *Id.* at 352-53.

Section III, Paragraphs 2 and 3 of the Revenue Requirement Stipulation provides that DEP's depreciation rates will be set based on the rates in DEP's 2021 Depreciation Study, as adjusted in the stipulation. In conjunction with the use of DEP's proposed accelerated retirement dates for its Mayo and Roxboro Units 3 and 4, the Revenue Requirement Stipulation provides that 75.0% of the increased depreciation expense due to the accelerated retirement dates will be placed in a regulatory asset. *Id.* Section 5 of S.L. 2021-165 permits securitization for 50.0% of the remaining net book value of subcritical coal plants. The Revenue Retirement Stipulation further provides that at retirement, the net book value amounts that are not securitized will be recovered with a return over an amortization period that the Commission will determine in a future rate case. *Id.* In addition, the Revenue Requirement Stipulation sets forth the following specific adjustments to DEP's depreciation rates: (1) the amortization periods Public Staff witness McCullar proposes for General Plant FERC accounts 391 and 397 will be adopted; and (2) the 70-year life for Transmission FERC account 356 witness McCullar proposes will be adopted. *Id.*

Summary of Evidence

Retirement Dates for Coal Plants

DEP witness Spanos testified that life span estimates included in depreciation studies are based on informed judgment, incorporating factors for each facility such as facility technology, management plans and outlook for the facility, and estimates for similar facilities of other utilities. Tr. vol. 10, 358. Witness Spanos testified that he used these factors to evaluate DEP's recommended retirement dates and agreed that they were reasonable. *Id.* at 417. The 2021 Depreciation Study identified the following retirement dates for the Mayo and Roxboro units:

Unit	2021 Depreciation Study Retirement Dates
Mayo 1	December 31, 2028
Roxboro 1	December 31, 2028
Roxboro 2	December 31, 2028
Roxboro 3	December 31, 2027
Roxboro 4	December 31, 2027

As DEP witness Spanos testified, the Mayo and Roxboro lifespans are shorter than those identified in DEP's 2018 Depreciation Study, with Mayo Unit 1 having a change in retirement date from 2029 to 2028 and Roxboro Units 3 and 4 having a change in retirement date from 2029 to 2027. Tr. vol. 10, 359. The 2021 Depreciation Study indicates a life span for Mayo Unit 1 of 45 years, for Roxboro Unit 3 of 54 years, and for Roxboro Unit 4 of 47 years. *Id.* Witness Spanos testified that while the most common range of life spans for steam production facilities had been 55 to 65 years, these originally proposed life spans have been shortened in recent years due to unit efficiencies and environmental regulations. *Id.* He also testified that the industry average of similar units in recent years has been 46 years. *Id.*

In connection with these retirement dates, DEP witness Jiggetts testified that DEP was requesting permission to defer to a regulatory asset 50.0% of the impact of the accelerated depreciation of DEP's coal plants for North Carolina retail customers in order to preserve the ability to recover those costs through securitization as S.L. 2021-165 authorizes. Tr. vol. 13, 208. Jiggetts testified that because the accelerated dates reflected in the 2021 Depreciation Study would reduce the net book value of the plants at retirement and because DEP wants customers to benefit from any savings that securitization could provide, upon retirement of the facilities DEP proposes to defer to a regulatory asset 50.0% of the remaining net book value. *Id.* Witness Jiggetts testified that this approach preserves for securitization the level of net book value that would have resulted had the expected retirement dates not been updated in the 2021 Depreciation Study. *Id.* DEP also seeks permission to defer to this regulatory asset any costs related to obsolete inventory, net of salvage, at the time of retirement. *Id.* at 208-09.

Public Staff witnesses Lucas and McCullar both addressed the coal plant retirements and life spans in their testimony. In his direct testimony, witness Lucas recommended the use of the retirement dates DEP provided in its 2014 and 2016 Integrated Resource Plans filed in Docket Nos. E-100, Sub 141 and 147, respectively. Tr. vol. 20, 38.

Witness Lucas testified that his recommended retirement dates differ solely for calculating rates in the rate case, not for planning purposes. *Id.* He does not dispute the physical retirement dates that the Commission's Carbon Plan Order established, rather, he testified that issues of reliability and cost inform his recommendations. *Id.* at 38-39; Order Adopting Initial Carbon Plan and Providing Direction for Future Planning (Carbon Plan Order), *Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC, 2022 Biennial Integrated Resource Plans and Carbon Plan*, No. E-100, Sub 179 (Dec. 30, 2022). Witness Lucas testified that if DEP can accelerate depreciation before retirement, customers will not only pay more in the near-term but also that the plants will have less value to securitize in the long-term, thereby muting the benefit of securitization to ratepayers. *Id.* at 39. He testified that because Session Law 2021-165 and Commission Rule R8-74 allow securitization of remaining plant value, the financial benefit of potentially delaying the retirement of either Mayo or Roxboro should not accrue solely to DEP. *Id.*

Witness Lucas further testified that DEP has a plan to replace Roxboro's capacity with hydrogen-enabled combustion turbines and combined-cycle capacity, but it has not fully developed this plan. *Id.* He also testified that DEP has not indicated its plans for replacing general capacity for the Mayo plant. *Id.* Witness Lucas stated that if DEP retires either Mayo or Roxboro before its recommended date, DEP should securitize 50.0% or more of the remaining book value while continuing to depreciate any amount not securitized. *Id.*

Witness McCullar proposed depreciation rates based on the final retirement years provided by witness Lucas. Tr. vol. 21, 138.

FPWC witness Tomcyzk recommended final retirement dates for certain coal units that are later than dates proposed by DEP and recommended that the Commission reject DEP's request to defer 50.0% of the incremental increase in the depreciation expense because implementation of FPWC's revised retirement dates renders the deferral unnecessary. Tr. vol. 21, 729, 734. FPWC's recommended retirement dates would make DEP's request to defer 50.0% of the incremental depreciation unnecessary. *Id.* Witness Tomcyzk stated that, should the Commission approve DEP's retirement dates or otherwise accelerate retirement, then all of the resulting incremental depreciation expenses should be deferred to a regulatory asset. *Id.* at 734-35.

CIGFUR witness Gorman recommended that the Commission reject DEP's proposal to recover the 50.0% of non-deferred accelerated depreciation expenses associated with Mayo Unit 1 and Roxboro Units 3 and 4 through its base rates. Tr. vol. 21, 436. Witness Gorman testified that accelerating the retirement of these units may not be feasible and recommended that the Commission not allow DEP to include costs for such early retirement in its cost of service. *Id.* at 434.

In rebuttal, DEP witness Spanos testified that the retirement dates for the Mayo and Roxboro plants are consistent with informed judgment based on each unit and the expectation within the industry. Tr. vol. 10, 358-59. He testified that many other coal plants either have been or are planned to be retired with lifespans of around 40-45 years and that the proposed lifespans of DEP's plants are consistent with those of other utilities. Tr. vol. 10, 373. DEP witness Jiggetts testified that the retirement dates Public Staff witness Lucas proposed are from DEP's 2013 Depreciation Study and that it is inappropriate to use dates from a 2013 Depreciation Study that is almost 10 years old. Tr. vol. 23, 91. Further, in response to Public Staff witness Lucas' recommendation that DEP securitize 50.0% or more of the remaining book value while continuing to depreciate any amount not securitized, DEP witness Jiggetts responded that S.L. 2021-165 only permits securitization for 50.0% of the remaining net book value for subcritical coal plants and, therefore, that it is only appropriate to apply this proposed ratemaking treatment to 50.0% of the plant balances. *Id.*

In response to Public Staff witness Lucas' proposal to change coal plant retirement dates "for ratemaking purposes only," DEP witness Jiggetts testified that DEP is aligned with this proposal in principle, but not in methodology. *Id.* at 90. DEP witness Jiggetts testified that the depreciation rates should be set based on the actual planned retirement dates, and then deferrals and regulatory assets should be used for jurisdictionally specific ratemaking purposes. *Id.* Witness Jiggetts testified that the methodology is particularly important because securitization of the coal plant balances is only available for DEP's North Carolina retail jurisdiction and, therefore, the more appropriate way to accomplish the result that Public Staff witness Lucas supports is to use deferral and regulatory assets. *Id.* at 91.

Amortization Periods for General Plant FERC Accounts 391 and 397

Public Staff witness McCullar and FPWC witness Tomczyk both object to DEP's proposal to change the amortization period for General Plant FERC account 391, Office Furniture and Equipment, from 20 years to 15 years, and to change the amortization period for General Plant FERC account 397, Communication Equipment, from 20 years to 10 years. Tr. vol. 21, 142, 754. Both witnesses recommend the continued use of the currently approved 20-year amortization period for these accounts. *Id.* Public Staff witness McCullar noted that the Commission previously approved the continued use of 20-year amortization periods for accounts 391 and 397 in the 2019 Rate Case. Witness McCullar stated that DEP is proposing the same amortization periods for these accounts that it initially proposed in the 2019 Rate Case and others. She further stated that the 2021 Depreciation Study in this case did not provide any life data for either account. Tr. vol. 21, 142-43.

In response, DEP witness Spanos notes that the amortization period for these accounts are approved for DEC, and asserted that it is reasonable to use the same amortization periods currently approved for DEC, as those periods are more representative of the appropriate useful life. Tr. vol. 10, 397. He further testified that witness Tomczyk's rationale supporting her proposal to maintain the periods approved in a prior case is insufficient and that an amortization period should reflect the most reasonable useful life of the actual assets in each account. *Id.*

70-year life for Transmission FERC Account 356

For Transmission FERC account 356, Overhead Conductors and Devices, DEP proposes a 65-year estimated average service life with an R2.5 survivor curve. In contrast, Public Staff witness McCullar proposes a 70-year estimated average service life. Witness McCullar argued that the Public Staff's proposal is mathematically a better fit to the actual data and that her estimate included a review of historic observed life data provided in the 2021 Depreciation Study, the relevant information DEP provided in response to discovery, and her previous experience. *Id.* at 147-48.

In response, DEP witness Spanos testified that the witnesses have taken different approaches in interpreting the relevant data, and that he disagrees with these approaches. Tr. vol. 10, 382. FPWC witness Tomczyk and Public Staff witness McCullar both stated that they considered other factors in the development of their life estimates, but they appear to support their estimates primarily with mathematical fitting results, which is one, but not the only, factor to consider when developing a life estimate. *Id.* at 386. DEP witness Spanos argued that the life estimates witnesses Tomczyk and McCullar propose omit any consideration of changes to the transmission system resulting from impacts of DEP's evolving generation fleet, produce overall life cycles that are longer than what is reflected in the historical data, and serve only to lengthen the proposed life of the assets and reduce depreciation expense. *Id.* Additionally, DEP witness Spanos testified that their estimates reflect an expectation that too high a percentage of the overhead conductors will remain reliable.

Other Depreciation Recommendations

Other Production FERC Account 343 and Transmission FERC Account 352 – Survivor Curves

FPWC witness Tomczyk recommends adjustments to the survivor curve applied to Other Production FERC account 343, Prime Movers, and Transmission FERC account 352, Structures and Improvements.

For Other Production FERC account 343 FPWC witness Tomczyk recommends the use of the L0-35 survivor curve, as opposed to the L0-30 survivor curve DEP witness Spanos proposes. Tr. vol. 21, 739. Witness Tomczyk testified that DEP did not provide a reason either in its 2021 Depreciation Study or in DEP witness Spanos' direct testimony as to why the actuarial data for this account was truncated at 39.5 years in the original and smooth survivor curve graphs in the 2021 Depreciation Study. When selecting her recommended survivor curve, witness Tomczyk testified that she considered the sum of the squared deviations (SSDs) for both truncated and full curves to be important. *Id.* at 741. Additionally, she considered the survivor curves other electric utilities use for this account and relied on her professional judgment. Based on her experience, the survivor curves other comparable utilities use typically have associated service lives that exceed those that DEP recommends in this case. *Id.* at 741-42. FPWC witness Tomczyk noted that the only supporting information DEP provided for its survivor curve for this account is that its statistical analyses resulted in “good to excellent indications” of the survivor patterns experience for this account. *Id.* at 742.

For Transmission FERC account 352, FPWC witness Tomczyk recommends the use of an R2.5-70 survivor curve, while DEP recommends an R2.5-65 survivor curve. She testified that, in response to data requests, DEP noted that it truncated actuarial data for this account at 56.5 years in the original and smooth survivor curve graph because assets exposed to retirement above 56.5 years are less significant when compared to the total assets exposed to retirement. Additionally, the retirement activity occurring at ages in excess of 56.5 years is not typical of retirement activity for assets of those ages. Witness Tomczyk generally noted that her proposed survivor curves had lower SSDs when not truncated. Additionally, she noted that FPWC requested, but DEP did not provide, any information that explained the rationale for DEP’s recommended survivor curve. As with account 343, the only information DEP provided indicated that their statistical analyses resulted in what DEP characterized as “good to excellent indications” of the survivor patterns experienced for this account.

In rebuttal, DEP witness Spanos stated that the primary reason for differences between his estimates and FPWC’s estimates for survivor curves is that the parties interpreted the data differently. For Other Production FERC account 343, he argued that FPWC witness Tomczyk appears to base her proposed estimate solely on “mathematical curve matching,” whereas he used a method of “visual curve matching.” He also stated that FPWC witness Tomczyk’s proposed survivor curve for account 343 appears to ignore the most significant portion of the historical data, and instead focuses on assets that have been in service for 35 years or more. These assets represent less than half of the assets exposed to retirement during the overall band of experience and are ones that are less indicative of asset lives into the future. Witness Spanos testified that this is inappropriate when considering an interim survivor curve and that the narrow mathematical curve matching approach is not reasonable. In regard to Transmission FERC account 352, witness Spanos testified that a review of witness Tomczyk’s mathematical approach for this account shows that she was focusing her proposed, elongated survivor curve on a period reflecting nominal retirement experience and that this is not consistent with the future expectations of retirement activity in this account. Tr. vol. 10, 391. Witness Spanos explained during his cross-examination that the job of an analyst doing life estimation is not to match what has happened in the past, but rather to predict what is happening going forward. *Id.* at 462-63. Witness Spanos testified that a focus on mathematical matching can only match what has occurred in the past, which is only a part of the necessary overall analysis. *Id.* at 463.

Transmission FERC Account 353 – Net Salvage Rate

FPWC witness Tomczyk recommends that the Commission use a net salvage rate of negative 10.0%, as opposed to DEP’s proposed net salvage rate of negative 15.0%. Tr. vol. 21, 750. In support of this recommendation, she noted that for the period 1979 through 2021, net salvage averaged 9.0% and that the most recent five-year average is negative 10.0%. *Id.* She also noted that, after reviewing net salvage statistics, the swings in the more recent three-year moving averages for account 353 were much less significant than for most other transmission accounts. *Id.* at 751. She testified that, based on her recent experience, net salvage rates for account 353 most often are in the negative 10.0% to negative 15.0% range. *Id.*

In rebuttal, DEP witness Spanos testified that, although the numbers FPWC witness Tomczyk cited from the 2021 Depreciation Study are correct, she ignored the fact that two of the last five years (2019 and 2021) reflect very low, anomalous cost of removal activity, which DEP should consider when developing a net salvage estimate. Tr. vol. 10, 391. During recent years, annual retirements have been increasing. *Id.* However, in 2019 and 2021, the recorded cost of removal was extremely low related to the retirements. *Id.* Given this nominal cost of removal activity in 2019 and 2021, DEP gave these years less weight than prior years. *Id.* at 391-92. Therefore, given the lag in recording cost of removal to the associated retirements and the increase in the industry for removal cost for substation equipment, witness Spanos argued that the negative 15.0% net salvage estimate is a more reasonable representation of net salvage for future retirements. *Id.* at 392.

Revenue Requirement Stipulation

Sections III, Paragraphs 2 and 3 of the Revenue Requirement Stipulation provide that DEP's depreciation rates will be set based on the rates in the 2021 Depreciation Study as adjusted in the stipulation. In conjunction with use of DEP's proposed accelerated retirement dates for its Mayo and Roxboro Units 3 and 4, the Revenue Requirement Stipulation provides that the 75.0% of the increased depreciation expense due to the accelerated retirement dates will be placed in a regulatory asset. *Id.* S.L. 2021-165 permits the securitization for 50.0% of the remaining net book value for subcritical coal plants. The Revenue Retirement Stipulation further provides that at retirement the net book value amounts that are not securitized will be recovered with a return over an amortization period that the Commission will determine in a future rate case. *Id.* The Revenue Requirement Stipulation sets forth the following specific adjustments to DEP's depreciation rates: (1) the amortization periods proposed by Public Staff witness McCullar for General Plant FERC accounts 391 and 397 will be adopted; and (2) the 70-year life for Transmission FERC account 356 proposed by witness McCullar will be adopted. *Id.*

Discussion and Conclusions

Retirement Dates for Coal Plants

Based on the Revenue Requirement Stipulation and the entire record in this proceeding, the Commission concludes that it is appropriate to depreciate Mayo Unit 1 and Roxboro Units 1-4 based on the accelerated retirement dates proposed by DEP. Section III, Paragraph 2 of the Revenue Requirement Stipulation provides that DEP's proposed retirement dates for its coal plants will be used to set depreciation rates. Witness Spanos testified that he performed a thorough analysis of the life spans for Mayo

Unit 1 and Roxboro Units 1-4 using accepted depreciation methods. His analysis specifically considered factors for each facility such as facility technology, management plans and outlook for the facility, and the estimates for similar facilities for other utilities. As witness Spanos testified on cross-examination, he made site visits, had discussions with operational personnel at each plant site, and took the necessary steps to understand the expectations for the assets and how things may change functionally for various reasons. Tr. vol. 10, 405. Witness Spanos has reviewed DEP's facilities in developing his depreciation studies over numerous years and has a great deal of experience with the specific facilities at issue in this proceeding, as well as steam plants across the country. Furthermore, the life spans DEP proposes for Mayo and Roxboro are consistent with the 45-to-50-year life spans that are occurring across the industry as more utilities transition away from coal burning generation facilities.

The Commission is not persuaded by FPWC witness Tomczyk's assertion regarding the level of uncertainty regarding the retirement dates of Mayo and Roxboro. The Commission notes that the asset retirement dates are established by the Commission in the integrated resource planning process and the retirement dates for Mayo Unit 1 and Roxboro Units 1-4 were addressed in the Carbon Plan Order. The Commission determines that the agreement encapsulated in the Revenue Requirement Stipulation, which addresses DEP's plans for Mayo Unit 1 and Roxboro Units 1-4 using the accelerated retirement dates while also accomplishing the type of rate mitigation that witness Lucas proposed strikes a reasonable balance. The Commission further determines that the provision in the Revenue Requirement Stipulation to increase the proposed deferral to a regulatory asset from 50.0% to 75.0% of the incremental depreciation expense that results from the accelerated retirement is reasonable and appropriate. As provided under the Revenue Requirement Stipulation, DEP will recover 50.0% of net book value through securitization and will recover the remaining amount, with a return, over an amortization period to be determined in a future rate case.

Amortization Periods for Plant FERC Accounts 391 and 397, and 70-year life for Transmission FERC Account 356

Based upon the evidence Public Staff witness McCullar presented, the Commission finds that the settled-upon amortization periods for General Plant FERC accounts 391 and 397 and the 70-year life for Transmission FERC account 356, as outlined in the Revenue Requirement Stipulation, are just and reasonable and appropriate for use in this case.

Other Production FERC Account 343 and Plant FERC Account 352 – Survivor Curves

Based on the entirety of the record the Commission concludes that the survivor curves proposed by DEP in this proceeding are just and reasonable and appropriate for use in this case.

Transmission FERC Account 353 – Net Salvage Rate

Based on all the evidence presented, the Commission concludes that it should not adopt FPWC witness Tomczyk's Transmission FERC account 353 proposal. In particular, the facts that annual retirements have been increasing in recent years, and that DEP reduced the weight afforded to removal activity in 2019 and 2021, weigh in favor of DEP's proposed net salvage rate. Accordingly, the Commission concludes that the proposed net salvage rate of negative 15.0% is just and reasonable and appropriate for use in this case.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 14

Base Period Plant-Related Items

The evidence supporting this finding of fact appears in DEP's verified Application and Form E-1; the testimony and exhibits of DEP witnesses Turner, Jiggetts, Guyton, Maley, and Ray, and Public Staff witnesses Metz, Thomas, Michna, and T. Williamson, the joint settlement testimony of Public Staff witnesses Metz and McLawhorn, and the joint testimony of Public Staff witnesses Boswell and Zhang; the Revenue Requirement Stipulation; and the entire record in this proceeding.

Summary of Evidence

Generation Capital Investments

DEP witness Turner described DEP's traditional/renewable/storage generation fleet and the operational performance of those assets during the test year. Tr. vol. 12, 91. Witness Turner testified as to the major capital projects undertaken by DEP for maintenance of its fossil, renewable, and storage fleets. *Id*. at 96. In testifying on the importance of the traditional fossil fleet to customers in North Carolina, she explained that the diversity of the resource and fuel mix, and availability of coal generation during the transition away from coal, must be strategically managed to ensure the remaining coal fleet can reliably contribute to resource adequacy. She testified that as DEP makes plans to retire its remaining coal fired assets, and replace those assets with other resources, DEP must keep these remaining units in efficient working order to support the energy needs of its customers. She explained that DEP will continue to make investment in these assets to ensure that the same reliable cost effective electricity that customers have counted on for decades remains available while the replacement of those units is developed and implemented. Additionally, she testified that the combination of generation resources that replaces coal must be able to provide the same level of reliability that the coal units have provided and that because natural gas is critical to the resource mix – particularly during the winter months and while energy storage capacity is being developed and deployed – DEP will continue to rely on its natural gas fleet as part of the diverse and dispatchable resource mix to ensure the reliability of service to DEP customers. Tr. vol. 12, 91-95. Witness Turner also testified regarding DEP's hydro fleet capital maintenance projects, which were undertaken primarily for regulatory compliance. She further testified as to DEP's addition of three battery installations, including the

Asheville/ Rockhill storage project, the Hot Springs Microgrid, and the Camp Lejeune project. *Id.* at 96-97. Finally, she testified as to her opinion that DEP has reasonably and prudently operated its fossil/hydro/solar fleet during the test period. *Id.* at 99-101.

DEP witness Ray described DEP's nuclear generation assets and capital additions made to the fleet since the 2019 Rate Case to enhance safety and efficiency preserve performance and reliability of the plants throughout their extended life operations, and address regulatory requirements. Tr. vol. 16, 154. Witness Ray described how these capital additions are or would be by the capital cutoff date used and useful in safely and efficiently providing reliable electric service to DEP's customers. Tr. vol. 16, 152-62. He testified about the exceptional performance of the nuclear fleet during the test period and initiatives that DEP has undertaken to increase nuclear operational efficiency. *Id.* at 168-70. He testified that, in comparison to others in the industry, DEP's nuclear fleet has a history of top performance, including a test period capacity factor of 94.94%, which exceeds the average capacity factor for comparable units published in the most recent North American Electric Reliability Council's (NERC) Generating Unit Statistical Brochure. *Id.* at 70.

Public Staff witnesses Metz, Thomas, and Michna reviewed aspects of DEP's capital investments in its traditional/renewable/storage generation fleet. Public Staff witness Metz described his review of DEP's historic costs associated with projects placed in service for the period June 2020 through November 2022, noting that his investigation included multiple site visits to DEP's fleet of generating stations and to an operations center, as well as numerous meetings with DEP personnel. Tr. vol. 16, 412. Witness Metz did not propose any adjustments to the base case capital investment costs for the fossil/hydro or nuclear fleets. Public Staff witness Thomas reviewed DEP's capital additions to solar, storage and hydro plant since the 2019 Rate Case and recommended an adjustment regarding the Blewett Falls Fishing Pier and the Hot Springs Microgrid. Tr. vol. 19, 172. Public Staff witness Michna reviewed DEP's capital additions for steam generation since the 2019 Rate Case and recommended an adjustment to the aqueous ammonia conversion project at Mayo Station (Mayo Ammonia Conversion Project). Tr. vol. 21, 285.

Blewett Falls Fishing Pier

Public Staff witness Thomas recommended that DEP remove the Blewett Falls fishing pier from the base case and include it in the MYRP Rate Year 1 based on his conclusion that, although DEP asserted that it placed the fishing pier in service in 2021, it is not yet complete or open for public use and will remain closed for safety reasons. Tr. vol. 19, 208-09.

DEP witness Turner testified that DEP placed the pier in service pursuant to DEP's capital accounting guidelines in January 2021, but that it is not currently open for public access due to ongoing construction of a fish passage facility directly next to the pier. Witness Turner asserts that public accessibility does not determine whether an asset is in service, and that Public Staff witness Thomas did not meaningfully challenge DEP's application of the accounting guidelines, which govern the in-service determination. Tr. vol. 12, 141.

In the Revenue Requirement Stipulation, DEP accepted the Public Staff's recommendation to move the fishing pier project and its associated costs out of the base case and into the MYRP Rate Year 1. Revenue Requirement Stipulation § II.33.a, Tr. Ex. vol. 7. DEP witnesses Abernathy and Jiggetts and Public Staff witnesses McLawhorn and Metz supported this provision in their settlement supporting testimony. Tr. vol. 13, 138-40, 254-55, 262; Tr. vol. 16, 514.

Mayo Ammonia Conversion Project

Public Staff witness Michna recommended an adjustment to remove $3,230,371 in costs for the Mayo Ammonia Conversion Project. Witness Michna recommended the adjustment based on his conclusion that DEP's decision to not update the cost benefit analysis for the project after significant delays to account for significant changes in cost and the projected station retirement date was not prudent. Tr. vol. 21, 295-97.

DEP witness Turner testified that DEP's development and execution of the project has been reasonable and prudent, emphasizing that the driving factor for the project was elimination of the safety risk to plant personnel that the existing ammonia system presents. Tr. vol. 12, 139-40.

As part of the Revenue Requirement Stipulation, DEP accepted the Public Staff's proposed adjustment related to the Mayo Ammonia Conversion Project. Revenue Requirement Stipulation § III.10, Tr. Ex. vol. 7. DEP witness Jiggetts and Public Staff witnesses McLawhorn and Metz supported this provision in their settlement supporting testimony. Tr. vol. 13, 254-55, 263; Tr. vol. 16, 514.

Hot Springs Microgrid

Public Staff witness Thomas recommends that the solar costs associated with the Hot Springs Microgrid be allocated 100.0% to the "Other Production Plant" account as opposed to DEP's proposed allocation of 50.0% to "Distribution Plant" and 50.0% to "Other Production Plant." Tr. vol. 19, 192. DEP accepted this recommendation in rebuttal testimony and agreed to make the corresponding accounting adjustment. Tr. vol. 11, 47. The Revenue Requirement Stipulation reflects this adjustment.

Transmission and Distribution Base Period Investments – Non-Grid Improvement Plan (GIP)

In their direct testimonies, DEP witnesses Guyton and Maley discussed DEP's distribution and transmission investments since its last general rate case. DEP Witness Guyton testified that DEP had invested approximately $814 million in new distribution infrastructure since DEP's last rate case, which included investments in DEP's GIP. Witness Guyton testified that non-GIP distribution investments during the base period included targeted reliability and maintenance programs, and customer driven line and substation expansions. Tr. vol. 10, 38. In his direct testimony, witness Maley testified that DEP had spent approximately $390 million in additional transmission infrastructure since its last rate case, the bulk of which was for reliability and capacity improvements. Tr. vol. 10, 169-70.

In their direct testimonies, Public Staff witnesses Metz and T. Williamson took issue with some of the transmission and distribution capital investments made by DEP since its last case, as discussed in more detail below. Specifically, witness Metz took issue with the inclusion in rate base of capital associated with a newly refurbished transmission service building project (Project Florence), as well as the timing of inclusion in rate base of investments in a new Electric Systems Operation center (Project Walter). In addition, in his direct testimony, witness T. Williamson recommended a $712,867 disallowance for costs associated with contractor damage to a Wilmington voltage regulator platform.

Project Florence and Project Walter

Public Staff witness Metz described DEP's Project Florence to support maintenance and construction for transmission service projects in Florence, South Carolina. Project Florence included demolishing facilities at DEP's existing site to build a new consolidated single building to serve DEP's Carolinas East Southern Region. Tr. vol. 16, 416-18. In his direct testimony, Public Staff witness Metz recommended removal of the costs for Project Florence due to insufficient information from DEP to justify the project. *Id.* at 420.

Witness Metz also described DEP's Project Walter, a new energy control/operations center to operate DEP's bulk electric system and manage DEP's distribution system. Tr. vol. 16, 424. Based on his review of when the project would begin to serve its intended purpose, witness Metz recommended that DEP include the project in Rate Year 1 of the MYRP rather than in the base period. *Id.*

On rebuttal, DEP witness Guyton testified that Project Florence was prudent, and that the refurbishment of facilities was necessary to efficiently meet increased and growing demand on the transmission operations center in terms of personnel and equipment and that the pre-existing buildings were no longer sufficient to meet DEP's need. Tr. vol. 10, 139-40. On rebuttal, witness Guyton also asserted that Project Florence is currently used and useful as evidenced by the fact that construction is complete, local authorities have issued certificates of occupancy, and the building is in active use for certain functionalities, with the remaining functionalities to be working out of the building before rates are in effect in this proceeding. Tr. vol. 10, 135.

Section III, Paragraph 9 of the Revenue Requirement Stipulation provides that the Project Florence costs shall be included in rate base and the costs of Project Walter shall be moved into Rate Year 1 of the MYRP as recommended by Public Staff witness Metz.

Wilmington Voltage Regulator Platform

Public Staff witness T. Williamson described the Wilmington Voltage Regulator Platform project, which DEP undertook in order to provide additional clearance below the regulator platform DEP uses in its Distribution System Demand Response (DSDR) project. Tr. vol. 21, 203-04. Witness T. Williamson recommends an adjustment due to equipment damage a contractor caused during this project. *Id.* at 205. In his rebuttal testimony, DEP witness Guyton challenged the amount of the Public Staff's disallowance for the Wilmington voltage regulator platform incident, on the grounds that witness T. Williamson did not allege that DEP had been negligent or responsible in any way for the contractor damage. Witness Guyton also asserted that any adjustment should only be for the incremental cost of the contractor damage ($267,282), rather than the entire cost of the project. Tr. vol. 10, 140.

Section III, Paragraph 7 of the Revenue Requirement Stipulation reduces the Wilmington voltage regulator costs as Public Staff witness Williamson recommended but with the further adjustment witness Guyton suggested in his rebuttal testimony.

Discussion and Conclusions

Based on the entire record in this proceeding, the Commission concludes that the costs related to DEP's investments in its fossil, renewable, storage, and nuclear fleet assets as well as its transmission and distribution investments made during the test period, as adjusted by the Revenue Requirement Stipulation, were reasonably and prudently incurred and should be recovered. The Commission further concludes that the adjustments for the Blewett Falls Fishing Pier, the Mayo Ammonia Conversion Project, and the Hot Springs Microgrid as the Public Staff and DEP agreed in the Revenue Requirement Stipulation are reasonable. Finally, the Commission concludes that the adjustments related to Project Walter, Project Florence, and the Wilmington Voltage Regulator Platform project, as included in the Revenue Requirement Stipulation are reasonable.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 15-17

Grid Improvement Plan Cost Recovery

The evidence supporting these findings of fact is included in the testimony and exhibits of DEP witnesses Guyton, Maley, and Jiggetts, Public Staff witnesses Zhang and Boswell, the Revenue Requirement Stipulation, and the entire record in this proceeding.

Summary of Evidence

DEP witness Maley testified that DEP's GIP is enabling new grid capabilities and that the System Intelligence program has begun deployment of dynamic, smart devices with the ability to remotely locate, sectionalize, and assess damage. Tr. vol. 10, 179. Witness Maley testified that the deployment of remote monitoring and control devices with digital relays supports rapid response to system outages and disturbances to quickly restore power to the maximum number of customers and to enable better management of distributed energy resources. *Id.* DEP installed approximately 350 relays and 9 remotely capable switches over the 19 months immediately preceding the date on which DEP filed the Application. In the period starting June 1, 2020, through December 31, 2021, DEP made North Carolina GIP transmission investments totaling $9.2 million. *Id.* at 179-80. Witness Maley testified that DEP was on track to complete North Carolina GIP work scope in its three-year plan by December 31, 2022. *Id.* at 181.

DEP witness Guyton testified that DEP developed its GIP to build grid capabilities needed to address the implications of seven megatrends. These megatrends represent key trends that drive the need to prepare the grid to safely and efficiently distribute the energy which customers depend on in their daily lives. *Id.* at 56. Witness Guyton also testified about the operational benefits associated with the GIP work that DEP had completed as of the filing of the Application. He testified that the GIP projects, which reduce the frequency and impact of outages, are contributing to the improving trends for the System Average Interruption Index (SAIFI) and the System Average Interruption Duration Index (SAIDI). *Id.* at 50. He testified that, as an example, the Self Optimizing Grid program redesigns key portions of the distribution system, transforming it into a dynamic, smart-thinking grid that can automatically reroute power around trouble areas so that power can be quickly restored to the maximum number of customers and line crews can directly and rapidly be dispatched to the source of the outage. *Id.*

He testified that the GIP distribution investments and the North Carolina retail allocated portion of general and intangible plant investments through the December 31, 2021, test period totaled $52.6 million. *Id.* at 54.

DEP witness Jiggetts testified that in the 2019 Rate Case the Commission approved deferral of certain GIP-related costs for projects placed in service through December 31, 2022, until the costs could be considered for recovery in DEP's next general rate proceeding. Tr. vol. 13, 194-95. With respect to the specific costs that have been deferred, DEP witness Maley testified that DEP has deferred incremental O&M expenses, depreciation, and property taxes associated with the GIP, as well as the carrying cost on the investments and the deferred costs at DEP's weighted average cost of capital. Tr. vol. 10, 182. In her initial direct testimony DEP witness Jiggetts testified that by of the end of 2022, DEP will have placed in service investments of approximately $236.7 million on a North Carolina retail basis. She explained that DEP proposes to amortize the GIP regulatory asset of $38.8 million over a three-year period, which results in an amortization expense of $12.9 million. Tr. vol. 13, 195. In supplemental testimony, DEP witness Jiggetts updated the GIP-related costs to replace estimated data with actual amounts incurred through December 31, 2022, and to reflect a change in the capital cutoff date to March 31, 2023. [6] *Id.* at 224. Witness Maley testified that DEP proposes to roll these costs into base rates in the current rate case. Tr. vol. 10, 182.

While the Public Staff agreed with DEP's assertion that the Commission approved deferral accounting treatment for the GIP programs, the Public Staff took issue with DEP's calculation of the GIP deferral balance. Tr. vol. 19, 59-63. Specifically, Public Staff

[6] The total GIP investment made by DEP as of December 31, 2022, on a North Carolina retail basis is approximately $197 million as shown in the December 2022 NC GIP Biannual Report filed on March 1, 2023 in Docket Nos. E-7, Sub 1214B and E-2, Sub 1219B and Jiggetts Partial Settlement Exhibit 4.

witnesses Zhang and Boswell testified that DEP's inclusion of O&M expenses are outside of the allowable expenses envisioned by the Commission's approval in the 2019 Rate Case. Tr. vol. 19, 62-63. The Public Staff argued that the GIP deferral approved in the 2019 Rate Case is restricted to incremental expenses net of operating benefits. Therefore, the deferral does not include overhead or administrative and general costs but may include a reasonable allocation of management and supervision costs. *Id.* The Public Staff asserted that some of the O&M expenses included in the deferral were not incremental, that DEP had not determined the amount of any operating benefits, and that the O&M expenses included overhead and administrative and general costs. *Id.* As explained by DEP witness Jiggetts, the Public Staff proposed the following adjustments related to DEP's proposed recovery of the deferred GIP costs: 1) removal of $6 million in system O&M costs based on the contentions that DEP did not provide support for amounts after March 2022 and that certain of the costs did not meet the criteria for deferral based on 2019 Rate Case; and 2) an amortization period of 30 years.

DEP witness Guyton testified on rebuttal that the labor expense deferred for GIP projects was incremental to base labor included in rates since DEP had already reduced the deferral by the amount of installation O&M included in current rates. He asserted that the Public Staff's adjustment to remove O&M for GIP O&M-only projects is not reasonable, on the basis that incremental installation is correctly accounted for as O&M. Tr. vol. 10, 141. He also disputed the Public Staff's position on administrative and general costs and testified that such costs were appropriately included in allocation pools that are added to capital projects in accordance with DEP's accounting practices and cost allocation manual. *Id.* at 142. DEP witness Jiggetts also testified on rebuttal as to DEP's disagreement with the Public Staff's adjustment to remove O&M expenses, with the contention that certain expenses were not appropriately allocated to the GIP projects, and with the contention that 30 years is the appropriate amortization period. Tr. vol. 23, 67-70.

Section III, Paragraph 11 of the Revenue Requirement Stipulation provides that DEP is permitted to recover the full balance of its Grid Improvement Deferral over an 18-year amortization period, with a debt-only return during the deferral period and rate base treatment during the 18-year amortization period. No intervenor took issue with this provision of the stipulation. The costs associated with the GIP deferral, as settled upon by the Public Staff and DEP, results in a deferred balance on September 30, 2023, of $22.364 million, and annual amortization expense of $1.242 million, as set forth in DEP witness Jiggetts Partial Settlement Exhibit 4. Tr. Ex. vol. 14.

Discussion and Conclusions

The Commission concludes that the evidence presented supports the treatment of the deferred GIP-related costs as agreed to by DEP and the Public Staff in the Revenue Requirement Stipulation and that the treatment strikes a just and reasonable balance between recovery of costs and mitigation of impacts to customers and, thus, should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 18-19

Coal Ash

The evidence supporting these findings of fact is included in the Coal Combustion Residuals Settlement Agreement approved in the Commission's Order in the 2019 Rate Case, Order Accepting Stipulations, Granting Partial Rate Increase, and Requiring Customer Notice, *Application by Duke Energy Progress, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina*, No. E-2, Sub 1219 (Apr. 16, 2021) (CCR Settlement); DEP's verified Application and Form E-1; the testimony and exhibits of DEP witnesses Jiggetts and Hill, Public Staff witnesses Zhang and Boswell and Lucas, CIGFUR witness Gorman; and the entire record in this proceeding.

DEP witness Hill provided testimony as to DEP's activities to close ash basins and landfills along with other CCR management units for the period since DEP's last rate case. Tr. vol. 16, 86. Witness Hill testified that the actual and forecasted activities, as well as costs incurred, were reasonable and prudent. *Id.* Moreover, he testified that DEP implemented its plans in accordance with closure and corrective action plans that have been approved by the relevant state environmental agencies – in North Carolina, the Department of Environmental Quality, and in South Carolina, the Department of Health and Environmental Control. *Id.* He testified that DEP has also complied with its obligations under the CCR Settlement. DEP witness Jiggetts presented DEP's request to amortize deferred costs associated with the CCRs and to continue deferring costs related to compliance with coal ash regulations. Tr. vol. 13, 163. Witness Jiggetts testified as to the key components of the CCR Settlement and the associated adjustments made in this case to comply with the CCR Settlement, including the use of proceeds from insurance claims to offset CCR compliance costs. *Id.* at 191. She explained that the CCR costs sought for recovery are based upon actual costs incurred from March 1, 2020 through December 31, 2022, and updated amounts through March 31, 2023, provided in the supplemental filing made on April 18, 2023. *Id.*; Tr. vol. 23, 63. She testified that the cost, less the adjustments, totals approximately $647.8 million on a system basis and $399.3 million on a North Carolina retail basis. *Id.* She testified that DEP's adjustment amortizes the net deferred balance over a five-year period. *Id.* Witness Jiggetts also testified that DEP proposes to offset the over-amortization for the CCR costs established in the 2017 Rate Case in the amount of $8.5 million against the Coal Ash CCR ARO deferral DEP sought recovery of in this case. Witness Jiggetts testified that the balance sought for recovery in this case is being offset by North Carolina retail customer's share of insurance proceeds, calculated in accordance with the CCR Settlement terms, of $80.7 million. *Id.* at 193.

Public Staff witness Lucas investigated DEP's management of CCRs, construction and operation of DEP's CCR beneficiation projects, and proceeds from DEP's litigation of CCR insurance claims. Tr. vol. 20,15. After performing a thorough review, witness Lucas concluded that DEP's CCR management practices have been sufficient to prevent unnecessary costs to its customers, that DEP has complied with the coal ash beneficiation statute and the Commission's requirements, and that DEP's construction and operation of its two beneficiation projects since the last rate case have been sufficient to prevent unnecessary costs to customers. *Id.* at 20-25. Finally, witness Lucas found that DEP properly credited North Carolina retail customers with proceeds from the insurance litigation. *Id.* at 26.

Public Staff witnesses Zhang and Boswell recommended that the Commission return all expiring amortizations to customers as a single rider over a period of one year with interest. Tr. vol. 19, 73.

CIGFUR witness Gorman recommended two revenue requirement adjustments to DEP's recovery of CCR compliance costs. Tr. vol. 21, 438-39.

The adjustments recommended by the Public Staff and CIGFUR regarding CCR costs were resolved in the Revenue Requirement Stipulation. While the Revenue Requirement Stipulation did not specifically address the CCR cost adjustments recommended by CIGFUR or the Public Staff, Section III of the stipulation provides that no further adjustments other than those specifically identified in the stipulation would be made to DEP's base period revenue requirement. In addition, Paragraph 7 of Section II of the Revenue Requirement Stipulation notes that the Public Staff's proposal to return expiring amortizations to customers in a single rider only applies to non-CCR over-amortizations. Tr. Ex. vol. 7.

Based on the entire record in this proceeding, including the testimony cited above as well as the relevant provisions of the Revenue Requirement Stipulation, the Commission concludes that the CCR costs sought for recovery are reasonable and prudent and consistent with the CCR Settlement. The Commission also concludes that DEP has complied with the CCR Settlement and has made the agreed-upon adjustments in this case to reflect that settlement. The Commission approves DEP's applying the over-amortization of CCR costs as established in the 2017 Rate Case in the amount of $8.5 million against the CCR deferred balance in this case, and the Commission approves the recovery of the net deferred balance over a five-year period. The Commission also approves DEP's request to continue the deferral of any CCR cost DEP incurs subsequent to March 31, 2023, for future recovery consistent with the CCR Settlement.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 20-21

Harris Land Sales

The evidence supporting these findings of fact is included in DEP's verified Application and Form E-1; the testimony and exhibits of DEP witness Jiggetts and Public Staff witnesses Zhang and Boswell; the Revenue Requirement Stipulation; and the entire record in this proceeding.

The Commission required deferral of the gains on the sale of excess land at DEP's Harris nuclear plant in its August 13, 1992 Order in Docket Nos. E-2, Subs 537 and 333. In 2020 and 2021, DEP completed five sales transactions of excess land and deferred the North Carolina retail share of the gains on those transactions in compliance with the Commission's order. Tr. vol. 13, 195. DEP proposes to amortize those deferred gains over a six-year period. *Id.* The Public Staff, however, proposed a four-year amortization period. Tr. vol. 19, 72. The Revenue Requirement Stipulation provides for a three-year amortization period. Revenue Requirement Stipulation § III.22, Tr. Ex. vol. 7. No intervenor took issue with this provision of the stipulation. The Commission concludes that the evidence supports the three-year amortization period the parties propose in the Revenue Requirement Stipulation, and that the three-year amortization period is just and reasonable and fair to all parties and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 22-23

Roxboro Wastewater Treatment Regulatory Asset

The evidence supporting these findings of fact is in DEP's verified Application and Form E-1; the testimony and exhibits of DEP witness Jiggetts and the joint testimony and exhibits of Public Staff witnesses Zhang and Boswell; the Revenue Requirement Stipulation; and the entire record in this proceeding.

In the 2019 Rate Case, the Commission allowed DEP to establish a regulatory asset for the unrecovered costs associated with the Roxboro Wastewater Treatment Plant at the time of its early retirement. The Commission allowed amortization of the regulatory asset at the existing depreciation rate to continue until it determined an appropriate amortization period in a future rate case. DEP proposed to amortize the remaining regulatory asset over a five-year period. Tr. vol. 13, 189-90. Public Staff witnesses Zhang and Boswell recommended an amortization period of 11 years, consistent with the overall remaining depreciable life of the assets if they had remained in service. Tr. vol. 19, 71. The Revenue Requirement Stipulation, Section III, Paragraph 24, provides for a 12-year amortization period for the recovery of the Roxboro Wastewater Treatment Plant regulatory asset. Tr. Ex. vol. 7. The Commission concludes that the evidence presented supports the 12-year amortization period in the Revenue Requirement Stipulation, and that the 12-year amortization period is just and reasonable and fair to all parties and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 24-25

Revenue Requirement Stipulation – Storm Securitization Overcollections

The evidence supporting these findings of fact is in DEP's verified Application and Form E-1, the testimony and exhibits of DEP witness Jiggetts, and the entire record in this proceeding.

In the Agreement and Stipulation of Partial Settlement with the Public Staff filed in Docket No. E-2, Sub 1262, DEP agreed to establish regulatory asset or regulatory liability accounts for the purpose of tracking up-front financing costs and servicing and administration fees related to storm securitization. In the instant proceeding, DEP proposed to amortize the regulatory liability of $1.0 million for overcollections associated with storm securitizations over a three-year period. Tr. vol. 13, 202-03. The Public Staff did not oppose this recovery timeframe. No intervenor took issue with this proposal. The Commission concludes that the evidence supports the three-year amortization period DEP proposes, and that the three-year amortization period is just and reasonable and fair to all parties and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 26

Cost of Debt

The evidence supporting this finding of fact is in DEP's verified Application and Form E-1, the testimony and exhibits of DEP witness Newlin, the Revenue Requirement Stipulation, and the entire record in this proceeding.

DEP witness Newlin testified that DEP's long-term debt cost as of December 31, 2021, was 3.71%, which was the value DEP used to determine the revenue requirement in DEP's Application. Tr. vol. 9, 97. Section III, Paragraph 1 of the Revenue Requirement Stipulation establishes that the embedded cost of debt as of March 31, 2023 shall be used to calculate DEP's revenue requirement. Tr. Ex. vol. 7. DEP witness Jiggetts presented in her supplemental testimony that the embedded cost of debt as of March 31, 2023, is 4.03%.

No intervenor offered any evidence opposing this provision of the stipulation. The Commission therefore concludes that the use of a debt cost of 4.03% per the terms of Section III, Paragraph 1 of the Revenue Requirement Stipulation is just and reasonable to all parties considering all the evidence presented.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 27

Accounting Adjustments in Revenue Requirement Stipulation

The evidence supporting this finding of fact is included in DEP's verified Application and Form E-1; the testimony and exhibits of DEP witnesses Council, Jiggetts, Quick, Speros, Stewart, Ray, and Turner, Public Staff witnesses Zhang and Boswell, McLawhorn, and Metz, and CIGFUR witness Gorman; the Revenue Requirement Stipulation; and the entire record in this proceeding.

Summary of Evidence

Incentive Compensation

In his direct testimony, DEP witness Stewart included as a cost of service incentive compensation at target levels that are assigned or allocated to DEP. Tr. vol. 16, 212. Public Staff witnesses Zhang and Boswell testified that incentive compensation related to the Earnings Per Share (EPS) and Total Shareholder Return (TSR) metrics for all employees should be removed from the revenue requirement because these metrics provided a direct benefit to shareholders rather than ratepayers. Tr. vol. 19, 48-49. CIGFUR witness Gorman concurred with this assessment. Tr. vol. 21, 405.

In rebuttal, DEP witness Stewart refuted these contentions, asserting that metrics such as EPS and TSR are appropriate for recovery, as they benefit customers. Tr. vol. 23, 293-95.

The Revenue Requirement Stipulation establishes that DEP employee incentives should be adjusted to remove incentive pay related to EPS and TSR for the top levels of DEP's leadership, but not for the remainder of the employees. Revenue Requirement Stipulation § III.12, Tr. Ex. vol. 7. No intervenor took issue with this provision of the Revenue Requirement Stipulation. The Commission concludes that the Revenue Requirement Stipulation provides a reasonable resolution of this issue for purposes of this proceeding.

Rent Expense

DEP witness Jiggetts' direct testimony included a pro forma adjustment to increase O&M expenses to reflect incremental rent expenses, net of savings, associated with the changes in the Charlotte real estate portfolio and the Duke Energy Plaza building. Tr. vol. 13, 187. Public Staff witnesses Zhang and Boswell removed the portion of rent expense related to the Duke Energy Plaza building because the building is still under construction and cannot be utilized for its intended purpose. Tr. vol. 19, 58. The Public Staff included additional amounts to bring the rent expense to a representative level by utilizing some 2021 costs and applying the updated DEBS allocation. In addition, the Public Staff expressed concerns about the real estate portfolio, considering the reduction in work force and DEP's new workforce model allowing employees to work a hybrid schedule, reducing the office facilities necessary at any given time. *Id.*

In rebuttal testimony, DEP witness Jiggetts testified that DEP does not agree with the Public Staff's adjustments to rent expense and that the rent expense as calculated by DEP reflects all known and measurable updates to the rent costs expected to be incurred by DEP. Tr. vol. 23, 76-77. In addition, she noted that DEP began incurring rent expense for the Duke Energy Plaza on January 1, 2023, and that DEP included a full year of expense for the building because, as explained in the rebuttal testimony of DEP witness Council, the detailed schedule for the building shows that all construction will be completed, and the building occupied by the effective date of the new rates in this proceeding. *Id.* at 77. Thus, she testified that the Duke Energy Plaza rent expense is a known and measurable and prudent and reasonable expense that will be incurred by DEP, which is a fact that the Public Staff had not challenged. *Id.* Further, she testified that because DEP is paying rent expense to DEC for the Duke Energy Plaza building, if the Duke Energy Plaza rent expense is removed from DEP's revenue requirement, the comparable adjustment to remove the rent income from DEC should be made to keep the revenue and costs between the affiliates aligned. *Id.* at 78. In her rebuttal testimony, DEP witness Council testified that the Duke Energy Plaza building is presently in use, with several floors currently occupied, and that the entire building is anticipated to be completed and fully occupied by third quarter 2023, which is before the requested rates become effective in this case. *Id.* at 247.

The Revenue Requirement Stipulation, in Section III, Paragraph 13, provides for an increase in test year rent expense of $4,440,000 on a North Carolina retail basis for increased rent expense, net of depreciation savings. Tr. Ex. vol. 7. The parties further agreed to address the reasonableness and prudence of the costs of the Duke Energy Plaza in the DEC Rate Case in Docket No. E-7, Sub 1276. Tr. vol. 23, 78. The Commission concludes that the Revenue Requirement Stipulation provides a reasonable resolution of this issue for purposes of this proceeding.

Reliability Assurance O&M Adjustment

In her direct testimony, DEP witness Turner testified regarding the importance of keeping DEP's remaining coal-fired assets in efficient working order to support customer's energy needs as DEP plans for those units' retirement and explained that DEP will continue to incur costs for these assets as appropriate and prudent to ensure that reliable cost-effective electricity remains available while DEP develops and implements replacement of the coal fleet. Witness Turner also testified that the fossil/hydro units operated efficiently and reliably during the test period. Tr. vol. 12, 94-95, 99.

In her supplemental testimony, witness Turner explained the rationale for DEP's pro forma adjustment to O&M expenses for reliability assurance. Witness Turner stated that the adjustment increased by $7.8 million the test period O&M costs related to planned reliability assurance projects. These additional projects are necessary to contribute to the reliability of plans for the Roxboro and Mayo plants and include winterization projects. Tr. vol. 12, 118.

Public Staff witness Metz testified regarding DEP's historic operations of its generating fleet since the 2019 Rate Case and other discrete performance metrics over the last decade. Part of his review considered the overall system reliability, service quality, and reasonableness of using DEP's test year O&M costs as a proxy for expected future costs. The primary purpose of the review was to determine whether and how DEP's historic operation of its generation fleet has changed. Witness Metz supported the use of the weighted equivalent availability factor (WEAF) or weighted equivalent unplanned outage factor (WEUOF), as well as other metrics, in reviewing fleet performance and noted that different conclusions are possible depending on the performance metrics one uses. He clarified that the intent of the review was not to determine reasonableness or prudence of DEP's historic operations of its fleets. Witness Metz concluded that the fossil fleet's performance has degraded over the last decade, and suggested that if that trend continues, reliability could be impacted, especially as these units must perform in a different manner than originally designed and as DEP removes other generation units from service. Witness Metz also noted DEP's reduction of fleet O&M expenses, which DEP accomplished in part by reducing staffing, in the years following its recent rate cases. Tr. vol. 16, 431-42, 447.

Witness Metz testified that there is merit to the proposed adjustment based on the coal unit availability and outage rates but also asserted that DEP reduced the level of ongoing generating plant non-fuel O&M expense the very next year after Commission approval in the last two general rate cases. Tr. vol. 16, 447. Based on the concerns he identified with O&M expenses and fleet performance, witness Metz recommended several modifications to the adjustment to coal test year O&M expenses (Form E-1, Item 10, NC-2160[7]):

- Since DEP should have already completed the Reliability Threat Analysis and Winterization O&M project work, witness Metz recommended exclusion of the costs related to Reliability Threat Analysis work from any proposed pro forma adjustment and supported the inclusion of a reduced amount for the Winterization O&M work. Tr. vol. 16, 449.

- Since the majority of the costs related to reliability improvements appeared to be capital-related rather than O&M related, witness Metz recommended inclusion of those costs in the MYRP and their exclusion from the pro forma adjustment. *Id.* at 450.

- Since there is no certainty that DEP will hire and continue to employ the proposed level of increased staff at the Roxboro and Mayo coal plants, witness Metz proposed decreasing by half DEP's 2023 staffing work request. *Id.*

- Witness Metz recommended that the Repair Hold category adjustment should be rejected because this category is an attempt to clear a backlog of a larger volume of inventory (spare parts) to be repaired. *Id.* at 449-51.

In her rebuttal testimony, DEP witness Turner described the challenge of optimizing plant investments and maintaining sufficient staffing for the coal-fired assets that DEP will retire in the near-term future. Mayo and Roxboro Stations will be the last DEP coal-fired stations DEP will retire, but DEP continues to need them to serve customers. Witness Turner explained that DEP must maintain the continued reliability of these units until replacement generation is in place. Witness Turner explained further that DEP's strategy for addressing this challenge has evolved as circumstances have changed. DEP seeks to allocate more investment to the fossil units that are the most efficient and economical, and therefore most often dispatched (as well as projected to be necessary over the long term), while still making prudent but measured investments in the coal units, balancing the need to maintain their reliability while looking forward to their eventual retirement. Tr. vol. 12, 121-22.

Witness Turner also responded to witness Metz's specific recommendations regarding the Reliability Assurance pro forma NC-2160 and provided additional details regarding this work. With respect to the major components/Reliability Threat Analysis work, she explained that DEP identified this work as necessary through the Reliability Threats

[7] Pro-forma NC-2160 was filed in DEP's February update.

Analysis that DEP conducted in late 2022 and that DEP intends the work to address large items of equipment DEP needs to maintain unit reliability. Witness Turner disagreed with witness Metz's recommendation to remove the costs for the major components/Reliability Threat Analysis work from the pro forma. She explained that the Reliability Threat Analysis is not winter storm related and that, therefore, DEP would not have done the work reflected in the pro forma item subsequent to previous winter storms. Tr. vol. 12, 124-25. Witness Turner testified that the winterization O&M project category represents work DEP identified as necessary in early 2023 following winter storm Elliott and includes the estimated cost of a study of needed repairs and installation of additional insulation, wind breaks, and updated heat trace systems to address freeze issues. Witness Turner stated that the operator workaround project category of reliability improvements represents a deeper level review of system health at the coal stations. The operator workaround project category typically addresses smaller items that can impact reliability, particularly when combined with other reliability issues. *Id.* at 127-29. Witness Turner testified that the staffing project category represents DEP's forward projection of costs, primarily salary, benefits, and overhead, to ensure that DEP has adequate resources to operate the coal units until retirement. *Id.* at 130-31. Witness Turner also testified that DEP identified the repair hold project category through the Reliability Threat Analysis and that it represents major components that do not have a readily available spare and have long lead times that supply chain challenges have exacerbated. *Id.* at 131-32.

Witness Turner also responded to witness Metz's testimony regarding fossil fleet performance and O&M investment, noting that it is important to view the entire fleet's performance and not focus solely on coal. Based on the equivalent forced outage factor (EFOF) metric, she stated that DEP's fossil fleet is performing consistent with or better than the industry average, and the natural gas units have exceeded industry average performance. Tr. vol. 12, 133-35. Witness Turner emphasized that the evaluation of fleet performance and reliability assurance needs has changed over time and will differ between coal units and natural gas units. She concluded that the Reliability Assurance pro forma represents the adjustments that DEP has identified as needed to maintain the coal units in reliable condition. *Id.* at 136-38.

The Revenue Requirement Stipulation provides for inclusion of an additional $6 million (North Carolina retail) of annual incremental spend for ongoing O&M for DEP's coal generation fleet for discrete programs and targeted categories that witness Turner lists in her supplemental and rebuttal testimony and for which she includes supporting workpapers. The parties agreed that DEP will track and report on an annual basis the actual spend and employee head count for each coal generation station over the MYRP period in a manner to be agreed upon between DEP and the Public Staff. DEP will record any cumulative underspend to a regulatory liability account accrued through the end of the MYRP period (September 2026) and return it to customers in the next general rate case. Revenue Requirement Stipulation § III.14, Tr. Ex. vol. 7. DEP witness Jiggetts and Public Staff witnesses McLawhorn and Metz supported this provision in their settlement supporting testimony. Tr. vol. 13, 254-56, 259; Tr. vol. 16, 513.

The Commission concludes that the Revenue Requirement Stipulation provides a reasonable resolution of this issue for purposes of this proceeding. DEP has demonstrated that these funds are necessary to maintain the reliability of the coal units until their anticipated retirement. The Public Staff raised valid concerns regarding the performance of the DEP fossil fleet, specifically the coal units, and the Commission recognizes that reviews of performance can have different results depending on the metric the reviewer uses to evaluate it. DEP's tracking and annual reporting of the actual spend and employee head count for each coal generation station over the MYRP period will help to further inform this discussion as these units' retirements approach. The parties' agreement that DEP will record any cumulative underspend to a regulatory liability account accrued through the end of the MYRP period and return it to customers in the next general rate case addresses the concerns the Public Staff raised regarding O&M spending. In its first annual report, the Commission directs DEP to update the Commission on the agreed-upon specifics for the tracking and reporting of the actual spend and employee head count for each coal generation station.

Aviation Expense

In its initial filing, DEP removed 50.0% of corporate-related aviation expenses allocated to DEP in the test period that are not related to aerial patrol. DEP witness Jiggetts testified that DEP believes these costs were reasonable, prudent, and appropriate to recover from customers, but elected to remove them in this case. Tr. vol. 13, 184. Public Staff witnesses Zhang and Boswell recommended, in addition to the 50.0% already removed by DEP, removal from DEP's cost of service of additional flight costs that the Public Staff found to be unrelated to the provision of utility service, including portions of certain commercial international flights. Tr. vol. 19, 49.

The Revenue Requirement Stipulation removes aviation expenses associated with international flights, in addition to the 50.0% of aviation expenses removed in the Application. Revenue Requirement Stipulation § III.15, Tr. Ex. vol. 7. No intervenor took issue with this provision of the stipulation. The Commission concludes that the Revenue Requirement Stipulation provides a reasonable resolution of this issue for purposes of this proceeding.

Executive Compensation

In its Application, DEP removed 50.0% of the compensation of the five Duke Energy executives with the highest level of compensation allocated to DEP. DEP witness Jiggetts explained that while DEP 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, 181. Public Staff witnesses Zhang and Boswell recommended an additional adjustment to remove 50.0% of the benefits of these top five Duke Energy executives, noting that the adjustment was consistent with similar recommendations the Public Staff has made and the Commission has approved in past rate cases. Tr. vol. 19, 45-46.

Section III, Paragraph 16 of the Revenue Requirement Stipulation provides for removal of 50.0% of the benefits of the five Duke Energy executives with the highest amounts of compensation, in addition to the 50.0% of their compensation DEP removed in the Application. Tr. Ex. vol. 7. No intervenor took issue with this provision of the stipulation. The Commission concludes that the Revenue Requirement Stipulation provides a reasonable resolution of this issue for purposes of this proceeding.

Charitable Contributions and Sponsorships

In his direct testimony, DEP witness Speros certified that DEP's cost of service does not include any expenditures for charitable contributions in accordance with the requirement of Commission Rule R12-13(a) as amended. Tr. vol. 13, 46. Witness Speros testified that Commission Rule R12-13(a) requires that in every application for a change in rates, a utility must certify in its prefiled testimony that its application does not include certain costs, including charitable contributions. *Id.* Witness Speros further explained that he performed additional reviews of DEP's cost of service to ensure that DEP did not include any costs that Commission Rule R12-13 prohibits in the Application. *Id.* at 47.

Public Staff witnesses Zhang and Boswell recommended an adjustment to charitable contributions of approximately $152,000 to exclude expense amounts paid to the Chambers of Commerce and other donations. Tr. vol. 19, 56; Tr. vol. 23, 59; the Public Staff Accounting Exhibit 1, Schedule 1, line 33, Tr. Ex. vol. 19. Witnesses Zhang and Boswell stated that these expenses should be disallowed because they do not represent actual costs of providing electric service to customers. Tr. vol. 19, 56.

In his rebuttal testimony, witness Speros explained that Chambers of Commerce promote business and economic development, which in turn helps to retain and attract customers to DEP's service territory. In addition, funds DEP paid to Chambers of Commerce that DEP does not specify as a donation or lobbying are in fact supporting business or economic development and DEP properly considers them utility operating expenses and includes them in DEP's cost of providing electric service to customers. Tr. vol. 13, 73.

The Revenue Requirement Stipulation establishes that no adjustment will be made to charitable contributions and sponsorships. Revenue Requirement Stipulation § III.17, Tr. Ex. vol. 7. No intervenor took issue with this provision of the stipulation. The Commission concludes that the Revenue Requirement Stipulation provides a reasonable resolution of this issue for purposes of this proceeding.

Board of Directors Expense

With respect to Board of Directors expense, Public Staff witnesses Zhang and Boswell recommended an adjustment to remove 50.0% of the expenses associated with the Board of Directors of Duke Energy that had been allocated to DEP, similar to the Public Staff's recommendation regarding executive compensation and benefits of the five Duke Energy executives with the highest level of compensation allocated to DEP in the test period. Tr. vol. 19, 47. In his response, DEP witness Stewart indicated that the law requires DEP 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. 23, 304. He argued that it is not fair or reasonable to penalize DEP for being an investor-owned utility with attendant requirements to that corporate structure. *Id.*

The Revenue Requirement Stipulation accepts the Public Staff's recommended adjustments to the Board of Directors' expenses. Revenue Requirement Stipulation § III.18, Tr. Ex. vol. 7. No intervenor took issue with this provision of the stipulation. The Commission concludes that the Revenue Requirement Stipulation provides a reasonable resolution of this issue for purposes of this proceeding.

Lobbying Expense

In his direct testimony, DEP witness Speros certified that DEP's cost of service does not include any expenditures for lobbying, political or promotional advertising, political contributions, or charitable contributions in accordance with the requirement of Commission Rule R12-13(a) as amended. Tr. vol. 13, 47. Witness Speros further explained that he performed additional reviews of DEP's cost of service to ensure that DEP did not include costs that Commission Rule R12-13 prohibits in the Application. *Id.* With respect to lobbying expenses, Public Staff witnesses Zhang and Boswell adjusted O&M expenses to remove additional costs associated with Federal Government Affairs, Governmental Affairs and External Relations, and National Engagements that DEP recorded above the line in the test year. Witnesses Zhang and Boswell stated that Commission Rule R12-12 and the Commission's Order in Dominion Energy North Carolina's 2012 Rate Case (2012 DENC rate case) justify removal of these expenses. Tr. vol. 19, 50.

In rebuttal testimony, witness Speros stated that DEP disagrees that any adjustment to remove any additional cost from the cost of service under Commission Rule R12-12 or the Commission's decision in the 2012 DENC rate case is necessary. Tr. vol. 13, 63.

The Revenue Requirement Stipulation establishes that, while DEP maintains its position that its cost of service in this case did not include any lobbying expenses, for the purposes of settlement, DEP accepted the adjustments proposed by the Public Staff for lobbying expenses. Revenue Requirement Stipulation § III.19, Tr. Ex. vol. 7. No intervenor took issue with this provision of the stipulation. The Commission concludes that the Revenue Requirement Stipulation provides a reasonable resolution of this issue for purposes of this proceeding.

Nuclear End-of-Life Reserve

Public Staff witness Metz recommended an $8 million disallowance of four-year Repair Hold and Quality Assurance (QA) Hold costs for nuclear inventory that has been on hold for four years or more. Tr. vol. 16, 427-28. He further recommended that a 5.0%

salvage value be applied to nuclear materials and supplies (M&S) inventory for purposes of calculating DEP's end of life nuclear reserve. *Id.* at 430.

In his rebuttal testimony, DEP witness Ray opposed witness Metz's recommendation of removal of $8 million from the end-of-life nuclear reserve, explaining that DEP holds this inventory to support plant operations and it is therefore beneficial to customers. Tr. vol. 23, 282. Witness Ray clarified that the fact that DEP maintains an item of M&S inventory in Repair Hold or QA Hold longer than four years does not mean that DEP will not ultimately use such inventory or have it available for use. *Id.* at 282-85. Regarding salvage value, witness Ray testified that if DEP receives approval of its requests for subsequent license renewal of its nuclear units, there will be few to no similar technology nuclear plants in operation at the time DEP's units retire in the next 20 years. With few to no similar vintage nuclear or coal plants in operation, the market for the more expensive inventory items such as pumps, motors, and valves will be severely limited or nonexistent. DEP does not expect markets for inventory components at or near market value to exist. Witness Ray indicated that, while DEP generally agrees that there may be some small amount of salvage value for nuclear M&S inventory at its end of life, disposal expenses will largely offset any such value. He concluded that DEP does not support maintaining a particular salvage value going forward until the retirement of the nuclear units because doing so would reduce DEP's ability to adjust the salvage value for M&S inventory as needed in the future based on changed circumstances. *Id.* at 288.

The Revenue Requirement Stipulation accepts the Public Staff's adjustment to end-of-life nuclear materials and supplies reserve expense, reduced as described in the direct testimony of Public Staff witness Metz. Revenue Requirement Stipulation § III.20, Tr. Ex. vol. 7. DEP witness Jiggetts and Public Staff witnesses McLawhorn, Metz, Zhang, and Boswell supported this provision in their settlement supporting testimony. Tr. vol. 13, 254, 60; Tr. vol. 16, 512. The Commission concludes that the adjustments to the nuclear end-of-life reserve established in the Revenue Requirement Stipulation are supported by the evidence presented, is just and reasonable and fair to all, and should be approved.

Coal Inventory

Based on DEP's historical performance, updated coal inventory analysis, and recent coal inventory holdings, Public Staff witness Michna recommended that DEP maintain its current coal inventory of 35 days of 100.0% full load burn and reduce the corresponding DEP adjustment that increased coal inventory to 40 days by $9,971,719 to account for this change. Tr. vol. 21, 292-93.

DEP witness Turner opposed witness Michna's adjustment. Witness Turner asserted that the adjustment failed to contemplate the changing market factors impacting a reliable fuel supply, namely the inability of the coal supply chain to timely respond to volatility in coal generation demand and ignored DEP's updated average inventory of 38.8 days. Witness Turner concluded that it is prudent to increase the target from 35 days to 40 days. Tr. vol. 12, 142.

The Revenue Requirement Stipulation accepts the annual 35 full load day burn average to establish the level of coal inventory for purposes of establishing a revenue requirement. Revenue Requirement Stipulation § III.21, Tr. Ex. vol. 7. DEP witness Jiggetts and Public Staff witnesses McLawhorn, Metz, Zhang, Boswell supported this provision in their settlement supporting testimony. Tr. vol. 13, 254, 261; Tr. vol. 16, 513-15. The Commission concludes that the 35-day coal inventory target proposed in the Revenue Requirement Stipulation is supported by the evidence presented, is just and reasonable and fair to all, and should be approved.

Credit Card Payment Fees

In her direct testimony, DEP witness Quick proposed to offer a Fee-Free program for small and medium nonresidential customers who make payments using debit, credit, prepaid, or electric check (Card Payments) to pay their electric bills. Tr. vol. 7, 65. In support of DEP's request, she noted that residential customers have a transaction Fee-Free program for Card Payments, which the Commission approved in DEP's last general rate case. Witness Quick recounted that nonresidential customers making a Card Payment are subject to a convenience fee of $8.50 per payment for payments up to $10,000; for payments in excess of $10,000, the convenience fee is 2.75% of the amount paid. *Id.* at 105. DEP's vendor charges the convenience fee and DEP receives no portion of it. *Id.* at 105-06. Based on customer feedback and requests, witness Quick proposed in this case to offer the Fee-Free program for Card Payments to nonresidential customers making bill payments up to $3,000. *Id.* at 106. DEP, instead of the customer, would pay the vendor the convenience fees for these Card Payments and incorporate the expense into the cost of service for recovery through its base rates. Tr. vol. 7, 104-06.

In their joint testimony, Public Staff witnesses Zhang and Boswell opposed DEP's proposal to socialize the credit card payment fees for nonresidential customers. Tr. vol. 19, 51. They noted that the current volume of customers who use this method of payment accounts for less than 1.0% of the overall bill pay transactions volume. *Id.* Additionally, witnesses Zhang and Boswell distinguished this proposal from the socialization of the residential credit card fees the Commission allowed in DEP's previous general rate case order by noting that the residential Fee-Free program had the potential to produce reductions in late payments and uncollectibles, but nonresidential customers do not experience the same level of late payments and uncollectibles as residential customers. *Id.* Therefore, they testified that they found no offsetting benefit of socialization of Card Payment fees for the nonresidential customers to general ratepayers. *Id.*

The Revenue Requirement Stipulation establishes that the credit card payment fees for nonresidential customers shall be removed from the revenue requirement in this case. Revenue Requirement Stipulation § III.23, Tr. Ex. vol. 7. The Commission concludes that the Revenue Requirement Stipulation provides a reasonable resolution of this issue for purposes of this proceeding.

Payroll and Benefits

DEP and other Duke Energy affiliates continuously review operational matters including workforce staffing levels. In connection with such a review, DEP implemented planned headcount reductions beginning in 2021 through the first part of 2023, leading to a reduction in DEP's otherwise applicable revenue requirement. While DEP witness Jiggetts' schedules reflected the reduction through the March 31, 2023 cutoff date applicable to this case, Section III, Paragraph 25 of the Revenue Requirement Stipulation provides for a further reduction of the revenue requirement for the payroll costs and associated benefits for the former employees subject to the Work Reduction Initiative through the end of May 2023. *Id.* No intervenor took issue with this provision of the stipulation. The Commission concludes that the Revenue Requirement Stipulation provides a reasonable resolution of this issue for purposes of this proceeding.

Production O&M Reduction to Reflect Capitalization Policy Change

In his supplemental testimony, Public Staff witness Metz described how DEP reclassified miscellaneous line items from O&M to capital plant. Witness Metz did not take issue with this action for purposes of this proceeding but testified to his concern that test year O&M expenses used to establish an ongoing expectation of future spending may be overstated. To account for the impact of the reclassification, he recommended the removal of $463,000 on a system basis from DEP's test year expenses. Tr. vol. 16, 506-08.

The Revenue Requirement Stipulation establishes a reduction in production O&M of $463,000 on a system basis to account for the change in DEP's capitalization policy. Revenue Requirement Stipulation § III.26, Tr. Ex. vol. 7. DEP witness Jiggetts and Public Staff witnesses McLawhorn, Metz, Zhang, and Boswell supported this provision in their settlement supporting testimony. Tr. vol. 13, 254, 262; Tr. vol. 16, 512. The Commission concludes that the production O&M reduction proposed in the Revenue Requirement Stipulation is supported by the evidence presented, is just and reasonable and fair to all, and should be approved.

Vegetation Management O&M

In his direct testimony, DEP witness Maley described DEP's transmission Integrated Vegetation Management (IVM) Plan and its goal of removing and/or controlling incompatible vegetation within and along transmission rights of way. Witness Maley indicated that the IVM includes planned corridor work, reactive work, and floor management work, with DEP's prioritizing the first two categories based on threat assessments. Witness Maley also indicated that DEP had included an increase in vegetation management costs in its test period pro forma adjustments to account for increased outside labor costs and that this adjustment also covers vegetation management costs associated with the expansion of existing substation sites. Tr. vol. 10, 178-79.

In his direct testimony, DEP witness Guyton testified that DEP utilized a reliability prioritization model to drive its routine IVM program. The other important components of

DEP's vegetation management include the following programs: herbicide management, hazard trees, reactive customer requested activities, and post outage vegetation management activities. Witness Guyton also testified that DEP continues to utilize a seven-year cycle for distribution vegetation management in nonurban areas and a three-year cycle in urban areas consistent with DEP's 2015 Tree Growth Study. Tr. vol. 10, 51-52.

In his direct testimony, Public Staff witness T. Williamson described DEP's IVM Plan and provided a summary of the operation of that plan since 2015. This description included both vegetation within DEP's rights of way and vegetation that lies outside DEP's rights of way. DEP's hazard tree program manages the vegetation which lies outside DEP's rights of way. Witness T. Williamson also recommended changes to DEP's assessment activities (which would increase the frequency of its review of distribution lines), and recommended reductions in two parts of the Distribution System Vegetation Management budgets. Finally, witness T. Williamson recommended changes to the Distribution and Transmission vegetation plan reporting requirements. Tr. vol. 21, 205-18.

In his rebuttal testimony, DEP witness Guyton addressed Public Staff witness T. Williamson's vegetation plan recommendations and indicated that the significant increase in work that would be necessary to implement his recommendations for increased observation of the distribution system would increase costs and endanger DEP's ability to meet its other vegetation management plan goals. Witness Guyton further stated that reductions in Distribution Vegetation Management plan budgets were contrary to DEP's actual experience of increasing vegetation management costs. Tr. vol. 10, 143. Witness Guyton also objected to two of the additional reporting requirements witness T. Williamson suggested on the grounds that the practicalities of how the vegetation management plan operates precludes reporting on vegetative miles and hazard tree targets. *Id.*at 147.

No other party presented evidence on these matters.

The Revenue Requirement Stipulation provides for a reduction in DEP's Distribution O&M Demand Program budget to $2,721,604[8] and for adoption of the additional vegetation management reporting requirements recommended by Public Staff witness T. Williamson except for reporting on vegetative miles and hazard tree targets, as noted on page 52 of the rebuttal testimony of DEP witness Guyton. Revenue Requirement Stipulation §§ III.27 and IV.37, Tr. Ex. vol. 7. The Commission concludes that these adjustments in the Revenue Requirement Stipulation are supported by the evidence presented and are just and reasonable and fair to all and should be approved.

Lead-Lag Study

As part of its filing in this case, DEP submitted a lead-lag study that was performed by Ernst & Young, LLP, and approved in the Commission's Order in the 2019 Rate Case.

[8] The $2,721,604 is the adjusted total related to O&M Demand Program. The amount of the adjustment was $789,309 on a system basis.

Tr. vol. 13, 43; Speros Direct Ex. 2, Tr. Ex. vol. 13. The lead-lag study was used to analyze transactions throughout the year to determine the number of days between the time services are rendered and payment is received (revenue lag), and the number of days between the time expenditures are incurred and payment is made for such services (expense or payment lead). Public Staff witnesses Zhang and Boswell recommended that DEP prepare and file a fully updated lead-lag study in its next general rate case. Tr. vol. 19, 43.

In his rebuttal testimony, DEP witness Speros stated that DEP plans to pursue a merger of the DEP and DEC utilities in the next rate case and will work with the Public Staff to determine if the timing of the next lead-lag study makes more sense before or after that case. Tr. vol. 13, 73.

The Revenue Requirement Stipulation incorporates DEP's agreement to perform a lead-lag study before the next general rate case proceeding and incorporate the results of that study in DEP's next rate case application. No intervenor took issue with this provision of the stipulation. The Commission concludes that the Revenue Requirement Stipulation provides a reasonable resolution of this issue for purposes of this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT 28.

The evidence supporting this finding of fact is included in DEP's verified Application and Form E-1; the testimony and exhibits of Public Staff witnesses Metz, Zhang, and Boswell, including Accounting Second Supplemental Ex. 1, the Supplemental Revenue Requirement Stipulation, including Ex. 1; and the entire record in this proceeding.

The Revenue Requirement Stipulation involves a comprehensive resolution between the stipulating parties of a majority of the revenue requirement issues in this case. Because the Revenue Requirement Stipulation was entered into before the Public Staff had completed its audit of DEP's third and final update of costs, the stipulation provides expressly that the stipulation does not prevent the Public Staff from completing its audit of DEP's updates or making proposed adjustments to the updated revenue requirements based on the audit. The Public Staff completed its audit of the updates in June 2023, and the Public Staff and DEP entered into the Supplemental Revenue Requirement Stipulation, filed on June 27, 2023, in which the parties agreed to certain further minor adjustments to the revenue requirement. The Supplemental Revenue Requirement Stipulation lists four areas of agreement between DEP and the Public Staff. Tr. Ex. vol. 24.

Sheds (New Hill Timpson Training Sheds)

DEP and the Public Staff agreed that DEP shall remove 50% of the costs associated with the New Hill Timpson Training Sheds from its revenue requirement for purposes of this proceeding only. The removal will result in a decrease of $186,000 in Plant in Service on a North Carolina retail basis. *Id.*

Wilson 230kV Project

DEP and the Public Staff agreed that DEP will reclassify $670,989 system amount related to the Wilson 230kV project from distribution to transmission plant. They further agreed that DEP shall offset the March 2023 plant in service amount of $1.423 million on a system basis associated with the Wilson 230kV project with an estimate of the insurance proceeds in the amount of $897 thousand on a system basis that DEP will receive. The parties acknowledged that actual proceeds received may be different than the estimates captured and agree that they will address any necessary adjustments in a future proceeding. *Id.*

Laptop Issuance

DEP and the Public Staff agreed that, for purposes of this proceeding, DEP will remove new laptop devices not issued to employees as of the capital cutoff date from the revenue requirement. The removal will result in a decrease to Plant in Service of $2,370,000 on a North Carolina retail basis. *Id.*

Capitalization Policy

DEP and the Public Staff agreed that there will be no adjustment to the capitalized costs related to the February 2023 Brunswick Unit 2 nuclear refueling outage in this proceeding. They further agreed that DEP will assist the Public Staff in reviewing DEP's capitalization procedures before DEP files its next general rate case. *Id.*

On June 27, 2023, the Public Staff filed the joint supplemental settlement testimony of witnesses Metz, Zhang, and Boswell in support of the Supplemental Revenue Requirement Stipulation. According to the Public Staff witnesses, the most important benefits that the stipulation and the agreed upon adjustments provide are: (1) an aggregate reduction in DEP's proposed revenue increase in this proceeding; and (2) the avoidance of litigation between the parties on the settled issues and the associated increased accumulation of rate case expense recovery from ratepayers. Tr. vol. 24, 47. The Public Staff further testified that the Commission should approve the Supplemental Revenue Requirement Stipulation because of these benefits to ratepayers. *Id.*

The Commission concludes that the adjustments in the Supplemental Revenue Requirement Stipulation are supported by the evidence presented and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 29

MYRP Capital Investments

The evidence supporting this finding of fact is included in DEP's verified Application and Form E-1; the testimony and exhibits of DEP witnesses Maley, Guyton, Ray, Turner, Strasburger, and LaRoche, Public Staff witnesses Thomas, Metz, T. Williamson, Nader, Zhang, and Boswell, AGO witness Nelson, NCJC, et al. witnesses Hill and Duncan, , Sierra Club witness Goggin; the Revenue Requirement Stipulation; and the entire record in this proceeding.

In its Application, DEP identified capital spending projects projected to be placed in service during the MYRP period. These projects consist of transmission and distribution infrastructure, solar and battery storage, enterprise technology and security, and fossil, hydro, and nuclear investments.

DEP provided support for its MYRP projects through its Application, direct, supplemental direct, and rebuttal testimony of DEP witnesses discussed below, as well as at the July 2022 Transmission and Distribution Technical Conference. Furthermore, the Public Staff conducted substantial discovery regarding the projects DEP proposed in its MYRP. DEP's witnesses assert that DEP has provided sufficient information to justify the MYRP projects, while the Public Staff witnesses offered multiple critiques of DEP's documentation of the MYRP projects. The Revenue Requirement stipulating parties agreed to support the MYRP projects as modified in the Revenue Requirement Stipulation.

Transmission

DEP witness Maley testified in support of the MYRP transmission projects. Regarding future needs, witness Maley testified that, while DEP has worked hard to maintain the system and reliably meet customer needs, it must do more to improve the state's energy infrastructure to meet the challenges and opportunities that lie ahead. Tr. vol. 10, 170. Witness Maley testified that DEP designed its MYRP to address future challenges and opportunities and that the MYRP transmission projects include investments in the following categories: system intelligence, hardening and resiliency, transformer and breaker upgrades, and capacity and customer planning. *Id.* at 185.

Witness Maley testified that DEP selected and grouped targeted reliability improvements in the following MYRP projects, based on the areas that provide the greatest value to customers: system intelligence, vegetation management, transmission line hardening and resiliency, substation hardening and resiliency, transformer upgrades, breaker upgrades, and capacity and customer planning. *Id.* at 187. He explained that although these seven proposed MYRP investments are the same as those DEP presented in the July 25, 2022, MYRP Technical Conference, DEP has refined some of the location details and informed the Cost Benefit Analysis (CBA) with those details. *Id.*

In witness Maley's direct testimony and accompanying exhibits, he described the estimated costs of DEP's proposed MYRP transmission projects. *Id.*

In his supplemental direct testimony, witness Maley provided an update on the cost estimates applicable to transmission projects that DEP included in its MYRP based on certain criteria agreed upon with the Public Staff. *Id.* at 212-13. Witness Maley identified additional transmission MYRP project locations that DEP added to the MYRP after filing his direct testimony, and identified those that it removed, along with the reasons behind such changes. *Id.* at 208. He provided updated project cost estimates for certain transmission MYRP projects, including explanations for the basis for such updated cost estimates. *Id.* at 212-13.

DEP witness Maley's Direct Supplemental Exhibit 1 provides the total updated costs of the proposed MYRP Transmission projects as follows:

1. Breakers - $103,434,999;

2. Capacity and Customer Planning - $624,078,511;

3. Substation Hardening and Resilience - $359,579,976;

4. System Intelligence - $72,766,544;

5. Transmission Line Hardening and Resiliency - $129,651,500;

6. Transformers - $114,269,580; and

7. Vegetation Management - $113,884,377.

Tr. Ex. vol. 10.

The modifications to proposed MYRP Transmission projects described in witness Maley's supplemental direct testimony and accompanying exhibits resulted in an updated estimated capital cost of DEP's proposed MYRP Transmission projects of $1,517,665,486.

Public Staff witness Metz testified as to multiple concerns with the MYRP projects, including outdated cost estimates, insufficient staffing levels to complete the projects on schedule, and the lack of coordination between business groups to increase project efficiencies. Tr. vol. 16, 461, 465-66, 481-83. Witness Metz recommended reducing the project contingency by half, arguing that DEP failed to justify the high contingency amount DEP budgeted for the projects. *Id.* at 491-92. He further recommended a 5.0% downward adjustment for all transmission projects in the MYRP to address potential construction efficiencies that could arise in the implementation of the MYRP. *Id.* at 494. Witness Metz also recommended the removal of certain transmission projects from the MYRP based on the analysis of Public Staff witness Chiles. *Id.* at 458.

AGO witness Nelson critiqued DEP's transmission planning and made several recommendations. AGO witness Nelson recommended that the Commission require DEP to conduct a study on the costs and benefits of grid-enhancing technologies (GETs). Tr. vol. 18, 123-30. Witness Nelson also recommended that DEP engage in regional transmission planning and asserted that regional planning could potentially displace projects in the MYRP. *Id.* at 138-41. Finally witness Nelson recommended that DEP pursue all funding options for transmission projects that are part of the IRA. *Id.* at 134.

Sierra Club witness Goggin recommended that the Commission require DEP to file a proactive transmission plan for all transmission expansion and upgrades needed to accommodate the interconnection of all new renewable resources required by 2035 under Duke's Carbon Plan. Tr. vol. 21, 789. Witness Goggin also recommended that the Commission direct DEP to use a "multi-value approach to planning transmission so that the identified upgrades meet needs related to public policy, economics, reliability, expanded interconnection with neighboring Balancing Authorities, and other categories of benefits…" Tr. vol. 21, 790.

Witness Maley addressed testimony from Public Staff witnesses Metz and Chiles. Specifically, he: (1) spoke of each MYRP project witnesses Metz and Chiles challenged and explained why the projects are necessary and appropriate for inclusion in the MYRP; (2) discussed DEP's methodology for ensuring that there is no overlap between the scope of different projects; (3) countered the argument that the Commission should reduce contingency components of the estimates for all MYRP transmission projects by 50.0%; (4) explained the basis for the contingency component of DEP's transmission projects; and (5) addressed witness Metz's recommendation that the Commission reduce all transmission project estimates by 5.0%. Tr. vol 10, 227-29, 246-47.

Witness Maley also addressed testimony of witnesses for the AGO and the Sierra Club. Witness Maley stated that he disagreed with AGO witness Nelson's recommendations. *Id.* at 259-60. Witness Maley testified that witness Nelson's recommendation to study GETs is inappropriate in this proceeding because the Commission already considered GETs in the Carbon Plan proceeding. *Id.* at 260. Also, witness Maley disputed witness Nelson's recommendations because they require activities already underway or that should be considered in the Carbon Plan or in the North Carolina Transmission Planning Collaborative (NCTPC). *Id.* Witness Maley mentioned that DEP witness Roberts explained how GETs are evaluated in his Carbon Plan testimony. Witness Maley stated that the Commission has already noted in its Carbon Plan Order that it "expects Duke to pursue all potential tax incentives or federal funding." *Id.* Witness Maley countered that new requirements imposed in this proceeding that circumvent resource planning and transmission planning are not reasonable. *Id.*

In his rebuttal testimony, witness Maley responded that Sierra Club witness Goggin's recommendations regarding transmission planning would fit better in the Carbon Plan and Integrated Resource Process (CPIRP) efforts than within the limited three-year window of the MYRP. Tr. vol. 10, 261. Witness Maley explained that Duke Energy stated in the March 15, 2023, NCTPC Transmission Advisory Group (TAG) presentation that it is pursuing the integration of a multi-value strategic transmission planning study into the local transmission planning process. Tr. vol. 10, 261. Since DEP is already pursuing this in the NCTPC, witness Maley testified that any further requirement is unnecessary. *Id.*

The Revenue Requirement Stipulation includes a 50.0% adjustment to the contingency amounts of the transmission projects as recommended by Public Staff witness Metz. The stipulation further provides that DEP will leverage project efficiencies to the extent practical in the implementation of the MYRP. The stipulation also establishes that the transmission MYRP projects identified in DEP witness Abernathy's February 2023 MYRP update of Exhibit 4, Workpaper 5 and described in the direct and supplemental testimonies of DEP witness Maley are appropriate for inclusion in the MYRP. Based on the entire record in this proceeding, the Commission finds that DEP's proposed transmission projects are reasonable and shall be included in the MYRP for recovery. Tr. Ex. vol. 13.

The only parties that opposed portions of DEP's transmission projects included in the MYRP but not resolved through the Revenue Requirement Stipulation and other settlements are the AGO, as indicated by the testimony filed by AGO witness Nelson, and the Sierra Club, as indicated by witness Sierra Club witness Goggin.

The Commission agrees with DEP witness Maley's assertion that the recommendations of AGO witness Nelson and Sierra Club witness Goggin regarding transmission planning are designed to change DEP's decision-making regarding the types of transmission projects it undertakes. The Commission finds that the appropriate proceeding for consideration of changes to transmission planning is the CPIRP, or other proceedings.

N.C.G.S. § 62-133.16(c)(1)(a) provides that for the first year of an MYRP, the

> base rates . . . shall be fixed in a manner prescribed under G.S. 62-133 . . . plus costs associated with a known and measurable set of capital investments, net of operating benefits, associated with a set of discrete and identifiable capital spending projects to be placed in service during the first rate year.

The same provision specifies that:

> [s]ubsequent changes in base rates in the second and third rate years of the MYRP shall be based on projected incremental Commission-authorized capital investments that will be used and useful during the rate year and associated expenses, net of operating benefits, including operation and maintenance savings, and depreciation of rate base associated with the capital investments, that are incurred or realized during each rate year of the MYRP period.

N.C.G.S. § 62-133.16(c)(1)(a).

After having carefully reviewed all the evidence in the record, the Commission concludes that the evidence demonstrates that the proposed MYRP transmission projects satisfy the requirements set forth in N.C.G.S. § 62-133.16(c)(1)(a). The Commission further concludes that the evidence supports approval of the Revenue Requirement Stipulation's provisions regarding these transmission projects and that the transmission MYRP costs thereunder are just and reasonable and consistent with the public interest.

Distribution

DEP witness Guyton described the discrete and identifiable capital spending projects associated with DEP's distribution system proposed to be placed in service for each rate year of the MYRP. His testimony included the reason for, scope of, timing for (projected in-service month and year), and operating benefits of each project. Tr. vol. 10, 35-36. Witness Guyton testified that DEP's proposed MYRP distribution and other projects covered in his testimony total $2.2 billion and include the $1.8 billion in distribution MYRP projects discussed at the T&D technical conference held on July 25, 2022, as well as $0.4 billion in other non-T&D MYRP projects. *Id.* at 42. The other MYRP project categories include DEP's allocated share of the costs of enterprise communications and enterprise systems, as well as facilities and fleet electrification infrastructure. *Id.* These other projects are closely aligned with the distribution business or enabling the grid capabilities. *Id.*

While discussing the preliminary findings in the ongoing Climate Risk and Resilience Study (CRRS) of the Carolinas transmission and distribution system, witness Guyton testified that the preliminary findings of the CRRS reinforces the benefits of the proposed MYRP projects, and that the additional headroom provided by capacity upgrades and improvements accommodates customer load growth and generation, but also increases resilience to the effects of extreme heat. *Id.* at 63-64. He testified that targeted undergrounding, distribution hardening and resiliency, and hazard tree removal increase resilience to the impact of wind and storms, which are likely to increase in frequency and strength due to climate change. *Id.* at 64. Witness Guyton also testified that Duke Energy implemented Integrated Systems Operations Planning (ISOP) to leverage increasing amounts of data, such as the propensity of customers to adopt solar and purchase EVs, when planning future projects. *Id.* at 40. He testified that, when appropriate, the distribution projects will take advantage of new processes and technologies that will aid in the delivery of the energy goals and requirements of North Carolina. *Id.* at 40-41. As such, he stated that the proposed MYRP projects and the grid capabilities that are achieved through these projects will serve as a foundation to support future technologies, and will result in significant customer benefits, particularly in the areas of reliability and resiliency. *Id.* at 41.

With respect to reliability, witness Guyton stated that DEP anticipates fewer and shorter outages resulting from programs such as Self-Optimizing Grid (SOG), Targeted Underground (TUG), distribution automation, and equipment retrofitting. *Id.* Regarding resiliency, the MYRP projects will provide increased protection against physical/cyber-attacks and severe weather impacts. Increases in capacity and voltage regulation and management will accommodate increasing amounts of renewable resources and Distributed Energy Resources (DERs). *Id.* Enhanced automation and control, and situational awareness will enable DEP to operate the grid more efficiently and support new customer programs, which will provide customers more options to control their energy usage and decrease their energy costs. *Id.* Witness Guyton testified that DEP will spread its proposed distribution MYRP projects across its service territory and retail customer classes to provide equitable access to these benefits. *Id.* The programs in

DEP's MYRP projects make the grid more flexible and adaptable. Automation and control technologies will help generate and capture large volumes and types of data which was not previously available. *Id.* Witness Guyton asserted that these benefits are helpful not only for DEP's Grid Operators but also for its Planning Engineers as they analyze and model DEP's grid for future improvements and capabilities using ISOP toolsets like Morecast and Advanced Distribution Planning (ADP). *Id.* at 41-42. He indicated that grid technologies will continue to and will be integrated into new solutions to address changing customer needs. *Id.* at 42.

Witness Guyton testified that distribution projects included in the MYRP total $2,197,627,366 in estimated capital investment and fall into four investment categories: (1) Substation and Line MYRP projects which total estimated capital costs of $1.582 billion comprise most of the distribution MYRP project costs; (2) Retail and System Capacity Projects which total estimated capital costs of $0.210 billion include the traditional identification and execution of capacity projects to support traditional loads as well as DERs and EVs; (3) Hazard Tree Removal Projects which total estimated capital costs of $0.028 billion consist of the traditional identification and execution of hazard tree removal which is performed in conjunction with normal trimming cycles; and (4) non-transmission and distribution MYRP projects which total estimated capital cost of $0.4 billion include DEP's allocated share of the cost of enterprise communications and systems as well as facilities and fleet electrification infrastructure. *Id.* at 42-44, 64-65.

Witness Guyton testified that the Substation and Line MYRP projects are geographically based and include a combination of ongoing work necessary for safe and reliable service and the work necessary to deliver essential grid capabilities that DEP has identified to address the megatrends and support the clean energy transition. *Id.* at 42. DEP's Distribution MYRP consists of the following 12 programs:

1. SOG Program, also known as the smart-thinking grid, redesigns key portions of the distribution system and transforms it into a dynamic self-healing network that isolates grid issues and limits customer impacts to hundreds versus thousands of customers. The total capital cost for this program is $231.9 million.

2. Voltage Regulation and Management Program improves the grid's ability to address intermittency and fluctuations that DERs cause and improves power quality to customers. The total capital cost for this program is $204.6 million.

3. Distribution Automation Program targets the lateral segments of the grid and focuses on modernizing single-use fuses with automated devices capable of intelligently resetting themselves for reuse. The total capital cost for this program is $50.3 million.

4. Capacity Upgrades and Improvements Program consists of the same work that DEP has always performed to serve its new and existing customers. The total capital cost for this program is $461.6 million.

5. Hardening and Resiliency – Laterals Program focuses on the lateral sections or tap lines, which branch from the main feeder lines and feed neighborhoods, businesses, and commercial/industrial customers. The total capital cost for this program is $175.3 million.

6. Hardening and Resiliency – Public Interference Program improves reliability by targeting DEP's most outage prone overhead backbone power line sections most impacted by vehicle accidents and determining the proper hardening and resiliency solution to reduce the number of outages customers experience. The total capital cost for this program is $18.1 million.

7. Hardening and Resiliency – Storm Program consists of improvements to locations of the distribution grid that DEP has identified, through analysis of historical outage data, as being more vulnerable to outage impacts from extreme weather events. The total capital cost for this program is $77.2 million.

8. Equipment Retrofit Program improves reliability by targeting equipment prone to outages from animal interference, lightning, and clearance issues by upgrading the assets to modern design standards. The total capital cost for this program is $80.4 million.

9. Long Duration Interruption (LDI) Program relocates segments of main overhead feeder lines in hard-to-access areas to improve accessibility for utility trucks. The total capital cost for this program is $2.6 million.

10. TUG Program improves reliability by strategically identifying DEP's most outage prone overhead power line sections and relocating them underground to reduce the number of outages customers experience. The total capital cost for this program is $103.0 million.

11. Hazard Tree Removal Program maintains or improves reliability by identifying and removing dead, structurally unsound, dying, diseased, leaning, or otherwise defective trees that could strike electrical lines or equipment of the distribution system from outside the maintained right of way. The total capital cost for this program is $48.0 million.

12. Distribution Infrastructure Integrity Program identifies and mitigates risk factors such as end-of-service equipment, technology obsolescence, and damaged in-service distribution equipment. The total capital cost for this program is $366.1 million. *Id.* at 66-71.

.Witness Guyton testified that DEP's description of its distribution MYRP programs and associated exhibits reflect the detailed project information that Commission Rule R1-17B. *Id.* at 72. The projected annual net O&M benefits that Commission Rule R1-17B(d)(2)k requires reflect the operational O&M savings offset by the incremental cost to operate the new technology. *Id.* at 73. The O&M savings stem from fewer outages resulting from reliability improvements and the reduction in vegetation management resulting from the undergrounding of overhead lines, for example, in the TUG program. *Id.* DEP netted these savings with the ongoing O&M costs associated with maintaining the added equipment installed under the SOG and Voltage Regulation programs. *Id.*

In his supplemental direct testimony, witness Guyton identified distribution MYRP project locations that DEP either added to or removed from the MYRP period and explained the reasons for such changes. *Id.* at 88-89. Witness Guyton provided updated project cost estimates for certain distribution MYRP projects and explained the basis of the updated cost estimates. *Id.* Witness Guyton testified that his direct testimony included 44 distribution projects (comprised of 301 distribution sub-projects at the location/task level) totaling $2.2 billion, while his supplemental direct testimony included 44 distribution projects (comprised of 297 sub-projects at the location/task level) totaling $2.0 billion representing an overall net reduction of $226.7 million across all the distribution MYRP projects. *Id.* Additionally, he testified that DEP and the Public Staff reached a consensus regarding the criteria pursuant to which DEP would update information regarding MYRP projects and their cost estimates. The updates to the distribution MYRP projects witness Guyton presented in his supplemental direct testimony meet those criteria. *Id.* at 90.

DEP removed three project locations from the MYRP period, including deferring the Franklinton 115kV location within the Substation and Line – Triangle North 262 MYRP Project totaling $0.9M to a later time outside the MYRP window, and moving both the Advanced Distribution Management System (ADMS) CVR project location, totaling $1.7M, and the ADMS Advanced Fault Location project, totaling $0.6M, outside the MYRP window. *Id.* at 91-92. Witness Guyton described cost updates to 148 total distribution MYRP projects. *Id.* at 92. Witness Guyton also explained that at the time of DEP's Application, the distribution MYRP projects were at various stages of the project management lifecycle under DEP's Project Management Center of Excellence (PMCoE) standards. *Id.* at 93. Under the PMCoE approach, as a project moves through the development cycle, DEP continues to refine the costs and project schedules based on project development, detailed design, and construction planning. *Id.* at 93.

Witness Guyton testified that the Substation and Line and Area Capacity projects comprise a significant percentage of the MYRP distribution projects. *Id.* at 94. When these projects were initially identified, a spreadsheet cost estimate was constructed based on past work scope completed for similar assets at similar locations primarily based on engineering analysis and data driven models *Id.* Planning and engineering activities that occurred after the filing of DEP's Application and engaged in as part of the PMCoE process provided the opportunity to refine the scope of work and cost estimates on 125 of the total 190 Substation and Line sub-projects at the location/task level in the MYRP based on actual circuit and equipment and site conditions. *Id.* at 94-95.

Guyton Supplemental Direct Exhibit 3 identifies the total estimated capital costs of the Distribution MYRP projects to be $1,970,915,190. Tr. Ex. vol. 10.

Public Staff witness Thomas recommended reduction of the project costs for four Area Capacity projects and one Facilities project to align with updated cost estimates. Tr. vol. 19, 218. Specifically, he recommended reduction of the cost estimates for the Wilmington 421 230kV Capacity, Wilmington Sunset Park 115kV #2 Capacity, Youngsville 115kV Capacity, Wake Tech 230kV Capacity, and Aberdeen Facilities projects. *Id.* Witness Thomas also recommended reduction of the cost estimates for the Area Capacity program by 5.0% as a financial incentive for DEP to maximize efficiencies for the Area Capacity and Substation and Line programs. *Id.* at 222-23.

Public Staff witness Metz raised multiple concerns about the MYRP projects, including outdated cost estimates, insufficient staffing levels to complete the projects on schedule, and the lack of coordination between business groups to increase project efficiencies. Tr. vol. 16, 461, 465-66, 481-83. Witness Metz recommended reducing the project contingency by half, arguing that DEP failed to justify the high contingency amount DEP budgeted for the projects. *Id.* at 491-92. Public Staff witness Lawrence recommended removal of the costs for the Electrification Charging Infrastructure (ECI) Program that would support the deployment of electric vehicles to DEP facilities and the homes of select DEP employees from the MYRP because DEP had not provided sufficient information or support for the program. Tr. vol. 21, 172-75.

NCJC, et al. witnesses Hill and Duncan made several recommendations related to DEP distribution planning. First, they recommended that the Commission initiate a working group to redesign DEP's CBA methodologies for selection of projects in the MYRP and that the Commission initiate an investigation into distribution system planning. Tr. vol. 21, 849, 874. Witnesses Hill and Duncan also recommended that the Commission require DEP to conduct non-wire (NW) pilot projects and that DEP update its MYRP cost estimates to account for federal funds available through the IRA and IIJA. *Id.* at 850-54, 879.

In his rebuttal testimony, DEP witness Guyton responded to the Public Staff's distribution related MYRP and base case testimony, and to NCJC, et al. witnesses Hill and Duncan's testimony. Tr. vol. 10, 97-98. Specifically, he: (1) described the process DEP used to select certain distribution projects for inclusion in the MYRP and provided specific, data-driven reasons why their selection was appropriate; (2) discussed the methodologies and procedures DEP used to develop cost and contingency estimates for distribution projects; (3) countered the argument that the Commission should reduce contingency components of the estimates for all distribution projects in the MYRP by 50.0%; and (4) addressed witness Thomas's recommendation that the Commission reduce certain distribution project estimates by 5.0%.

The Revenue Requirement Stipulation included certain modifications to DEP's MYRP distribution projects. Those modifications include: (1) inclusion of the 50.0% adjustment to the contingency amounts of the distribution projects as recommended by Public Staff witness Metz; (2) rejection of project efficiency adjustment to the MYRP revenue requirement but DEP agreement to leverage project efficiencies to the extent practical in the implementation of the MYRP; (3) removal of the costs of the Fleet Electrification Charge Infrastructure Project; (4) inclusion of the cost of Project Walter in the MYRP; (5) agreement to discuss scope and content of proposed reporting on reliability O&M; (6) reduction of the Wilmington 421 230kV Capacity, Wilmington Sunset Park 115kV #2 Capacity, Youngsville 115kV Capacity, Wake Tech 230kV Capacity, and Aberdeen Facilities project cost estimates; and (7) reduction in the costs of the Substation & Line Targeted Undergrounding projects. Tr. Ex. vol. 7.

The Revenue Requirement Stipulation did not address the concerns raised by NCJC, et al. witnesses Hill and Duncan.

In response to the recommendations of NCJC, et al. witnesses Hill and Duncan, witness Guyton testified that the recommendations fail to acknowledge activities that are already underway, and for which Commission approval is therefore unnecessary. *Id.* at 105. Witness Guyton asserted that the recommendation of NCJC, et al. that the Commission initiate a working group to update DEP's CBA methodologies is unnecessary since DEP has demonstrated the current methodology, and no other intervenor disputed the current methodology or its usefulness in the current rate case. Tr. vol. 10, 149-50. He contends that witnesses Hill and Duncan also do not acknowledge specific improvements in the CBA methodology DEP used in the current rate case that DEP made in response to stakeholder feedback in DEP's last rate case. *Id.* at 150. Witness Guyton also asserted that the NW pilot projects witnesses Hill and Duncan suggest are unnecessary because DEP has already initiated other customer-solution NW approaches. Tr. vol. 21, 854-55. Witness Guyton points out that their recommendation that the Commission initiate distribution system planning is not necessary because the Commission has already initiated the ongoing ISOP stakeholder engagement efforts. *Id.* at 870. Similarly, witness Guyton asserts that their recommendation to require DEP to update MYRP cost estimates to account for federal funds available through the IRA and IIJA is unnecessary as DEP is actively pursuing grant funding opportunities for the benefit of customers. Tr. vol. 10, 151. Witness Guyton also points to DEP witness Abernathy's testimony, in which she testified that DEP requests that the Commission issue an accounting order authorizing deferral of all IRA and IIJA impacts, including benefits and costs, for addressing in a future filing. *Id.*

The Commission gives significant weight to the compromise agreements reflected in the Revenue Requirement Stipulation. The Commission is not persuaded that the recommendations of NCJC, et al. witnesses Hill and Duncan related to DEP's proposed MYRP distribution projects are necessary at this time. The majority of the recommendations of witnesses Hill and Duncan are related to distribution system planning that should be considered in other proceedings such as the CPIRP proceeding. With respect to witnesses Hill and Duncan's recommendation that the Commission require DEP to update its distribution MYRP investments to account for available federal funds, the Commission notes that the record demonstrates that DEP is pursuing such funds and re-emphasizes its direction to DEP to pursue such funds. As discussed later in this Order, impacts associated with the IIJA and IRA will be deferred, and the Commission declines to adopt Witness Hill and Duncan's recommendation related thereto.

After having carefully reviewed all the evidence in the record on DEP's distribution MYRP proposal in this docket, and based on that evidence, the Commission finds that DEP's distribution MYRP projects satisfy the requirements set forth in N.C.G.S. § 62-133.16(c)(1)(a). The Commission further concludes that the evidence supports approval of the Revenue Requirement Stipulation's provision regarding these distribution MYRP projects.

Nuclear

DEP witness Ray testified in support of the nuclear projects DEP included in the proposed MYRP, the process DEP used to select the projects, and the method by which DEP calculated projected costs for the projects. Tr. vol. 16, 171-72. Witness Ray explained that DEP selected the projects based on their value in maintaining safe and reliable operation of the nuclear stations and on a high level of confidence in their cost estimates and schedule. Witness Ray stated that DEP based the projected costs on its long-range nuclear planning tool, which it updates regularly. *Id.* at 170. Witness Ray presented additional details regarding nuclear fleet-wide projects and the projects DEP planned for each of DEP's nuclear stations. *Id.* at 173-76; Application at 15-16, Tr. Ex. vol. 7. He concluded that DEP prudently and reasonably selected these projects as they will enable DEP to maintain the fleet in reliable and efficient condition for customers' benefit. *Id.* at 172. Witness Ray's Direct Exhibit 1 provided additional details regarding projected cost, schedule, scope, and justification for each nuclear MYRP project. Tr. Ex. vol. 16.

In his supplemental direct testimony, DEP witness Ray updated the information on the MYRP nuclear projects. Witness Ray testified that DEP did not include any new nuclear projects with its supplemental filing, but identified two nuclear projects that it was postponing until after the MYRP period and, therefore, removed from the MYRP. Tr. vol. 16, 179-80. Witness Ray explained the basis for updating MYRP project costs as agreed upon with the Public Staff and the method by which DEP developed the updated project costs. *Id.* at 181-83. Witness Ray's Supplemental Exhibits 1 and 2 provided updated in-service dates and projected costs for the nuclear MYRP projects. Tr. Ex. vol. 16

Public Staff witness Metz discussed the Public Staff's review of DEP's initial and supplemental MYRP filings and updates. Witness Metz testified that the Public Staff initiated multiple sets of discovery and participated in multiple meetings with DEP on the MYRP. Tr. vol. 16, 458. The Public Staff did not make any adjustments or raise any concerns with the need for, scope of, or projected costs for the nuclear MYRP projects. *Id.* at 478-81.

In his rebuttal testimony, DEP witness Ray noted that neither the Public Staff nor any other party recommended rejection or cost reduction for any nuclear projects DEP proposed for the MYRP. Tr. vol. 23, 289.

Based on the entire record in this proceeding, the Commission finds that DEP's projected nuclear MYRP capital investments satisfy the requirements set forth in N.C.G.S. § 62-133.16(c)(1)(a) and will be used and useful in the appropriate rate year. The Commission notes that no party offered any evidence to challenge any of the nuclear

MYRP projects. Therefore, the Commission concludes the evidence supports approval of the Revenue Requirement Stipulation's provisions regarding the nuclear MYRP projects.

Fossil/Hydro

In her direct testimony, DEP witness Turner outlined the projected natural gas, coal, and hydroelectric capital investments DEP included in the MYRP. Witness Turner described DEP's prioritization process for identification of the projects to include in the MYRP. Tr. vol. 12, 101-02. She explained that DEP applied its project management guidelines for project scope development and cost estimation. *Id.* at 102. Witness Turner presented additional details regarding the MYRP projects proposed for the natural gas, coal, and hydro generation fleets. *Id.* at 105-08; Application at 16, Tr. Ex. vol. 7. Witness Turner also testified to the importance of keeping DEP's remaining coal fired assets working efficiently to support customer's energy needs as DEP plans for those units' retirement and explained that DEP will continue to incur costs for these assets as appropriate and prudent to ensure that reliable cost-effective electricity remains available while DEP develops and implements replacement of the coal fleet. She noted that due to the continued importance of natural gas to DEP's resource mix, particularly during winter months and while DEP is developing and deploying energy storage capacity, DEP will continue to rely on its natural gas fleet as part of the diverse and dispatchable resource mix. *Id.* at 94-95. She concluded that DEP's decision to invest in these projects is prudent and reasonable as they will enable DEP to continue to provide safe, reliable, and affordable service to customers as well as comply with regulatory requirements. *Id.* at 105-06. Witness Turner's Direct Exhibit 1 provided additional details regarding projected cost, schedule, scope, and justification for each fossil/hydro MYRP project.

In her supplemental direct testimony, DEP witness Turner supported the additional fossil and hydro projects that DEP proposed to include in its MYRP. Tr. vol. 12, 112-15. She explained why certain projects that DEP removed from the MYRP were determined to be no longer necessary. *Id.* at 115-16. Witness Turner explained the basis for updated MYRP projected costs as agreed upon with the Public Staff and the method by which DEP developed the updated project costs. *Id.* at 116-17. Witness Turner's Supplemental Exhibits 1 and 2 provided updated in-service dates and projected costs for the fossil and hydro MYRP projects and cost, schedule, scope, and reasoning information for the newly added fossil and hydro projects. Tr. Ex. vol. 12.

Public Staff witness Metz testified that the Public Staff reviewed DEP's initial and supplemental MYRP filings and updates, initiated multiple sets of discovery, and participated in multiple meetings with DEP on the MYRP. Tr. vol. 16, 458, 478-81. Public Staff witness Michna testified that he did not dispute the inclusion of Steam Plant in Service projects in the MYRP, and that he agreed with DEP's philosophy of prioritizing unit reliability and resource adequacy in capital spending decisions. Tr. vol. 21, 302. Public Staff witness Thomas recommended a delay in the in-service date for the Blewett Falls fish passage project that would move the project from MYRP Rate Year 1 into MYRP Rate Year 2 due to previous and anticipated extensions of commencement of operations, and a reduction the projected cost for the project based on his review of the contractor bid selection and internal funding approval processes, which he concluded resulted in significant excess contingency for the project. Tr. vol. 19, 208-13.

In rebuttal testimony, DEP witness Turner described how DEP's cost estimates for the Blewett Falls fish passage project, particularly the contingency allotted for the project, were based on the project's unique nature and challenges. Witness Turner disagreed with the delay of the project in service date to MYRP Rate Year 2, explaining that the timing for testing of the project is separate from the capital project construction, which according to current plans should go in service during Rate Year 1. Tr. vol. 12, 147-50.

The Revenue Requirement Stipulation accepts the Public Staff's recommended changes to the Blewett Falls fish passage project cost estimate and postponement of this project's in-service date to March 2025. Revenue Requirement Stipulation § III.33.e, Tr. Ex. vol. 7. Further, the stipulation accepts the Public Staff's recommendation for inclusion of the costs of the Blewett Falls fishing pier in the MYRP and removal from the historic test period. Revenue Requirement Stipulation § III.33.a, Tr. Ex. vol. 7. DEP witnesses Abernathy and Jiggetts and Public Staff witnesses McLawhorn and Metz supported these provisions in their settlement supporting testimony. Tr. vol. 13, 138-40, 262; Tr. vol. 16, 514.

Based on the entire record in this proceeding, the Commission finds that DEP's proposed natural gas, coal, and hydro MYRP projects satisfy the requirements set forth in N.C.G.S. § 62-133.16(c)(1)(a). DEP demonstrated that these projects are primarily in the normal course of business for maintaining the fossil and hydro fleets for reliability, safety, and regulatory compliance. In addition, DEP provided substantial evidence regarding the continued importance of the coal and natural gas fleets to its ability to continue to provide reliable service to customers and the need to continue to invest in the coal fleet until its retirement and in the natural gas fleet to reliably manage the transition away from coal. The Commission further concludes that the evidence supports approval of the Revenue Requirement Stipulation's provisions regarding these fossil/hydro projects.

Cybersecurity

In his Supplemental Direct Testimony, DEP witness Strasburger provided support for DEP's information technology (IT)/operational technology (OT) Cybersecurity project DEP will include in the MYRP. Tr. vol. 16, 184-88. Witness Strasburger explained that the purpose of the IT/OT Cybersecurity project is to assure safe and sustainable operations through proactive and effective cybersecurity design, implementation and operation of critical energy systems and their underlying technology. *Id.* at 186. He testified that the IT/OT Cybersecurity project will update OT governance and risk and compliance standards and processes, implement a new OT specific asset, patch and vulnerability management system, and deliver new OT cybersecurity threat logging and monitoring capabilities. *Id.* at 185-86. The project will also focus on expanding monitoring and threat response capabilities and will introduce proactive elements to reduce cybersecurity risks. *Id.* at 186. He noted that his Strasburger Exhibit 1 contained information regarding the IT/OT Cybersecurity project required by Commission Rule R1-17B(d)(2)j.(i)-(iii). He further testified that as DEP continues to see increased cyber threats against operational assets, including potential geopolitical threats, cybersecurity becomes a larger component of DEP's energy transition and grid protection initiatives, and that the Commission should approve the MYRP IT/OT Cybersecurity project. *Id.* No other party offered any evidence regarding DEP's MYRP Cybersecurity project.

After having carefully reviewed the entirety of the evidence in the record on DEP's MYRP IT/OT Cybersecurity project, the Commission finds that the IT/OT Cybersecurity MYRP project satisfies the requirements set forth in N.C.G. S. § 62-133.16(c)(1)(a). DEP demonstrated that cybersecurity is becoming an increasingly critical component of its energy transition and grid protection initiatives, and that the IT/OT Cybersecurity project is reasonably necessary. Additionally, no party offered evidence to the contrary. The Commission further concludes that DEP put forth a reasonable plan to implement the IT/OT Cybersecurity project within the prescribed time period.

Battery Storage

DEP proposes a portfolio of MYRP battery energy storage projects. Tr. vol. 11, 22. The portfolio consists of six discrete and identifiable battery energy storage projects: (1) Riverside; (2) Warsaw; (3) Lake Julian; (4) Elm City; (5) Knightdale; and (6) Craggy. *Id.* DEP witnesses Tompson and Shearer (the Battery Energy Storage Panel) testified and detailed the projected cost, schedule, and scope for each MYRP project, as well as the reasoning for each project as Commission Rule R1-17B(d)(2)j requires. *Id.* at 21; *see also* Battery Energy Storage Panel Ex. 1, Tr. Ex. vol. 11. According to the Battery Energy Storage Panel, the proposed investments represent near-term investments that will play an integral role in the next phases of the energy transition. Tr. vol. 11, 21. Evidence appearing in Battery Storage Panel Exhibits 1-2 includes detailed information regarding projected cost, schedule, scope, and rationale supporting the investments. *Id.* Battery Energy Storage Panel Exhibit 2 also includes anticipated project timelines, including projected in-service month and year for each proposed project as Commission Rule R1-17B(d)(2)j requires. *Id.*

DEP's Battery Storage Panel testified as to the expected benefits associated with each proposed battery project including unique bulk power services. Tr. vol. 11, 23-25. The panel testified that battery resources are uniquely capable of serving multiple grid functions across generation, transmission, and distribution systems. *Id.* at 25. The panel testified that the Craggy, Lake Julian, and Riverside projects each comply with the Western Carolinas Modernization Project (WCMP) and support the Mountain Energy Act. *Id.* at 23-24. Additionally, the battery projects at Elm City and Warsaw both leverage and provide experience with surplus solar interconnection capacity, and they also utilize existing interconnection infrastructure thereby reducing development costs and project timelines. *Id.* at 24. Furthermore, the Knightdale battery project will be the largest battery DEP has installed and this size project provides the next phase of critical operating experience. *Id.* The Knightdale battery project will provide bulk system services including energy arbitrage and ancillary services with a grid scale battery system. *Id.* at 24-25.

Public Staff witness Thomas testified regarding DEP's proposed battery energy storage portfolio. Tr. vol. 19, 184-99. Witness Thomas recommended that DEP classify the Craggy battery project as 50.0% "Other Production Plant" and 50.0% "Transmission Plant," given that DEP sited and sized the project for a potential transmission deferral. *Id.* at 197. Witness Thomas noted that DEP has classified all battery storage projects as "Other Production Plant," with interconnection costs separated into either Transmission Plant or Distribution Plant, depending on where the facility interconnects to the grid*.* *Id.* at 196. For most of the projects, witness Thomas found this approach to be reasonable absent clear guidance from FERC. *Id.* For Craggy, however, witness Thomas testified that DEP identified Craggy as part of a first of a kind non-wires alternative study and sized and sited the project for a potential transmission deferral designed to alleviate a future DEP-West balancing area transmission constraint. *Id.* at 197. For those reasons, witness Thomas recommended reclassification of the Craggy battery project as 50.0% "Other Production Plant" and 50.0% "Transmission Plant." *Id.*

The Battery Energy Storage Panel rebutted witness Thomas' Craggy-related recommendation, asserting that the proposed project would not defer a transmission investment. Tr. vol. 11, 49. The panel explained that the Craggy battery would mitigate against certain delays in implementing the 230kV Craggy-Enka line project; however, it would not defer transmission investment entirely. *Id.* at 48. The panel further testified that DEP does not anticipate dispatching the Craggy battery for transmission deferral purposes – the proposed project remains cost-effective based on low interconnection costs in an area with limited generation resources. *Id.* The panel maintained that the originally proposed allocation of 100.0% Production for the project is reasonable. *Id.* at 49.

The Revenue Requirement Stipulation adopts the allocation factor by plant classification for the Craggy battery project, as proposed by DEP. Revenue Requirement Stipulation § III.33.c, Tr. Ex. vol. 7.

After careful review all the evidence in the record on DEP's MYRP proposal in this docket, and based on that evidence, the Commission finds that DEP's battery storage MYRP projects satisfy the requirements set forth in N.C.G.S. § 62-133.16(c)(1)(a). The Commission further finds that the evidence supports approval of the Revenue Requirement Stipulation's provisions regarding the battery storage MYRP projects.

Solar

DEP witness LaRoche addressed the need, rationale, and cost estimates for two solar development projects a solar project from the 2022 Solar Procurement Program DEP expects to be in service between 2025 and 2026 (2026 Solar Investment Project) and a 9.5 MW solar facility DEP proposes to place in service at the DEP Asheville Generating Plant site in Buncombe County by September 2025 (Asheville Solar Project). Application at 14; Tr. vol. 16, 113-18. Witness LaRoche stated that to identify the 2026 Solar Investment Project, DEP considered the solar investments that will result from the 2022 Carolinas Carbon Plan, the 2022 Solar Procurement Program Request for Proposals, and DEP's WCMP commitments. Tr. vol. 16, 113. Additionally, he testified that

DEP's most recent integrated resource plan (IRP) identified the need for new solar resources to reliably serve DEP's projected customer load. *Id.* at 114. Witness LaRoche also stated that N.C.G.S. 62-110.9 was a "key driver" of the 2026 Solar Investment Project, as that statute requires DEP and DEC to take all reasonable steps to achieve 70.0% carbon emission reductions by 2030 and carbon neutrality in North Carolina by 2050. *Id.* The WCMP, approved by the Commission on March 28, 2016, was also a primary regulatory driver of the program, as the Asheville Solar Project directly relates to and is a commitment stemming from the WCMP. *Id.* at 116.

Public Staff witness Thomas recommended that the Commission delay the in-service date for the Asheville Solar Project to March 2026. Tr. vol. 19, 181. Witness Thomas stated that he based this recommendation on DEP's history of delays with solar project completion as well as the potential for new challenges that may emerge during project development and construction. *Id.* at 181-82. Additionally, the Public Staff is concerned about the Asheville Solar project's costs, as the cost per kW is 50.0% higher than the cost per kW for the 2026 Solar Investment project. *Id.* at 181.

Regarding the delayed in-service date, DEP witness LaRoche testified in his rebuttal testimony that the use of historical delays is inappropriate, as blanket comparisons between past and future solar projects are not on an apples-to-apples basis. Tr. vol. 23, 262. For example, witness LaRoche noted that Public Staff witness Thomas cited DEP's delays in the Woodfin project to support his recommended delay but did not assess whether the same delays are likely to impact the Asheville Solar Project or whether DEP has taken steps to mitigate that risk. *Id.*

After having carefully reviewed the evidence in the record on DEP's Solar MYRP proposal in this docket, and based on that evidence, the Commission finds that DEP's solar MYRP projects satisfy the requirements set forth in N.C.G.S. § 62-133.16(c)(1)(a). The Commission concludes that the evidence supports approval of the Revenue Requirement Stipulation's provisions regarding the solar MYRP projects.

MYRP Implementation

Public Staff witness Metz testified to his concern regarding DEP's ability to complete the proposed MYRP projects within the three-year MYRP period. Based on his review of DEP's historic and projected 2023 staffing, Witness Metz asserted that DEP does not have a plan to increase staffing for planned MYRP projects while continuing to perform traditional work of the utility. Tr. vol. 16, 465-81.

In his rebuttal testimony, DEP witness Murray overviewed DEP's wholistic and comprehensive approach to project planning and execution while noting that neither the Public Staff nor any party recommended disallowance or rejection of any MYRP project based on generalized project execution risks or challenges. Tr. vol. 23, 313. Witness Murray discussed how Duke Energy's Project Management Center of Excellence (PMCoE) creates a common framework for managing projects across the enterprise and how DEP has successfully implemented prudent management processes historically.

While acknowledging that MYRP project execution will not be easy and that there likely will be unforeseen challenges that require DEP to, in some cases, modify planning MYRP projects to maximize benefits for customers, he explained that MYRP project execution is not a challenge that is fundamentally different than challenges inherent in DEP's historic capital project implementation and disagreed with the suggestion that DEP is not well prepared to successfully execute these projects. Tr. vol. 23, 312-18.

DEP witness Bowman also responded to the witness Metz's concerns regarding DEP's ability to execute on certain MYRP projects. Tr. vol. 21, 1211. She testified that DEP is confident in its ability to execute the MYRP projects and acknowledged DEP's obligation, as confirmed by the Commission, to continually assess the MYRP projects and ensure that customer benefits are maximized throughout the execution phase. *Id.* She explained that although DEP will encounter unforeseen challenges and circumstances, in all instances DEP will leverage its execution experience to maximize benefits for customers. *Id.*

After review of the evidence presented by DEP's various generation, transmission, and distribution witnesses, as well as the evidence presented by DEP regarding its processes, procedures, and project management experience the Commission finds that DEP has the obligation to prudently and reasonably implement the MYRP in a manner that benefits its customers. Any modification to the implementation of MYRP projects will be reported by DEP on a quarterly basis, as required under Commission Rule R1-17B(h(2)) and will be subject to audit in future base rate case proceedings. While the Commission recognizes the risk about which the Public Staff is concerned, the Commission determines, on the evidence presented, that DEP has demonstrated a reasonable plan to complete the MYRP projects within the prescribed time periods.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 30

Reporting Requirements

The evidence supporting this finding of fact is included in DEP's verified Application and Form E-1; the testimony and exhibits of DEP witnesses Bowman, Abernathy, Jiggetts, and Guyton, and Public Staff witnesses Zhang, Boswell, McLawhorn, Metz, Nader, T. Williamson, and Thomas; the Revenue Requirement Stipulation; and the entire record in this proceeding.

Rider EC

In his testimony, Public Staff witness Nader testified that to ensure that the proposed Rider EC continues to be in the public interest, the Commission should require annual reporting on the impacts of Rider EC. Tr. vol. 21, 106. Witness Nader recommended that DEP should report the gross level of incentives DEP paid, the number of recipients, the amount of investment, load, and jobs associated with the incentives, and an overall marginal cost analysis of Rider EC to determine if the gross level of incentives DEP paid exceeds the marginal cost to serve the gross pool of participants. *Id.*

CIAC Reporting

In their joint direct testimony, Public Staff witnesses Zhang and Boswell stated that DEP was booking contributions in aid of construction (CIAC) related to interconnection agreements (IA) inconsistently. Witnesses Zhang and Boswell recommended that the Commission order DEP to review its CIAC policy to ensure that DEP properly accounts for CIAC and report the results of that review in the next general rate case. Tr. vol. 19, 39-40. In rebuttal, DEP witness Speros rebutted the notion that DEP was booking its CIAC related to IAs inconsistently but stated that DEP did not oppose in principle reporting to the Commission on its CIAC policy in the next general rate case. Tr. vol. 13, 63.

Vegetation Management Reporting

Public Staff witness T. Williamson recommended that the Commission require DEP to perform additional reporting requirements beyond the Vegetation Management Program Performance report DEP files annually. He recommended that DEP report on the additional following topics: (1) distribution vegetation management herbicide actuals, target, and variance for spending and miles; (2) distribution vegetation management number of miles of vegetated distribution lines that require trimming or herbicide treatment; (3) distribution vegetation management hazard tree program actuals, target, and variance for spending and tree counts; and (4) distribution vegetation management reactive/demand events, and the number of events worked annually. Tr. vol. 21, 217-18. In his rebuttal testimony, witness Guyton stated that DEP can provide the recommended additional distribution reporting requirements beyond the Vegetation Management Program Performance DEP files annually with two exceptions. Tr. vol. 10, 147.

Hot Springs CBA

In his testimony, Public Staff witness Thomas recommended the Commission direct DEP to perform an updated cost benefit analysis for Hot Springs. Tr. vol. 19, 194. He further recommended that DEP provide the updated cost benefit analysis with its operational report for the Hot Springs facility on October 31, 2023, in Docket No. E-2, Sub 1185. *Id.*

Discussion and Conclusions

The Revenue Requirement Stipulation establishes certain reporting obligations. Specifically, Paragraph 34 obligates DEP to report on Rider EC, subject to agreement of the Revenue Requirement stipulating parties regarding the scope and content of the report. Paragraph 35 obligates DEP to report on the CIAC issue in its next general rate case application. Paragraph 36 addresses a reporting on reliability O&M as discussed by Public Staff witness Metz, and a management reporting requirement as discussed by Public Staff witness T. Williamson, except for reporting on the two issues noted in the rebuttal testimony of DEP witness Guyton. In Paragraph 38, the Revenue Requirement stipulating parties agree to discuss the need for a report on the Hot Springs CBA as requested in the testimony of Public Staff witness Thomas. Besides the exceptions noted in Paragraphs 34-38 of the Revenue Requirement Stipulation, Paragraph 39 indicates that DEP agrees to all reporting requirements proposed by the Public Staff.

No other party offered any evidence addressing the reporting obligations outlined in the Revenue Requirement Stipulation. The Commission concludes that the reporting obligations agreed-upon in Section IV of the Revenue Requirement Stipulation are reasonable. Based upon the record evidence and consistent with the Revenue Requirement Stipulation, the Commission finds and concludes that the reporting obligations outlined in Section IV of the Revenue Requirement Stipulation are approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 31

The evidence supporting this finding of fact is in DEP's verified Application and Form E-1; the testimony and exhibits of DEP witnesses Hunsicker, Quick, and Jiggetts; the supplemental and settlement testimonies of Public Staff witnesses Zhang and Boswell; and the entire record in this proceeding.

In prior DEP rate cases, including Dockets No. E-2, Sub 1023, E-2, Sub 1142, and E-2, Sub 1219, the Commission has approved a calculation of "storm normal" expenses based upon a 10-year average of storm costs, after reducing the costs associated with major storms, to include in rates. Witness Jiggetts explained the methodology for the calculation of storm normal in this case. Tr. vol. 14, 29-30. The resulting amount to include in rates per DEP's calculation is approximately $22.2 million. Jiggetts Partial Settlement Ex. 4, Tr. Ex. vol. 14.

No party disputes DEP's calculation of storm normal expenses to include in rates, and DEP witness Jiggetts testified that the Public Staff agrees with the amount as calculated by DEP. Tr. vol. 14, 58.

Accordingly, the Commission finds that the appropriate North Carolina retail normalized annual level of storm costs to include in DEP's rates in this case is $22.243 million.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 32-34

Distribution System Demand Response

The evidence supporting this finding is in the verified Application and Form E-1; the testimony and exhibits of DEP witnesses Jiggetts and Hunsicker; the testimony and exhibits of Public Staff witnesses Zhang and Boswell; and the entire record in this proceeding.

In this case, DEP proposed to move the future costs associated with its DSDR energy efficiency program from the DSM/EE rider into base rates starting on the effective date for the new rates established in this proceeding as the Commission instructed in its Order from the 2019 Rate Case. Tr. vol. 13, 204. DEP witness Jiggetts explained that

DEP will continue to recover costs deferred to the regulatory asset before the effective date for new rates in this proceeding through the DSM/EE rider until they are fully amortized. *Id.* Public Staff witnesses Zhang and Boswell testified that DEP's proposal to recover the future DSDR costs in base rates is appropriate because all customers benefit from DSDR. Tr. vol. 19, 74.

No party opposed DEP's request.

Payment Navigator

The evidence supporting this finding is in the verified Application; the testimony and exhibits of DEP witnesses Jiggetts and Quick; and the entire record in this proceeding.

In her direct testimony, DEP witness Jiggetts stated that DEP proposed several new programs in this rate case to benefit customers, including the CAP, the Tariffed On-Bill program, and the Payment Navigator Program that DEP witnesses Harris and Quick also discussed in their testimony. If the Commission approves each program, DEP requests permission to establish a regulatory asset and defer to the account the incremental implementation and administration O&M costs related to the programs. Tr. vol. 13, 209.

DEP witness Quick described DEP's Affordability Ecosystem in her direct testimony. The Affordability Ecosystem is a multi-pronged approach to assist customers who have challenges in affording to pay their electric utility bills. The Affordability Ecosystem includes products and services, including bill pay assistance and weatherization programs, and DEP equips its customer service team to inform customers about opportunities to address their affordability challenges. Tr. vol. 7, 75. Consistent with DEP's Affordability Ecosystem, witness Quick requested approval of the Payment Navigator program, which DEP specifically designed to comprehensively support not only low-income customers in arrears on their bills, but all customers seeking assistance in managing their electric utility bills. *Id*. at 172. The Payment Navigator program is based on a pilot that DEP tested during the COVID-19 pandemic with customers seeking support in paying their electric bills. *Id*. at 175-77. As witness Quick described, in accordance with the Payment Navigator program, DEP proactively contacts customers who are struggling with arrearages to invite them to speak with a Payment Navigator specialist. A Payment Navigator specialist is a call center agent trained to empathetically handle more complex calls assisting customers who have fallen behind in their bills, and the specialist can take the necessary time to work with customers on obtaining the assistance they need. *Id.* at 177. Based on the customer's situation, the Payment Navigator specialist may tailor a unique set of recommendations to assist the customer in becoming current on payments and provide longer-term guidance on how to ease the customer's electric energy burdens by connecting the customer to assistance funding, referring them to energy efficiency or demand side management options, or enrolling them in programs like Budget Billing, Pick Your Own Due Date, and more. *Id.* at 78-79.

DEP witness Quick highlighted the positive feedback and insights that DEP received regarding the Payment Navigator pilot and the success that DEP had in referring customers to agencies for assistance, enrolling them in deferred payment arrangements, and recommending flexible billing programs. *Id.* at 79. During the pilot, by assisting customers to access this available funding, Payment Navigator helped customers obtain all the funding available to them from certain assistance agencies, in contrast to previous years when agencies' funds were not utilized. *Id*. at 175-76. Witness Quick also stated that during the pilot, DEP learned that about 50.0% of the customers that DEP contacted were not aware of the assistance available to them. She noted that some customers have difficulty reading and completing applications, and DEP learned during the Payment Navigator pilot that customers dropped out sometime during the application process and did not complete the applications. Witness Quick indicated that Payment Navigator specialists could benefit customers by working with them to complete the applications so that they can access all available funding. Tr. vol. 22, 132-33.

DEP witness Quick also testified that Payment Navigator would complement the CAP that DEP witness Harris described. She noted that CAP will directly benefit customers by reducing their monthly electric energy burden through a bill discount. After a customer enrolls in CAP, DEP can continue to work with the customer to understand the customer's needs and analyze what other products and services (such as Share the Light, Budget Billing, energy efficiency offerings, weatherization, and payment plans) are available to support the customer over the longer term. Tr. vol. 7, 80.

Witness Quick concluded by requesting that the Commission approve the Payment Navigator program and associated costs, which she estimated to be $3 million over the next three years. She noted that the deferral request that DEP witness Jiggetts describes in her testimony addresses the associated incremental O&M costs that the $3 million estimate includes. Witness Quick testified that DEP would not defer any capital costs associated with the program. *Id*. at 80-81

No party contested the implementation of the Payment Navigator program.

Customer Connect

In its Application, DEP requested recovery of the approximately $60 million North Carolina retail allocated capital investment associated with implementation of its Customer Connect project, the new customer engagement platform, and CIS. Tr. vol. 16, 71, 82. DEP witness Hunsicker testified that in November 2021, DEP implemented the Customer Connect platform including a CIS, which is a system that manages the billing, accounts receivable, and rates for DEP as a central repository for all customer information. *Id.* at 71-72. She explained that CIS links the consumption and metering process to payments, collections, and other downstream processes, including additional work order requests such as service connections and disconnections, outages, and trouble requests. CIS also manages customer profiles and integration of data to provide a holistic view of the customer and it should enable expected customer capabilities. *Id.* at 72-73. Witness Hunsicker explained that DEP developed its previous CIS almost 30 years ago and the system could not efficiently support new capabilities, and thus required complex add-ons and manual performance of some complex billing functions. *Id.* at 71.

Witness Hunsicker explained that Customer Connect benefits customers by providing a modern, configurable billing system that allows DEP to keep pace more efficiently with changing customer expectations and needs. Improvements with Customer Connect include a customer-centric data model and more holistic customer data analytics capabilities, which allow DEP to better know its customers and the usage needs across the entire Duke Energy footprint and provide a more customized experience. She explained that since she first testified to the need for Customer Connect in the 2017 Rate Case, DEP has kept stakeholders informed of the status of the implementation and that, while no complex, enterprise-wide CIS implementation is without challenges, its Customer Connect implementation benchmark metrics compare favorably to industry benchmarks. *Id.* at 72.

No party contested DEP's request to recover its costs related to Customer Connect.

Discussion and Conclusions

No parties opposed DEP's requests related to DSDR, Payment Navigator, or Customer Connect. 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 Commission can accept the uncontested evidence of a public utility regarding the reasonableness of its costs as satisfying the utility's burden of proof on the question of cost recovery. The Commission concludes that DEP has met its burden of showing that its proposals related to DSDR, Payment Navigator, and Customer Connect are just and reasonable.

More specifically, the Commission concludes that DEP's proposal to include future DSDR program costs in base rates starting with the effective date of the rates established in this proceeding to be reasonable and appropriate. Further, the Commission concludes that DEP's requested recovery of costs associated with its Customer Connect project is just and reasonable to all parties considering the evidence presented.

Finally, the Commission approves implementation of Payment Navigator and recognizes and appreciates the work of DEP to undertake this effort during the COVID-19 pandemic and to devote resources and expertise to connecting customers with assistance during the crisis. The Commission recognizes the customer benefits that arise, particularly in the context of those customers most in need, when DEP (and its affiliates) apply their specialized knowledge and resources in direct support of the customers. The Commission encourages DEP to continue to partner with assistance agencies across its service area and to proactively contact struggling customers to direct them to contact a Payment Navigator specialist for assistance in managing their electric utility bills.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 35

COSS Stipulation

The evidence supporting this finding is in DEP's verified Application and Form E-1; the COSS Stipulation; the testimony and exhibits of DEP witness Hager, Public Staff witnesses McLawhorn and D. Williamson, and CIGFUR witness Phillips; and the entire record in this proceeding.

Summary of Evidence

DEP Direct Testimony

Cost of Service Study Overview

In her testimony, DEP witness Hager described the purpose of a cost of service study (COSS) and how costs are assigned pursuant to such study. She explained that the COSS is used to align the total costs incurred by DEP in the test period with the jurisdictions and customer classes responsible for those costs. Tr. vol. 11, 82. Using the principle of cost causation, the COSS assigns or allocates DEP's revenues, expenses, and rate base to the regulatory jurisdictions and to customer classes that caused such costs to be incurred. *Id.* Costs are first grouped according to their function. *Id.* at 84. 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.* at 84-85. Once all costs and revenues are assigned, the COSS identifies the return on investment that DEP has earned for each customer class during the test period, and these returns can then guide rate design. *Id.* at 83.

The COSS Stipulation

On September 13, 2022, DEP, DEC, the Public Staff, CIGFUR, and CIGFUR III (the COSS Stipulating Parties) filed the COSS Stipulation with the Commission. Tr. vol. 11, 80. The COSS Stipulation provides that production and transmission demand costs are first allocated to the North Carolina retail jurisdiction using the 12 CP method, and then production demand costs are allocated within North Carolina retail rate classes using the Modified A&E method. *Id.* Because transmission demand does not have average or excess energy components, the transmission demand factors at the customer class level are equivalent to the 12 CP calculation. *Id.* The stipulation also provides that, for purposes of allocating production demand costs on a jurisdictional basis as well as to North Carolina retail rate classes, DEP will make an adjustment to exclude certain curtailable/interruptible loads if they were not curtailed at the twelve system peak hours during the test year. *Id.* By its terms, the COSS Stipulation only applies in the current rate case, and COSS Stipulating Parties are free to advocate for different methodologies in future DEP cases. *Id.* DEP witness Hager testified that the stipulation is reasonable and that the Commission should approve it, noting that it was the result of the give-and-take inherent in coming to a settlement among parties with diverse views on the appropriate methodologies. *Id.* at 80-81. The COSS Stipulating Parties urge the adoption of the stipulation in this case as a fair and reasonable methodology for the allocation of costs. COSS Stipulation at 4-5, Tr. Ex. vol. 7.

The 12 CP Method

Under the COSS Stipulation, the 12 CP method will be used to allocate costs to the North Carolina retail jurisdiction. COSS Stipulation at 3, Tr. Ex. vol. 7. Witness Hager testified that in its previous rate case, DEP recommended, and the Commission approved, the summer coincident peak (Summer CP) method to allocate the fixed portion of production and transmission demand-related costs. *Id.* at 89. However, DEP now believes it is appropriate to move from Summer CP to 12 CP, which utilizes the average of the test year's twelve monthly peaks. *Id.* Witness Hager testified that DEP's integrated resource planning period has shifted away from an emphasis solely on summer peaks, and that by averaging the twelve monthly peaks, the 12 CP method is less volatile than a single coincident peak. She further testified that the 12 CP method is regularly used by other utilities and has been approved by state commissions and the FERC. *Id.* at 89-90.

The Modified A&E Method

The COSS Stipulation also proposes a Modified A&E method to allocate production demand costs across North Carolina retail customer classes. COSS Stipulation at 3, Tr. Ex. vol. 7. DEP witness Hager testified that the Modified A&E method adopted under the COSS Stipulation considers that generation facilities are needed to serve a utility's "average load" as well as its "excess or peak load" in assigning responsibility for the recovery of production demand-related costs. Tr. vol. 11, 81. The excess demand is the excess of a rate class' non-coincident peak (NCP) demands over its average demands. Under this method, all groups of customers are allocated some portion of the production plant investment and fixed expenses related to the generation of power. *Id.* at 96. A rate class' coincident peak demand is the class' load at the time of the system's peak demand, while a rate class' NCP is the maximum demand regardless of the time of occurrence. *Id.* Witness Hager explained that each customer class' non-coincident demand likely occurs at different times. *Id.* She noted that the A&E method is used in several jurisdictions including at least a third of the 30 utilities she examined and is a reasonable method for allocating demand-related production costs to the North Carolina retail classes in this case. *Id.* at 156, 81. However, DEP modified the method to conform the A&E allocators to the 12 CP method used at the North Carolina retail jurisdictional level. *Id.* at 97. In response to Commissioner Clodfelter's question, witness Hager testified that this method was used by Dominion in Virginia, but has never been used by Dominion in North Carolina. *Id.* at 130. Additionally, Witness Hager testified that since the sum of NCPs exceeds the coincident system peak, the excess components for each rate class were scaled down proportionally, such that the sum of their demand matches the coincident system peak. *Id.* at 133. In response to Commission questions, DEP witness Hager stated that DEP did not use the 12 CP method for both jurisdictional and rate class allocation for this proceeding as it did in South Carolina, a difference which Witness Hager attributed to the COSS Stipulation. *Id.* at 134.

Removal of Certain Curtailable/Interruptible Loads

DEP witness Hager testified that, historically, DEP has allocated production fixed costs based on the demands served at its peak hour. *Id.* at 97. She testified that aligning firm load with firm capacity to serve that load is more consistent with the principle of cost causation than the previous method. *Id.* at 98. DEP does not plan for, and does not purchase capacity for, the curtailable load of customers. *Id.* Since DEP can curtail customers who take interruptible service so that their load does not contribute to the system peak, interruptible load does not factor in to how much the utility must invest in capacity to meet the system peak. *Id.* If the utility curtails all possible curtailable load in the test year during system peaks, there is no need for adjustments, as revenues and loads both reflect only firm load. *Id.* However, there can be a mismatch between revenues and loads if there is some non-firm load in the test year peaks. *Id.* Accordingly, DEP has removed non-curtailed non-firm load present during the test year peaks where its presence would create a mismatch with revenues. *Id.* This adjustment ensures a matching of firm load with firm load revenues. *Id.* This practice is also consistent with FERC precedent. *Id.* Witness Hager testified that this proposed method will eliminate the volatility of having load in one test year and out in the next test year. *Id.* at 100.

Adjustments were made to remove certain curtailable load at both the North Carolina retail jurisdiction level with the 12 CP method, as well as at the North Carolina retail rate class level with the modified A&E method. *Id.* at 101. The demand-related transmission costs were allocated to rate classes based on 12 CP demand, without adjustment for curtailable load. *Id.*

Distribution Costs

DEP witness Hager testified that most distribution investments are identified and then directly assigned to the state in which they are located. *Id*. Distribution costs identified as customer-related are allocated using customer allocation factors, and the remainder are designated as demand-related and allocated to customers based on NCP demand allocators. *Id.*

NCP allocators are developed to account for the different levels of the distribution system where customers may take service. *Id.* Witness Hager explained that 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 several different NCP allocators are developed 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 is included in the development of the NCP allocator used to allocate secondary distribution lines and poles. *Id.* at 101-02.

Further, witness Hager testified that NCP allocators are used for demand-related distribution investment because distribution facilities serve individual neighborhoods, rural areas, or commercial districts; they do not function as a single integrated system in meeting system peak demand. *Id.* at 102. The individual distribution system serving an area must be able to meet the peak demand in the area it serves, whenever the peak occurs. *Id.* Accordingly, Witness Hager testified that contribution to NCP is the appropriate measure of determining customers' responsibility for costs, because it best measures the factors that drive investment to support that part of the system. *Id.*

Energy Allocators

DEP witness Hager testified that energy-related costs, such as fuel costs and variable production costs at generating stations, reflect the variable cost of producing, transmitting, and delivering electricity. *Id.* at 102. She testified that these costs are allocated using DEP's kWh of generation and deliveries during the test period. *Id.* Witness Hager explained that kWh sales information is collected and adjusted for the level of losses attributable to each class and jurisdiction to determine the level of kWh at the generator attributable to that class or jurisdiction. *Id.*

Customer Allocators

DEP included operating expenses in FERC accounts 901-917 for allocation as customer-related costs that include meter reading, billing and collection, and customer information and services. Tr. vol. 11, 103. DEP has also included in this category a portion of distribution costs that it has identified as customer-related, such as meters and service drops (FERC accounts 369 and 370) and a portion of transformers (FERC account 368). *Id.* A portion of costs for distribution lines and poles (FERC accounts 364-367) were also identified as customer related. *Id.* The remaining distribution plant and associated costs were classified as demand-related, except for FERC account 363, Energy Storage Equipment – Distribution. *Id.*

Account 363, beginning in 2020, had a small balance of approximately $11 million related to batteries. *Id.* DEP witness Hager testified that storage battery equipment functionalized to distribution (FERC account 363) is allocated across customer classes using gross distribution plant excluding batteries. *Id.* This approach recognizes that batteries provide benefits to or support different parts of the distribution system. *Id.*

Witness Hager testified that a portion of distribution costs related to FERC accounts 364-68, including costs of poles, towers, fixtures, overhead and underground conductors, and transformers, are customer-related. *Id.* at 104. NARUC discusses using two methods for allocating these customer-related distribution costs: the Minimum System Method and the Zero-Intercept Method. *Id.* Witness Hager testified that both methods recognize that some portion of the distribution system is necessary to serve customers, regardless of whether the customers take any energy from the system. *Id.* The Minimum System Method seeks to determine the minimum size distribution system that can be built to serve the minimum load requirements of customers. *Id.* This method develops the cost of the minimum set of distribution assets that are needed to serve customers, and allocates those costs based on the number of customers. *Id.* The Zero-Intercept Method, according to witness Hager, similarly allocates a portion of the same distribution accounts on the basis of the number of customers and seeks to identify the portion of distribution plant that is associated with no load using regression techniques. *Id.*

Witness Hager testified that DEP incorporated the Minimum System Method into its COSS and testified that this was appropriate for the allocation of customer-related distribution costs. *Id.* at 105. She explained that the Zero-Intercept Method is a more complex and time-consuming methodology. Witness Hager further explained that the Minimum System Method, which is sound and consistent with cost causation, produces results that are not materially different from the Zero-Intercept Method. *Id.* DEP's Minimum System Study allowed DEP to classify the distribution system into customer-related and demand-related portions. *Id.* She testified that because every customer requires some minimum amount of wires, poles, and other distribution infrastructure, every customer "causes" DEP to install some amount of distribution assets. *Id.* The concept used by DEP in developing its Minimum System study was to consider what distribution assets would be required if every customer had only a minimum level of usage. *Id.* This allows DEP to assess how much of its distribution system is installed simply to ensure that electricity can be delivered to each customer. *Id.* Once minimum system costs are identified, distribution costs over this amount and direct assignments of those extra costs are determined to be driven by demand. *Id.*

Witness Hager testified that the PBR Statute requires the use of the minimum system methodology to allocate distribution costs between customer classes. *Id.* at 106.

The Public Staff Testimony

Public Staff witness McLawhorn testified in support of the COSS Stipulation and discussed the stakeholder process that led to that settlement. Witness McLawhorn discussed the Commission's March 31, 2021, Order Accepting Stipulations, Granting Partial Rate Increase, and Requiring Customer Notice issued in Docket No. E-7, Sub 1214, in which the Commission adopted the Second Agreement and Stipulation of Partial Settlement (Sub 1214 Partial Settlement). Tr. vol. 16, 398-99. The Sub 1214 Partial Settlement provided for an analysis of various cost of service methodologies in which DEP and DEC agreed to consult with the Public Staff and interested parties to analyze and develop cost of service studies based upon specific criteria, including the analysis of the various strengths and weaknesses of each respective methodology, and to file the resulting COSS with the Commission before DEP filed its next rate case. *Id.* at 399. As witness McLawhorn described, the stakeholders met several times throughout 2021, holding the final meeting on November 16, 2021. *Id.* On January 25, 2022, DEP and DEC filed the results of the COSS in Docket Nos. E-2, Sub 1219 and E-7, Sub 1214, as the Commission required. *Id.* at 400. Although the stakeholder process did not result in a consensus as to the appropriate cost of service allocation methodology to utilize, it helped certain parties arrive at the COSS Stipulation that is before the Commission in this case. *Id.*

Public Staff witness D. Williamson also testified in support of the COSS Stipulation, including the results of his investigation on how the COSS influences the way DEP's base rate charges will reflect the requested revenue requirement changes. Tr. vol. 20, 133. As witness D. Williamson explained, it is important that the utility consider all costs in the COSS to ensure that it is reasonably able to recover its full cost to serve all customers, while also ensuring that all jurisdictions and customer classes bear the appropriate responsibility for the respective costs they impose upon the system. *Id.* at 149-50. In discussing the 12 CP methodology for jurisdictional allocations and the modified A&E methodology for NC retail allocations, witness D. Williamson confirmed that the use of different cost of service allocation methodologies may be unusual for a general rate case in North Carolina, but use of two methodologies does occur in some other jurisdictions. *Id.* at 152. In sum, witness D. Williamson recommended approval of the COSS Stipulation and DEP's use of the methodologies to which the parties agreed in the COSS Stipulation. *Id.* at 180.

CIGFUR Testimony

CIGFUR witness Phillips filed testimony in support of the COSS Stipulation. Witness Phillips testified that the COSS Stipulation is reasonable and that the Commission should approve it in its entirety. Tr. vol. 21, 477. Witness Phillips also testified that both the 12 CP and modified A&E methodologies are theoretically sound, reflect principles of cost causation as required by N.C.G.S. § 62-133.16(a)(1) and (b), and should be used for ratemaking in this proceeding. *Id.* at 474, 477. Witness Phillips further testified that DEP has appropriately allocated distribution system costs to customer classes in a manner consistent with N.C.G.S. 62-133.16(b), which requires the use of minimum system methodology by an electric public utility for the purpose of allocating distribution costs. *Id.* at 473. Witness Philips additionally testified about the relation between the excess component of the A&E method as it relates to additional capacity requirements. *Id.* at 479.

CUCA Testimony

CUCA is not a party to the COSS Stipulation. CUCA witness O'Donnell acknowledged that such settlements are a product of give-and-take settlement negotiations. Tr. vol. 21, 648. Despite this, witness O'Donnell testified that the results of any model should be viewed considering the economic impact that DEP rate increases will have on the economic drivers in North Carolina. *Id.* Witness O'Donnell recommended that if the Commission were to accept the modified A&E cost allocation method, then the Commission should set rates with the recognition that North Carolina is losing manufacturing jobs more than other southern states. *Id.* at 652-53. Witness O'Donnell questioned whether the time is right for DEP to transition to full implementation of the A&E method. *Id.* at 653. Nevertheless, he testified that CUCA does not oppose the COSS Stipulation. *Id.* at 648.

The Commercial Group Testimony

The Commercial Group is not a party to the COSS Stipulation. However, Commercial Group witness Chriss testified that for the purposes of this rate case, the Commercial Group does not oppose DEP's proposed production capacity cost allocation methodology. Tr. vol. 21, 520.

North Carolina League of Municipalities (NCLM)

The NCLM was the only party to cross-examine DEP witness Hager during the expert witness hearing on May 8, 2023. Tr. vol. 11, 113-58. NCLM questioned witness Hager as to whether a 20.0% increase in lighting rates in year one of the MYRP would be considered a "gradual" change. *Id.* at 117-20. In response, witness Hager testified that, while the change in cost of service methodology did lead to DEP's allocating more cost to the Lighting class, only a portion of that increase was driven by the change in cost of service methodology. *Id.* at 119. She also testified that the point of a cost of service study is to determine allocation of costs to customer classes, but that rate design ultimately uses the cost of service study to determine rates for customers. *Id.* at 120. Witness Hager acknowledged that this COSS allocates more costs to lighting. *Id.* at 119. But she also testified that this is reasonable because the COSS determined that this increase was consistent with cost causation principles, meaning that lighting customers are causing more costs to be incurred on the system. *Id.* at 120.

Further, NCLM questioned whether all parties participated in the COSS collaborative and in settlement discussions. *Id.* at 121-22. Witness Hager testified that DEP invited all entities that were parties to the previous rate case to participate in the COSS collaborative that led to settlement discussions, which then led to the COSS DEP uses in this case. *Id.* at 122. NCLM was a party to the prior case but did not participate in the COSS collaborative and did not offer any alternative cost of service methodology in this rate case.

Discussion and Conclusions

Although the COSS Stipulation is not unanimous, no other party to this proceeding has proposed an alternative cost of service methodology. Tr. vol. 11, 125.

Based upon the evidence presented in this case, including the evidence offered in support of the stipulation as well as the evidence elicited through cross-examination as discussed hereinabove, the Commission approves the COSS Stipulation. The Commission notes that the use of the diversified non-coincident peak demand to calculate the excess allocation portion of the Modified A&E methodology is a departure from both the method approved currently for DEP as well as the A&E method applied in South Carolina. Therefore, the Commission directs DEP to provide a more detailed justification for the use of a NCP demand over a coincident peak demand for any cost allocation purpose in future rate cases.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 36

TCA Stipulation

The evidence supporting this finding of fact is contained in DEP's verified Application and Form E-1; the testimony and exhibits of DEP witnesses Abernathy and Bateman and Public Staff witness Metz; the TCA Stipulation; and the entire record in this proceeding.

As explained by DEP witness Maley, the Red Zone Expansion Plan transmission projects (RZEP Projects) included in DEP's MYRP consist of transmission upgrades needed to enable interconnection of additional solar generation on the DEP transmission system. DEP witness Abernathy testified as to the revenue requirement sought by DEP for the RZEP Projects, which involved allocation of all RZEP costs to DEP. In light of concerns expressed by the Public Staff in the Carbon Plan proceeding regarding the imbalance of transmission costs being incurred between DEC and DEP associated with the interconnection of new generation, DEP presented (but did not propose) an alternative allocation of RZEP costs as between DEC and DEP based on respective retail transmission demand load ratio share. Tr. vol. 13, 99-101. Witness Abernathy testified that DEP did not support this allocation but included the calculation in the event the Commission determined that such an allocation was more appropriate in light of the concerns of the Public Staff. *Id.* at 102.

While the Public Staff found merit in DEP's alternative proposal, Public Staff witness Metz recommended a different proposal that focused on the net energy transfers between DEP and DEC. Tr. vol. 16, 454-55. DEP witness Metz explained that the Public Staff's alternative proposal utilizes the non-firm transmission rate from the FERC-approved OATT of DEC, Duke Energy Florida, LLC (Duke Energy Florida), and DEP, which incorporates capital and ongoing O&M costs of the DEC and DEP transmission systems. He testified that DEP's alternative allocation only considers a discrete portion of each utility's system and does not consider the O&M costs. The OATT, updated annually and listed on the OASIS website, provides an established calculation for transmission system capital and O&M costs that is transparent and easily verifiable. *Id.*

DEP and the Public Staff resolved their differences on this issue and, as set forth in the TCA Stipulation, agreed to a pro forma adjustment of approximately $20 million to increase the revenue requirement in the DEC Rate Case and a corresponding decrease the revenue requirement in the instant proceeding.

DEC, also a party to the stipulation, DEP, and the Public Staff agreed to calculate the pro forma amount of transmission expense for DEC and transmission revenue for DEP by multiplying the net transfers from DEP to DEC under the JDA in 2022 by the DEP non-firm transmission rate from the FERC-approved Joint OATT of DEP, DEC and Duke Energy Florida. The stipulation makes clear that the adjustment is for North Carolina ratemaking purposes only and will neither change the terms or conditions of the JDA nor result in any accounting entries for DEP or DEC. The TCA Stipulation provides that the adjustment will become effective on October 31, 2023, for both DEP and DEC and will terminate at the sooner of the effective date of rates in DEP's or DEC's next general rate case or the effective date of a full merger of DEP and DEC, unless the Commission orders otherwise. TCA Stipulation § II, Tr. vol. 7, 23.

DEP witness Bateman testified in support of the TCA Stipulation. Tr. vol. 14, 146. She testified that the TCA Stipulation is the result of substantial discovery and extensive negotiation among the stipulating parties and that it reflects a constructive near-term approach to addressing rate disparity concerns arising from the increasing net energy transfers from DEP to DEC under the JDA. *Id.* Public Staff witness Metz also testified in support of the TCA Stipulation. Tr. vol. 16, 517-18. Witness Metz testified that the TCA Stipulation addresses the growing level of net energy transfers and the subsequent rate disparity between DEP and DEC in North Carolina and explained that the adjustment will compensate DEP and DEC ratepayers for the use and annual maintenance of each utility's transmission system for energy transfers under the JDA. *Id.*

The Commission concludes that the TCA Stipulation itself, along with the expert testimony discussed above, is credible evidence and is entitled to substantial weight in the Commission's ultimate determination on this issue. No party offered evidence opposing the TCA Stipulation, and the Commission concludes that the TCA Stipulation, as supported by the testimony cited above, establishes a reasonable method to align costs with cost causation principles. Utilization of this method appropriately balances DEC and DEP benefits to the least cost dispatch of their respective systems. Accordingly, the Commission concludes that the provisions of the TCA Stipulation are in the public interest and are just and reasonable to all parties in this proceeding. Therefore, the TCA Stipulation is approved for the purposes of DEP's Application in this proceeding. The Commission notes that all parties have an opportunity in the pending DEC PBR proceeding in Docket No. E-7, Sub 1276 to address the DEC impacts of the TCA Stipulation before the Commission addresses the TCA Stipulation in that proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS FOR FACT NOS. 37-38

PIMs Stipulation

The evidence supporting these findings and conclusions is contained in DEP's verified Application and Form E-1; the testimony and exhibits of DEP witnesses Bateman and Stillman, Public Staff witnesses D. Williamson and Thomas, AGO witness Nelson, and CIGFUR witnesses Phillips and Gorman; the PIMs Stipulation; and the entire record in this proceeding.

PIMs

DEP initially proposed the following PIMs in its Application: (1) Peak Load Reduction, (2) Low-Income/Affordability, (3) Reliability, and (4) Renewables Integration and Encouragement. Tr. vol. 14, 91-99.

As filed, the Peak Load Reduction PIM encouraged DEP to reduce peak load, based on the estimated winter peak kilowatt reduction resulting from new customer enrollment in DEP's dynamic and time differentiated rate programs. *Id.*

The Low-Income/Affordability PIM provided incentives for DEP to encourage voluntary contributions to its existing "Share the Light" Fund, which provides financial assistance to customers who are struggling to pay their energy bills, through a structure that establishes graduated shareholder contributions and shareholder bonus matching contributions to fund health and safety repairs for low-income residences based upon target levels of contributions to the Share the Light Fund. *Id.*

The Reliability PIM held DEP accountable to maintain service reliability as measured by SAIDI (excluding Major Event Days (MEDs)). This PIM features graduated penalties DEP shall distribute to customers for failure to maintain SAIDI below tiered threshold levels that DEP will base upon historic averages adjusted for statistical confidence levels and increased outages due to additional grid work that DEP expects during the MYRP. *Id*.

The Renewables Integration and Encouragement PIM involved three metrics to incent and reward DEP. The Distributed Energy Resource (DER) Integration Metric A provided graduated rewards to DEP for exceeding targets for the number of net-metered DER customers interconnected to the DEP system. *Id.* at 104. The Large Customer Renewable Program Encouragement Metric B provided an incentive for DEP to design, obtain approval of, and subscribe customers to new renewable programs that meet these customers' desires for access to clean energy resources. *Id.* at 106. The Residential Customer Shared Solar Program Encouragement Metric C encouraged DEP to subscribe residential customers to new shared solar programs. *Id.* at 107.

In addition to the PIMs, DEP also proposed three tracking metrics in the areas of customer service, carbon dioxide (CO2) emissions, and beneficial electrification. The proposed customer service tracking metric supported maintaining adequate levels of customer service per N.C.G.S. § 62-133.16(d)(2)j. *Id*. at 113. The proposed CO2 emissions tracking metric would report progress towards compliance with the CO2 reduction requirements of S.L. 2021-165 and the Carbon Plan. *Id.* at 113-14. Finally, the third metric proposed to report on incremental load from EVs. *Id.* at 114.

Public Staff witnesses D. Williamson and Thomas expressed concerns with each PIM, beginning with the metric DEP proposed in the Peak Load Reduction PIM. Tr. vol. 18, 390. The Public Staff testified that time of use (TOU) customers have complete control over whether they act on price signals and shift their load, and enrollment in TOU rates does not directly correlate to winter peak load reductions across DEP's footprint. The Public Staff notes that DEP's TOU report suggests a modest winter peak load reduction for customers who could be presumed to be early adopters or have a greater awareness of energy usage, but there is no guarantee that this level of winter peak load reductions will occur with greater enrollment. *Id.* at 390. The Public Staff also testified that, as DEP is already receiving a performance incentive for its DSM and EE programs through its

DSM/EE rider, a winter peak load reduction PIM should have to demonstrate incrementally greater savings above those being observed through DSM and EE programs, particularly for customers who are on TOU rates and participate in DSM or EE programs. *Id.* at 391.

The Public Staff expressed concerns regarding the Low-Income/Affordability PIM, primarily based on the fact that the Share the Light Fund is not a regulated activity, and the impacts of this PIM would not be reflected in the annual PIM rider. The Public Staff testified that while customer contributions are an input in the calculation of this PIM, shareholders presently have great discretion to adjust the amount of their overall contributions to the Share the Light Fund. *Id.* at 392.

Regarding the Reliability PIM, which targets reliability by tracking DEP's SAIDI score, the Public Staff expressed concern that because benchmarking for the tiered performance structure proposed by DEP is based on five years of historical SAIDI data, consideration of any expected advancements in reliability that will occur as a result of grid investments included in the proposed MYRP is foreclosed. In addition, the Public Staff expressed the concern that the five years of historical performance data includes data that were collected before DEP's GIP investments were placed into service. *Id.* at 393.

Finally, the Public Staff testified as to concerns with the Renewables Integration and Encouragement PIM. *Id.* at 394-96. With respect to Metric A, the Public Staff testified that Net Energy Metering (NEM) adoption is largely outside of DEP's control, that NEM adoption has been steadily increasing over time as individual customers make individual financial decisions, that two recent Commission orders that have not been incorporated into the forecast or financial structure of this proposed PIM that have the potential to skew the adoption rates above what DEP has already forecast, and that the new NEM rate schedules involve customer enrollment in certain TOU rates, which links this metric to the Peak Load Reduction PIM. *Id.* at 394-96. With respect to Metrics B and C, the Public Staff expressed concerns that DEP has complete control over all renewable program capacity available to large customers and that a capacity limit that is set below anticipated enrollment requests could result in DEP easily surpassing the enrollment thresholds. Additionally, the Public Staff testified that existing large customer programs have been popular without an incentive, and the Public Staff noted that performance data on which Metric B and Metric C are based are linked to new programs and there is therefore insufficient data for determining whether a financial incentive is necessary. *Id.* at 396.

In light of the Public Staff's concerns, the Public Staff proposed three modified PIMs in response to the PIMs DEP proposed. The Public Staff proposed a Time-Of-Use Enrollment PIM, a Customer Reliability PIM, and a Renewable Interconnections PIM, which involve both modifications to DEP proposals as well as new proposals. *Id*. at 396-97.

In response to DEP's proposed Low-Income/Affordability PIM, NCJC, et al. witness Howat and Sierra Club witness Colton expressed concerns with the effectiveness of the proposed PIM as designed in advancing a policy goal of low-income energy affordability.

Id. at 205, 252. Both witnesses filed a suggestion to include a tier structure under this PIM for consideration. *Id.* at 211.

CIGFUR witness Gorman's direct testimony expressed concern regarding DEP's proposed Reliability PIM. Tr. vol. 21, 459. Witness Gorman proposed expanding the PIM to include a metric for measuring and ensuring the maintenance of adequate power quality and the avoidance of power quality incidents. *Id.* Commercial Group witness Chriss raised similar concerns about the Reliability PIM, stating that DEP should restructure the PIM to hold itself accountable for poorly performing circuits. *Id.* at 509.

AGO witness Nelson proposed a Carbon Reduction PIM as an alternative to Metrics B and C of the Renewables and Integration PIM. *Id.* at 165. Witness Nelson expressed concern that the PIMs Stipulation does not incentivize DEP to lower emissions at least cost. *Id*. at 90. DEP witness Stillman and Public Staff witness Thomas expressed concerns with a Carbon Reduction PIM's compatibility with S.L. 2021-165. *Id.* at 435, 468-69; Tr. vol. 23, 209-11.

CUCA witness O'Donnell and NCJC, et al. witness Posner proposed conceptual fuel cost PIMs. Tr. vol. 21, 671, 1104. Witness O'Donnell's proposed fuel cost PIM would attempt to manage fuel costs and volatility and encourage selection of generation resources based on fuel costs. *Id*. at 671.

DEP witnesses Bateman and Stillman explained how the carbon reduction requirement in N.C.G.S. § 62-110.9 is an aggregate requirement on DEC and DEP, meaning that the law does not require DEP to independently reduce its CO2 emissions by 70.0%. *Id.* at 211.

DEP, the Public Staff, and CIGFUR resolved their differences of opinions on PIMs proposed in this proceeding in the PIMs Stipulation. PIMS Stipulation, Tr. vol. 7, 23.

DEP's PBR Policy Panel provided testimony in support of the PIMs Stipulation. Tr. vol. 14, 131. The PBR Policy Panel testified that the resolution reached represents a balanced approach to achieving policy goals in DEP's first PBR Application. Tr. vol. 15, 17, 70. DEP witness Stillman testified as to how the settled PIMs originated from the North Carolina Energy Regulatory Process (NERP) PBR Working Group, were informed by DEP's prefiling PIM stakeholder process, and evolved over discussions with the stipulating parties. Tr. vol. 14, 132-33. DEP witness Bateman testified that the Commission must examine DEP's PIMs proposals in the context of the entire MYRP. Tr. vol. 15, 15. Witness Bateman testified that DEP took a conservative approach in its first PBR Application so that DEP, customers, and the Commission could gain experience with the operation and implementation of PIMs. *Id.* at 69. DEP witness Stillman explained DEP's approach to designing the PIMs around the 1.0% cap in N.C.G.S. § 62-133.16 and stated that DEP deliberately chose only a select number of PIMs that meet the maximum number of policy goals. *Id.* at 65.

Public Staff witnesses D. Williamson and Thomas also provided testimony in support of the PIMs Stipulation. Tr. vol. 18, 424-25. Witnesses D. Williamson and Thomas testified that the PIMs Stipulation benefits ratepayers by providing improved compliance with N.C.G.S. § 62-133.16 and that each PIM in the stipulation appropriately targets a specific policy goal from N.C.G.S. § 62-133.16. They further testified that the PIMs Stipulation will benefit ratepayers through improved operational efficiencies, cost savings, and reliability of electric service over the course of the MYRP. *Id*.

The parties to the PIMs Stipulation did not achieve an agreement on the Low Income/Affordability PIM. The PIMs Stipulation includes the three PIMs described below; the PIMs are described with specificity, including thresholds, tiers, penalty and reward amounts, and projections of costs in PBR Policy Panel Settlement Exhibits 1, 3, and 4. Tr. Ex. vol. 14.

Time Differentiated and Dynamic Rate Enrollment PIM

DEP Witness Stillman testified that the Peak Load Reduction PIM was renamed as the Time Differentiated and Dynamic Rate Enrollment PIM (TOU Enrollment PIM) and was revised to provide DEP with a $5 incentive for every new customer enrolled in an eligible program. Tr. vol. 14, 135. Witness Stillman testified that this PIM targets and advances operational efficiency and cost savings and encourages DEP to design and seek approval of dynamic and time-differentiated rate designs. *Id*. at 93. Witness Stillman further testified that this PIM is an upside only PIM, with a shared savings-like structure that would distribute 30.0% of the total peak reduction joint benefit to DEP and 70.0% to customers. *Id.* at 135.

At the expert witness hearing, witness Stillman further explained that the purpose behind this PIM is to encourage DEP to develop and expand the use of TOU rates to help address peak load growth. *Id.* at 169-71. This PIM should encourage customers to adapt to new rate designs and subsequently shift their usage from high to low usage periods. *Id.* at 169. Witness Stillman testified that current subscribership to these programs is low, in the range of about 1.5% of residential customers, so one of the purposes behind this PIM is to encourage more customers to subscribe to TOU programs. *Id.* at 171. Witness Stillman also stated that DEP had statistically significant results demonstrating that customers that have participated in these rate designs have adapted and shifted their usage from on peak periods to off peak periods. *Id.* at 170. In response to concerns about insufficient data to measure impact on load due to enrollment in TOU programs, witness Stillman testified that the PIMs Stipulation addresses this concern and explained that DEP will conduct a broader Evaluation, Measurement, and Verification study on system benefits once there is sufficient participation in DEP's TOU rate schedules to achieve statistical significance. Tr. vol. 15, 38-39.

Public Staff witnesses Thomas and D. Williamson testified that the parties designed the TOU Enrollment PIM to increase the customer base subscribing to TOU rates to continue to ascertain how TOU rates impact load reduction. Tr. vol. 18, 459. Witness D. Williamson explained that it is appropriate to reward DEP for increasing the number of TOU customers to mitigate energy usage during peak periods when the grid is stressed, so that DEP can better operate and improve operational efficiencies of the grid. *Id.* at 460. Witness Thomas also explained that the parties based the $5 per customer reward amount on savings per customer from a previously conducted TOU Report. *Id.*

Reliability PIM

DEP witness Stillman offered direct settlement testimony in support of DEP's Reliability PIM, which is designed to facilitate maintaining or improving service reliability in compliance with N.C.G.S. § 62-110.9(3). Tr. vol. 14, 136-37. DEP's Reliability PIM would be measured by SAIDI, excluding MEDS. As originally proposed, DEP's Reliability PIM provided for graduated penalties based on DEP's failure to maintain SAIDI below certain threshold tiers based upon five-year historic averages, adjusted for statistical confidence levels, and increased outages due to expected grid work. Tr. vol. 14, 91-92.

At the expert witness hearing, witness Stillman explained that as part of the PIMs Stipulation, DEP agreed to revise the metric for this PIM to account for projected SAIDI improvement during the MYRP period due to expected grid investments. Tr. vol. 15, 41-43.

Renewables Integration and Encouragement PIM

DEP witness Stillman testified that DEP designed Metric A of the Renewables Integration and Encouragement PIM to incent rooftop solar and to provide DEP with an incentive to determine the most effective way to encourage adoption. Tr. vol. 15, 53. This metric was modified as part of the PIMs Stipulation to base the incentive tiers on the three-year rolling average of net metered interconnections. Tr. vol. 23, 194-95. Metric A would provide an incentive of up to $4 million to DEP if the number of net metered interconnections for each rate year exceeds the applicable preceding three-year rolling average by at least 25.0%. Tr. vol. 15, 50.

DEP witness Stillman testified at the expert witness hearing that the only difference between Metric B as proposed by DEP and the PIMs Stipulation is a decrease in the reward amount. Tr. vol. 15, 57. As filed, Metric B of the Renewables Integration and Encouragement PIM supports large commercial and industrial (C&I) customers, educational institutions, and local governments who have corporate goals related to electricity and are increasingly seeking access to renewable energy and programs. Tr. vol. 14, 106; Tr. vol. 23, 195-96. As witness Stillman explained, this component of the Renewables Integration and Encouragement PIM was proposed in response to feedback received from large customer representatives. Tr. vol. 14, 138; Tr. vol. 21, 460-61; *See* CIGFUR witness Gorman Direct Ex. 7; Tr. Ex. vol. 21. Public Staff witness Thomas testified that the reduction in the reward amount for Metric B, considering the PIMs Stipulation as a whole, helped to alleviate the Public Staff's concerns that DEP would be overly rewarded for the independent financial decisions of large commercial and industrial customers. Tr. vol. 18, 466-67.

Revised Metric C of the Renewables Integration and Encouragement PIM in the PIMs Stipulation is based on the recommendations of the Public Staff, addresses utility-scale interconnections, and is designed to increase operational efficiency by incentivizing interconnections above DEP's estimated annual limits. Tr. vol. 14, 139. This component includes incentive tiers and minimum MW thresholds for utility-scale interconnections in each MYRP rate year. *Id*. at 139. DEP witness Stillman testified that Metric C responds to recommendations from the Public Staff to develop a PIM to incentivize DEP to focus on utility-scale interconnections. Tr. vol. 15, 60. He further stated that the reward will not be possible until DEP exceeds the interconnections the Carbon Plan already required under the Carbon Plan. *Id*. at 63. The Public Staff also testified that the intent of Metric C is to incent DEP to be more efficient in the interconnection process. Tr. vol. 18, 472.

Tracking Metrics

DEP witness Stillman provided direct testimony stating that DEP selected the tracking metrics it proposed to quantitatively measure and monitor outcomes and/or utility performance that, although not tied to financial incentives or penalties, address DEP's progress in furthering important policy goals. He further stated that tracking metrics can provide useful information in evaluating potential future PIMs. Tr. vol. 14, 113-14.

In the PIMs Stipulation, the stipulating parties agreed to three tracking metrics. The first agreed-upon tracking metric is the proposed metric on customer service as DEP proposed in its initial testimony. DEP witness Stillman testified that under the customer service tracking metric DEP will provide a quarterly update during the rate year of the rolling 12-month call center answer rate and the average speed of answer. Tr. vol. 14, 140-41. Witness Stillman testified that this tracking metric is appropriate because customers often communicate with DEP about service and billing issues by telephone, it allows greater public access to the data, and it supports maintaining adequate levels of customer service. *Id.*

The second tracking metric is the proposed metric on beneficial electrification of EVs as DEP initially proposed. Witness Stillman explained that this metric requires DEP to report beneficial electrification from estimated incremental load from EVs and will provide data in an area of material public policy interest. *Id.*

The third tracking metric the PIMs Stipulation includes requires DEP to report the 10 worst performing circuits on an annual basis, including an analysis of the cause of each circuit's performance. DEP witness Stillman testified that the stipulating parties have agreed to confer on a definition for the metric for a worst performing circuit and file an update with the Commission on an agreed-upon metric no later than 60 days after issuance of the Commission's order in this proceeding. Tr. vol. 14, 141. Witness Stillman explained that the stipulating parties included this tracking metric in the PIMs Stipulation due to the importance of reliability and the information this reporting will provide to interested parties. Tr. vol. 15, 43.

Discussion and Conclusions

Upon review of the testimony of DEP, the Public Staff, and CIGFUR witnesses regarding the PIMs Stipulation, the Commission concludes that the PIMs Stipulation is the product of give-and-take negotiations between DEP, CIGFUR, and the Public Staff to achieve PIMs and metrics that are consistent with N.C.G.S. § 62-133.16 and strike an appropriate balance.

The Commission must give full consideration to a non-unanimous stipulation itself, along with all evidence presented by non-stipulating parties in determining whether the stipulation's provisions should be accepted. *CUCA I*, 348 N.C. at 466; *CUCA II*, 351 N.C. at 231. The Commission has considered the testimony of the parties to this proceeding on the PIMs, as cited above, and notes that some of the non-stipulating parties' recommendations and modifications are addressed by the PIMs Stipulation. For example, with the inclusion of the worst-performing-circuit tracking metric, certain intervenor recommendations on reliability PIMs are accounted for outside of an express PIM, and data on reliability and circuit performance will be gathered as a result. PIMS Stipulation § III.2, Tr. Ex. vol. 7.

As this is the first PBR application considered by the Commission and, therefore, the first set of PIMs to be adopted, the Commission concludes that it is reasonable and appropriate to take measured steps to implement PIMs and tracking metrics as allowed for under N.C.G.S. § 62-133.16. The PIMs and the tracking metrics set forth in the PIMs Stipulation achieve this measured approach and are balanced, reasonable, and consistent with the requirements of the PBR Statute, encourage behavior that is sought by customers, and could provide meaningful operational and financial benefits to customers. Therefore, the Commission concludes that the PIMs Stipulation is entitled to substantial weight. Accordingly, the Commission concludes that the PIMs and tracking metrics set forth in the PIMs Stipulation should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 39

Power Quality Stipulation

The evidence supporting this finding of fact is in the direct testimony of DEP witnesses Stillman and Guyton; the supplemental direct testimony of CIGFUR witness Phillips in support of partial settlement; the Power Quality Stipulation; and the entire record in this proceeding.

The Power Quality Stipulation provides that DEP and CIGFUR will work together to identify up to 13 industrial customer premises with DEP-owned transmission to distribution retail substations that DEP exclusively or primarily dedicates to the respective CIGFUR member (Eligible Premises). Subject to a feasibility review, DEP will install power quality monitoring technology for each Eligible Premises and meet with the identified CIGFUR members at least once annually to review the data from the power quality monitoring technology. Power Quality Stipulation at 3; Tr. Ex. vol. 7.

In support of the Power Quality Stipulation, CIGFUR witness Phillips testified that the stipulation will help satisfy the requirement of N.C.G.S. § 62-110.9 to maintain or improve reliability as utilities implement the Carbon Plan. Tr. vol. 21, 495. Witness Phillips testified that the Commission has recognized the well-documented reliability risks that inverter-based resources pose. *Id*. at 496-97.

Witness Phillips further testified that the pilot program the parties outline in the Power Quality Stipulation will allow DEP to mitigate the reliability risks associated with inverter-based resources. *Id*. at 497-98. Specifically, it would allow DEP to: (1) proactively monitor power quality as utilities implement the Carbon Plan; (2) gather and share data analytics with the Public Staff and the Commission; (3) determine whether power quality incidents are the result of an individual circuit or customer problem, or potentially part of a larger trend; (4) diagnose potential power quality issues and, pursuant to review, implement solutions to address any such issues; and (5) take a proactive approach to customer service and service quality. *Id.*

With respect to the cost of the pilot program, DEP witness Stillman stated in cross examination that the Power Quality Stipulation does not set a cost cap. Tr. vol. 15, 76. He estimated that the cost of installing the power quality monitoring technology would be approximately $10,000 to $25,000 per meter, while the total number of meters needed for this pilot was not specified. *Id.* at 75. He further stated that the cost of implementing solutions, as contemplated in the Power Quality Stipulation, will depend on the cause of the specific power quality issue for each premises. He added that the lessons learned from the pilot program will help the whole system, because the more meters that are installed, the more DEP will learn about where the power quality issues are arising. In acknowledging that DEP intends to seek cost recovery on a cost of service basis, witness Stillman stated in direct testimony that the pilot program will help DEP to understand the system and power quality issues better, and that it will ultimately be to the benefit of all customers. Tr. vol. 21, 474-76.

The Commission notes that no party introduced evidence in this docket suggesting that industrial customers are experiencing degraded power quality issues due to inverter-based resources. In addition, the Commission notes that the pilot program as the parties propose in the Power Quality Stipulation would be available for participation to only 13 CIGFUR members, and that DEP would recover the costs, with no cost cap, on a cost of service basis from all DEP ratepayers. This method would result in the cross subsidization of these industrial customers by all ratepayers, including residential customers.

The Commission acknowledges the effort required to craft a pilot program and a mutually agreeable stipulation. A well-designed pilot program focused on improving power quality for individual customers and for the entire system has merit and could provide benefits for all ratepayers. It is premature, based on the information provided in the Power Quality Stipulation, for the Commission to approve the pilot program as contemplated between the two parties absent additional details, including information regarding parameters for a feasibility review, participant eligibility, and cost, and absent an opportunity for interested parties to undertake a thorough review of the proposal and provide comments to the Commission. Particularly with respect to pilot programs, the Commission needs sufficient information to ensure that the program is properly scoped and bounded. The Commission therefore concludes that the record evidence does not support approval of the power quality pilot program.

However, DEP may file an application for a power quality pilot program with the Commission in a new docket that addresses the concerns noted by the Commission, should it so choose.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 40-41

Affordability Stipulation/CAP

The evidence supporting these findings of fact is in DEP's verified Application and Form E-1; the testimony and exhibits of DEP witnesses Harris, Bateman, and Stillman, Public Staff witnesses D. Williamson and Thomas, NCJC, et al. witnesses Howat and Posner, and Sierra Club witness Colton; the Affordability Stipulation; and the entire record in this proceeding.

Summary of Evidence

Low-Income/Affordability PIM

DEP's PBR Policy Panel testified in support of DEP's proposed Low-Income/Affordability PIM. Tr. vol. 14, 91. The PBR Policy Panel testified that the Low-Income/Affordability PIM would: (1) target and advance cost savings; (2) reduce low-income energy burdens; and (3) encourage carbon reductions. *Id.* at 94. The PBR Policy Panel testified that the proposed PIM would advance the identified policy goals by providing DEP with an incentive to promote voluntary contributions to the Share the Light Fund. *Id.* at 101.

Public Staff witnesses Thomas and D. Williamson recommended that the Commission deny DEP's proposed Low-Income/Affordability PIM. Tr. vol. 18, 418. The Public Staff expressed concern that the PIM fails to meet some of the Public Staff's guiding principles for the development of PIMs because the Share the Light Fund is not a regulated Company activity and DEP's annual PIM rider would not reflect the impacts of the PIM. *Id.* at 392.

Sierra Club witness Colton recommended that the Commission reject DEP's proposed Low Income/Affordability PIM and adopt Sierra Club's alternative proposal. Witness Colton expressed concerns that DEP's proposed Low-Income/Affordability PIM would insufficiently measure and promote the advancement of the PIM's stated goals and was not adequately in DEP's direct control. *Id.* at 295-300, 313. Alternatively, Sierra Club witness Colton recommended that the Commission require DEP to adopt a series of "outcome" metrics to measure DEP's performance and the accomplishment of program objectives. *Id.* at 293.

NCJC, et al. witness Howat recommended that the Commission reject DEPs Low-Income/Affordability PIM given his concerns that the originally proposed Share the Light Fund contributions would not directly advance low-income energy burden reductions and that there was no explicit commitment to measure potential low-income energy burden reductions attributable to the Low-Income/Affordability PIM. Witness Howat instead recommended that the Commission direct DEP to implement an alternative Energy Burden Reduction PIM based on a reduction in involuntary residential non-pay disconnections over a four-year period in the service territory zip codes with the highest disconnection ratios. Tr. vol. 18, 224. Additionally, he recommended that the Commission implement reporting requirements. *Id.* at 230. NCJC, et al. witness Posner echoed many of the same concerns as witness Howat and ultimately recommended that the Commission reject the Low-Income/Affordability PIM and advised the Commission to adopt NCJC, et al. witness Howat's Energy Burden Reduction PIM instead. Tr. vol. 21, 1103.

In rebuttal testimony, DEP's PBR Policy Panel reiterated DEP's position that the PIM strikes the appropriate balance between encouraging outcomes sufficiently within DEP's control and providing meaningful funding to address low-income issues. Tr. vol. 23, 186.

Customer Assistance Program

In its Application, DEP requested approval of the CAP and two new tariffs, the CAP Rider and the Customer Assistance Recovery Rider (CAR Rider). DEP witness Harris testified that the CAP proposal, initially developed in the Low-Income Affordability Collaborative (LIAC) docket, is designed to assist low-income customers who are facing affordability challenges. Witness Harris described the program structure, framework, and reasoning behind the program. Tr. vol. 12, 204-05. Under the CAP, eligible customers would automatically receive a $42 monthly bill credit for a 12-month period. Tr. vol. 12, 205.

Regarding CAP eligibility, witness Harris explained that customers who are eligible for and receive funds from either the Low Income Energy Assistance Program (LIEAP) or the Crisis Intervention Program (CIP) would qualify for assistance under the CAP. DEP would automatically enroll eligible customers into CAP using a list of customers provided by the North Carolina Department of Health and Human Services (DHHS). Tr. vol. 12, 207. Moreover, DEP could re-enroll customers in CAP for another 12 bill cycles if they are re-certified as LIEAP or CIP eligible after expiration of the initial enrollment. Tr. vol. 12, 215.

Witness Harris testified that in addition to the $42 bill credit on their next 12 monthly bills, DEP will also refer CAP customers to other income-qualified weatherization and energy efficiency services that can assist customers with reducing energy usage. Tr. vol. 12, 215. DEP would spread the costs for the $42 CAP credit among all customer classes, excluding lighting schedules, through the CAR Rider. Residential customers would pay approximately 86.0% of the CAR Rider on a per kWh basis, with non-residential customers paying the approximately 14.0% remaining on a per bill basis. Tr. vol. 12, 215. The CAR Rider would have a rolling recovery factor that DEP would true-up annually to reflect the actual amount of CAP credits paid. Tr. vol.12, 207.

Public Staff witness D. Williamson recommended that the Commission: (1) approve the CAP proposal for a three-year term; and (2) require that DEP, as part of the CAR Rider proceeding, file a report addressing several issues and metrics, including the number of CAP recipients, CAP administration costs, and observed impacts of CAP on arrearage management and disconnections for nonpayment. Tr. vol. 20, 147. Witness D. Williamson noted that the Public Staff would prefer a clear legislative requirement directing the development of a program like CAP; however, he also noted that the Commission has broad authority to determine whether programs utilities design to address affordability issues are in the public interest. Tr. vol. 20, 146. Witness D. Williamson highlighted that in the Commission's Order for the 2019 Rate Case, the Commission exercised this authority by requiring that parties collaborate on developing programs that would serve the public interest and address affordability challenges for low-income customers. Tr. vol. 20, 146-47.

Sierra Club witness Colton testified that absent a program like CAP, electric bill affordability in the DEP service territory would significantly deteriorate given the increased rates proposed in the proceeding. Tr. vol. 18, 274. Witness Colton concluded that the general policy underlying DEP's CAP proposal was reasonable. Tr. vol. 18, 275. Witness Colton proceeded to make modest recommendations to the CAP proposal to advance the achievement of affordable electric bills for low-income households. Among his recommendations, witness Colton emphasized the importance of defining an affordable bill burden as a percentage of a household's income. Tr. vol. 18, 252. Witness Colton maintained that an affordable bill burden is a range and not a point, and it is appropriate, in principle, to measure affordability by reference to bills as an affordable percentage of income – regardless of the ultimate burden target the Commission deems appropriate to adopt. Tr. vol. 18, 266. Witness Colton recommended modifying the proposed across-the-board flat bill credit to a tiered, percent of bill discount. Tr. vol. 18, 276. As proposed, witness Colton's alternative program design seeks to achieve affordable bills as a percentage of household income and reduce affordability disparities between customers at different income levels, measured by the Federal Poverty Guidelines. Tr. vol. 18, 281-84.

NCJC, et al. witness Howat provided observations and analysis regarding the variances between CAP and Consensus Proposal 24 from the LIAC, the hallmarks of effective bill payment assistance programs, low-income energy usage, and burdens. Witness Howat ultimately recommended that the Commission adopt a tiered discount affordability program. Tr. vol. 18, 203-22.

CIGFUR witness Phillips testified that the costs of the proposed CAP that DEP would recover though the CAR Rider should only be recovered from residential customers, and that the creation of a new cross-subsidy benefitting residential customers at the expense of non-residential customers contradicts the express directive of the PBR Statuteto minimize interclass cross-subsidization by the greatest practicable extent possible by the end of the MYRP period. Tr. vol. 21, 482.

The Affordability Panel of DEP witnesses Barnes, Harris, and Quick responded to the affordability-related testimony and recommendations proposed by the Public Staff and other intervenors. Witness Barnes described DEP's Affordability Ecosystem as a multi-pronged approach resulting from the LIAC's findings. Witness Barnes explained that bill payment assistance represents one lever for addressing affordability challenges, and she pointed to energy efficiency programs as another major component in DEP's Affordability Ecosystem. Tr. vol. 22, 84. Witness Barnes further disputed witness Colton's claim of LIAC's adoption of an energy burden threshold, distinguishing LIAC's target electric energy burden from CAP from witness Colton's 5.0% definition of total home energy. Tr. vol. 22, 85. Witness Barnes testified to DEP's willingness to participate in an evaluation study of North Carolina customers that would inform findings for adopting an electric energy burden threshold for Duke Energy's North Carolina customers. Witness Barnes stated that providing the zip-code level data intervenors requested would violate DEP's Code of Conduct, which prohibits disclosing aggregated non-public customer data. Tr. vol. 22, 87. DEP witness Quick testified that while DEP tracks participants in the Winter Moratorium that Commission Rule 12-11(1) established, it does not routinely collect and track customers' income status. Tr. vol. 22, 88. Due to the complexity and costs that would be added to the work of DEP's call center representatives from collecting, validating, and tracking such sensitive information, she disagreed with recommendations that DEP should collect such data and instead endorsed DEP's continued work with state or assistance agencies with the necessary experience and expertise to assist customers. Tr. vol. 22, 89.

DEP witness Harris testified that DEP agrees with the Public Staff's testimony and recommendations related to the CAP and does not oppose the proposed annual report. Tr. vol. 22, 90-91. Harris disagreed with CIGFUR witness Phillips' conclusion regarding interclass cross subsidization and stated that the program will put downward pressure on all rates. Tr. vol. 22, 91. He further testified that DEP would be amendable to a tiering feature for future versions of the CAP. Witness Harris explained that the auto-enrollment mechanism, which is a core design feature of CAP, cannot currently support tiering. Tr. vol. 22, 92-93. Further, witness Harris disagreed with recommendations that DEP, DHHS, or other organizations provide another intake service for CAP, explaining that the estimated operating costs from a third party would increase the total cost of operating CAP by a factor of almost 11. Tr. vol. 22, 93. Witness Harris testified that using a percentage discount, rather than a dollar amount, would reduce the incentive for energy efficiency investments, reduce the financial incentives for customers to respond to dynamic rate designs, and make the program's costs less predictable. Tr. vol. 22, 94.

Affordability Stipulation

On May 4, 2023, DEP, DEC, Sierra Club, NCJC, et al., and the Public Staff filed the Affordability Stipulation. Pursuant to the terms of the Affordability Stipulation, DEP will withdraw the Low-Income/Affordability PIM and, instead, a shareholder contribution of $16 million to benefit income-eligible customers will be made as follows: $10 million in support of health and safety repairs that would allow for energy efficiency and weatherization upgrades to homes; and $6 million for the Share the Light Fund, which offers customers bill payment assistance. Tr. vol. 22, 99-100. In addition, DEP and DEC agree to collect and annually report the monthly payments ratio, which is the number of residential payments remitted divided by the number of active residential accounts. DEP and DEC will file this data annually in Docket No. M-100, Sub 179. Furthermore, pursuant to the terms of the Affordability Stipulation, DEP would establish its CAP program as a three-year pilot. If the Commission approves CAP, DEP agrees to convene a stakeholder engagement process to consider CAP data, metrics, and future CAP program features. The Affordability Panel, the Public Staff, Sierra Club witness Colton, and NCJC, et al. witness Howat each provided testimony supporting the Affordability Stipulation. Tr. vol. 18, 326-66.

Considering all testimony and evidence along with the Affordability Stipulation, the Commission finds that the provisions of the Affordability Stipulation are reasonable and should be approved for the following reasons.

The Commission gives significant weight to the testimony of DEP witnesses Harris, Barnes, and Quick, and Public Staff witness D. Williamson regarding the Affordability Stipulation and DEP's CAP proposal. As Public Staff witness D. Williamson and DEP witness Harris highlighted in their testimony, the Commission has broad authority to set rates in the public interest. Tr. vol. 20, 146; Tr. vol. 13, 22. The question of whether the Commission should approve the CAP proposal and corresponding tariffs as outlined in the Affordability Stipulation is largely a public policy issue requiring a balancing of costs and benefits to DEP customers. The Commission established the LIAC in the 2019 Rate Case and tasked the collaborative with addressing affordability issues for low-income residential customers.

The statute authorizing performance-based regulation emphasizes reducing interclass subsidies and reducing low-income energy burdens. N.C.G.S. 62-133.16(b) requires the minimization of interclass subsidies to the greatest extent practicable by the end of the multiyear rate period. Further, N.C.G.S. § 62-133.16(d)(1) requires the Commission to consider whether the PBR application, in its entirety, "assures that no customer or class of customers is unreasonably harmed" by the proposal. N.C.G.S. § 62-133.16(d)(2) provides that the Commission may consider whether the PBR application "reduces low-income energy burdens." The Commission concludes that DEP reasonably designed the CAP proposal to meet and balance these statutory directives.

The Commission finds that the Affordability Stipulation advances the objective of reducing low-income energy burdens without causing unreasonable harm to any customer or class of customers. The Commission gives substantial weight to the DEP testimony that: (1) although the CAP causes a small interclass subsidy, residential customers primarily fund it; and (2) there is potential for the program to put downward pressure on rates for all customers, by having fewer stranded costs from disconnected accounts and arrearages, which would otherwise be passed on to the general body of ratepayers in the next general rate case.

The Commission approves the CAP as a limited-term pilot, which will allow the Commission, the Public Staff, DEP, and other parties, over time, to examine whether the CAP credit meets the public policy objectives and whether the CAP results in rates that are unreasonably discriminatory or preferential to certain customer classes. As such, the

Commission finds that it is reasonable for DEP to launch the CAP and implement the corresponding tariffs associated with the CAP proposal for a period of three years as set forth in the Affordability Stipulation.

Affordability – Next Steps

The Commission appreciates the consensus achieved by the parties in the Affordability Stipulation. Several provisions in the Affordability Stipulation provide for reporting of information. In order to examine whether the CAP meets public policy objectives, the Commission determines that it is necessary to provide guidance on these requirements.

Stakeholder Group and Report

In the Affordability Stipulation, the stipulating parties agree to convene a stakeholder engagement process to (i) consider data and reporting issues that may be necessary for the CAP, (ii) consider metrics and inputs used to assess the CAP pilot, and (iii) agree to update the Commission on the stakeholder process. The Commission directs DEP to convene this stakeholder group within 90 days of the issuance of this Order. The stakeholder group shall include the stipulating parties to the Affordability Stipulation. DEP is also directed to invite members of the LIAC to join the stakeholder group. Further, the Commission directs that the group meet at least quarterly, and that no later than 6 months after the issuance of this Order, the group must agree upon the data and information that will be provided in an annual report that will be filed each year the CAP is effective. The Commission directs that the annual report shall include, but shall not be limited to, the following information:

1. How many customers enrolled in the CAP by zip code.

2. How many dollars given in assistance by zip code.

3. Percentage of total customers enrolled in the CAP by zip code.

4. Percentage of total customers enrolled in the CAP that have had disconnections.

5. Identification of the zip codes which have the highest number of residential nonpayment disconnections.

6. Range, average, and median bill size for customers enrolled in the CAP.

7. Recommendations relating to potential changes in the CAP that would have the potential to improve the program during the pilot or as part of a subsequent program.

DEP is directed to inform the Commission if it is unable to report any of the above listed data.

The Commission notes that in Paragraph 2 of Section II the Affordability Stipulation, DEP and DEC agree to collect and report data regarding health and safety repairs that are made with shareholder funds. The Commission directs that the following information shall be provided and filed semiannually regarding these funds:

1. Dollar amount given in weatherization help to customers by zip code.

2. Dollar amount given to energy efficiency help to customers by zip code.

3. Percentage of customers that receive CAP and receive weatherization and/or EE assistance by zip code.

The report shall also identify the most frequent types of health and safety repairs that may be necessary and required to enable customers to qualify for weatherization programs.

Tiered Customer Assistance Program

The Commission further notes that the Affordability Stipulation states that parties agree to explore "a tiered customer assistance program based on income levels if that feature can be incorporated into the design of the CAP." In order to address affordability challenges in the state the Commission finds that it is necessary to direct the stakeholder group to develop a tiered program. Further, DEP is directed to file a report relating to the feasibility and proposed structure of a program the later of (i) 18 months after the entry of the order in this proceeding, or (ii) when there is one year of data from the CAP Rider. DEP shall also provide a report to the Public Staff and the Commission every six months after the entry of an order in this proceeding which summarizes the ongoing work of the stakeholder group, and which identifies any challenges as well as opportunities for improving the CAP program. DEP shall also seek from the Commission any waivers necessary or required to obtain or provide the zip code related data set forth in this Order as well as any zip code level data necessary or required to design a tiered customer assistance program.

Tracking Metrics

The Commission further finds that in order to inform future PIMs, DEP is directed to report on the following tracking metrics related to Affordability in the same manner as the tracking metrics agreed to the PIMS Stipulation:

1. The average Disconnect for Non-Payment (DNP) percentage of active residential customers over the last 12 month period.

2. The ratio of the average annual residential customer bill (1,000 kWh of usage per month) divided by the annual federal poverty income level for family of four according to the Federal Poverty Guidelines.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 42-48

Objectives of Rate Design

The evidence supporting these findings of fact is in DEP's verified Application and Form E-1; the testimony and exhibits of DEP witnesses Reed and Byrd, Public Staff witnesses Williamson and Nader, Commercial Group witness Chriss, Kroger Co. and Harris Teeter witness Bieber, DoD-FEA witness Blank, CIGFUR witnesses Phillips and Gorman, AGO witness Nelson, and CUCA witnesses O'Donnell and Heilig; the Partial Revenue Requirement Stipulation; and the entire record in this proceeding.

DEP witness Reed testified that she used the cost-of-service information prepared by DEP and examined by DEP witness Hager to design rates. Tr. vol. 11, 176. Witness Reed testified that she also reviewed and considered the rates of return across the customer classes derived from the COSS when designing rates. *Id.* Finally, witness Reed noted that she reviewed DEP's Advanced Metering Infrastructure (AMI) data to examine customers' usage characteristics and to determine relationships between energy and demand, both on a coincident peak and non-coincident peak basis that might prove pertinent to the design of DEP's rates, including the development of new TOU periods. *Id.* at 176-77.

Witness Reed stated that one objective of DEP's proposed rate design is to achieve the necessary increase in rates to collect the total revenue requirement. *Id.* at 177. Witness Reed also stated that another DEP objective is to gradually align the cost to serve customers within its residential, general service, and lighting rate schedules. *Id.* Witness Reed also noted that DEP's goal is to design rates that reflect the costs that a customer causes DEP to incur. *Id.* With respect to the rate increases proposed in this case, witness Reed stated that the base rate increase has been allocated to the rate classes by base rate amounts. *Id.* at 180. Witness Reed claimed that this allocation methodology aims to distribute the increase equitably to the classes while maintaining each class's deficiency or surplus contribution to return. *Id.*

In his direct testimony, DEP witness Byrd testified that DEP, as ordered by the Commission, participated in a year-long Comprehensive Rate Design Study (CRDS) with external stakeholders to develop DEP's future pricing and rate design options. *Id.* at 231. Following this engagement, DEP proposed several rate design changes to incorporate stakeholder requests and input. *Id.* at 232.

DEP witness Reed testified in detail regarding changes that DEP proposes to the residential rate schedules, the SGS rate schedules, the MGS rate schedules, the LGS rate schedules, the seasonal and intermittent rate schedules, and to the lighting rate schedules. Tr. vol. 11, 183-202. DEP witness Reed also testifies in detail regarding the proposed revisions to DEP's service riders, which are offered to reflect special customer needs and requirements. Her testimony describes how the riders have been revised to better reflect cost of service. *Id.* at 202-06.

Having considered the record evidence on the issue of rate design, the Commission concludes that the objectives of DEP's rate design – which are to: (1) achieve the necessary increase in rates to collect the total revenue requirement; (2) further align the cost to serve customers within DEP's residential, general service, and lighting rate schedules; and (3) design rates that reflect the costs a customer causes DEP to incur – are reasonable. Further, the Commission concludes that DEP's proposed allocation of the approved revenue increase to the customer classes is reasonable to all parties, considering the evidence presented and is approved for the purposes of this proceeding. Finally, for the foregoing reasons, the revisions to the rate schedules and to the service riders proposed by DEP in this proceeding are reasonable and are approved as proposed, unless otherwise specifically addressed hereinafter in this Order.

Subsidy Reduction

DEP evaluated rates of return across customer classes emanating from DEP's COSS. Tr. vol. 11, 179. DEP witness Reed testified that the historical per books rate of return indices as measured by the ratio of class rate of return to retail rate of return, shows that over a lengthy period, residential customers have been subsidized. She testified that his historical subsidy has, in the past, been beyond the range of reasonableness, which DEP defines as class rates of return within 10.0% of the total Company rate of return. *Id.* She also testified that an updated comparison through the test period now shows significant convergence of the class rate of return over all classes towards the band of reasonableness demonstrating the success of the strategy of gradually reducing the subsidy/excess by 10.0%. *Id.* at 180-81.

DEP witness Reed explained that in designing rates, the base rate increase was allocated to the rate classes by rate base amounts and that this allocation method distributes the increase equitably to the classes while maintaining each class's deficiency or surplus contribution to return. *Id.* at 18.

DEP witness Reed testified that, in this proceeding, DEP is also recommending a variance reduction of 10.0% to help reduce interclass subsidies to better align each rate class to the average rate of return. *Id.*

CIGFUR witness Phillips testified that he disagreed with DEP's proposed 10.0% subsidy reduction and instead recommended that a 25.0% subsidy reduction, consistent with DEP's last rate case proceeding, be the minimum reduction for this proceeding. Tr. vol. 21, 483. Witness Phillips testified that a subsidy reduction of 50.0% or even 100.0% would be preferable. *Id.* Witness Phillips claimed that LGS customers are subsidizing other rate classes by approximately $47.7 million under current rates, that the proposed 10.0% subsidy reduction does not adequately correct this cross-subsidization, and that LGS customers should receive a rate reduction to eliminate the subsidy. *Id.*

Witness Phillips also stated that DEP's proposed 5.8% LGS rate increase will "continu[e] the large subsidy paid by these customers". *Id.*

DoD-FEA witness Blank also took issue with DEP's proposed 10.0% subsidy reduction and stated that DEP's proposed allocation of base rate revenue increases deviates substantially from its COSS results. *Id.* at 310. Witness Blank claimed that DEP's proposed rate increases result in the LGS class subsidizing other classes, particularly the residential class. *Id.* at 326. Witness Blank argued that the use of any variance, even a higher variance than DEP's proposed 10.0%, will not alleviate the subsidization faced by the LGS class, will still lead to rate increases for LGS and LGS-TOU rate classes, and will lead to rate increases "well above a level that I would be comfortable with," for rate classes farther away from cost-based rates. *Id.* Therefore, witness Blank recommended that the Commission reject the use of a variance reduction approach, even at a higher level (e.g., 25.0%) than the 10.0% DEP proposed. *Id.*

On rebuttal, witness Reed testified that the proposed 10.0% subsidy reduction "balances the rate increases requested … so that no rate class receives a disproportionate increase [due to] the proposed changes to the cost-of-service methodology [shifting] costs among rate classes." Tr. vol. 11, 264. Specifically, witness Reed explained that if DEP had employed witness Phillips' recommended 25.0% subsidy reduction the proposed increase to the residential class would increase from 9.9% to 10.4% and the proposed increase to the Lighting class would increase from 19.9% to 24.9%. *Id.* at 265. Witness Reed stated that DEP's 10.0% subsidy reduction proposal applies the concept of gradualism to align revenues collected from each class with cost causation from DEP's class cost of service study (CCOSS) but that DEP does not intend it to signal that DEP will limit future subsidy reductions to 10.0%. *Id.*

During the expert witness hearing, in response to cross-examination by CIGFUR, CUCA, and DoD-FEA, witness Reed acknowledged that other customer classes have historically subsidized residential customers. *Id.* at 324, 360, 386-87. However, witness Reed explained that DEP intends for the 10.0% subsidy reduction to move the rate increase for each rate class toward parity with the rate of return while avoiding harm to certain classes. *Id.* at 387-88. Moreover, witness Reed reiterated that in determining the 10.0% subsidy reduction, DEP attempted to balance the change in cost-of-service with the requested rate increases so that certain rate classes would not be overly burdened with a rate increase. *Id.* at 326. Witness Reed further explained that employing a 25.0% subsidy reduction "would really harm certain [customer] classes." *Id.* at 388.

During the expert witness hearing, witness Reed also asserted that DEP's proposed 10.0% variance reduction was consistent with N.C.G.S. § 62-133.16. *Id.* at 318-21, 330. During cross-examination by CIGFUR, witness Reed acknowledged that N.C.G.S. § 62-133.16 requires DEP to minimize interclass subsidization. However, witness Reed emphasized that the statute only requires DEP to minimize interclass subsidization "to the greatest extent practicable," which is what it has done. *Id.* As witness Reed explained in response to cross-examination by the NCLM, this is particularly true given that the PBR Statute also requires the Commission to consider the possibility for rate shock. Tr. vol. 12, 14. As such, witness Reed testified that DEP appropriately considered “competing priorities” such as cost causation, rate shock, and gradualism in proposing the 10.0% variance reduction. Tr. vol. 11, 320-21.

Based on the evidence in the record, the Commission agrees that a variance reduction of 10.0% is reasonable for application in this proceeding. In reaching this conclusion, the Commission gives significant weight to the testimony of witness Reed that a 10.0% subsidy reduction helps move towards eventual rate parity and minimize interclass subsidization, including but not limited to the historic subsidization of the residential class, while considering and incorporating other important factors. Additionally, the Commission recognizes that witness Phillips’ argument in support of a greater variance reduction raises a legitimate concern, but concludes that, a variance reduction is not the only issue that a utility must consider when designing rates. The Commission also declines to accept witness Blank’s recommendation to completely disallow a variance reduction. The Commission has historically approved a variance reduction for DEP and witness Blank has offered no compelling evidence warranting a departure from this prior practice. Accordingly, the Commission finds that a 10.0% subsidy reduction is just and reasonable and consistent with the PBR Statute, moves rates closer to cost for all customer classes and is less likely to lead to rate shock than a larger subsidy reduction.

Migration Adjustment

DEP witness Reed testified that during the rate design process, DEP analyzed rate migration, which occurs when customers change from their current tariff to a tariff that is more cost-effective for them. Tr. vol. 11, 181. Witness Reed claimed that, due to the introduction of new tariffs, the redesign of other tariffs to better align with system costs, and the ability of DEP’s new Customer Connect billing system to perform rate comparisons and suggest the best rate for customers, DEP recommends a migration adjustment to the residential, MGS, and LGS classes. *Id.* at 181, 265-66. Specifically, DEP requests a migration adjustment to residential and MGS classes for customers who would save 10.0% or more annually and to the LGS class for customers who would save 5.0% or more annually. *Id.* at 181, 266. Witness Reed noted that this proposal would result in a $12 million migration adjustment for the residential class in Rate Year 0, an approximately $8 million migration adjustment for the MGS class each rate year, and an approximately $1.2 million migration adjustment for the LGS class each rate year. *Id.* at 181-82. Witness Reed noted that DEP is only requesting a migration adjustment for the residential class in Rate Year 0 and not Rate Years 1, 2, or 3 because under the MYRP a migration adjustment is unnecessary due to the Residential Decoupling Mechanism. *Id.* at 181-82, 370. In contrast, witness Reed testified that the proposed migration adjustment for the MGS and LGS classes will carry forward in each rate year including Rate Year 0 and Rate Years 1, 2 and 3 under the MYRP. *Id.* at 182. Witness Reed explained that the primary driver for the migration adjustment requests for the MGS and the LGS classes is the realignment of TOU windows to system costs which allows customers to respond to more economically efficient price signals. *Id.* Witness Reed’s Direct Exhibits 4, 4_1, 4_2, and 4_3 provided the requested migration amounts. *Id.* Tr. Ex. vol. 11.

DoD-FEA was the only party to challenge DEP's requested migration adjustment. DoD-FEA witness Blank requested that the Commission deny DEP's proposed migration adjustment because it artificially increases DEP's base revenue recovery to account for an amount of lost future revenue that is not known or measurable. Tr. vol. 21, 314. Witness Blank argued that the migration adjustment presumes customers will switch rate schedules when they understand potential utility bill savings even though customers choose rate schedules for reasons beyond those a simple bill analysis suggests. *Id.* Witness Blank argued that the relative risk between rate designs and anticipated events that may affect future demand and usage influences actual customer choice. *Id.* Witness Blank argued that DEP's migration adjustments assume that customers will switch rate schedules and does not account for customer risk aversion, which may impact their willingness to switch even when potential utility bill savings are possible. *Id.* Witness Blank acknowledged that some migration will likely occur but argued that it is reasonable for DEP to bear such risk since it is a short-term risk that it can remedy during its next rate case when it better knows customer behavior. *Id.* at 314-15. Witness Blank also noted that future changes to customer electricity usage and billing are "an overall unknown," including potential increases that expanding EV ownership or a rise in the number of homes using electric heating could drive. *Id.*

In rebuttal testimony, DEP's Rate Design Panel, witnesses Byrd and Reed, disagreed with witness Blank's contention that the migration adjustment accounts for lost revenue that is unknown and unmeasurable. Tr. vol. 11, 266-68. The Rate Design Panel testified that in determining the migration adjustment, actual customer billing data was used to calculate actual savings on customer bills. *Id.* at 267. Specifically, the Rate Design Panel explained that for each participant in the rate class, individual customer bills were calculated on their current rate schedule at proposed rates and at other available rate schedules in their rate class at proposed rates. *Id.* at 266. The net annual savings from individual customers saving more than the threshold were then aggregated to determine the migration adjustment amount. *Id.* The Rate Design Panel further stated that DEP considers its proposed 10.0% and 5.0% savings thresholds to be conservative estimates of anticipated migration levels. *Id.* During cross-examination by the DoD-FEA, witness Reed explained that the proposed migration adjustment is a "conservative estimate" because it only considered "structural savers" – i.e., customers that would automatically save money simply by transitioning to a different rate schedule – and does not include customers below the savings threshold that may want to switch or customers that may save money through behavioral changes. *Id.* at 372, 376.

The Rate Design Panel also testified that the availability of several tools that will help customers switch to the best rate mitigates witness Blank's concerns regarding the migration adjustment. *Id.* at 267-68, 373. First, customers who have 12 months of usage history will have access to DEP's Rate Comparison Tool – an online tool (part of Customer Connect) that leverages historic interval data to determine a customer's best rate. *Id.* at 267. Second, customers may also contact DEP's Call Center Representatives to request a rate comparison. *Id.* Third, LGS class customers can also utilize their Large Account Managers. Tr. vol. 11, 267, 373. As witness Reed explained during cross-examination by the DoD-FEA, these Large Account Managers help LGS customers both manage their complex rates and determine the best rate. *Id.* at 373.

The Commission concludes that DEP's proposed migration adjustment is just and reasonable considering the evidence of record in this proceeding. The Commission is not persuaded by DoD-FEA witness Blank that the lost revenues for which the migration adjustment is intended to compensate are unknown and unmeasurable. DEP witness Reed offered convincing testimony that the Rate Design Panel calculated the migration adjustment based on actual customer billing data and that the 10.0% and 5.0% savings thresholds are reasonable, conservative estimates of DEP's migration exposure. The Commission also considers witness Reed's testimony, describing how the Rate Comparison Tool, Call Center Representatives, and Large Account Managers will mitigate migration concerns and help customers switch to rates that may allow them to lower their bills, to be an adequate response to witness Blank's concerns. The Commission therefore accepts DEP's proposed migration adjustments and finds they should be approved as DEP proposed them for the purposes of this proceeding.

Customer Growth and Weather Normalization

DEP witness Reed testified that she provided the retail sales and number of customers to DEP witness Jiggetts for use in calculating the pro forma adjustment for growth in customers. Tr. vol. 11, 173. Witness Reed explained that to arrive at the appropriate number of customers served and the attendant annualized sales levels at the end of the test period, DEP used a combination of regression analysis and a customer-by-customer approach. *Id.* at 173-74.

In her supplemental direct testimony, witness Reed testified that DEP had agreed with the Public Staff to periodically update the Customer Growth Analysis to extend the results to the end of the pro forma period. *Id.* at 223. As such, witness Reed testified that DEP had updated the Customer Growth Analysis through December 31, 2022, for informational purposes only, as DEP witness Jiggetts' Supplemental Direct Testimony Exhibit 4 Pro forma NC1040 demonstrates. Tr. Ex. vol. 13.

CIGFUR witness Gorman testified that DEP's sales projection for residential and SGS customers in the base period is unreasonably low. Tr. vol. 21, 405, 425-26. Witness Gorman claimed that DEP bases its pro forma adjustments on weather normalized use per customer in a single year, which does not reflect how customers' usage can vary due to customer behavior, introduces uncertainty, and does not provide a reasonable projection of likely future customer electricity usage. *Id.* at 426. Witness Gorman recommended that DEP instead use a four-year average projected use per residential customers normalized sales projection. *Id.* at 428.

On rebuttal, the Rate Design Panel disagreed with witness Gorman's claim that DEP's residential weather normalized sales were too low. Tr. vol. 11, 268. The Rate Design Panel testified that DEP bases energy usage projections for the residential and SGS customer classes on historical actual weather normalized sales, which means that

DEP uses kWh sales over the test year and extended period and applies monthly factors based on 30 years of historical weather data to normalize sales for weather. *Id.* The Rate Design Panel also testified that witness Gorman was incorrect in his claim that DEP's pro forma adjustments are based on weather normalized use per customer in a single year. *Id.* The Rate Design Panel explained that the true-up of DEP's test year and extended period estimate of number of customers is based on the best fit of seven different regression models and that the analyses use four, three, two, and one-year time periods for projections. *Id.* at 268-69. The regression analysis that is best aligned with the data (highest statistical "R" value) is then selected. *Id.* at 269. Finally, the Rate Design Panel disagreed with witness Gorman's recommendation that DEP use a four-year average projected use per Residential customer normalized sales projection; the method currently used has been thoroughly vetted by the Public Staff and has been approved by the Commission in prior rate cases. *Id.* Moreover, the Rate Design Panel explained that if the Commission approves DEP's request for an MYRP, residential revenues will be decoupled. *Id.*

The Commission concludes that DEP's proposed weather normalization and customer growth adjustment are reasonable in light of the evidence presented. The Commission, therefore, rejects witness Gorman's recommendation because his proposal does not appear to provide a meaningful improvement over DEP's current methodology. Moreover, the Commission concludes that the evidence in this case does not support a departure from a customer normalized sales projection methodology that the Public Staff has scrutinized and the Commission has approved previously.

Updated Time of Use Periods

DEP witness Byrd, in his direct testimony, testified that DEP is proposing updated and aligned TOU periods across its tariffs that contain time-differentiated pricing for residential and non-residential customers. Tr. vol. 11, 233. Specifically, DEP is proposing to refresh TOU periods as follows (peak periods do not include weekends or holidays):

- On-Peak (Summer) – 6:00 p.m. – 9:00 p.m.
- On-Peak (Non-Summer) – 6:00 a.m. – 9:00 a.m.
- Discount (Summer) – 1:00 a.m. – 6:00 a.m.
- Discount (Non-Summer) – 1:00 a.m. – 3:00 a.m. and 11:00 a.m. – 4:00 p.m.
- Summer consists of the months May – September
- Non-Summer consists of the months October – April.

Id. at 234. Witness Byrd testified that the impacted rate schedules include Residential Service Time-of-Use Schedule R-TOU, Residential Service Time-of-Use Demand Schedule R-TOUD, SGS-TOUE, SGS Time-of-Use Schedule SGS-TOU (renamed Schedule MGS-TOU), LGS-TOU, LGS-RTP, and the Large Load Curtailable Rider LLC. *Id.* at 241. Schedules R-TOU-CPP and SGS-TOU-CPP already use these proposed periods and will not be impacted. *Id.*

Witness Byrd explained that DEP's existing TOU periods, established decades ago, are no longer appropriate and increasingly do not align with DEP's current and anticipated system needs. *Id.* at 235. Witness Byrd stated that the new TOU periods will benefit customers and advance several policy goals. *Id.* at 241. Specifically, witness Byrd testified that the new TOU periods will properly align price signals to cost differences that exist across different seasons and hours, thereby encouraging peak load reduction and efficient system usage; provide the opportunity for economic use of new technologies, such as smart energy management devices, energy storage, and EVs; and encourage flexible consumption during times of low system costs, providing incentives for distributed energy resource adoption. *Id.* at 234, 241-42. Witness Byrd testified that the TOU periods proposed were taken directly from observations of the Cost Duration Model (CDM) and were discussed and evaluated at length with stakeholders during the CRDS. *Id.* at 235-36. Moreover, witness Byrd notes that the proposed TOU periods have already been approved by the Commission for two of DEP's current tariffs: R-TOU-CPP and SGS-TOU-CPP. *Id.* at 235.

The AGO was the only party that recommended any revisions to DEP's proposed TOU periods. AGO witness Nelson recommended that DEP shift its proposed Summer On-Peak period one hour earlier to 5:00 to 8:00 p.m. Tr. vol. 18, 89. Witness Nelson claimed that this Summer On-Peak period would better reflect system costs during each year of the CDM output (2021, 2026, and 2030). *Id.* at 86. Witness Nelson was particularly concerned with DEP's use of the 2030 CDM output and argued that DEP should not weight it as heavily as 2021 and 2026 output when designing current rates since it is farthest in the future and therefore the most uncertain. *Id.* at 89.

In his rebuttal testimony, DEP witness Byrd disagreed with the AGO's position that DEP should shift the Summer On-Peak period to 5:00 to 8:00 p.m. Tr. vol. 11, 269. Witness Byrd reiterated that DEP discussed and evaluated the proposed 6:00 to 9:00 p.m. Summer On-Peak period at length with stakeholders during the CRDS; DEP based the proposal on observations from the CDM; and the peak period balances several factors, including system costs through 2030 and customer experience. *Id.* at 270. In response to the AGO's concerns regarding DEP's forward-looking approach in designing the new TOU periods, witness Byrd explained that it is important that DEP revise its TOU periods now, before many residential customers are on TOU rates, to minimize disruption once more customers are on TOU rates and have established behavioral patterns. *Id.* at 304. Additionally, witness Byrd explained that TOU periods that consider expected system evolution are appropriate because they will be durable and can last for several years. *Id.* Moreover, witness Byrd testified that if the Commission adopted witness Nelson's recommendation to shift the Summer On-Peak period to 5:00 to 8:00 p.m., customers on Rate Schedules R-TOU-CPP and SGS-TOU-CPP – under which the Summer On-Peak period is 6:00 to 9:00 p.m. – would experience a change in TOU periods after having only been on these rate schedules for a short period. *Id.* at 270. As such, given the recent approval of Rate Schedules R-TOU-CPP and SGS-TOU-CPP, shifting the Summer On-

Peak period to 5:00 to 8:00 p.m. would presumably alter these customers' expectations of TOU period stability. *Id.* Finally, witness Byrd testified that the proposed 6:00 to 9:00 p.m. Summer On-Peak period better aligns with the anticipated increased levels of solar generation on the system, as contemplated in the Commission's Carbon Plan, which will shift the net peak to later in the afternoon. *Id.* at 270-71.

The Commission declines to adopt witness Nelson's recommended change to shift the Summer On-Peak period to 5:00 to 8:00 p.m. DEP witness Byrd offered convincing testimony that it would not be reasonable to shift the Summer On-Peak period to 5:00 to 8:00 p.m. given that the CRDS analyzed the 6:00 to 9:00 p.m. Summer On-Peak period,, DEP based the proposal on the CDM, and the Commission has already approved the Summer On-Peak period for DEP's Rate Schedules R-TOU-CPP and SGS-TOU-CPP. In addition to ensuring proper price signaling and encouraging customer adoption of new technologies, the evidence strongly indicates that DEP's modernized TOU periods will improve price and cost causation alignment. Accordingly, the Commission concludes that DEP's new TOU periods should be approved as proposed.

Residential

The residential rate class includes the following rate schedules: Residential Service Schedule RES, Residential Service Time-of-Use Demand Schedule R-TOUD, Residential Service Time-of-Use Schedule R-TOU, and Residential Service Time-of-Use with Critical Peak Pricing Schedule R-TOU-CPP. Tr. vol. 11, 184.

DEP witness Reed testified that DEP proposes to re-open and modify Residential Rate Schedule R-TOUD to modernize the TOU periods and to update the demand charge structure to better reflect cost causation. *Id.* Witness Reed explained that the CRDS addressed R-TOUD tariff redesign and that the modified tariff will provide customers with more choices regarding their energy consumption. *Id.* at 185. Additionally, witness Reed testified that in response to feedback from customers, DEP also proposes to expand the applicability of residential rates to include detached garages, barns, or other structures that are at the same service address as a separate, primary residential account. *Id.* at 187. Witness Reed testified that if the Commission approves the expansion, DEP will allow existing customers to move from a general service schedule to a residential schedule for detached structures at the same premises as the residential account. *Id.* at 188. Further, witness Reed testified that while DEP's unit cost study justifies an increase to the monthly Basic Customer Charge to better reflect customer-related costs and minimize customer cross-subsidization, DEP is not proposing to raise the Basic Customer Charge in this proceeding. *Id.* at 186. Specifically, witness Reed testified that DEP is proposing to maintain the monthly residential Basic Customer Charge for the R-TOUD, R-TOU, and R-TOU-CPP rate schedules at $16.85. *Id.* Reed Direct Exhibits 6, 6_1, 6_2, and 6_3 illustrate the Basic Customer Charges for the major customer classes for the proposed rate years. *Id.* at 170. Tr. Ex. vol. 11.

In his direct testimony, AGO witness Nelson recommended that the Commission explore making TOU rates default for the residential class. Tr. vol. 18, 111-12. Witness

Nelson argued that DEP's default residential rate schedule – Schedule RES – includes a non-time-varying energy rate that does not send accurate price signals to residential customers, thereby causing more costs to be incurred by customers and DEP during peak hours. *Id.* at 110-11. As such, witness Nelson argued that providing DEP with an incentive to get residential customers on a TOU rate is inappropriate and costly. *Id.* at 111. Instead, the Commission should explore other avenues for expanding residential TOU rates, such as making TOU rates default for the residential class. *Id.* at 111-12.

In his direct testimony, Public Staff witness Williamson testified that while he generally supports the proposed changes to the rate schedules, he proposed a few minor modifications. Tr. vol. 20, 172. Specifically, witness Williamson recommended that the Commission approve DEP's proposal to allow detached garages, barns, and other structures on the same residential premise to be served under a residential rate schedule. *Id.* at 173-75. However, witness Williamson recommended that DEP notify all SGS customers of this change through bill insert or separate mailing. *Id.* at 175, 180. Additionally, regarding DEP's Basic Customer Charge, witness Williamson recommended that DEP set the Basic Customer Charge for Schedules R-TOU and R-TOUD at the same $14.00 per month rate as Schedule RES. *Id.* at 173, 180.

DoD-FEA witness Blank also testified regarding DEP's proposed rate increase for the residential class. Tr. vol. 21, 322-23. Specifically, witness Blank recommended that DEP's proposed rate increase for the residential class not exceed 1.25 times the overall retail base revenue increase. *Id.*

In their rebuttal testimony, the Rate Design Panel disagreed with witness Nelson's recommendation to make TOU rates default for the residential class. Tr. vol. 11, 281. Witnesses Reed and Byrd testified that the choice to switch to a TOU rate should be with the customer because TOU rates only yield system benefits if customers respond to price signals and shift load away from peak periods. *Id.* During the expert witness hearing, witness Reed explained that forcing a residential customer to switch to a TOU rate could be harmful and result in higher bills if they cannot manage their energy usage in response to price signals. *Id.* at 312. Therefore, witness Reed testified that DEP's preferred approach to expanding TOU rate adoption is to make TOU rates more appealing and encourage voluntary adoption. *Id.* at 281, 311.

In response to the Public Staff's recommendations relating to the residential class, the Rate Design Panel accepted the Public Staff's proposal to notify all SGS customers through bill insert or a separate mailing about the expanded applicability of residential rates to include detached garages, barns, and other structures that are at the same service address as a separate, primary residential account. *Id.* at 283. DEP also accepted the Public Staff's proposal to set the Basic Customer Charge for Rate Schedules R-TOU and R-TOUD at $14.00. *Id.* at 280.

The Rate Design Panel also disagreed with witness Blank's recommendation to cap the rate increase for the Residential class. *Id.* at 282. The Rate Design Panel explained that witness Blank's rate increase proposal would shift the rate increase for the LGS class to other customer classes which is not in line with the need to balance cost causation alignment, gradualism, and the avoidance of rate shock. *Id.* During the expert witness hearing, witness Reed explained that by shifting the rate increase from the LGS class to other customer classes, including the residential class, witness Blank's rate increase proposals benefit the LGS class at the expense of all other customer classes, including rate increases of over 100 percent for some classes. *Id.* at 385-86, 390.

In light of the parties' testimony and all the evidence presented, the Commission concludes that DEP's proposed rate design for the residential rate class, including the Public Staff modifications to which DEP agreed, is just and reasonable. The Commission agrees with witnesses Reed and Byrd that the decision to switch to a TOU rate should be with the customer. Additionally, the Commission accepts the Public Staff's testimony regarding the appropriateness of modifying the Basic Customer Charge for Schedules R-TOU and R-TOUD to be set at the same $14.00 rate as Schedule RES. This is the same Basic Customer Charge the Commission approved in DEP's last rate case, when it found that it appropriately balances the needs to offer rates that more clearly reflect actual cost causation, minimize subsidization, and provide proper price signals to customers in the rate class, while also moderating the impact of rate increases on low-usage customers. *See* 2019 DEP Rate Order 203. Accordingly, the Commission concludes that the Basic Customer Charges as set forth in Reed Exhibits 6, 6_1, 6_2, and 6_3 are just and reasonable and are therefore approved.

Medium General Service (MGS) and Large General Service (LGS)

The MGS rate class includes all nonresidential customers with demand requirements from 30 kW to 1,000 kW and consists of the following rate schedules: MGS, SGS-TOU (proposed to be renamed MGS-TOU), SGS (Thermal Energy Storage) Schedule GS-TES, Agricultural Post-Harvest Processing (Experimental Thermal Energy Storage) Schedule APH-TES, Church Time-of-Use Schedule CH-TOUE, Church and School Service Schedule CSE, and Church and School Service Schedule CSG. Tr. vol. 11, 190. The LGS class includes all nonresidential customers with demand requirements of 1,000 kW or greater and consists of the following rate schedules: LGS, LGS-TOU, and LGS (Real Time Pricing) Schedule LGS-RTP. *Id.* at 194.

In her direct testimony, DEP witness Reed described the proposed rate design for the MGS and LGS rate schedules[9]. *Id.* at 190-93. Witness Reed testified that DEP is proposing to increase the Basic Customer Charge for the MGS and LGS classes to better reflect the cost of serving these customers. *Id.* at 190. Specifically, witness Reed stated that DEP proposes to increase the Basic Customer Charge for the MGS class for all rate years from $28.50 to $30.00 per month for single-phase service, or $39.00 if the customer requests three-phase service and/or is on Schedule SGS-TOU (MGS-TOU). *Id.* at 190-91. Additionally, DEP proposes to increase the Basic Customer Charge for the LGS class for all rate years from $200.00 to $210.00 per month. *Id.* at 194.

[9] Note that DEP's proposed changes to Schedule LGS-RTP are discussed *supra*.

DEP witness Byrd testified explaining DEP's proposal to change the demand charge structure for renamed Schedule MGS-TOU and Schedule LGS-TOU. *Id.* at 243-45. Specifically, witness Byrd stated that DEP proposes a three-part demand structure consisting of the following components: a Base Demand Charge, designed to recover distribution costs, which DEP would apply to the higher of either (1) a customer's highest maximum demand across all periods over the previous 12 months, or (2) 50.0% of the Contract Demand; a Mid-Peak Demand Charge, designed to recover off-peak and discount allocation of production and transmission costs, which DEP would apply to a customer's maximum demand during off-peak or on-peak periods but excluding discount periods; and a Peak Demand Charge, designed to recover peak allocation of production and transmission costs resulting from the customer's contribution to system demand during peak hours, which DEP would apply to a customer's measured on-peak demand. *Id.* at 243-44. Witness Byrd explained that the proposed three-part demand structure will improve price transparency and better align with cost causation based on both the size and timing of customer demands and is meant to work in tandem with DEP's proposed TOU periods. *Id.* at 244.

Additionally, witness Byrd testified that, in response to stakeholder feedback during the CRDS, DEP evaluated the alignment of bills and pricing to cost causation. *Id.* at 245. Witness Byrd stated that this analysis showed that shifting a portion of fixed cost recovery from energy charges to demand charges improved alignment to cost causation across a wide spectrum of customer energy usage profiles with very little impact on customer bills. *Id.* Witness Byrd stated that as a result of this evaluation DEP witness Reed proposed that DEP institute pricing that reflects slightly higher recovery through demand charges for TOU rates. *Id.*

Kroger Co. and Harris Teeter witness Bieber testified regarding DEP's proposed MGS-TOU rate design. Tr. vol. 21, 694-702. In his direct testimony, witness Bieber acknowledged that DEP's proposed MGS-TOU rates "improve alignment between the charges and the underlying embedded costs," but noted that they are "...still substantially lower than the demand unit cost." *Id.* at 694. Witness Bieber recommended "moderate" and "revenue-neutral" changes to DEP's proposed MGS-TOU energy and demand charges that he contends will improve the alignment between the rate component and the underlying costs while employing the principle of gradualism and mitigating intra-class rate impacts. *Id.* at 697-98. Specifically, witness Bieber recommended that DEP's proposed three-part demand charges each be increased by an additional 20.0% and that the proposed off-peak energy charge be reduced by a corresponding amount. *Id.* at 698. If the Commission determines that an even more gradual approach to align rates with DEP's underlying costs is appropriate, witness Bieber provided an alternative recommendation: that MGS-TOU Base Demand Charge, Mid-Peak Demand Charge, and Peak Demand Charge each be increased by proportionally so that the sum of the three charges is no less than 60.0% of the unit cost of demand from DEP's proposed COSS for the corresponding rate year, with a corresponding adjustment to the off-peak energy charge so that the modification is revenue neutral. *Id.* at 700.

Commercial Group witness Chriss also expressed concern that DEP's proposed MGS-TOU rate design does not reflect the underlying cost to serve and as a result shifts cost responsibility within the rate classes. *Id.* at 527-28. Witness Chriss claimed that DEP has not fully aligned the proposed MGS-TOU demand charges with the underlying demand-related costs. *Id.* at 527. Witness Chriss testified that collecting demand-related costs through an energy charge is inconsistent with cost causation principles and results in a shift in demand cost responsibility from lower load factor customers to higher load factor customers, which will overpay for demand-related costs DEP incurs through providing service to them. *Id.* at 528. Witness Chriss also claimed that DEP would benefit by recovering more demand-related costs through a demand charge instead of through the energy charge since it would be less susceptible to weather-related and other fluctuations in usage, resulting in greater revenue certainty and more stable utility earnings. *Id.* at 528-29. Witness Chriss testified that, for the purposes of this case, the Commercial Group does not oppose DEP's proposed rate levels for MGS-TOU at DEP's proposed revenue requirement, if there is a decrease from the proposed revenue requirement, the Commercial Group recommended that DEP apply such decrease proportionately to the energy charges to better align costs to the cost of service. *Id.* at 529.

In his direct testimony, AGO witness Nelson also took issue with DEP's proposal to increase the level of fixed costs it recovers through demand charges. Tr. vol. 18, 20, 93-101. Witness Nelson testified that DEP has not sufficiently demonstrated that its approach to increasing cost recovery through demand charges will improve alignment with cost causation or that it will result in superior price signals. *Id.* at 94-97. Specifically, witness Nelson claimed that the way DEP categorizes electric system costs as fixed and not fixed does not account for many power system characteristics and "reflects an oversimplification of cost classification…over-emphasizes short-term costs [and] revenue collection and de-emphasizes long-term asset avoidance and system efficiency". *Id.* at 95. Accordingly, witness Nelson recommended that DEP increase energy charges for Schedules MGS-TOU and LGS-TOU to a level that is above marginal cost while maintaining strong price ratios between On-Peak, Off-Peak, and Discount periods to send price signals to customers, and correspondingly decrease demand rates to reflect the revised energy rates. *Id.* at 93, 97, 99. Witness Nelson also recommended that DEP propose Critical Peak Pricing (CPP) rate options for MGS and LGS customers since they can contribute to lower costs and improved system reliability. *Id.* at 93, 101-06. Witness Nelson claimed that while well-designed TOU rates can improve alignment with system costs, they are not precise enough to sufficiently incentivize load shifting during critical peak events. *Id.* at 102-05. Witness Nelson testified that CPP tariffs provide utilities with the ability to flexibly identify peak load events and incentivize customers to shift load during short, but highly impactful, periods of system load. *Id.* at 102.

CUCA witness O'Donnell testified regarding DEP's proposed LGS-TOU rate design. Tr. vol. 21, 655-60. Overall, witness O'Donnell claimed that the LGS-TOU rate design is "overly complex", not beneficial to the LGS class, and would benefit DEP, not energy consumers. *Id.* at 657-59. Witness O'Donnell also testified that he did not agree with DEP's proposals to implement a Mid-Peak Demand Charge, which is "not consistent with the realities of how much manufacturing happens in North Carolina," noting that when manufacturers are "on they are on for as long as it takes," meaning they are not typically able to shutdown mid-production to avoid peak times. *Id.* at 655-56. Witness O'Donnell stated that he objected to the inclusion of a ratchet in the Base Demand Charge, which he argued could lock customers into an overly expensive and unrepresentative demand charge if their peak demand occurs during an on-peak period. *Id.* at 658-59. As such, witness O'Donnell recommended removal of the Mid-Peak Demand Charge and the ratchet from the Base Demand Charge. *Id.* at 655-56, 659.

In their rebuttal testimony, the Rate Design Panel disagreed with the intervenors' various adjustments to DEP's proposed MGS and LGS rate design. Tr. vol. 11, 271-79. Specifically, DEP disagreed with witness Bieber's recommendation to increase the MGS-TOU three-part demand charges by an additional 20.0% and to reduce the proposed off-peak energy charge by a corresponding amount. *Id.* at 271-72. The Rate Design Panel explained that while witness Bieber's proposal is directionally aligned with DEP's approach, it does not sufficiently consider gradualism and would lead to materially adverse outcomes, such as rate shock, for lower load factor customers. *Id.* at 272. In contrast, the Rate Design Panel testified that DEP's approach to slightly increasing demand charges and correspondingly decreasing energy charges better balances gradualism with alignment to cost-of-service. *Id.*

Additionally, while DEP disagreed with witness Chriss' recommendation that DEP allocate any decreased revenue requirement proportionately to the energy charges on Schedule MGS-TOU, the Rate Design Panel noted that DEP is willing to balance lowering energy and demand, as appropriate, to meet the revenue requirement; ensure that it treats both low load factor and high load factor customers equitably; and provide that rate change shifts occur gradually. *Id.* at 271. The Rate Design Panel also testified that DEP agrees with witness Chriss that demand charges should align with demand-related costs. *Id.* at 276. However, the Rate Design Panel explained that DEP must also balance alignment to cost causation with gradualism. *Id.* at 277. As such, the Rate Design Panel testified that DEP's proposed rates, which reflect higher fixed cost recovery through demand charges, result in improved alignment to cost-of-service while also including necessary gradualism in order to avoid potential adverse impacts to lower load factor customers. *Id.*

Additionally, the Rate Design Panel rebutted witness Nelson's argument that DEP should increase cost recovery through energy charges and correspondingly decrease demand charges for Schedules MGS-TOU and LGS-TOU. *Id.* at 272. The Rate Design Panel explained that contrary to witness Nelson's recommendation, DEP proposed a modest increase in fixed cost recovery through demand charges relative to such recovery through energy charges. *Id.* The Rate Design Panel testified that DEP's proposal to increase cost recovery through demand charges both improves alignment to cost-of-service and provides meaningful price signals to encourage system beneficial behavior. *Id.* The Rate Design Panel explained that witness Nelson's suggestion would penalize higher load factor customers, who more consistently use fixed assets and require less cost to serve per unit of energy, and thus increase subsidization between customers with varying load factors. *Id.* at 273. The Rate Design Panel further explained that witness Nelson's proposed rate design would encourage more consistent consumption reduction throughout the month and weaken price signals that are meant to reduce consumption at peak times, thereby increasing the strain on the grid and subsequently increasing the need for investments, ultimately increasing costs for all customers. *Id.* at 274. In contrast, the Rate Design panel testified that DEP's proposed rate design would encourage targeted behavioral modification to reduce demand during the times when additional demand would drive more fixed cost investments. *Id.*

Further, in response to witness Nelson's recommendation that DEP adopt a CPP rate option for MGS and LGS customers, the Rate Design Panel claimed that a CPP rate was unnecessary. *Id.* at 276. The Rate Design Panel noted that during the CRDS, stakeholders generally favored new hourly pricing options relative to CPP options. *Id.* Additionally, the Rate Design Panel stated that DEP's MGS and LGS rate design proposals offer suitable and sufficient options for customers with flexible loads. *Id.*

The Rate Design Panel also testified that it disagreed with witness O'Donnell's recommended changes to DEP's Mid-Peak Demand Charge and Base Demand Charge under Schedule LGS-TOU. *Id.* at 277-79. The Rate Design Panel explained that DEP's proposed Mid-Peak Demand Charge plays an important role in collecting significant amounts of fixed costs associated with non-peak production and transmission assets. *Id.* at 278. Similarly, the Rate Design Panel testified that the Base Demand Charge is carefully designed to reflect certain system costs under the CDM and to recover costs for distribution assets that remain constant year-round and are close to the customer, and thus appropriately utilizes a ratchet. *Id.* The Rate Design Panel explained that customers that exhibit consistent loads year-round, including some manufacturing customers, benefit from the ratchet feature because demand charges would be higher overall without such a feature. *Id.* at 278-79. Moreover, as witness Byrd testified during the hearing, the Base Demand Charge reduces bill volatility for customers by allocating and recovering costs through "very consistent charges". *Id.* at 364-65. The Rate Design Panel also disagreed with witness O'Donnell's characterization of the LGS-TOU rate as overly complex because customers taking service under Schedule LGS-TOU are generally sophisticated and capable of understanding rate design. *Id.* at 279. Moreover, as described in the CRDS, DEP's proposed tariffs appropriately balance simplicity and understandability with alignment to cost-of-service. *Id.*

DEP, the Commercial Group, and Kroger Co. and Harris Teeter entered into the MGS Partial Rate Design Stipulation resolving some of the issues in this proceeding between the parties. The MGS Partial Rate Design Stipulation provides that 75.0% of the reduction in revenue requirement, as determined by final Commission order, applicable to Rate Schedule MGS-time-of-use (TOU), should be applied to energy rates. The MGS Partial Rate Design Stipulation also provides that Kroger Co. and Harris Teeter agree to withdraw its proposal that DEP study the possibility of, and propose, a multi-site aggregate commercial rate. Finally, the MGS Partial Rate Design Stipulation provides that Kroger Co. and Harris Teeter does not oppose the Revenue Requirement Stipulation or the PIMs Stipulation.

DEP and CIGFUR entered into the LGS Partial Rate Design Stipulation, resolving some of the issues in this proceeding between the parties. The LGS Partial Rate Design Stipulation provides that any increase in energy charges resulting from an increase in

DEP's revenue requirement to be recovered from the LGS, LGS-TOU, and LGS-Real Time Pricing (RTP) rate schedules, as determined by final Commission order, shall be limited to a percentage that is less than half of the approved overall increase percentage to the LGS, LGS-TOU, and LGS-RTP classes, respectively, exclusive of any decrements for the LGS, LGS-TOU, and LGS-RTP rate schedules. The LGS Partial Rate Design Stipulation also applies to any customers currently taking service under an LGS, LGS-TOU, or LGS-RTP rate schedule that switch tariffs to either the High Load Factor tariff or Hourly Pricing (HP) tariff, in the event the Commission approves such tariffs in this proceeding.

Schedule LGS-RTP is a historical rate option that provides DEP's LGS customers with exposure to marginal pricing above a Customer Baseline Load (CBL) threshold. Tr. vol. 11, 251. Schedule LGS-RTP is currently available to customers with a load of 1,000 kW or greater and is capped at 85 nonresidential customers. *Id.* In his direct testimony, DEP witness Byrd testified that DEP proposes to freeze Schedule LGS-RTP to new applicants but grandfather current customers. *Id.* Specifically, witness Byrd testified that DEP will close Schedule LGS-RTP to new applications beginning October 1, 2023, and discard the waitlist to join schedule LGS-RTP. *Id.* at 338-39. Witness Byrd explained that DEP proposes to freeze Schedule LGS-RTP because it is administratively burdensome and does not contain ongoing CBL adjustments, creating scalability issues by allowing incremental load to remain on marginal pricing indefinitely. *Id.* at 251.

Additionally, witness Byrd testified that freezing Schedule LGS-RTP is appropriate considering the new Schedule HP proposed by DEP. *Id.* Witness Byrd explained that DEP created Schedule HP in response to stakeholder and customer requests during the CRDS for a more flexible marginal price rate with expanded availability. *Id.* at 248. Like the LGS-RTP, witness Byrd stated that Schedule HP will be available to customers with a load of 1,000 kW or greater. *Id.* at 249. Under Schedule HP, DEP will reestablish the CBL, which defines the level above which DEP will bill all kWh at the hourly energy prices, every four years based on a customer's 12-month usage history, with modifications to reflect price-responsiveness during times of grid constraints. *Id.* at 249. Witness Byrd explained that this new approach to reestablishing CBLs will restrict marginal prices to only four years for growing loads that are not consistently price-responsive, resulting in embedded cost recovery from such loads after the periodic CBL reestablishment. *Id.* Witness Byrd stated that the newly proposed CBL management is average kW and kWh by TOU period. *Id* at 250. Schedule HP will include a margin adder of $6.00 per megawatt-hour to account for day-ahead pricing uncertainty and provide some fixed cost recovery from the marginal energy purchases. *Id.* Witness Byrd testified that DEP proposes Schedule HP without a participation cap due to the durability and scalability of the new program design. *Id.*

DoD-FEA witness Blank recommended that the Commission deny DEP's request to freeze the LGS-RTP rate because DEP has not demonstrated a need to close the rate. Tr. vol. 21, 336-37, 341. Witness Blank testified that LGS-RTP is fully subscribed and that by freezing the rate DEP would prevent the possibility of a new customer replacing a departing LGS-RTP customer, which may provide a "financial windfall" to DEP. *Id.* at 336. Additionally, witness Blank argued that DEP should not close LGS-RTP because

Schedule HP is "categorically different" from Schedule LGS-RTP and therefore is not a suitable replacement for the LGS-RTP tariff. *Id.* at 336, 338. Witness Blank did not express any concerns with Schedule HP. *Id.* at 337-38.

In rebuttal, the Rate Design Panel disputed witness Blank's recommendation that the LGS-RTP rate should remain open. Tr. vol. 11, 284-88. In response to witness Blank's concerns that a departing LGS-RTP customer could provide a windfall to DEP, the Rate Design Panel testified that it does not anticipate that an existing RTP customer would switch to a non-RTP rate because under such scenario, a customer would be voluntarily switching to a higher rate. *Id.* at 285. The Rate Design Panel explained that witness Blank's imagined scenario is unrealistic because customers taking service under LGS-RTP are generally sophisticated and large and would not normally leave the rate for a less attractive option. *Id.* Rather, the Rate Design Panel testified that to the extent attrition occurs on LGS-RTP, the customer would likely be leaving DEP's service territory or otherwise switching to a lower-cost rate, thus lowering DEP's revenues. *Id.*

The Rate Design Panel also disagreed with witness Blank that Schedule HP is not a suitable substitute for LGS-RTP. *Id.* The Rate Design Panel testified that several similarities exist between Schedule LGS-RTP and Schedule HP. *Id.* Specifically, the Rate Design Panel stated that both the LGS-RTP tariff and Schedule HP: (1) are available to customers with a load of 1,000 kW or greater; (2) have energy priced at a marginal rate above a CBL threshold; and (3) contain incremental demand charges and an incentive margin. *Id.* at 285-86. Furthermore, the Rate Design Panel stated that the differences between LGS-RTP and Schedule HP demonstrate that Schedule HP is superior to LGS-RTP. *Id.* at 286*.* For instance, since under Schedule HP DEP will reestablish CBLs every four years and reduce them using a method that recognizes the benefits of price-responsiveness during times of grid constraints, loads DEP presently serves under the CBL could have exposure to marginal pricing after consistent price-responsive behaviors—a customer benefit that does not exist under the LGS-RTP tariff. *Id.* at 286. The Rate Design Panel explained that these adjustments are appropriate because loads that customers can reduce during times of system peak consistently over several years reduce the need for additional peaking resources and lower costs overall for the grid*. Id.* Similarly, a CBL reestablishment every four years ensures that loads that are not price responsive eventually move under the CBL and receive pricing under embedded costs, which is appropriate as such loads begin to drive investments in additional capacity assets. *Id.* at 286-87. Additionally, because of the reduced administrative burden and four-year CBL reestablishment, the Rate Design Panel testified that DEP was able to offer Schedule HP without a participation cap. *Id.* at 287. Finally, the Rate Design Panel explained that Schedule HP will more effectively serve as an economic development tool than the LGS-RTP tariff since Schedule HP is not capped and thus prospective new customers can confidently expect to be able to sign on to the rate if they wish to do so. *Id.* In summary, the Rate Design Panel stated that while several core elements in Schedule HP mirror Schedule LGS-RTP, the proposed improvements in Schedule HP relative to the LGS-RTP tariff yield a more scalable, durable, and accessible rate option for customers. *Id.* at 287-88.

During the expert witness hearing, witness Reed elaborated on the administrative burdens associated with Schedule LGS-RTP. *Id.* at 381-85. Specifically, witness Reed explained that Schedule LGS-RTP requires creation of a CBL and calendar mapping that reflect an individual customer's operations. *Id.* at 381-82. Witness Reed testified that under such processes, DEP sets a CBL for every hour of every day in Excel and must then update this data both annually and every time there is a change in scheduled shutdown days. *Id.* at 381-82. Witness Reed also described the administrative burden of manually billing and calculating the RTP bill for customers. *Id.* at 382. Witness Reed further noted that it takes two full-time personnel to manage Schedule LGS-RTP. *Id.* In contrast, witness Byrd testified that Schedule HP is much simpler and more scalable than Schedule LGS-RTP. *Id.* at 385. For example, witness Byrd explained that Schedule HP uses a CBL management approach that is already in place for DEC's hourly pricing program. *Id.* at 250, 385*.* This process of CBL management will eliminate the need for the administratively burdensome calendar mapping and special days process currently in use for the existing RTP rate. *Id.* at 250. Instead, after establishment of an initial CBL, DEP will automatically reestablish every four years. *Id.*

At the reconvened hearing on July 24, 2023, Public Staff witness D. Williamson testified regarding the Public Staff's concerns with the LGS Partial Rate Design Stipulation. Specifically, Public Staff witness D. Williamson testified that the Public Staff opposes the stipulation on the basis that it constricts the rate designer's ability to appropriately figure out how the revenue requirement that would get assigned to that class should be allocated between the energy and demand components of the rates. Tr. vol. 24, 89. He testified that while the stipulation might move in alignment with the cost of service, the stipulation, in the Public Staff's position, inappropriately predetermines how cost is apportioned between energy and demand components. *Id.* He explained that rate designers, not parties to the proceeding, should apportion costs among the various components of rates as rate designers have a better understanding of load shapes individual classes, specifically with respect to all customers in the class. He explained the Public Staff's position that, for this reason, the rate designer is in the best position to adequately price energy, demand, the customer charges. *Id.* at 92- 93. Ultimately, he concluded that the rate designer is in the best position to ensure that rates are designed to recover costs from customer classes most in alignment with the costs incurred by the utility to serve each class. *Id.* at 94. He also concluded that rates designed to be in alignment with cost causation are just and reasonable. *Id.* at 95. Ultimately, he testified that the Public Staff recommends that the Commission not approve the stipulation in order to allow rate designers to do their work. He testified that if the rate designer reaches the same conclusion on rate design as that set forth in the stipulation, then the Public Staff would support it. *Id.* at 97.

DEP witness Byrd testified that the LGS Partial Rate Design Stipulation would not involve any interclass subsidy and that the dynamic of allocating the revenue requirement between the energy and demand components of the rate impacts only the specific rate schedule for the customer class. *Id.* at 74. DEP witness Byrd testified that the possibility of moving capacity-related costs to the demand component of the rate was discussed during the Comprehensive Rate Design process. He testified that:

> At a high level, [DEP] looked at cost of service and determined that it would be appropriate to increase the amount of fixed costs recovered through demand charges relative to energy. We wrote about that in the roadmap, and so the Company proposed in this case -- our original proposed rates, particularly for LGS-TOU, increased the amount of fixed cost recovery through demand charges.

Id. at 75.

DEP witness Byrd testified that while the stipulation would not result in any interclass subsidization, there might be a slight bill impact to customers within the class, based on load factor but this impact is in alignment with cost of service. *Id.* at 77-78, 83-84. CIGFUR II witness Collins confirmed that the LGS Partial Rate Design Stipulation would not cause an interclass subsidy. Tr. vol. 24, 72.

Considering the parties' testimony and the evidence the parties presented, the Commission concludes that DEP's proposed rate design for the MGS and LGS rate classes, including the modifications agreed to in the MGS Partial Rate Design Stipulation and the LGS Partial Rate Design Stipulation, is just and reasonable. The Commission concludes that DEP's proposed Basic Customer Charge increases, including Basic Customer Charges of $30.00 for the MGS class and $210.00 for the LGS class, strike an appropriate balance that provide rates that accurately reflect cost causation, minimize subsidization, and provide proper price signals to customers in the MGS and LGS rate classes, while also moderating the impact of such increase on lower-load factor customers.

In addition, the Commission concludes that the MGS Partial Rate Design Stipulation and LGS Partial Rate Design Stipulation are the products of arm's-length negotiations between parties who took opposing positions on these subjects in their prefiled testimony. The Commission also finds that the MGS Partial Rate Design Stipulation and LGS Partial Rate Design Stipulation reduce the number of contested issues the parties present to the Commission for resolution regarding rate design. Both stipulations address only intra-class issues, not inter-class issues, and focus on increasing the amount of fixed cost recovery through demand charges as opposed to energy, which is consistent with DEP's COSS. The Commission acknowledges the concern of the Public Staff regarding rate design and the preference that the rate designer not be constrained by agreements between the utility and certain customers regarding the apportionment of costs between demand and energy components of the rates. Specifically, the Commission takes note of the concern that this may give rise to "winners and losers" within a particular customer class and appreciates the Public Staff's vigilance for all customers within a class. The Commission is persuaded by DEP witness Byrd that the LGS Partial Rate Design Stipulation does not result in an interclass subsidy and impacts customers within the class only slightly and in a manner that aligns with cost causation. The Commission notes that no party presented any evidence that the MGS Partial Rate Design Stipulation results in any interclass subsidization, involves inter-class allocation of revenue requirement, or is not in alignment with DEP's COSS. Therefore, the Commission concludes that the MGS Partial Rate Design Stipulation and LGS Partial Rate Design Stipulation are reasonable and should be approved. However, in recognition of the concerns raised by the Public Staff, the Commission approval in this proceeding shall not be taken as an indication that the Commission generally looks favorably on rate design settlements, and the Commission will scrutinize rate design settlements between the utility and any customer or customer group going forward, with the objective of achieving just and reasonable rates for all customers.

Testimony from witnesses Reed, Byrd, Bieber, and Chriss indicates that the change to the MGS-TOU rate design agreed to in the MGS Partial Rate Design Stipulation is reasonable and based on cost causation. The Commission notes that the Partial Rate Design Stipulation provision relating to MGS-TOU energy rates applies only to the MGS-TOU rates proposed in this rate case. This provision does not bind DEP to any particular rate design structure in future rate cases and does not limit its ability to study alternative rate designs. Furthermore, testimony from witnesses Reed, Byrd, and Phillips indicates that the change to the LGS rate design agreed to in the LGS Partial Rate Design Stipulation is reasonable and based on cost causation. The Commission observes that the LGS Partial Rate Design Stipulation provision relating to LGS energy rates applies only to the LGS, LGS-TOU, and LGS-RTP rates proposed in this rate case, and any customers currently taking service under Rate Schedules LGS, LGS-TOU, or LGS-RTP that subsequently switch to either the HLF tariff or the HP tariff. This provision does not bind DEP to any particular rate design structure in future rate cases and does not limit DEP's ability to study alternative rate designs.

Additionally, the Commission concludes that DEP's proposal to freeze Schedule LGS-RTP to new customers effective October 1, 2023, is reasonable. The Commission further concludes that DEP's proposed Schedule HP is reasonable. The Commission declines to adopt witness Blank's recommendation to keep LGS-RTP open to new customers after DEP's proposed freeze date. Witness Reed offered convincing testimony that keeping LGS-RTP open is unduly burdensome and unnecessary given DEP's new Schedule HP. Accordingly, the Commission agrees with DEP that it is appropriate to freeze LGS-RTP. Additionally, the Commission rejects witness Blank's characterization of Schedule HP as "categorically different" than Schedule LGS-RTP. The Commission concludes that though Schedule LGS-RTP and Schedule HP contain several core similarities the differences between the two rate schedules indicate that Schedule HP will be more effective and efficient than Schedule LGS-RTP.

The Commission declines to adopt witness Nelson's recommended modifications to DEP's proposed MGS and LGS rate designs. The Rate Design Panel offered convincing testimony that it is appropriate to increase the level of fixed costs recovered through demand charges in this proceeding since doing so will improve alignment to cost causation across the range of customer load factors while also providing meaningful price signals. In contrast, the Commission finds that witness Nelson's proposal will likely result in subsidization between customers with varying load factors and weaken price signals. The Commission also rejects witness Nelson's request that the Commission adopt a CPP rate at this time given the design of the MGS-TOU and LGS-TOU rates and the introduction of new hourly pricing options.

The Commission also declines to adopt the recommendation of witness O'Donnell to remove the Mid-Peak Demand Charge and the ratchet from the Base Demand Charge on the grounds that these charges are based on a rate design that more accurately reflects DEP's cost of service and provides customers with flexible loads the opportunity to shift consumption patterns and reduce costs.

Small General Service (SGS)

The SGS rate class includes all nonresidential customers with demand requirements below 30 kW and consists of the following rate schedules: SGS, SGS-TOUE, and SGS-TOU-CPP. Tr. vol. 11, 188.

In her direct testimony, DEP witness Reed described the proposed rate design for the SGS rate schedules. *Id.* at 188-89. Witness Reed testified that DEP is proposes to increase the Basic Customer Charge for the SGS class to better reflect the cost of serving these customers. *Id.* at 189. Specifically, witness Reed stated that DEP proposes to increase the Basic Customer Charge for the SGS class for all rate years from $21.00 to $22.00 per month for all SGS schedules to minimize the percentage increase in bills for customers with low monthly usage and to maintain a similar overall proposed increase for customers within the SGS class. *Id.* Witness Reed testified that DEP proposes to keep the Base Customer Charge at $22.00 per month for all rate years. *Id.* Witness Reed also testified that DEP proposes retaining the current kWh energy block structure, with the second block being approximately 18.0% less than the first block kWh energy rate. *Id.* Witness Reed stated that SGS energy rates are adjusted to recover the requested revenue increase. *Id.*

In his direct testimony, AGO witness Nelson recommended that DEP revise Schedule SGS-TOU-CPP. Tr. vol. 18, 105-06. Witness Nelson claimed that as currently designed, Schedule SGS-TOU-CPP does not appear to provide any tangible benefit in comparison to DEP's default TOU option under Schedule SGS-TOUE and, that in fact, Schedule SGS-TOU-CPP would be costlier for customers. *Id.* Witness Nelson claimed that Schedule SGS-TOU-CPP has higher rates across every time period, serving as a strong disincentive for customers to enroll and provide grid services during critical peak events. *Id.* at 106. He testified that DEP had previously acknowledged that "there is a pricing concern with SGS-TOU-CPP" and that as of February 2023 only a single customer had enrolled in the tariff. *Id.* As such, witness Nelson argued that DEP should redesign SGS-TOU-CPP so that customers who opt for the rate over the default TOU option have opportunities to save if they respond appropriately to critical peak events. *Id.*

DoD-FEA witness Blank also testified regarding DEP's proposed rate increase for the SGS class. Tr. vol. 21, 323. Specifically, witness Blank recommended that DEP maintain its proposed rate increase for the SGS class at $469,000 or 8.16%. *Id.*

In their rebuttal testimony, the Rate Design Panel acknowledged that there is a pricing concern with SGS-TOU-CPP. Tr. vol. 11, 282. As such, the Rate Design Panel stated that DEP will adjust the pricing on SGS-TOU-CPP to be more competitive relative to Schedule SGS-TOUE to encourage adoption of the more dynamic tariff. *Id.* Regarding witness Blank's recommendation on the proposed increase to the SGS class, the Rate Design Panel testified that witness Blank's rate increase proposal would shift the rate increase from the LGS class to other classes, contrary to DEP's goals of alignment to cost causation, gradualism and the avoidance of rate shock. *Id.*

Considering the parties' testimony and the evidence presented, the Commission concludes that DEP's proposed rate design for the SGS class, subject to modification in its compliance filing, is just and reasonable. The Commission concludes that DEP's proposed Basic Customer Charge increase to $22.00 per month for all SGS schedules strikes an appropriate balance that provides rates that accurately reflect cost causation and thus, minimizes subsidization and provides proper price signals to customers in the SGS customer class. Additionally, the Commission agrees with the Rate Design Panel that DEP should make a compliance filing to adjust the pricing on SGS-TOU-CPP to be more competitive and to encourage adoption of the tariff. Further, the Commission declines to adopt witness Blank's proposed revenue adjustments to the SGS class because his proposal would result in greater subsidization and does not align with the principles of gradualism or cost causation.

Lighting

DEP provides outdoor lighting service under the following rate schedules: Area Lighting Service Schedule ALS, Street Lighting Service Schedule SLS, and Street Lighting Service (Residential Subdivisions) Schedule SLR. Tr. vol. 11, 198. DEP also provides lighting service under Sports Field Lighting Service Schedule SFLS, Traffic Signal Service (Metered) Schedule TFS, and Traffic Signal Service Schedule TSS. *Id.* at 197.

In her direct testimony, DEP witness Reed testified in support of DEP's proposed changes to its Lighting class schedules. *Id.* at 197-202. With respect to outdoor lighting, witness Reed testified that DEP has adjusted the rates in the proposed outdoor lighting schedules to achieve a combined outdoor lighting revenue target and to reduce or eliminate the difference between the monthly rates in the Area and Street Lighting Service Schedules for similar fixtures and poles/posts. *Id.* at 198. Witness Reed explained that because the current SLS class has a significantly lower return than DEP realizes under Schedule ALS, DEP recommends a higher increase for Schedules SLS and SLR. *Id.* Witness Reed also testified that DEP proposes to freeze Schedule SLR to new applicants to align with DEC's outdoor lighting offering. *Id.* at 201. Witness Reed explained that DEP will continue to serve existing customers under Schedule SLR until such time as they move to another schedule and new customers can take service under Schedules SLS or ALS, as applicable. *Id.*

In their direct testimonies, NCLM witnesses Saffo and Mann testified that DEP's proposed increases for the Lighting class are far too high and have the potential for rate shock. Tr. vol. 21, 761-62, 765, 777-78, 783. Witness Mann testified that the proposed increases for Lighting class customers are almost triple the average increase in the base rate, and almost double the average increase across the MYRP period. *Id.* at 762. Witness Mann also asserted that DEP's proposed Lighting class rate increases will force municipalities in North Carolina "to choose between cutting services and programs or raising property taxes on citizens," since one of the most significant costs for municipalities is street lighting. *Id.* at 766. Witness Saffo described DEP's 30.0% rate increase to the Lighting class over three years as "the opposite of gradual". *Id.* at 779. Witnesses Saffo and Mann requested that the Commission carefully review proposed rate increases for services to municipalities to be assured that DEP has taken all steps to minimize any rate increases. *Id.* at 765, 783.

In his direct testimony, Public Staff witness D. Williamson recommended approval of DEP's proposed changes to Schedule SLR, including the accompanying amendments to its Outdoor Lighting Service Regulations. Tr. vol. 20, 176-77. However, witness D. Williamson recommended that DEP notify all Schedule SLR customers of this change by bill insert or separate mailing. *Id.* at 177.

In their rebuttal testimony, the Rate Design Panel recognized that the Lighting class is facing a large rate increase but explained that a change in cost-of-service methodology primarily drives the proposed increase. Tr. vol. 11, 283-84. The Rate Design Panel testified that to mitigate some of the increase, DEP proposes to limit the reduction in the subsidy to 10.0% as opposed to the 25.0% it implemented in prior rate cases, resulting in a 19.9% increase instead of a 24.9% increase for the Lighting class. *Id.*

Regarding Public Staff witness D. Williamson's recommendation regarding Schedule SLR, the Rate Design Panel testified that DEP is willing to notify all Schedule SLR customers of its proposal to freeze the rate schedule, including the accompanying amendments to DEP's Outdoor Lighting Service Regulations, via bill insert or separate mailing. *Id.* at 284.

During the expert witness hearing, DEP witness Reed reiterated that the COSS indicated that the Lighting class should have received a substantial increase. Tr. vol. 12, 16. To mitigate this increase to the lighting class, witness Reed stated that DEP is proposing to reduce the subsidy reduction to 10.0%. *Id.* Witness Reed explained that the reduction from 25.0% to 10.0% amounts to approximately $4 million in savings to the lighting class. *Id.* While witness Reed acknowledged the substantial rate increase to the Lighting class, she explained that DEP needs to recover its revenue requirement and that DEP has limited options to shift these costs to other customer classes. *Id.* at 18. Witness Reed explained that, to the extent possible, she levelized the rate increase between the rate schedules within the lighting class. *Id.*

Considering the parties' testimony and the evidence the parties presented, the Commission finds that DEP's proposed rate design for the Lighting class, with the modification Public Staff witness D. Williamson suggested and DEP agreed to, is just and reasonable for the purposes of this proceeding. The Commission concludes that the rate increase for the Lighting class is due to the change in cost-of-service methodology and, while substantial, reflects actual cost causation. As such, while the Commission gives some weight to the testimony of NCLM witnesses Saffo and Mann and acknowledges that the rate increase to the Lighting class may prove to be burdensome, it also recognizes the need for rates to reflect cost causation and thus approves DEP's proposed rate design for the lighting class.

Service Riders

In his direct testimony, DEP witness Byrd described DEP's proposed new service riders – Economic Development Rider (Rider EC) and Non-Residential Solar Choice Rider (Rider NSC) – that DEP intends to offer so it may expand the rate options available to customers. Tr. vol. 11, 230. Witness Byrd testified that proposed Rider EC and Rider NSC stemmed from discussions with stakeholders during the CRDS. *Id.* at 247, 253.

Witness Byrd testified that Rider EC will be available to customers: (1) with new load exceeding 1,000 kW with a minimum load factor of 40.0%; (2) that have applied for and received economic assistance from either the state or local government or another public agency; and (3) that meet certain employment and investment minimums relative to the size of the new load. *Id.* at 253. However, witness Byrd stated that new loads that are predominantly for serving EV charging are exempted from Rider EC's employment and load factor requirements and may participate for new load sizes above 500 kW, and that existing customers considering plant investments with possible relocation outside of DEP's service territory may qualify for Rider EC by meeting the investment and employment thresholds, but their new load calculation will exclude reductions associated with the removal of historic equipment or processes. *Id.* at 253-54. Witness Byrd stated that in light of new Rider EC, DEP proposes to close its existing Economic Development Rider (Rider ED) and Economic Redevelopment Rider (Rider ERD) to new applicants. *Id.* at 257. Witness Byrd explained that customers DEP currently serves under Rider ED and Rider ERD will continue to take service under these riders until completion of their existing contracts. *Id.*

Witness Byrd testified that Rider EC contains several improvements to Rider ED. *Id.* at 254-55. First, witness Byrd explained that Rider EC will provide more flexibility for customers to tailor benefits based on both electric grid and regional economic benefits associated with the participant's investment and load characteristics. *Id.* at 252-53. For example, Rider EC will consider the following criteria in developing appropriate benefit levels on an individual customer basis: peak monthly demand; average monthly load factor; DEP's incremental costs to serve; the number of new full-time employees; economic multiplier; and the total new capital investment of the customer. *Id.* at 254. Second, witness Byrd testified that in contrast to Rider ED, under which participants are required to begin taking credits 18 months after the first date service is supplied under the contract (the ramp up period), Rider EC allows participants to wait to take credits until 36 months after the first date of service, recognizing that some industries require significant start-up time for new facilities and that an 18-month ramp up period may constrain their ability to take advantage of Rider EC's benefits. *Id.* at 254-55. Third, witness Byrd testified that unlike Rider ED, which provides benefits that steadily decline over a five-year period on a rigid schedule, Rider EC allows benefits up to 10 years, with possible differences across the years as determined by the project merits. *Id.* at 255. For example, witness Byrd stated that DEP will require projects receiving greater levels of benefits for longer periods to meet higher thresholds of investment and employment. *Id.* Finally, witness Byrd explained that Rider EC provides a reduction of up to 75.0% of the applicable demand charges on the monthly bill, while Rider ED provides a reduction in demand charges that would require modification in order to align it with DEP's proposed demand charge structure redesign. *Id.* Overall, witness Byrd explained that Rider EC will enable DEP to improve its ability to compete for, attract, and retain customers that are adding jobs and making capital investments in its service territory, ultimately reducing the prices all customers pay and promoting the prosperity of the citizens and businesses in North Carolina. *Id.* at 252-53, 255-56.

With respect to Rider NSC, witness Byrd testified that, as a result of DEP's proposed new TOU periods and the new three-part demand charge structure, DEP proposes new Rider NSC to implement several changes for non-residential customers who seek to pursue self-generation through NEM. *Id.* at 246. Witness Byrd stated that to be eligible for Rider NSC, customers must take service under a general service rate schedule that includes TOU periods. *Id.* Witness Byrd explained that because DEP's TOU periods include the proposed modified demand charge structure, this eligibility requirement ensures price alignment with system utilization and cost causation. *Id.* at 246-47. Additionally, witness Byrd stated that Rider NSC will be available to customers with NEM systems that do not exceed the lesser of 100.0% of the customer's contract demand or 5,000 kW. *Id.* at 247. Moreover, under Rider NSC, DEP proposes eliminating the standby charge for customers with a capacity factor of 60.0% or less. *Id.* Finally, unlike Rider NM, energy exported would be netted against imports during the same TOU period and excess energy exported would be credited at an average avoided cost rate calculated using the Net Energy Credit calculation proposed by DEC and DEP in Docket No. E-100, Sub 175. *Id.*

With the advent of Rider NSC, witness Byrd testified that DEP is proposing that all new non-residential NEM applications take service under Rider NSC and that current Rider NM be frozen to new customers beginning on October 1, 2023. *Id.* at 248. Accordingly, witness Byrd explained that only existing non-residential NEM customers served under Rider NM prior to the availability of Rider NSC would continue service under Rider NM. *Id.* Witness Byrd stated that existing NEM customers could continue service under Rider NM until they request service under Rider NSC or until September 30, 2033, at which point all non-residential NEM customers receiving service under Rider NM will be moved to Rider NSC or another appropriate tariff, as available at that time. *Id.*

In his direct testimony, Public Staff witness Nader testified that Rider EC is in the public interest and not unduly discriminatory, will assist in preventing job loss. and fairly balances costs and benefits. Tr. vol. 21, 104-06. Witness Nader explained that Rider EC mitigates the potential for further loss of economic activity in communities that the state has already designated as economically distressed by targeting new investment in load, employment, and economic activity. *Id.* at 104-05. Witness Nader also stated that requiring participants to demonstrate that they have received state or local assistance conveys a sense of fairness between the costs to non-participants and the benefits to participants. *Id.* at 105. Moreover, witness Nader testified that the retention of jobs is critical given the competitive pressures manufacturing and large energy customers experience, and Rider EC should assist with keeping jobs in economically distressed communities. *Id.* Witness Nader also noted that Rider EC's longer ramp-up period and extended period of access should help ensure that system load and employment will remain in communities for some time. *Id.* Finally, witness Nader testified that the Public Staff is "reasonably satisfied" that the costs and benefits of Rider EC are balanced and fair. *Id.* at 106. However, to ensure that Rider EC continues to be in the public interest, witness Nader recommended that the Commission require annual reporting of the impacts of Rider EC. *Id.* At a minimum, witness Nader stated that DEP should report the gross level of incentives paid, the number of recipients, the amount of investment, load, and jobs associated with the incentives, and an overall marginal cost analysis of Rider EC to determine if the gross level of incentives paid exceeds the marginal cost to serve the gross pool of participants. *Id.*

With respect to Rider NSC, Public Staff witness Nader recommended that DEP's proposed 5,000 kW cap on installed capacity be eliminated. *Id.* at 108. Witness Nader testified that by requiring all non-residential NEM customers to subscribe to a TOU schedule and the proposed three-part demand structure, the full fixed cost of service should be recovered regardless of system size, thereby mitigating the risk for material cross-subsidization. *Id.* Witness Nader also argued that large non-residential customers that seek to install on-site generation will be subject to the capital funding limitations of their own businesses, serving as another limitation to prevent generation in excess of site load from being installed. *Id.* at 108-09. Although witness Nader found DEP's concerns regarding reliability if the installed capacity limit were increased to be valid, but he testified that these concerns could be addressed though customer generator controls and communication. *Id.* at 109.

Regarding Rider NSC. AGO witness Nelson recommended that: (1) customers have the option to enroll in Rider NSC for a contract term of up to five years, with the option for annual renewal thereafter; and (2) DEP permit customers enrolling in a rate that does not include a demand charge to retain their renewable energy credits (RECs). Tr. vol. 18, 108. Witness Nelson explained that providing an option for customers to enroll for a term length of up to five years balances the need to provide customers with rate certainty with the imperative to ensure that tariffs adapt to reflect evolving grid dynamics. *Id.* at 108-09. Additionally, witness Nelson argued that DEP's requirement that customers who do not enroll in rates containing a demand charge cede RECs to DEP appears arbitrary and would unduly harm or discourage the participation of SGS customers who do not currently have the option of enrolling in demand-based rates. *Id.* at 110.

Although not raised by DEP in this proceeding, Public Staff witness D. Williamson recommended that DEP analyze the standby service being offered under Riders 7 and 57 in his direct testimony. Tr. vol. 20, 178-79. Witness D. Williamson claimed that the rates and terms of service under Riders 7 and 57 likely do not cover the costs incurred to serve customers. *Id.* at 178. Additionally, witness D. Williamson argued that keeping Riders 7 and 57 – which only serve five large industrial customers – closed to all other customers and allowing only five customers to benefit results in an unduly discriminatory rate design. *Id.* Therefore, witness D. Williamson recommended that the Commission require DEP, prior to filing its next rate case or PBR application, to analyze the impact of transferring the five customers currently taking service under Riders 7 and 57 to other standby service riders. If the analysis shows that viable options to do so exist, witness D. Williamson recommends that DEP propose a transition period in its next general rate case or PBR proceeding to temper any potential rate shock that doing so may cause the customers currently taking service under Riders 7 and 57. *Id.* at 179.

On rebuttal, the Rate Design Panel testified that it did not agree with Public Staff witness Nader's recommendation for elimination of the 5,000 kW cap on Rider NSC. *Id.* at 291. The Rate Design Panel explained that the 5,000 kW limit strikes a reasonable balance between stakeholders' requests during the CRDS for larger system sizes and DEP's concerns regarding grid operations and reliability. *Id.* The Rate Design Panel noted that DEP's proposed 5,000 kW limit for Rider NSC represents a 500.0% increase over Rider NM. *Id.* Moreover, the panel testified that DEP's proposed Schedule HP would allow customer generating systems above the 5,000 kW limit for Rider NSC. *Id.* Importantly, the Rate Design Panel explained that the larger the NEM system, the more complicated the interconnection study due to the of the unpredictability of their output to the grid. *Id.* DEP witness Byrd, during the expert witness hearing, testified that the sort of unpredictability in output (which becomes a bigger problem in the context of larger systems) has the potential to create large swings in load, which poses reliability challenges. Tr. vol. 12, 32. Accordingly, given the sizable move from 1,000 kW to 5,000 kW and operational considerations associated with going beyond 5,000 kW, witness Byrd testified that DEP believes it is inappropriate to remove the cap. *Id.* at 74.

In response to witness Nelson's recommendations with respect to Rider NSC, the Rate Design Panel testified that it did not agree with his recommendation. Tr. vol. 11, 292-93. Specifically, the Rate Design Panel explained that it did not agree with witness Nelson's recommendation that DEP permit customers to enroll in Rider NSC for a term of up to five years because DEP merely intends that the specific tariff language it proposes for Rider NSC – that "[t]he Customer shall enter into a contract for service under this Rider for a minimum original term of one (1) year, and the contract shall automatically renew thereafter . . . ." – correspond to and align with the core tariff language. *Id.* at 292. Additionally, the Rate Design Panel testified that it did not agree that DEP should permit its customers enrolling in a rate that does not include a demand charge to retain their RECs since DEP's retention of RECs from systems is a long-standing practice in North Carolina and DEP is not proposing any changes to this practice in this proceeding. *Id.* The Rate Design Panel further noted that currently effective Rider NM similarly requires DEP customers to cede RECs if they receive service under a schedule other than a TOU schedule with demand rates. *Id.* at 292-93.

Finally, in response to Public Staff witness D. Williamson's recommendation that DEP analyze the standby service DEP is offering under Riders 7 and 57, the Rate Design

Panel testified that the DEP does not oppose analyzing the effects to customers' bills of moving Riders 7 and 57 customers to another standby service rider or closing Riders 7 and 57 and moving customers to other available standby service options in a manner that lessens rate shock. *Id.* at 293.

During the expert witness hearing, DEP witness Byrd provided further support for Rider NSC. Witness Byrd testified that stakeholders discussed Rider NSC at length during the CRDS and that it captures stakeholders' proposals and feedback. Tr. vol. 11, 340-42, 347. Witness Byrd reiterated that Rider NSC better reflects cost causation. *Id.* at 351, 355. Witness Byrd, in response to questions from Commissioner Clodfelter, elaborated on DEP's justification for allowing it to retain RECs for customers who are not served under a TOU rate. Tr. vol. 12, 38-39. Witness Byrd explained that while DEP's Residential Solar Choice Rider (Rider RSC) allows customers to retain their RECs regardless of rate schedule, there are differences between Rider NSC and Rider RSC that justify the disparate treatment. *Id.* at 39. Specifically, witness Byrd stated that certain components of Rider RSC – e.g., CPP netting, non-bypassable charges, monthly grid access fee, and the monthly minimum bill – do not appear in Rider NSC and, therefore, the differences in REC retention are appropriate. *Id.*

DEP witness Byrd also provided further support for Rider EC during the expert witness hearing. In response to questions by Chair Mitchell, witness Byrd elaborated on the differences between Rider EC and Rider ED. Tr. vol. 12, 63. Witness Byrd testified that Rider EC is much more flexible than Rider EC and allows DEP to provide a more tailored incentive structure based on demand over a longer period. *Id.* Additionally, witness Byrd testified that Rider EC's 36-month ramp up period, as compared to the 18-month ramp up period under Rider ED, results in a more competitive offer to prospective customers considering sites in North Carolina. *Id.* at 63-64. Overall, witness Byrd testified that Rider EC is a more competitive and flexible offer that will put North Carolina in a better position to attract potential customers. *Id.* at 64-65.

Based on the evidence in the record, the Commission concludes that DEP's proposed new Rider EC, with the reporting obligation witness Nader suggested and DEP agreed to, is reasonable and should therefore be approved. The Commission views DEP's proposed Rider EC as an effort to attract economic development in North Carolina and concludes that implementation of the rider is in the public interest. As with other economic development tariffs this Commission has previously approved, approval of Rider EC is based in part on an evaluation of the expected economic benefits resulting from the tariff. The Commission has considered the goal of attracting new economic development in North Carolina as well as the impact of Rider EC on non-participating ratepayers and concludes that Rider EC strikes the appropriate balance between the two. The Commission agrees with witness Byrd that Rider EC will result in broad state and regional benefits by enabling DEP to assist North Carolina and local communities when competing for projects. The Commission gives substantial weight to the testimony of witness Byrd that Rider EC represents an improvement from Rider ED and that it is, therefore, appropriate for DEP to close existing Rider ED and Rider ERD.

The Commission also concludes, considering the evidence, that DEP's proposed new Rider NSC is reasonable and should therefore be approved. The Commission finds that Rider NSC is appropriate given DEP's new TOU periods and three-part demand structure and will help ensure price alignment with system utilization and cost causation. In arriving at this conclusion, the Commission gives weight to the testimony of DEP witness Byrd. The Commission is not persuaded by Public Staff witness Nader's recommendation that DEP eliminate the 5,000 kW cap on nameplate capacity. The Commission also gives weight to the operational and reliability concerns expressed by DEP. By increasing the cap from the existing 1,000 kW to 5,000 kW, DEP will gain more experience with larger systems, and this experience can be used to inform the Commission regarding the operational and reliability challenges and mitigative measures that can be adopted in future proceedings in the context of increasing the system limit. Therefore, the Commission rejects the Public Staff's recommendation to remove the 5,000 kW limit under Rider NSC. In addition, the Commission rejects the recommendations of AGO witness Nelson on the grounds that his proposals are inconsistent with past Commission practice. Finally, the Commission finds it reasonable to freeze Rider NM to new customers as of October 1, 2023, and allow existing NEM customers to continue service under Rider NM until they request service under Rider NSC or until September 30, 2033.

The Commission further requires before filing its next rate case, to DEP shall analyze the impacts of transferring customers receiving service under Riders 7 and 57 to other standby service riders and, if that analysis reveals viable options for transferring these customers, DEP shall move these customers to other standby service riders over a reasonable transition period and in a manner that lessens or avoids rate shock.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 49-51

Cost of Capital

The evidence supporting these findings is in DEP's verified Application and Form E-1; the testimony and exhibits of the public witnesses; the testimony and exhibits of DEP witnesses Morin and Newlin, Public Staff witness Walters, CUCA witness O'Donnell, DoD-FEA witness Reno, NCJC, et al. witness Ellis, Commercial Group witness Chriss, CIGFUR witness Gorman; and the entire record in this proceeding.

Cost of Equity Capital

Summary of Evidence

DEP's rate of return expert, Dr. Roger Morin, recommended a rate of return on common equity of 10.4% with a capital structure consisting of 53.0% common equity and 47.0% debt. The recommendations of intervenor expert rate of return witnesses are as follows:

Witness Walters/The Public Staff	9.45%[10]
Witness O'Donnell/CUCA	9.25%[11]
Witness Reno/ DoD-FEA	9.3%
Witness Ellis/NCJC, et. al	6.00%

Neither Commercial Group witness Chriss, nor CIGFUR witness Gorman, performed an independent expert rate of return on common equity analysis. Rather, both witnesses confined their rate of return testimony to commenting on average rates of return awarded to electric utilities over various time periods.

As is often the case with rate of return on common equity, the testimony is voluminous. Below, the Commission summarizes the prefiled testimony of the various witnesses, and addresses testimony it received at the hearings in its discussion of its findings and conclusions.

DEP Direct and Supplemental Testimony

In his direct testimony, DEP witness Morin recapped the regulatory framework under which a regulated entity's rates should be set, which is that the entity should have a fair opportunity to recover its prudently incurred costs, including taxes and depreciation, plus a fair and reasonable return on its invested capital. The allowed rate of return must necessarily reflect the cost of the funds obtained, that is, investors' return requirements. In determining a company's required rate of return, the starting point is investors' return requirements in financial markets. A rate of return can then be set at a level sufficient to permit a company the fair opportunity to earn a return commensurate with the cost of those funds. Tr. vol. 8, 31-32. Witness Morin noted that while the cost of debt is observable in the marketplace, the cost of equity – that is, investors' required rate of return on this source of financing – is more difficult to estimate. *Id.* Witness Morin concluded that the Commission's decision should allow DEP to earn a rate of return on common equity that is commensurate with returns on investments in other firms having corresponding risks; sufficient to assure confidence in DEP's financial integrity, and sufficient to maintain DEP's creditworthiness and ability to attract capital on reasonable terms. *Id.* at 32-34.

Witness Morin reiterated that the aggregate return required by investors is "the cost of capital," which he described as "the opportunity cost, expressed in percentage terms, of the total pool of capital employed by the utility." *Id.* at 34. He noted further that public utilities (or their publicly traded parent companies) must compete for capital, and that the price of capital is set in the same manner as it is set for other input factors of production – by supply and demand. *Id.* at 35.

[10] Witness Walters recommends a 20-basis point downward adjustment in rate of return on equity, to 9.25%, if DEP's MYRP is approved, and 9.45% otherwise.

[11] Witness O'Donnell recommends a 25-basis point downward adjustment in rate of return on equity, to 9.0%, if the MYRP is approved, and 9.25% otherwise.

Witness Morin testified that the focus is and must be on the investor and the investor's expectations. As witness Morin explained, "[t]he market required rate of return on common equity, or cost of equity, is the risk-adjusted return demanded by the equity investor. Investors establish the price for equity capital through their buying and selling decisions in capital markets." *Id.* at 38.

In estimating a fair rate of return on common equity for DEP, witness Morin applied three cost of capital methodologies, the Discounted Cash Flow (DCF) methodology, the Capital Asset Pricing Model (CAPM) methodology, and the Risk Premium methodology, all of which are market-based methodologies designed to estimate the return required by investors on the common equity capital committed to DEP. *Id.* at 39. Witness Morin stressed that multiple methodologies must be employed in the estimation of the cost of equity. As he noted:

> No one single method provides the necessary level of precision for determining a fair return, but each method provides useful evidence to facilitate the exercise of an informed judgment. Reliance on any single method or preset formula is inappropriate when dealing with investor expectations because of possible measurement difficulties and vagaries in individual companies' market data.
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> * * *
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> As a general proposition, it is extremely dangerous to rely on only one generic methodology to estimate equity costs. The difficulty is compounded when only one variant of that methodology is employed. It is compounded even further when that one methodology is applied to a single company. Hence, several methodologies applied to several comparable risk companies should be employed to estimate the cost of common equity.

Id. at 39-40.

He noted that the three methodologies he utilized, DCF, CAPM, and Risk Premium, are "broad market-based methods available to measure the cost of equity," and are all "accepted and used by the financial community and firmly supported in the financial literature." *Id.* at 40. Witness Morin utilized two sub-variants of each broad methodology, for a total of six studies.

In his direct testimony, witness Morin recommended a rate of return on common equity of 10.2%, which was the midpoint of the range of mathematical results from the six cost of capital studies he conducted. *Id.* at 26, 130. In his supplemental testimony, he updated all six of his studies, and provided the below comparison:

Method	Direct ROE	Supplemental ROE
DCF Value Line Growth*	9.9%	9.3%
DCF Analysts Growth*	9.3%	9.3%

CAPM*	10.8%	11.0%
Empirical CAPM*	11.1%	11.2%
Historical Risk Premium*	10.2%	10.8%
Allowed Risk Premium	10.2%	10.5%

* ROE estimate includes an adjustment for flotation costs.

Id. at 132. His updated rate of return on equity recommendation of 10.4% is again the midpoint of the range of these mathematical results.

For his supplemental testimony, witness Morin used the same proxy group as in his direct testimony, and the same methodologies in his studies as he had used in his direct testimony, but with updated capital markets data. The increase in his recommended rate of return on equity was largely the result of an increase in interest rates. As he noted, as of the time of his updated analysis, the level of U.S. Treasury 30-year long-term bond yield forecast is 4.3%, versus 3.7% when he prepared his direct testimony. *Id.* at 130. He noted further that the increase in forecast interest rates increases the CAPM, the empirical approximation to the CAPM (ECAPM), Historical Risk Premium, and Allowed Risk Premium results in his direct testimony. *Id.* at 33, 131. Finally, while his DCF modeling showed a slight decrease, the DCF results did not offset the increase in interest rates. *Id.* Dr. Morin concluded that the "net result of these capital market changes is a small increase in the cost of common equity." *Id.* at 131.

In his direct testimony DEP witness Morin also surveyed the current risk environment, describing a paradigm shift in the electric utility industry's risk profile. He described a "perfect storm" environment, in which "the industry is experiencing declining demand growth, rising operating costs, rising capital costs, while at the same time the industry is beset by lower allowed returns," and noted that as a result "[i]t is not surprising that investor risk perceptions have escalated" in this setting. *Id.* at 89.

Witness Morin attributed this increase in industry risk to four major challenges facing electric utilities: (1) declining growth in energy consumption due to improvements in energy science and productivity; (2) the need for record amounts of capital to replace aging infrastructure, improve reliability, and deliver renewable generation; (3) higher business risks, including the emergence of "prosumers," that is, customers (residential, commercial, industrial) who are both consumers and producers as a result of the increase in distributed generation; and (4) rising operating costs due to rising inflation and supply chain bottlenecks. *Id.* at 91-93. He concluded with the observation that "[g]iven the new paradigm shift in the industry, it is transparent that state regulatory support, including adequate returns on equity, will be instrumental to ensure ongoing capital attraction in the utility sector at reasonable costs." *Id.* at 93.

Finally, witness Morin surveyed economic conditions in North Carolina. He considered key macroeconomic factors such as GDP growth, employment data, and household income levels in North Carolina and DEP's service territory relative to the aggregate U.S. economy. *Id.* at 95. He opined that the economic conditions remain highly correlated with national conditions, such that they were reflected in the analyses used to determine the cost of equity. *Id.* at 103. He noted that economic conditions in North Carolina continue to improve from the COVID-19 pandemic, and they continue to be strongly correlated to conditions in the broader U.S economy. *Id.* He further noted that unemployment at the state level continues to fall and remains highly correlated with national rates of unemployment, and that GDP growth also remains well correlated with U.S. GDP growth. *Id.* 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.* Witness Morin concluded that, “the correlations between state-wide measures of economic conditions noted by the Commission in Docket No. E-22, Sub 479 remain strongly in place and, as such, they continue to be reflected in the models and data used to estimate the cost of equity capital.” *Id.*

Intervenor Testimony (rate of return experts)

The intervenor rate of return on common equity expert witnesses generally criticized DEP witness Morin’s analysis that resulted in his recommended 10.4% rate of return on common equity. In addition, they performed their own analyses as outlined below.

Direct Testimony of Public Staff witness Walters

Public Staff witness Walters used nearly the same proxy group of electric utilities relied on by DEP witness Morin, except that he excluded two utilities, FirstEnergy and MGE Energy. Tr. vol. 16, 248. He performed DCF, Risk Premium, and CAPM analyses for his proxy groups of electric utilities. *Id.* at 242. Witness Walters developed his DCF growth rate by relying on a consensus of professional securities analysts’ earnings growth estimates, averaging the growth rate forecasts from Yahoo Finance, MI, and Zack’s. *Id.* at 252-53. Public Staff witness Walters recommended a rate of return on common equity of 9.45% based on a capital structure of 52% common equity and 48% long-term debt. *Id.* at 247, 284. In the alternative, he recommended a rate of return on common equity of 9.25% if the Commission grants DEP’s MYRP and PBR application. *Id.* at 288.

Public Staff witness Walters applied the DCF model, Risk Premium Model, and CAPM that yielded the following results:

Discounted Cash Flow (DCF) – 9.0% Recommended DCF Result

	Mean	Median
Constant Growth – Consensus Analyst	9.01%	9.03%
Constant Growth – Sustainable Growth Rate	8.83%	8.47%
Multi-Stage Growth	7.91%	7.89%

Risk Premium Model – 9.9% Recommended Risk Premium Result

Projected Treasury Yield (3.700%)	9.74%	
	A-rated	Baa-rated
13-week Average Utility Bond Yield	9.93%	10.22%
26-week Average Utility Bond Yield	10.04%	10.34%

Capital Asset Pricing Model (CAPM) – 9.5% Recommended CAPM Result

	Current VL Beta	Historical VL Beta	Current MI Beta
D&P Normalized Method	9.22%	8.46%	8.69%
Risk Premium Method	10.72%	9.72%	10.02%
FERC DCF	9.78%	8.92%	9.18%

Id. at 264, 71, 83-84.

In his DCF analysis, witness Walters used the average of the weekly high and low stock prices of the utilities in the proxy group over a 13-week period ending on February 10, 2023. *Id.* at 251. For his constant growth model, he used the most recently paid quarterly dividend as reported in ValueLine and an expected growth rate based on a consensus of professional securities analysts' earnings growth estimates as a proxy for investors' dividend growth rate expectations. *Id.* at 251-53. For his sustainable growth model, he estimated the long-term growth rate based on DEP's current market-to-book ratio and on Value Line's three- to five-year projections of earnings, dividends, earned returns on book equity, and stock issuances. *Id.* at 256. His Multi-Stage growth model relied on inputs from three growth periods: (1) a short-term growth period consisting of the first five years; (2) a transition period, consisting of the next five years (6 through 10); and (3) a long-term growth period starting in year 11 and extending into perpetuity. *Id.* at 258. For the short-term growth period, he relied on the consensus of analysts' growth projections described above in relationship to his constant growth DCF model. For the transition period, he reduced or increased the growth rates by an equal factor reflecting the difference between the analysts' growth rates and the long-term sustainable growth rate. For the long-term growth period, he assumed each company's growth would converge to the maximum sustainable long-term growth rate. *Id.* at 259. Lastly, while not his typical practice, he provided DCF models using historical growth inputs, which resulted in DCF estimates ranging from 7.91% to 9.89%. *Id.* at 265.

Witness Walters' risk premium model is based on two estimates of an equity risk premium: the difference between the regulatory commission-authorized returns on common equity and (1) contemporary U.S. Treasury Bonds, and (2) contemporary Moody's "A" rated utility bond yields. He evaluated these premia over the period of 1986-2021 on an overall average and rolling five- and 10-year basis. *Id.* at 266-67. In addition, he evaluated the average spread between Treasury bonds and A- and Baa-rated utility bonds. *Id.* at 269. Finally, witness Walters added what he deems an appropriate premium in the third quartile of the rolling five-year average risk premia (6.04%) to his projected Treasury bond yields (3.7%), which produces a return on equity of 9.74%. Additionally, witness Walters applies a similar methodology to utility bond yields to estimate an equity risk premium of 4.63%.[12] He adds this to the 13- and 26-week average A- and Baa-rated utility bond yields. *Id*. at 270-71.

Witness Walters' CAPM analysis used the Blue Chip Financial Forecasts' projected 30-year U.S. Treasury bond yield of 3.7% for the risk-free interest rate. *Id.* at 274. He used the Value Line beta estimates of 0.89, the historical average Value Line beta since 2014 of 0.76, and the adjusted beta estimates provided by Market Intelligence's Beta Generator Model of 0.80 for his proxy group. *Id.* at 275. Witness Walters used two versions of the constant growth DCF model to develop his estimates of the market risk premiums. *Id.* at 278. He used the 6.85% average of his estimated market risk premiums of 6.4% and 7.3%. *Id.* at 279. He testified that his 6.85% market risk premium is a reasonable, if not a high-end estimate. *Id.* at 281.

Witness Walters concluded that the appropriate equity cost rate for DEP based on companies in his proxy group is in the 9.0% to 9.9% range, recommending the midpoint of 9.45%. *Id.* at 284. However, witness Walters testified that DEP's PBR application would shift risk from shareholders to ratepayers by reducing regulatory lag. *Id.* at 285. As such, he recommended a 9.25% rate of return on common equity, should the Commission grant DEP's MYRP and PBR application. *Id.* at 288. Witness Walters also testified as to current capital market conditions as of the date of his testimony in April 2020. He stated that the authorized rates of return on common equity for electric utilities have declined over the last several years. *Id.* at 222.

Direct Testimony of CUCA witness O'Donnell

CUCA witness O'Donnell proposed a rate of return on common equity of 9.25% (without regard to DEP's MYRP proposal), based upon DCF modeling and CAPM methodologies, as well as a comparable earnings approach. Tr. vol. 21, 627. Witness O'Donnell primarily relied upon the DCF model and testified that it is superior to the others because it has a direct and immediate link to stock prices. *Id.* at 602-03. Witness O'Donnell's DCF analysis results range from 8.7% to 9.7% with an overall result of 9.25%. *Id.* at 614. His CAPM analysis ranged from 7.25% to 8.25% with a midpoint of 7.75%. *Id.* at 626. His Comparable Earnings Analysis (CEA) ranged from 9.5% to 10.5% with a midpoint of 10.0%. *Id.*

Witness O'Donnell, like Public Staff witness Walters, made a downward adjustment to his rate of return on common equity recommendation in the event the

[12] Witness Walters states in his testimony that he adds 5.33%, but the math in his narrative indicates 4.63% was used, and 4.63% is supported by Exhibit CCW-12.

Commission approves DEP's MYRP. The downward adjustment would take his rate of return on equity recommendation from 9.25% to 9.0%. *Id.* at 627.

Direct Testimony of DoD-FEA Witness Reno

DoD-FEA witness Reno recommended that the Commission approve a rate of return on common equity of 9.3% and reject DEP's requested 10.4%. *Id.* at 349-50. She conducted her analysis by deriving average expected market returns for a proxy group of regulated electricity companies with risk comparable to DEP. *Id.* at 362. Her analysis applied two DCF models, CAPM, and ECAPM, as well as a Comparable Earnings Model. Witness Reno summarized her model results in her Table 7, reproduced below:

Table 7. ROE Estimates (%)

DCF Methodology	**30-Day Stock Price**	**90-Day Stock Price**	**Average**
Constant-Growth DCF (EPS Growth)	9.57	9.54	
Constant-Growth DCF (DPS, EPS and BVPS)	9.19	9.11	
Sustainable Growth DCF	8.42	8.35	
DCF Range:	**8.35**	**9.57**	**8.96**
CAPM & ECAPM Methodology	**CAPM**	**ECAPM**	
Capital Asset Pricing Model (Lg. Stock ERP, 30-yr T-Bond Rate)	10.42	10.63	
Capital Asset Pricing Model (Supply-Side ERM, 30-yr T-Bond Rate)	9.32	9.49	
Capital Asset Pricing Model (D&P Normalized Rate)	8.83	9.00	
CAPM Range:	**8.83**	**10.63**	**9.73**
Comparable Earnings Methodology			
Comparable Earnings Model (Historical ROE)	10.26		
Comparable Earnings Model (Adjusted ROE)	11.10		
Comparable Earnings Model (VL Forecasted ROE 25-27)	11.00		
CEM Range:	**10.26**	**11.10**	**10.68**
Summary			
DCF-Based ROE Average			8.96
DCF-CAPM-Based ROE Average			9.35
All-Model ROE Average			9.79
	Min	**Max**	**Midpoint**
ROE Range	8.96	9.57	9.26
Recommended ROE (%)			**9.30**

Id. at 395.

Witness Reno's recommended rate of return on equity of 9.3% represents the midpoint of her constant-growth DCF outcomes (her primary method) and is supported by the average of her DCF and CAPM methods of 9.35%. The average of all of witness Reno's models is 9.79%. *Id.* at 373.

Direct Testimony of NCJC, et al. witness Ellis

NCJC, et al. witness Ellis recommended a rate of return on common equity of 6.0%, based on the minimum required to maintain DEP's current A2 credit rating. *Id.* at 1071. Witness Ellis criticized DEP witnesses for their conflation of the rate of return on capital and the cost of capital, arguing that such confusion has led to excessive authorized returns. *Id.* at 940-42. He testified that his analysis relies on the premise that rate of return on common equity and capital structure are interrelated and cannot be determined separately. *Id.* at 1055-60.

Witness Ellis' analysis relies on the DCF and CAPM to estimate the cost of capital. *Id.* at 937. His analysis yielded the following results:

Multi-Stage Discounted Cash Flow: 6.25%

Capital Asset Pricing Model: 5.8%

Id. at 939.

He opined that the multi-stage DCF model should be used instead of the constant growth DCF model because it allows for more realistic cash flow projects, yielding more accurate results. *Id.* at 990. He testified that his CAPM analysis eliminates the upward biases seen in Witness Morin's CAPM analysis. *Id.* at 997.

Witness Ellis testified that rate of return on common equity and capital structure are interrelated and must be addressed together. *Id.* at 1056-57. He recommended along with his 6.0% rate of return on common equity that the Commission set DEP's capital structure at 58.0% equity and 42.0% debt and indicated that this combination would maintain DEP's credit rating. *Id.* at 1071.

Intervenor Testimony (other experts)

As noted above, both Commercial Group witness Chriss and CIGFUR witness Gorman provided rate of return on common equity-related testimony but did not perform any ROE analysis.

Direct Testimony of Commercial Group witness Chriss

While he did not provide a rate of return on common equity analysis in his testimony, witness Chriss for the Commercial Group testified that DEP's proposed rate of return on common equity was significantly higher than rates of return previously approved by the Commission from 2019 to the present. *Id.* at 513-14. Likewise, witness Chriss indicated that DEP's proposed ROE is significantly higher than most reported rate of return on common equity decisions by utilities commissions from 2019 to the present. *Id.* at 515-17. He testified that according to S&P Global Market Intelligence, 141 decisions were rendered during that time frame, with results ranging from 7.36% to 10.6%, with the median authorized ROE at 9.5%. *Id.* at 515. Removing distribution-only utilities and distribution service rates from the analysis, he testified that the average rate of return on common equity for vertically integrated utilities authorized from 2019 through the time of his direct testimony filing was 9.61%. *Id.*

Direct Testimony of CIGFUR witness Gorman

CIGFUR witness Gorman proposed that the Commission adjust DEP's authorized return on equity to reflect the current industry average of 9.6%. *Id.* at 405. He testified that for vertically integrated utilities, the authorized rate of return on common equity was around 9.53% in 2021, 9.69% in 2022, and currently holds around 9.6% for 2023. *Id.* at 409. He testified further that a fair ROE and a lower-cost, more balanced ratemaking capital structure would lower DEP's cost of service and support the implementation of more competitive rates. *Id.* at 411. He further testified that the proposed 10.4% ROE significantly exceeds the authorized returns on equity for other regulated utilities companies, which have been sufficient to maintain credit and provide utilities access to capital under reasonable terms and prices. *Id.* at 450-51.

DEP Rebuttal Testimony

In his rebuttal testimony, DEP witness Morin responded to criticism by intervenor ROE witnesses and commented upon deficiencies in their analyses. While he testified that he agrees with several of the views and procedures presented by witness Walters and witness O'Donnell, he noted that their recommendations understate the appropriate ROE for DEP. Tr. vol. 8, 139, 171. Particularly, he reasoned that their recommendations lie outside of the zone of currently authorized rates of return on common equity for vertically integrated electric utilities in the United States, which have averaged 9.7% in the past and have trended upward in more recent decisions in response to the surge in interest rates and inflation. *Id.* at 139, 169. He further noted that neither witness Walters, nor witness O'Donnell, nor witness Reno explained why or how DEP's cost of equity capital has decreased since it was awarded a rate of return on common equity of 9.6% in its last rate case in 2021, given a surge in interest rates and inflation that each of them acknowledged in their testimony. *Id.* at 223.

Witness Morin further disputed the contentions of witnesses Walters, O'Donnell, and Reno that the adoption of a performance-based ratemaking statute in North Carolina, including multi-year rate plans, should result in a lower rate of return on common equity for DEP. *Id.* at 135. He noted that the peer group of electric utilities also includes other risk-mitigating mechanisms, taken account in the use of the proxy group's financial data. *Id.* As such, further adjustment on the basis that an MYRP reduces risk amounts to double counting and should be rejected. *Id.*

Witness Morin additionally challenged the findings of the intervenors individually. While he noted that they shared quite a bit of common ground in their analyses, witness Morin testified that Public Staff witness Walters' recommended rate of return on common equity lies outside of the zone of currently authorized rates of return on common equity for vertically integrated utilities and opined that if his results were amended to reflect proper data inputs to the financial models, his results would exceed 10.0%. *Id.* at 139-67. He offered the following seven points of disagreement. *Id.* at 140.

Witness Morin criticized witness Walters' reluctance to accept flotation costs, explaining that the parent-subsidiary relationship does not eliminate the cost of stock issuance. *Id.* at 142. He disagreed with witness Walters' DCF technique, explaining that his sustainable growth rate approach was illogical and inconsistent with empirical evidence. *Id.* at 143-46. He testified that witness Walters' multi-stage DCF should not be given any weight by the Commission, as it is predicated on the idea that utilities grow at the same rate as the general macro-economy. *Id.* at 148. He wholly rejected witness Walters' use of the historical Value Line beta estimates and Vasicek-adjusted betas, explaining that their use is not standard and the extent to which market participants rely on them is unclear. *Id.* at 153-54. He argued that witness Walters' CAPM underestimates the appropriate cost of capital. *Id.* at 159-60. In challenging witness Walters' risk premium analysis, witness Morin testified that it fails to recognize the inverse relationship between risk premium and interest rates. *Id.* at 160-61. Finally, witness Morin disagreed with witness Walters' criticisms of his testimony, noting that nothing presented would cause him to alter any of his recommendations or methodologies. *Id.* at 167.

At the outset, witness Morin identified two fundamental flaws in CUCA witness O'Donnell's testimony, noting that his proposed 9.25% rate of return on common equity would be one of the lowest in the industry and that it is the result of a defective DCF analysis. *Id.* at 168-71. While witness Morin agreed with parts of witness O'Donnell's analysis, he identified six specific areas of disagreement over the appropriate data inputs for the CAPM and DCF models. *Id.* at 172. He explained that witness O'Donnell's recommended rate of return on common equity is outside the zone of currently authorized rate of return on common equity for vertically integrated electric utilities in the United States and that of his own sample of companies, noting that the currently authorized returns for his peer companies average nearly 10.0%, and the expected returns for these companies from his own Value Line data shown on Exhibit KWO-4 are in the range of 10.6% – 11.1%. *Id.* at 172-73. He asserted that two of witness O'Donnell's dividend yield estimates are understated because they are based on stock prices reaching back several months in the past, thus violating the notion of market efficiency. *Id.* at 173. Witness Morin raised concern with witness O'Donnell's choice of DCF growth rates, finding his reliance on 12 different rates, including historical growth rates, sustainable growth rates, and analysts' forecasts arbitrary and inconsistent with empirical evidence. *Id.* He further questioned witness O'Donnell's reliance on historical growth rates in his DCF model, explaining that the substantial changes occurring in the electric utility industry make use of those rates questionable. *Id.* at 174.

While he agreed with parts of witness O'Donnell's CAPM analysis, witness Morin argued that witness O'Donnell's risk-free rate assumption is too low. *Id.* at 182. Witness Morin also testified that witness O'Donnell's denunciation of analysts' growth forecasts as unreasonable proxies for the DCF growth rate is without foundation and inconsistent with empirical finance literature on the subject. *Id.* at 192.

Witness Morin challenged DoD-FEA witness Reno's analysis, particularly her exclusive reliance on her Constant Growth DCF. *Id.* at 196. He reiterated his concerns about using the sustainable growth methodology due to its inherent circularity and encourages the rejection of the 90-day stock price DCF in violation of the Efficient Market Hypothesis, leaving only two DCF results from her analysis to consider. *Id.* at 198. He agreed with witness Reno's decision to give little weight to the Kroll 6.0% normalized market risk premium (MRP), as well as her comparable earnings analysis results. *Id.* at 198-99. Finally, he disputed witness Reno's criticisms of his own analyses, noting that her risk premium analysis uses a group with a nearly identical beta risk estimate and that her opposition of a flotation allowance disregards the fact that the parent-subsidiary relationship does not eliminate the costs of a new issue of stock. *Id.* at 199-200.

Witness Morin highlighted the limited analysis performed by Commercial Group witness Criss and CIGFUR witness Gorman. *Id.* at 201. He testified that witnesses Criss and Gorman determined their recommendations merely by averaging what other regulators have allowed in 2022. *Id.* He criticized the circular nature of their recommendations and noted the large deviations among the utilities included in their proposed averages. *Id.* at 202. He encouraged the Commission to disregard their testimonies as not germane and to exercise a mind of its own rather than relying on the actions of other Commissions. *Id.* at 203.

Witness Morin wholly rejected the testimony of NCJC, et al. witness Ellis, describing his approach as "non-mainstream, far-fetched, and unorthodox for both methods he uses to estimate the cost of capital." *Id.* at 204. He described witness Ellis' recommendation as draconian and described the adverse consequences to DEP's creditworthiness, financial integrity, capital raising ability, and its customers, should the Commission adopt it. *Id.* He also identified witness Ellis' inconsistencies and contradictions, such as his challenging the validity of the same consensus economic forecasts he relies on to make his recommendations. *Id.* at 205. Witness Morin challenged witness Ellis' differentiation of cost of capital and rate of return and dismissed his position on the use of Market-to-Book ratios in utility regulation. *Id.* at 206-07. In addition to challenges to witness Ellis's recommendations, witness Morin offered a myriad of criticisms to the application of his methodologies. He explained that witness Ellis' misuse of geometric averages rather than arithmetic averages produces results clearly contrary to the most basic financial theory. *Id.* at 210-12. He further identified multiple other instances where witness Ellis' methods deviate from academic state of the art practices, including his rejection of the constant growth DCF analysis and his condemnation of Value Line beta estimates. *Id.* at 205, 214, 219.

Law Governing the Commission's Decision on Rate of Return on Equity

Rate of return on equity is often one of the most contentious issues to be addressed in a rate case. 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. Public Service Commission*, 262 U.S. 679 (1923) (Bluefield), and *Federal Power Commission v. Hope Natural Gas Co.,* 320 U.S. 591 (1944) (*Hope*), which establish:

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

Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction, *Application by Duke Energy Carolinas, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina*, No. E-7, Sub 1146 , at 50 (June 22, 2018); *see also State ex rel. Utils. Comm'n v. Gen. Tel. Co.,* 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.*

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). 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.

The North Carolina Supreme Court has long recognized that the Commission's subjective judgment is a necessary part of determining the authorized rate of return on common equity. *See, e.g., State ex rel. Utils Comm'n v. Public Staff-N.C. Util's. Comm'n*, 323 N.C. 481, 490, 374 S.E.2d 361, 369 (1988) (*Public Staff*). Likewise, the Commission has noted that such determination is not made by application of any one simple mathematical formula:

> 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, pp. 382 (notes omitted).

Order Granting General Rate Increase, *Application of Carolina Power & Light Co., 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 35-36 (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 Order).

Moreover, in setting rates the Commission must not only adhere to both the United States and North Carolina Constitutions, but as held by the North Carolina Supreme Court, it must set rates as low as possible consistent with constitutional law. *Public Staff*, 323 N.C. at 490, 374 S.E.2d at 370. Further, the North Carolina General Assembly has provided that the Commission must also set rates employing a multi-element formula set forth in N.C.G.S. § 62-133. The formula requires consideration of elements beyond just the rate of return on common equity element, and it inherently necessitates that the Commission make many subjective determinations, in addition to the subjectivity required to determine the rate of return on common equity. The subjective decisions the Commission must make as to each of the elements of the formula can and often do have multiple and varied impacts on all of the other elements of the formula. In other words, the formula elements are intertwined and often interdependent in their impact to the setting of just and reasonable rates.

The fixing of a rate of return on the cost of property used and useful to the provision of service (as determined through the end of the historic 12-month test period prior to the proposed effective date of a requested change in rates and adjusted for proven changes occurring up to the close of the expert witness hearing or projected in accordance with the provisions of N.C.G.S. § 62-133.16(c)(1)(a)) is one of several interdependent elements of the statutory formula to be used in setting just and reasonable rates. North Carolina General Statute § 62-133(b)(4) provides, in pertinent part, that the Commission shall:

> [f]ix such rate of return on the cost of the property . . . as will enable the public utility by sound management [1] to produce a fair return for its shareholders, *considering changing economic conditions and other factors* . . . [2] to maintain its facilities and services in accordance with the reasonable requirements of its customers in the territory covered by its franchise, and [3] to compete in the market for capital funds on terms that are reasonable and that are fair to its customers and to its existing investors. [Emphasis added.]

N.C.G.S. § 62-133(b)(4).

The North Carolina Supreme Court has interpreted the above-emphasized language as requiring the Commission to make findings regarding the impact of changing economic conditions on customers when determining the proper rate of return on common 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 common equity-related factors – the economic conditions facing DEP's customers and DEP's need to attract equity financing on reasonable terms in order to continue providing safe and reliable service. 2013 DEP Rate Order at 35-36. The Commission's determination in setting rates pursuant to N.C.G.S. § 62-133, which includes the fixing of the rate of return on common equity, always takes into account affordability of public utility service to the using and consuming public. The impact of changing economic conditions on customers is embedded in the analyses conducted by the expert witnesses on rate of return on common equity, as the various economic models widely used and accepted in utility regulatory rate-setting proceedings take into account such economic conditions. 2013 DEP Rate Order at 38. Further,

> [t]he Commission always places primary emphasis on consumers' ability to pay where economic conditions are difficult. By the same token, it places the same emphasis on consumers' ability to pay when economic conditions are favorable as when the unemployment rate is low. Always there are customers facing difficulty in paying utility bills. The Commission does not grant higher rates of return on common equity when the general body of ratepayers is in a better position to pay than at other times . . . .

Id. at 37.

Economic conditions existing during the modified test year, at the time of the public hearings, and at the date of the issuance of the Commission's order setting rates will affect not only the ability of the utility's customers to pay rates but also the ability of the utility to earn the authorized rate of return during the period the new rates will be in effect. However, in setting the rate of return on common equity, just as the Commission must assess the impact of economic conditions on customers' ability to pay for service, it likewise must assess the effect of regulatory lag on DEP's ability to access capital on reasonable terms. The Commission sets the rate of return on common equity considering both of these impacts taken together in its ultimate decision fixing a utility's rates.

Thus, in summary and in accordance with the applicable law, the Commission's duty under N.C.G.S. § 62-133, as well as N.C.G.S. § 62-133.16, is to set rates as low as reasonably possible to the benefit of the customers without impairing DEP's ability to attract the capital needed, at reasonable rates, in order to provide safe and reliable electric service and recover its cost of providing service.

Discussion and Conclusions

Two basic issues relating to ROE are presented in this case. First, the Commission must, based upon the evidence presented, select the appropriate ROE for DEP. Second, the Commission must determine whether a downward adjustment to that ROE is appropriate in light of North Carolina's adoption of PBR, in particular, the potential for an MYRP, and the Commission's approval of DEP's PBR Application, as modified by this Order. For the reasons set forth herein, the Commission determines that: (1) the appropriate ROE to be awarded to DEP in this case is 9.8%, and (2) downward adjustment to otherwise applicable ROE is not warranted in view of (a) the widespread acceptance of alternative regulation throughout the United States, and (b) a comparison of North Carolina's alternative regulation program as promulgated by the PBR Statute and other states' alternative regulation. The Commission is persuaded that that comparison shows, as DEP witness Bateman testified, that North Carolina is not "less risky, in terms of regulatory framework, than other states on average across the country." Tr. vol. 15, 96.

Setting the Rate of Return on Common Equity

As is the norm, the expert witnesses for DEP, the Public Staff, and other intervenors differ widely in their ROE recommendations.[13] A summary of the model outputs of the various witnesses illustrates this divergence (bold indicates a point estimate, while parenthetical figures below are the range of model outcomes provided by the witness):

	DCF (Constant Growth*)	CAPM	Risk Premium	Comparable Earnings	Overall
Morin (DEP Supp.)	9.3%	11.0%-11.2%	10.5%-10.8%	Not Performed	10.4%
Morin (DEP, Direct)	9.3%-9.9%	10.8%-11.1%	10.2%	Not Performed	10.2%
Walters (The Public Staff)	**9.0%** (8.47%-9.03%)	**9.5%** (8.46-10.72%)	**9.9%** (9.74-10.34%)	Not Performed	9.45%
O'Donnell (CUCA)	**9.25%** (8.7-9.7%)	7.25%-8.25%	Not Performed	Not relied upon 9.5%-10.5%	9.25%
Reno (DoD-FEA)	**9.3%** (9.11%-9.57%)	8.83%-10.63%	Not Performed	10.26%-11.1%	9.3%
Ellis (NCJC, et. al.)	6.25%	5.8%	Not Performed	Not Performed	6.0%
Gorman (CIGFUR)					9.6%

[13] The Commission places little weight on the rate of return on equity testimony of Commercial Group witness Chriss and CIGFUR witness Gorman as neither actually performed any rate of return on equity analysis, beyond looking to average authorized rate of return on equity awards by utility commissions, including this Commission. While looking to such industry average data can be beneficial, it does not substitute for the rigorous analysis the law and the Commission demand in setting the allowed rate of return on equity.

*Although Public Staff witness Walters and DoD-FEA witness Reno performed multi-stage and sustainable growth DCF models, they did not rely on their outputs. As such, the figures above exclude those results. NCJC, et. al. witness Ellis's 6.25% is the result of a multi-stage growth DCF analysis.

As is also typical of rate of return on equity testimony, the various expert witnesses rely on many of the same models to inform their cost of equity estimates. However, the results of these models vary due to differences of opinion on the appropriate inputs. In the following pages, the Commission will weigh and consider the inputs in order to narrow the range of reasonable outcomes. Further, while DoD-FEA witness Reno and CUCA witness O'Donnell primarily rely upon their DCF results, it has been the Commission's long-standing practice to consider and place weight on multiple models in order to protect against any one model's skewing the outcome in times when it may be less indicative of the true cost of capital. The Commission also notes that DEP witness Morin's figures above, with the exception of his Allowed Risk Premium measure, include a flotation cost adjustment of approximately 0.2%. Tr. vol. 8, 53-54, 73, 75, 78.

The Commission, for reasons discussed below, concludes that a flotation cost adjustment is not warranted in this case. As such, the following discussion excludes them from consideration in setting the allowed return on equity.

Discounted Cash Flow Model

Despite the wide range of overall recommendations provided by the expert witnesses, with the exception of NCJC, et al. witness Ellis's 6.25% result, the recommended results of the DCF models form a relatively tight band from 9.0% to 9.3%. While the remaining witnesses disagreed on the appropriate growth adjustment to apply to the dividend yield, a 30-basis point window of outcomes reflects consensus regarding an appropriate model output for the DCF model. This remains the case even after removing DEP witness Morin's 20 basis point flotation cost adjustment.

The Commission concludes that NCJC, et al witness Ellis's outcome of 6.25% is an outlier and should be ignored. Apart from being more than 300 basis points below any rate of return on equity ever approved by this Commission for DEP, it is scarcely 200 basis points above DEP's embedded cost of debt, a premium that is clearly insufficient to compensate investors for the added risks associated with equity ownership relative to a debtholder's claim on the same enterprise. Further, NCJC, et al witness Ellis is alone in his reliance on a DCF method other than the constant growth DCF model. In contrast, DoD-FEA witness Reno and Public Staff witness Walters both conducted a multi-stage DCF model, and subsequently ignored or discounted those results. Tr. vol. 16, 264; Tr. vol. 21, 395.

As a result of their relatively narrow band of 9.0% to 9.3%, the Commission concludes that the DCF analyses of DEP witness Morin, CUCA witness O'Donnell, Public Staff witness Walters, and DoD-FEA witness Reno, are credible, probative, and entitled to substantial weight.

Risk Free Rate

A key input to both the risk premium and CAPM models is the risk free rate. On cross examination, DEP witness Morin testified that, due to a decline in interest rates between the time of filing of his supplemental testimony and the hearing, his recommended rate of return on equity would have been 0.2% lower if recalculated. *Id.* at 323-324. The Commission appreciates DEP witness Morin's candor in this regard and understands that, due to the dynamic nature of financial markets, model outcomes calculated on any given day would reflect the inputs available on that day, and as such would change from day to day. With or without this correction, however, DEP witness Morin's preferred measure of the risk free rate that he used in his supplemental testimony, 4.3%, based on projections, diverges meaningfully from the actual 30-year Treasury rate both at the time of filing and during the hearing. DoD-FEA witness Reno reports the 30-day average yield on the 30-year Treasury bond was 3.79% as of February 28, 2023. Tr. vol. 21, 382. NCJC, et al. witness Ellis uses the January average of 3.66%. Tr. vol. 21, 939. DEP witness Morin himself reports the yield to be between 3.9% and 4.0% as of the date of the hearing. Tr. vol. 8, 324. CUCA witness O'Donnell uses the range of yields over the prior 12 months of 2.42% to 4.4%, and Public Staff witness Walters uses his own projected value of 3.7%. Tr. vol. 16, 274; Tr. vol. 21, 625.

In support of his use of projected interest rates, DEP witness Morin testified that,

> Cost of capital models, including both the CAPM and DCF models, are prospective (i.e., forward-looking) in nature and must take into account current market expectations for the future because investors price securities on the basis of long-term expectations, including interest rates. As a result, in order to produce a meaningful estimate of investors' required rate of return, the CAPM must be applied using data that reflects the expectations of actual investors in the market.

Tr. vol. 8, 60.

The Commission considers the single best indicator of "the expectations of actual investors in the market" to be the yield they are willing to accept on the bonds they own. Where this information is available, either in the form of current yields or forward yields based upon the same, the Commission will continue to prefer using these rates to projections offered by market commentators.

DEP Witness Morin's direct testimony relied upon a risk free rate of 3.7%, and in response to a question from Chair Mitchell, he confirms that had he relied on the same 3.7% rate in his supplemental testimony, the outputs would have largely been in-line with the model outputs from his direct testimony (i.e. 20 basis points lower than his supplemental testimony). As a result, the Commission will place somewhat more emphasis on DEP witness Morin's direct testimony than his supplemental testimony with regard to his CAPM and Risk Premium Model outcomes.

Capital Asset Pricing Model (CAPM)

The wide range of results for the CAPM from the various intervenors shed light on the importance of the underlying inputs to the model. Of primary importance are the assumed risk free rate, market risk premium and beta, as the model's output is the sum of the former and the product of the latter two. As discussed above, a risk free rate in the range of 3.7% to 3.9% reasonably aligns with prevailing 30-year Treasury yields at the time of the hearing, and with the exception of CUCA witness O'Donnell, the expert witnesses have each provided models utilizing this input. CUCA witness O'Donnell, for his part, utilized a range of yields that cover the considerable variability of the measure over the 12 months prior to his testimony (2.42% to 4.4%). Tr. vol. 21, 625. While not exactly a match, it would indicate that top half of his indicated range overlaps with the others on the basis of risk free rate.

Turning next to beta, the witnesses diverge considerably. DEP witness Morin was adamant that a beta of 0.89, reflecting the current Value Line average for the proxy group. Public Staff witness Walters also employed this figure, along with average betas going back to 2014 (0.76) and betas from Market Intelligence's Beta Generator. The Commission agrees with DEP witness Morin that using stale betas is incorrect and prefers the current Value Line average, as they better reflect current market fundamentals. The Commission also accepts DEP witness Morin's rationale for rejecting the Vasicek adjusted betas from Market Intelligence. CUCA witness O'Donnell appeared to agree with DEP witness Morin, and used a 0.88 beta for the proxy group, sourced from Value Line. Tr. vol. 21, 625. Similarly, DoD-FEA witness Reno relied upon a Value Line beta of 0.89. *Id.* at 384. NCJC, et al. witness Ellis rejected the Value Line beta because Value Line considers five years of trailing data, meaning it continues to reflect the effects of pandemic-related market turmoil and asserted that they do not reflect current investor risk perceptions. *Id.* at 1010. Instead he offers several alternatives, including from providers that allow users to modify beta calculation parameters. *Id.* at 1012. On rebuttal, DEP witness Morin testified that Value Line betas are widely used and well-known to investors, that Diana Harrington's work established them as consistently the best at predicting ensuing betas, and that NCJC, et al. witness Ellis's preferred alternatives are inferior. Tr. vol. 8, 213-14. The Commission accepts DEP witness Morin's rebuttal of NCJC, et al. witness Ellis on this point and finds reassuring the reliance of other intervening witnesses on Value Line betas in its determination of the appropriate beta.

The MRP, the last variable in the CAPM model, reveals a wider range of assumptions made by the intervening witnesses. DEP witness Morin used 8% in his initial testimony (composed of a historical MRP of 7.4% and a prospective MRP of 8.5%, averaged), and 7.3% in his supplemental testimony, each reflecting an expected market return of 12%. DEP witness Morin opined that an MRP in the range of 6.0% to 8.0% is a reasonable estimate of the cost of equity for CAPM and that the historical MRP approach is simple and difficult to improve upon. Tr. vol. 8, 71. Witness Walters utilized both a historical approach and DCF approach to estimate the MRP, yielding results of 7.9% and 6.85% respectively, and implying expected market returns of 11.6% and 10.52%. Witness Walters also utilized a method from Kroll that provides a normalized risk-free rate of 3.89% and an MRP of 6.0%. Tr. vol. 16, 278-

82. DEP witness Morin accepted witness Walters' first two estimates, but rejected the Kroll based estimate for several reasons, namely that Kroll is a highly selective source, that it lacks transparency, and falls at the bottom of a range indicated by Kroll's own analysis to be a reasonable estimate of the MRP. Tr. vol. 8, 156. Witness Reno used estimates from Kroll of 7.46% (historic arithmetic average) and 6.22% (Ibbotson-Chen supply side model). She also used a 6.0% Kroll recommended U.S. ERP paired with a normalized risk-free rate of 3.5%. Tr. vol 21, 382-83. Witnesses O'Donnell (3.5% to 4.5%) and Ellis (3.98%) offered substantially lower MRP estimates. Tr. vol. 21 939, Exhibit KWO-5; Tr. vol. 21. Witness Morin noted that these estimates are below several widely used estimates of the MRP for U.S. Stocks, that witness O'Donnell did not rely upon the CAPM, and that NCJC, et. al. witness Ellis incorrectly used geometric means in generating his MRP. Tr. vol. 8, 181-83, 210. The Commission agrees that the MRP rates of witnesses Ellis and O'Donnell are unreasonably low and should be ignored.

Witnesses Morin, Reno and Walters all seemed to agree that an estimate for the MRP within a range of 6.0% to 8.0% is reasonable. The Commission agrees.

In light of the foregoing, the Commission finds that a CAPM with inputs in the range of 3.7% to 3.9% for the risk free rate, a beta 0.89, and an MRP of 6.0% to 8.0% is a reasonable outcome. Witness Morin's use of an 8% MRP and 3.7% risk free rate from original testimony, when combined with the updated beta of 0.89 results in a CAPM rate (without flotation costs) of 10.82%. Witness Walters provided three estimates utilizing the current Value Line beta (9.22%, 9.78% and 10.72%), averaging 9.91%, while witness Reno's estimates using Value Line beta (but excluding the estimate which used a normalized risk free rate of 3.5%) were 9.32% and 10.42%, averaging 9.89%. Averaging the 9.9% results from the intervenors, with witness Morin's 10.82% modified result yields an estimated cost of equity of 10.35%. Thus, the Commission concludes that an estimate of 10.35% is a reasonable outcome for the CAPM model.

Empirical CAPM (ECAPM)

In this case, both DEP witness Morin and DoD-FEA witness Reno supported inclusion of an ECAPM result. The ECAPM, according to witness Morin, corrects for the fact that the CAPM under-predicts observed returns when beta is less than one. Public Staff witness Walters took issue with witness Morin's use of an adjusted beta as published by Value Line because the adjustments made in his ECAPM model are mathematically the same as adjusting beta. Tr. vol. 16, 306-07. In rebuttal, witness Morin testified that adjusted betas and ECAPM correct different problems, and that as a result, both are needed. NCJC, et. al. witness Ellis opposed the ECAPM on the grounds that it is not used elsewhere in finance and is not supported by updated research. Tr. vol. 21, 1038. Witness Morin contended the ECAPM is discussed in most finance textbooks, including one cited by witness Ellis. Tr. vol. 8, 217.

The Commission agrees with witness Walters's contention that mathematically, the Blume adjusted betas provided by Value Line achieve the same end. However, it finds witness Reno's support for using these same betas in the ECAPM persuasive and is further persuaded by witness Morin's testimony that both adjustments are needed because they correct for different things.

As witness Reno and witness Morin's ECAPM calculations were both approximately 20 basis points higher than their CAPM calculations, reflecting the Commission's CAPM conclusions above, the Commission accepts an ECAPM estimate of the rate of return on equity of 10.55% as reasonable.

Together with the results of the CAPM, a combined CAPM range of 10.35% to 10.55% will be used to calculate the required rate of return on equity in this case.

Risk Premium Model

The last major method relied upon by the cost of equity expert witnesses are the Risk Premium methods. DEP witness Morin utilized two variations of this approach. The first compares actual returns of the S&P Utility Index with contemporaneous Treasury returns and applies the 4.3% risk free rate. As with his other methods, he also applied a flotation cost adjustment. His second RPM represents the historical premium of allowed ROEs to the risk free rate. This method does not employ a flotation cost adjustment, as it assumes allowed ROEs factor that in. While the Commission has previously relied upon such models, and finds them credible, as mentioned above, the Commission finds that a risk free rate of 4.3% is overstated, and will instead rely upon witness Morin's Risk Premium Models as provided in his direct testimony, which used 3.7% risk free rate. Those results, after removing the adjustment for flotation costs, averaged 10.1%. The Commission finds this result credible, probative, and entitled to substantial weight.

Public Staff witness Walters also provided a risk premium method based on authorized returns for electric utilities. Witness Walters compares 37 years of authorized returns for electric utilities against contemporaneous bond yields and uses this method to estimate a return on equity of 9.9%. The Commission has given substantial weight to this method in the past and does so in this case as well. Taken together with the 10.1% RPM result of witness Morin, the Commission finds there is credible and probative evidence supporting an RPM-based cost of equity ranging from 9.9% to 10.1%.

Comparable Earnings Method

Although no witness relied upon a comparable earnings method in formulating their recommended rate of return on equity, CUCA witness O'Donnell and DoD-FEA Reno calculated results of 9.5% to 10.5% and 10.26% to 11.1% respectively. The Commission finds these results generally support its decision regarding rate of return on equity in this case.

Indicated Range Prior to Adjustments

In light of the foregoing, the Commission has identified a zone of reasonableness of 9.75% to 10%, reflecting the average of the ranges identified above. The Commission will next examine the proposed adjustments offered by the witnesses.

Flotation Cost Adjustment

Flotation costs are the expenses of issuing equity, such as printing fees, underwriter fees, attorney fees, and other similar fees. Tr. vol. 8, 337. DEP, itself, does not issue equity; instead, equity issuances are made by its publicly traded parent, Duke Energy.

Duke Energy issued no equity during the test year. Duke Energy forecasts there will be no common equity issued from 2023 through 2027. Public Staff Cross Examination Morin – Direct and Rebuttal, Ex. 10. Tr. Ex. vol. 9. DEP witness Newlin testified that "we've said publicly that the holding company is not planning to issue common stock until 2027 at the earliest." Tr. vol. 9, 111.

Flotation costs may not be recovered under these circumstances for the following two separate and independent reasons. First, it would be "unjustified" to cause customers to overpay DEP approximately $48 million dollars towards flotation costs when, in fact, no equity was or will be issued from 2021 through 2027. See, Order Approving Partial Settlement Agreement and Stipulation, Deciding Contested Issues, Approving Water and Sewer Investment Plan, Granting Partial Rate Increases, and Requiring Customer Notice, *Application by Aqua North Carolina, Inc. for Authority to Adjust and Increase Rates for Water and Sewer Utility Service in All Its Service Areas in North Carolina and for Approval of a Water and Sewer Investment Plan*, No. W-218, Sub 573, at 62 (June 5, 2023) (2022 Aqua Rate Case).

Second, the recovery of flotation costs is not allowed under North Carolina law where there is no evidentiary support. 2022 Aqua Rate Case at 61-62. The North Carolina Supreme Court in *State ex rel. Utilities Commission v. Public Staff,* 322 N.C. 689, 370 S.E.2d 567 (1988), reversed and remanded the ROE portion of the Commission's Order dated October 31, 1986, Docket No. E-7, Sub 408 for Duke Power Company. The Supreme Court directed the Commission on remand to reconsider the proper rate of return on Duke Power's common equity and also support its conclusion on flotation costs with specific findings. There was no evidence in that case that Duke Power intended to issue new stock for the next three or four years. On remand, the Commission issued its second E-7, Sub 408 Order, reassessed the evidence, and issued new findings of fact and conclusions. The Commission concluded that 13.2% was a fair rate of return on Duke Power's equity and there was a 0.1% increment in the approved 13.2% ROE to cover future stock issuance costs. On the second appeal, the Supreme Court held that the Commission's inclusion of the "stock" issuance increment is not supported by substantial evidence in view of the whole record. *State ex rel. Utils. Comm'n. v. Public Staff*, 331 N.C. 215, 218 (1992). The Supreme Court concluded the Commission's inclusion of a 0.1% ROE increment for purported future financing costs in the approved ROE was not based upon substantial evidence in view of the whole record. The Supreme Court stated:

> As we noted on the first appeal, an 0.1% upward increment in Duke's rate of return on common equity costs ratepayers $ 4.2 million annually in additional rates. Historically, Duke's average costs per issuance of stack

> was $ 3.2 million. In light of the whole record on this issue, particularly in the absence of any evidence that Duke intended to issue stock in the immediate future, there is simply no substantial evidentiary support for the Commission's addition of a 0.1% increment to Duke's rate of return on common equity to cover future stock issuance costs.

State ex rel. Utils. Comm;'n v. Public Staff, 331 N.C. 215 at 221-22.

The Supreme Court further stated and ruled:

> On the first appeal of this case, we questioned whether the record supported *any* adjustment whatever in the rate of return for purported future stock issuance, or financing, costs. We said:
>
>> Since *no* evidence was introduced that Duke intends to issue new stock for the next three or four years, and because there was no evidence regarding the probable cost of a prospective issuance, we question whether the record supports *any* financing cost adjustment. *State ex. rel. Utilities Commission v. Public Staff*, 322 N.C. at 700, 370 S.E.2d at 574 (emphasis added). We are not satisfied, for the reasons alluded to in our first opinion, that the record supports no such adjustment in the common equity rate of return.

Id. at 221.

As in that case, there was and is no plan to issue equity in the present case. Accordingly, there is no evidence to support DEP's request to increase its ROE by 20 basis points for flotation costs. Therefore, the Commission rejects DEP's inclusion of 20 basis points in its ROE request to cover flotation costs.

Downward Adjustment Due to MYRP

N.C.G.S. § 62-133.16(c)(1)(a) requires the Commission to consider any increased or decreased risk to either the electric public utility or its ratepayers that may result from having an approved MYRP.

Public Staff witness Walters and CUCA witness O'Donnell both made specific mathematical downward adjustments in their ROE recommendations to account for what they perceive as the less risky environment DEP now operates in as a result of the passage of the PBR Statute. Witness Walters's downward adjustment was 20 basis points, taking his ROE recommendation from 9.45% to 9.25%. Tr. vol. 16, 288. Witness O'Donnell's downward adjustment was 25 basis points, taking his ROE recommendation from 9.25% to 9.0%[14]. Tr. vol. 21, 627. Inasmuch as the Public Staff's recommendation is more fully explained in witness Walters's testimony, the Commission will address it, but the same factors described in this discussion apply with equal force to the recommendations of witnesses O'Donnell and Reno.

While asserting that there were other reasons to support a downward adjustment, witness Walters conceded that "the only stated adjustment for [DEP's] ROE is based on the MYRP." Tr. vol. 16, 336. Further, the actual quantification of the recommended downward adjustment was not performed by witness Walters at all. Instead, he simply adopted the Public Staff's methodology applied in the recent water utility cases, the 2022 Aqua Rate Case., and the general rate case proceeding for Carolina Water Service North Carolina in Docket No. W-354, Sub 400 (the 2022 CWSNC Rate Case). See Order Approving Partial Settlement Agreement and Stipulation, Deciding Contested Issues, Granting Partial Rate Increase, Approving Water and Sewer Investment Plan, and Requiring Customer Notice, *Application by Carolina Water Service, Inc. of North Carolina for Authority to Adjust and Increase Rates and Charges for Water and Sewer Utility Service in All Service Areas of North Carolina and Approval of a Three-Year Water and Sewer Investment Plan*, No. W-354, Sub 400 (Apr. 26, 2023); *See also* Order Approving Partial Settlement Agreement and Stipulation, Deciding Contested Issues, Approving Water and Sewer Investment Plan, Granting Partial Rate Increases, and Requiring Customer Notice, *Application by Aqua North Carolina, Inc., for Authority to Adjust and Increase Rates for Water and Sewer Utility Service in All Its Service Areas in North Carolina and for Approval of a Water and Sewer Investment Plan*, No. W-218, Sub 573 (June 6, 2023). In footnote 29 of his direct testimony, witness Walters linked to the Public Staff testimony filed in those two water utility cases to support quantification, noting that the "Public Staff has previously argued that approval of multi-year mechanisms that reduce the risk borne by water and wastewater utilities should result in a 20-basis point reduction in the allowed ROE." *Id.* at 287. The Commission did not accept the Public Staff position in either of the proceedings cited by witness Walters, and this downward adjustment is contrary to Commission's reasoning in the Orders in the 2022 Aqua Rate Case and the CWSNC Rate Case. Further, there is substantial evidence introduced in this case supporting DEP's position that no downward adjustment is warranted. Accordingly, the Commission rejects the downward adjustment theory.

In the Commission's Order in the 2022 CWSNC Rate Case, the Commission addressed and rejected the Public Staff's requested 20 basis point downward adjustment in otherwise applicable ROE and its holding was read into the record by Dr Morin:

> [T]he Commission is persuaded that this type of mechanism is prevalent across the country and within the proxy group. Although a WSIP is intended to reduce regulatory lag, the existence of similar mechanisms across the country and in the states where the proxy group utilities operate indicates

[14] DoD-FEA witness Reno did not make a specific downward adjustment to her rate of return on equity recommendation due to DEP's MYRP proposal but indicated that she had taken the MYRP proposal into account in setting rate of return on equity.

that the comparative risk reduction associated with a WSIP[[15]] for CWSNC, in this case, is zero.

Tr. vol. 9, 20-21 (emphasis added)[16].

The Commission's conclusion is in line with witness Morin's academic work on this subject, which is summarized in his most recent book, Modern Regulatory Finance, published in late 2021. *See* DEP Redirect Morin Direct and Rebuttal Ex. 1. Tr. Ex. vol. 9. At the hearing in this proceeding Witness Morin summarized the three reasons why he asserts the presence of risk-mitigating mechanisms should not result in a reduction in the cost of equity as presented on pages 58-59 of his Direct and Rebuttal Exhibit 1. *Id.*

First, witness Morin asserts that the ROE in a rate case is being set based upon a proxy group of comparable companies, and the use of a proxy group takes into account similar risk mitigating mechanisms that are pervasive in the industry, so "the addition of any discreet adjustment would be unwarranted double counting of the effect of these mechanisms." DEP Redirect Morin Direct and Rebuttal Ex. 1 at 58, Tr. Ex. vol. 9. In sum he states that the "current market data reflects or embeds the presence of risk mitigators." Tr. vol. 9, 17. Second, he states that empirical studies in peer-reviewed academic journals have examined the impact of risk mitigators on the cost of equity, and the results show that there is no impact. *Id.* at 17-18. Third, risks that are diversifiable are not considered relevant in cost of capital estimates for investors, because by definition they can be eliminated through diversification, and risk mitigators are in fact diversifiable. *Id.* at 18.

DEP witness Morin, quoting from his book, summarized that a downward adjustment would be "double counting" as the "market-derived returns are estimated for market information on the cost of common equity for other comparable companies, which already incorporates the impacts of these mechanisms." Tr. vol. 9, 17-18 (quoting DEP Redirect Morin Direct and Rebuttal Ex. 1 at 59), Tr. Ex. vol. 9.

The Commission is persuaded that DEP has proven, by the greater weight of the evidence, that the impact of alternative ratemaking mechanisms like the PBR Statute is already incorporated into the analysis and a downward adjustment in otherwise applicable ROE would be inappropriate "double counting."

DEP Late-Filed Exhibit (LFE) No. 11 and LFE No. 14 illustrate the prevalence of alternative ratemaking mechanisms. DEP LFE No. 11 is a map demonstrating that alternative ratemaking mechanisms are widespread throughout the United States. In fact, of the 51 jurisdictions depicted (the 50 states plus the District of Columbia), only five have no alternative ratemaking mechanism in place. By contrast, 36 (over 70%), have two or more such mechanisms, including North Carolina, which has two (MYRP and

[15] A "WSIP" (Water and Sewer Investment Plan) is the water utility analog to an MYRP for electric utilities.

[16] The Commission reiterated this holding, in identical language, in its recent Order in the 2022 Aqua Rate Case. See Order at 62.

decoupling). The other eleven states have a single mechanism, either a future test year or specific capital trackers. The exhibit validates DEP witness Bateman's observation that in the United States:

> [A]lternative ratemaking regulation is the norm and, therefore, contrary to Witness Walters's assertion, implementation of a MYRP does not warrant a reduction to the Company's ROE since this change simply makes North Carolina's ratemaking practices more aligned with the rest of the country. Notably, every single company in Witness Walters's proxy group operates either entirely or partially in states that have adopted alternative regulation.

Tr. vol. 23, 159-60.

LFE No. 14 shows the 23 electric utility holding companies in witness Morin's peer group used in connection with his ROE recommendation and the alternative ratemaking mechanisms in the applicable jurisdiction. Tr. vol. 8, 349. The LFE illustrates witness Morin assertion that "the proxy group companies all operate in … states [that have alternative ratemaking mechanisms], and more than one state in many cases." *Id.*

DEP witness Bateman compared the alternative ratemaking mechanisms available in North Carolina under the PBR Statute with similar mechanisms available in other jurisdictions. DEP witness Bateman stated that "the focus should not be on whether DEP has a Multiyear rate plan, but rather, how the North Carolina PBR framework compares to alternative regulation in other states in terms of risk to the utility." Tr. vol. 23, 160. Witness Bateman asserted that "North Carolina's framework places more risk with the utility than the frameworks in some other states." *Id.* She provided numerous examples of how North Carolina's framework places risk on the utility. As an example, she compared states with formula rates and riders for significant capital investments that allow for true-ups of costs increases to North Carolina's PBR mechanism under which she contends electric utilities bear "all the risk of and financial impact associated with cost increases on projects in between rate cases." *Id.* Witness Bateman also stated that unlike the PBR Statute many other states' MYRP mechanisms provide for fully forecasted growth of both capital and associated O&M expense. Tr. vol. 15, 91-92. Finally, she noted that ESM in North Carolina's PBR Statute is asymmetrical in that it assures that customers receive 100% of earnings once the utility's earnings exceed 50 basis points of its allowed ROE, but the utility does not receive an earnings boost if it underearns. *Id.* at 92-93; Tr. vol. 23, 160-61; *See also* DEP Redirect Bateman Stillman Direct and Settlement Ex. No. 1, Tr. Ex. vol. 16.

Witness Bateman concluded her review with the observation that she saw nothing that makes North Carolina "less risky, in terms of the regulatory framework than other states on average across the country." Tr. vol. 15, 96.

The Commission agrees with DEP witnesses Bateman and Morin and concludes that substantial evidence supports the reasonableness of a rate of return on equity ranging from 9.75% to 10.0%, without a downward adjustment due to the MYRP. The

Commission is persuaded by the evidence that similar types of mechanisms are prevalent across the industry as well as within the proxy group. The Commission is also persuaded that elements of the North Carolina statute are distinguishable as compared to other jurisdictions, as pointed out by witness Bateman, in terms of allocation of risk between utility and customers. The Commission is mindful that one of the objectives of the MYRP is to reduce the lag in recovery experienced by the utilities, which, in theory, benefits the utility. However, the Commission concludes that given the utility has entered a capital intensive period of time as it manages the transition of its system, it is critical that the utility be in a position to access capital on reasonable terms and the Commission concludes that the availability of the MYRP makes DEP competitive in terms of its ability to access capital on reasonable terms.

Regarding the obligation in accord with the holding in *Cooper I* to inform its selection of a rate of return on equity within that range, 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 DEP witness Morin and Public Staff witness Walters addresses changing economic conditions at some length. Witness Morin 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 national economy. As such, witness Morin 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 Walters generally agreed with DEP witness Morin that as of the time of the filing of his testimony, economic conditions had improved in North Carolina. As the Commission has noted, customer impact due to changing economic conditions is embedded in ROE expert witness analyses. Witness Morin'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 rate of return on equity.

The point is to see whether the econometric data relied upon by ROE expert witnesses captures the effects and impacts of changing economic conditions upon customers and the Commission concludes 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 rate of return on common equity of 9.8% will not cause undue hardship to customers even though some will struggle to pay the increased rates.

Indeed, affordability, especially for low-income customers, was a special focus of DEP and the intervening parties to this proceeding. As noted above, the Commission established the LIAC in its April 16, 2021, Order in the 2019 Rate Case and tasked the LIAC with addressing affordability issues for low-income residential customers. The efforts of the LIAC are apparent in this case and include the Affordability Stipulation as previously discussed in this Order. The provisions in the Affordability Stipulation, which includes the development of the CAP pilot, directly benefit customers with the least ability to pay in the current economic environment. In addition, as previously discussed in this Order, through the Payment Navigator program proposed in this proceeding, DEP will work closely with customers in need of assistance with managing bills and will connect those customers with sources of support and funding, based on the unique situation of the customer. While these programs will not ease the burden that electricity rates will place on certain of DEP's customers, the Commission expects these programs to provide a meaningful level of support to eligible customers. The Commission takes these facts into account in approving the 9.8% return on equity. However, the Commission also concludes, based on the evidence of record, that efforts to address energy burden and support for customers need assistance with their bills are but nascent. The LIAC allowed DEP and its stakeholders to generate data that illustrates the depth and breadth of the challenge in North Carolina. Work must continue to reach these customers and provide meaningful support both in terms of assisting customers use energy more efficiently so that bills are reduce and in terms of providing support to those customers when they are in need of bill assistance. The Commission recognizes the difficulties attendant to solving for these issues but emphasizes that the utility must continue this work. As has been previously expressed by this Commission, the electric utilities must pursue every opportunity presented by federal funding made available by the IRA and other federal legislation to support customers in need. The Commission has confidence that DEP, the Public Staff and stakeholders will identify such opportunities for customers and will develop programs that take advantage of every federal dollar that is available for customer support.

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. The Commission is mindful that, as shown by the evidence, relatively small changes in the rate of return on common equity 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 provisions in S.L. 2021-165 may intensify the risks facing DEP as it continues to navigate the challenges associated with the change in the mix of electric generating resources and with new load patterns, including ensuing the continued reliable operation of the electric system, and to work toward the requirements of N.C.G.S. § 62-110.9. As DEP witness Bowman asserted,

> [I]t is simply indisputable that the tasks currently before the Company—implementing the energy transition within the construct of the Carbon Plan while simultaneously evolving nearly every aspect of its business and pursuing a complex merger—are unprecedented, imposing new and unique execution risks on the Company across all phases and aspects of its business that are inarguably more far-reaching and complex than anything the Company has ever pursued in the past.

Tr. vol. 21, 1200-01.

The need to invest significant sums to serve its customers requires DEP to maintain its creditworthiness in order to compete for large sums of capital on reasonable terms. And, in addition, as recent years have demonstrated, macroeconomic, geopolitical, extreme weather, public health, and other exogenous events beyond DEP's control may necessitate – and indeed have necessitated – the need for DEP to access and invest significant sums during atypical and volatile market conditions. The Commission takes note of DEP witness Newlin's testimony that, particularly in light of DEP's present credit metrics, ROE is one predicate (capital structure being another predicate, discussed in detail below) to the level of creditworthiness necessary to efficiently access the capital markets on reasonable terms during all market cycles, including periods of high volatility, which access ultimately lowers borrowing costs passed through to customers during such time. Tr. vol. 9, 112-13; Tr. vol. 22, 206-07.

The Commission must weigh the impact of changing economic conditions on DEP's customers against the benefits that those customers derive from DEP's ability to provide safe, adequate, and reliable electric service 24/7/365, regardless of macroeconomic, geopolitical, environmental, and public health events. Safe, adequate, and reliable electric service is essential to the well-being of the people, businesses, institutions, and economy of North Carolina. The Commission is mindful of the burden that electricity rates will place on many of DEP's customers and the contribution of the ROE to those rates, but the Commission must balance the burden against DEP's being in a position to access capital: (1) on reasonable terms; and (2) in moments when DEP most needs capital in order to provide reliable service.

The Commission concludes in the exercise of its independent judgment and discretion that a 9.8% 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 DEP's ability to compete in the capital markets 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 9.8% 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. 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.

Capital Structure

Summary of Evidence

In his direct testimony, DEP witness Newlin proposed using a capital structure of 53% members' equity and 47% long-term debt. Tr. vol. 9, 94. Witness Newlin testified that DEP'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." *Id.* As of December 31, 2021, DEP's capital structure was 53.9% common equity and 46.1% long-term debt. *Id.* at 95.

Witness Newlin discussed the current credit ratings and forecasted capital needs of DEP and emphasized the importance of DEP's continued ability to meet its financial objectives. *Id.* at 87. He noted that DEP faces substantial capital needs over the next several years so as to provide cost-effective, safe, reliable, and increasingly cleaner electric service to its customers well into the future, so DEP must therefore appeal to debt and Duke Energy's equity investors to attract the capital it needs. *Id.* at 98-99. He explained that investors – both debt and equity – have a variety of investment opportunities available to them and require a return commensurate with the risk they incur, warning that they will invest elsewhere if they feel the expected return provided by a company for a given amount of risk is inadequate. *Id.* at 86. He further explained that lower credit quality weakens a company's attractiveness as an investment opportunity relative to companies with higher credit quality and similar return profiles. *Id.* at 86-87. As such, witness Newlin testified it is critically important that DEP maintain strong, investment-grade ratings to assure its financial strength and flexibility and ensure access to capital on reasonable terms. *Id.* at 96.

Discussing DEP's financial objectives, witness Newlin addressed specific objectives that support financial strength and flexibility, including maintaining 53% common equity for DEP on a financial capitalization basis; ensuring timely recovery of prudently incurred costs; maintaining sufficient cash flows to meet obligations; and maintaining a sufficient return on equity to fairly compensate shareholders for their invested capital. *Id.* at 97-98. He further testified that the ability to attract capital (both debt and equity) on reasonable terms is vitally important to DEP and its customers, and each of these specific objectives helps DEP both to maintain its investment-grade credit ratings and to meet its overall financial objectives. *Id.* at 87-88.

Intervenor witnesses disputed witness Newlin's recommendation. Public Staff witness Walters, CUCA witness O'Donnell, and DoD-FEA witness Reno all testified that DEP's proposed 53/47 capital structure exceeded the equity ratio for all proxy group companies. Tr. vol. 16, 245 (Walters); Tr. vol. 21, 592 (O'Donnell); Tr. vol. 21, 360 (Reno). The testimony of witnesses Walters and Reno also noted that the 53/47 recommendation was inconsistent with DEP's observed capital structure at various points in time. Tr. vol. 16, 246 (Walters); Tr. vol. 21, 360 (Reno). Witnesses O'Donnell, Reno, and Gorman testified that the 53/47 proposal exceeded the average capital structure authorized by other utility commissions. Tr. vol. 21, 360 (Reno); Tr. vol. 21, 593-94 (O'Donnell); Tr. vol. 21, 405, 408 (Gorman).

These witnesses' capital structure recommendations were as follows: Walters — 52/48 (Tr. vol. 16, 247); O'Donnell — 50/50 (Tr. vol. 21, 568); Reno — 52/48 (Tr. vol. 21, 360); and Gorman — 52/48 (Tr. vol. 21, 405).

NCJC, et al. witness Ellis took a different tack, recommending a capital structure of 58% equity and 42% debt. Tr. vol. 21, 1071. As noted above in connection with the Commission's discussion of ROE evidence, witness Ellis testified that ROE and capital structure are interrelated and must be addressed together. *Id.* at 1056-57. Accordingly, his 58/42 capital structure recommendation goes hand-in-hand with his 6.0% ROE recommendation. *Id.* at 1071. He indicated that this combination would minimize customer costs while meeting investor return expectations. *Id.*

In his rebuttal testimony, DEP witness Newlin took issue with the intervenor witness recommendations. He observed that the reliance of witnesses Walters, O'Donnell, and Reno on capital ratios of proxy group companies was misplaced, because the proxy companies are all publicly traded holding companies, not utility operating companies. Tr. vol. 22, 169. He testified that it is inappropriate to compare DEP's capital structure to the holding company capital structures, because the risk profiles are very different. *Id.* at 170. The appropriate comparison is to other utility operating companies. Witness Newlin performed that comparison for witness Morin's proxy group, which was essentially the same for the other rate of return on equity expert witnesses and presented the results in Newlin Rebuttal Exhibit 1. Tr. Ex. vol. 22. The results show that the average capital structure for operating utilities is 53.3% equity/46.7% debt – consistent with DEP's proposal. Tr. vol. 22, 172. 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. *Id.* at 172-73.

Witness Newlin further testified that witnesses Walters's and Reno's comparisons of DEP's proposed capital structure with DEP's actual capital structure at a specific point in time are inappropriate. *Id.* at 173. He explained that it is reasonable to expect DEP's capital structure to fluctuate above and below the target equity ratio, and that merely selecting a point in time is not representative of how DEP intends to capitalize its business in the long-term. *Id.* at 174. Moreover, the specific points in time utilized by witness Walters rely on a surveillance report which includes current maturities of long-term debt which are excluded for ratemaking purposes. *Id.*

Witness Newlin disputed the manner in which witnesses O'Donnell, Reno, and Gorman compare DEP's proposed capital structure with allowed common equity ratios granted by other state regulators, noting that their presentations are overly simplistic and misleading. *Id.* at 175. He explained that their considerations fail to give proper weight to trends of rising equity components not reflected in their historical observations. *Id.* at 176.

Witness Newlin also presented an analysis of the intervenor capital structure recommendation with the lowest equity ratio component, proposed by witness O'Donnell. He noted that selection of an optimal capital ratio requires balance between affordability and access to the capital markets. He noted that a strong capital structure and adequate ROE provide the balance sheet protection and cash flow generation to support high credit quality. This in turn creates financial flexibility to efficiently access the capital markets on reasonable terms during all market cycles, including periods of high volatility, which ultimately lowers borrowing costs passed through to customers. *Id.* at 180. He testified that witness O'Donnell fails to consider the impact his 50/50 capital structure recommendation would have on DEP's credit metrics and potentially its credit ratings. *Id.* Witness Newlin then presented an analysis showing the negative impact upon DEP's credit ratings of the 50/50 recommendation, concluding the recommendation along with witness O'Donnell's ROE estimate would further stress DEP's already distressed credit metrics and cash flows, with negative consequences to DEP's credit ratings and cost of debt. *Id.* at 181-88.

Witness Newlin also criticized witness Ellis' 6.0% rate of return on equity/58% equity layer recommendation, noting that with an ROE that low DEP would not be able to effectively compete for capital. *Id.* at 193. Witness Newlin presented a table showing alternate ROE comparisons of southeastern utilities, as follows:

Table 4: Authorized ROE Comparison of Peer Utilites in the Southeast since 2020

Regulated Utility	State	Docket/Case No.	Year of Order	Current Authorized ROE
Virginia Electric and Power	NC	E-22, Sub 562	2020	9.75%
Alabama Power Company	AL	reported by S&P, under RSE mechanism	2021	11.88%(1)
Dominion South Carolina	SC	2020-125-E	2021	9.50%
Duke Energy Carolinas	NC	E-7, Sub 1214	2021	9.60%
Georgia Power	GA	44280	2022	10.50%(2)
Florida Power & Light	FL	20210015 - ROE Trigger	2022	10.80%(3)
Duke Energy Florida	FL	20220143-EI	2022	10.10%(4)
Tampa Electric Co.	FL	20220122-EI	2022	10.20%(5)
Duke Energy Progress	SC	2022-254-E	2023	9.60%
Average				**10.21%**

Source: S&P Capital IQ. Past Rate Cases pulled on April 4, 2023.

(1) Alabama Power has a formula rate mechanism that allows for annual adjustments, and they have a variety of mechanisms to allow for the inclusion of new plant. Under this mechanism, they are allowed a relatively high ROE (S&P reported 11.88% in year 2021) that is balanced against limited annual rate adjustments with certain caps.

(2) Authorized retail ROE set under the 2022 Alternative Rate Plan approved by the Georgia Public Service Commission and evaluated against a range of 9.50% to 11.90%. Any retail earnings above 11.90% will be shared with Georgia Power retaining 20%, 40% applied to reduce regulatory assets, and 40% directly refunded to customers.

(3) ROE Trigger increased authroized ROE to a midpoint of 10.80% from 10.60%

(4) Originally approved ROE band was 8.85% to 10.85%. The ROE band will increase by 25 basis points beginning in 2023 as a result of the average 30-year U.S. Treasury rate increasing by more than 50 basis over a six-month period.

(5) Originally approved ROE band was 9.00% to 11.00%. The ROE band will increase by 25 basis points beginning in 2023 as a result of the average 30-year U.S. Treasury rate increasing by more than 50 basis over a six-month period.

Id. at 195.

Finally, witness Newlin provided an overview of market dynamics since DEP's last rate case, noting the dramatic changes in economic conditions, including persistently high inflation, geopolitical issues like the war in Ukraine, and bank failures. *Id.* at 196. The Federal Reserve has responded to inflation by dramatically raising short term interest rates, and long term rates have also spiked and remain volatile. He noted that this heightened level of market volatility and uncertainty has led to an unprecedented number of zero issuance days in the primary debt capital markets. Witness Newlin stressed the value during these times of high credit quality and strong investment-grade credit ratings, which allow Companies to not only access the market, if needed, but also provide flexibility to wait for more optimal market conditions. *Id.* at 196-97. In his testimony summary witness Newlin noted that DEP's existing strong investment grade credit ratings constitute a form of insurance against downgrades that will be the likely consequence of weakening DEP's financials and noted further that downgrades only work to the detriment of DEP and its customers. *Id.* at 201.

Discussion and Conclusions

For the reasons set forth herein, the Commission approves DEP's proposed capital structure of 53.0% equity and 47.0% long term debt.

The Commission is not persuaded by witness Ellis' recommendation. In the Commission's view, his testimony on capital structure is far outside the mainstream, just as it was for ROE. While the Commission appreciates – and no party disputes – witness Ellis's point that capital structure and rate of return on equity are related, the Commission is concerned that an ROE so low, even if connected to a high equity ratio, will render DEP at a severe disadvantage when competing for capital. The Commission is concerned that DEP will not find many equity investors willing to invest in an electric utility that runs nuclear plants and faces significant challenges and capital needs with respect to spearheading S.L. 2021-165's energy transition with a 6.0% rate of return on equity, no matter what the equity ratio – especially when, as indicated by DEP Redirect Newlin Rebuttal Exhibit 2, those same investors can invest in much less risky utility bonds yielding 5.24%. Tr. vol. 23, 47; Tr. Ex. vol. 22.

Turning next to the recommendations of the other witnesses, the Commission notes while witnesses Gorman, Reno, and Walters support use of the stipulated equity later from DEP's prior rate case, much of their testimony in support of lowering the equity layer from DEPs request is premised upon comparisons to the capital structures of publicly traded holding companies. The Commission has repeatedly rejected the use of holding company capital structures in the past. *See, e.g.,* Order Granting General Rate Increase and Approving Amended Stipulation, issued on December 7, 2009 in Docket No. E-7, Sub 909, 27-28. Moreover, witness Newlin persuasively establishes that DEP's proposed 53/47 capital structure is right in line with the capital structures of the utility operating companies that are subsidiaries of the holding companies in Dr. Morin's proxy group, which is essentially the same as all of these witnesses' proxy groups. *See* Newlin Rebuttal Ex. 1, Tr. Ex. vol. 22.

The seemingly slight difference between DEP's 53/47 proposal and the Public Staff's 52/48 proposal masks consequential impacts. Those impacts persuade the Commission that 53/47 is the optimal structure that appropriately balances affordability and DEP's access to capital on reasonable terms. With DEP's credit metrics as stressed as they are, further downward pressure in the form of a reduced equity layer and increased debt is decidedly not in the best interests of either DEP or its customers.

The credit stressors experienced by DEP are in some respects being felt industry wide. In his direct testimony, witness Morin referenced the "perfect storm" facing electric utilities like DEP: (1) slowing or even declining electricity growth in energy consumption; (2) at a time in which record amounts of new capital must be raised to replace aging infrastructure, improve reliability, and deliver renewable generation; (3) coupled with the need to implement a transition away from fossil fuel (particularly coal) and toward renewables, including electrification of the transportation sector; and (4) and layering on further the need to build new transmission infrastructure to strengthen the grid against weather events increasing in frequency and ferocity, as well as new renewable generation resources. Tr. vol. 8, 91-92.

As witness Bateman testified, DEP faces multiple risks on multiple fronts including risks associated with investment and new technologies; risks associated with operating a system that must be "on" 24/7/365 with new types of generation, including increasing amounts of solar; and risks associated with getting the retirement of existing coal generation "just right." Tr. vol. 15, 97-98. These risks all highlight the execution and operational risks facing DEP in connection with the mandates of S.L. 2021-165. Witness Bowman addressed this issue as well, as noted in the return on equity discussion above. Moving forward, these risks impose upon DEP the obligation to navigate a fast-changing landscape to secure ready access to capital upon reasonable terms, to ensure that it can make the necessary capital investments to ensure reliable and affordable service to its customers.

Credit rating agencies have noted these stressors, both on a national and a DEP-specific basis. On the national front, Moody's published in November 2022 an industry-wide report highlighting the agency's revision of the entire regulated utility sector outlook from stable to negative. *See* DEP Redirect Newlin Direct Ex. 3, Tr. Ex. vol. 10. The report highlights that the industry as a whole is confronting numerous financial pressures at a time when Moody's expects "the sector to maintain elevated capital spending focused on reducing carbon emissions to make progress toward net zero goals and overall system reliability" – precisely the execution risks DEP faces in connection with the mandates of S.L. 2021-165.

Specifically regarding DEP, Moody's has taken two very recent actions, both of which highlight the immediate credit metric challenges DEP faces. First, in April 2023 Moody's published a "Ratings Action" report (DEP Redirect Newlin Direct Exhibit 1) affirming DEP's A-level rating but at the same time issuing an explicit warning with regard to the principal credit metric utilized by Moody's, the ratio of Funds From Operations (FFO) to debt (FFO/Debt)[17]. Tr. Ex. vol. 10. In its April 2023 Ratings Action Moody's indicated that it was raising its FFO/Debt downgrade threshold for DEP from 20.0% to 21.0%, meaning that while it had in the past forecast a potential downgrade in DEP's credit rating if the FFO/Debt metric stayed below 20.0% on a sustained basis, it was now forecasting a potential downgrade if the metric stayed below 21.0% on a sustained basis. This is a particularly worrisome development because, as Company witness Newlin pointed out during his direct testimony, DEP's FFO/Debt ratio has been below 21.0% for a number of years. Tr. vol. 9, 17-18. In other words, DEP is already operating below the Moody's raised downgrade threshold and has already been doing so on a sustained basis. *Id.* at 18-19.

Between witness Newlin's appearance on direct on May 5 and his appearance on rebuttal on May 16, Moody's issued its May 2023 updated Credit Opinion regarding DEP, replacing its Credit Opinion issued in March 2022 (introduced into evidence as both Public

[17] In Moody's parlance FFO/Debt is called "preworking capital cash flow to debt" (Tr. vol. 9, 115), or "CFO pre-WC to debt." Both FFO and CFO pre-WC mean the same thing and are a measure of cash flow. *Id.*

Staff Cross-Examination Morin Direct and Rebuttal Exhibit No. 15 and DEP Redirect Newlin Direct Exhibit 2). Tr. Ex. vol. 10. In the updated Credit Opinion, Moody's explicitly referenced as factor that could lead to a downgrade the FFO/Debt ratio "remaining below 21% in 2023." DEP Redirect Newlin Rebuttal Ex. 1, 2; *see also* Tr. vol. 23, 36-37. Accordingly, Moody's not only alluded to its raised download threshold, but pointedly referenced 2023 – this very year.

The potential for downgrade is not a theoretical issue. The actions by Moody's beginning with its sector outlook publication in November 2022, running through its April 2023 raising of DEP's downgrade threshold, and culminating with its May 2023 updated DEP Credit Opinion are a series of escalating warnings.

Witness Newlin noted in his testimony that to ensure reliable and cost-effective service, and to fulfill its obligations to serve customers, DEP must continuously plan and execute major capital projects, and must be able to operate and maintain its business without interruption and refinance maturing debt on time, regardless of financial market conditions, even (and perhaps especially) in times of market volatility. Tr. vol. 9, 102. Customers benefit from DEP's financial strength, because its strong investment-grade credit ratings provide DEP with greater access to the capital markets on reasonable terms during such periods of volatility. *Id.* Responding to questions from Chair Mitchell, witness Newlin recounted a recent example of market dislocation, resulting from the collapse of Silicon Valley Bank, in which other Duke Energy subsidiaries were able to time entry into the market for the benefit of their customers, and he noted that only a "utility with good strong credit quality is able to do that." Tr. vol. 22, 207. He similarly alluded to market dislocation at the initial stages of the COVID-19 pandemic when Duke utilities were able to flexibly maintain market access when other utilities were unable to access the credit markets. *Id.* at 208. And widening credit spreads between higher- and lower-rated utilities mean that downgrade will have cost consequences for customers even if DEP were able to achieve access to the capital markets. *Id.* at 205; tr. vol. 23, 45-48.

Witness Newlin likened the flexibility derived from DEP's existing strong investment grade credit ratings as "a form of insurance against downgrades that will be the likely consequence of weakening the Company's financials," and noted that "downgrades only work to the detriment of DEP and its customers." Tr. vol. 22, 201 (emphasis in original). He cautioned against the Commission's taking action to weaken this insurance policy, "perhaps with unintended consequences." *Id.* The Commission heeds this warning, and the escalating series of warnings from Moody's, and finds that now is decidedly not the time to weaken DEP's credit profile and invite a credit downgrade. DEP must attract capital on reasonable terms in order to finance investment needed for the continued reliability of the system. Weakening DEP's capital structure or awarding too-low an ROE will make attraction of necessary capital that much more difficult – and certainly more expensive.

Accordingly, the Commission accepts witness Newlin's recommendation that DEP's capital structure be composed of 53.0% equity and 47.0% long term debt.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 52-56

COVID Deferral

The evidence supporting these findings of fact is contained in DEP's verified Application and Form E-1; the testimony and exhibits of DEP witnesses Bowman, Quick, Abernathy, Speros (together as a panel), and Jiggetts, Public Staff witnesses Zhang and Boswell; and the entire record in this proceeding.

Deferral Docket

In August of 2020, DEP and DEC (together, Duke) jointly petitioned the Commission for approval of orders for regulatory accounting purposes authorizing both Companies to establish a regulatory asset to account for incremental costs resulting from the unprecedented COVID-19 Pandemic and declared State of Emergency, so that such costs can be deferred pending further action by the Commission in the next general rate case filed by DEP and DEC. Joint Petition of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC for Approval of Accounting Orders to Defer Incremental COVID-19 Expenses, Docket Nos. E-2, Sub 1258 and E-7, Sub 1241 (August 7, 2020) (Covid Deferral Docket). DEC and DEP each requested permission to create a regulatory asset to defer costs associated with customer fees waived, bad debt expenses, employee stipends and safety-related costs, remote work costs, and other costs, including overtime and related call center costs.

The Public Staff filed comments the Covid Deferral Docket opposing Duke's request, arguing among other things that Duke had not substantiated a need for a deferral of the costs enumerated and recommending the Commission deny the request. Further, the Public Staff stated that if the Commission allowed Duke to defer costs, Duke should offset such costs with COVID-related savings such as federal tax credits and reductions in operating expenses.

The Commission granted the request to defer incremental costs and waived customer fees associated with the COVID-19 Pandemic for recovery in a future proceeding in its December 21, 2021 Order Approving Deferral Request (Deferral Order), in Docket Nos. E-2, Sub 1258, E-7, Sub 1241. The Commission noted the unique nature of the request, the severity of the ongoing pandemic, and the fact that many of the actions taken by the Companies were in part due to government mandates imposed upon Duke intended to ease both the financial and public health impacts of the pandemic on North Carolina and its citizens who might likely have been displaced from their homes. Deferral Order at 13.

The Commission determined that it would be patently unfair to penalize Duke by not allowing an opportunity to justify recovery of these costs in a future rate case and the Commission concluded that the costs allowed to be recovered may be amortized over a period of time determined in the future rate cases.

Although the Commission allowed Duke to include carrying costs on the deferred amounts for accounting purposes, the Commission concluded that the rate of that return, if any, and the amount to which that return is applied will be subject to determination in that future rate case.

Summary of Evidence

DEP Direct and Supplemental Testimony

In the present proceeding, DEP now seeks recovery of its deferred incremental COVID-related costs. In her direct testimony, DEP witness Jiggetts presented DEP's request. Witness Jiggetts explained that DEP deferred and requests to recover: (1) customer fees waived, (2) bad debt charge-offs, (3) employee stipends to cover unplanned expenses associated with the COVID pandemic, (4) costs related to employee safety, (5) costs related to remote work, and (6) miscellaneous costs, such as employee overtime. Tr. vol. 13, 197-99. Witness Jiggetts maintained that the costs included in the deferral are reasonable and prudent costs that were incurred as DEP provided its essential public service during the pandemic. *Id.* at 199.

In her direct testimony, DEP witness Quick explained the efforts DEP undertook to support its customers throughout the pandemic and the return to normal billing practices. Tr. vol. 7, 81-83. Witness Quick explained that DEP suspended service disconnections and waived fees for card payments, walk-in pay location payments, late payment charges, and insufficient funds. *Id.* at 81. Witness Quick also detailed how DEP worked with assistance agencies and customers on an individual basis to connect qualifying customers with assistance funding where possible. *Id.* Witness Quick described DEP's expanded outreach campaign efforts and, in particular, detailed the ways in which DEP adapted its customer operations resources to provide a more tailored experience for customers and utility assistance agencies. *Id.* at 82.

DEP witness Speros testified in support of DEP's bad debt calculation. Tr. vol. 13, 51-52. Witness Speros explained that the moratorium on disconnections and late payment fees led to an increase in the number and amounts of past due accounts outstanding, which in turn lead to increased bad debt expense. *Id.* Witness Speros testified that the deferred bad debt expense was calculated as the total amount of incremental bad debt expense exceeding the amount already being recovered in base rates from the period starting in March 2020 through the capital cut-off date in this case. *Id.* at 52. Witness Speros also explained that DEP is continuing to incur impacts to business operations from the pandemic, namely that charge-offs related to COVID delinquencies are ongoing and will continue to be. *Id.* at 53.

Witness Jiggetts explained that DEP's additional deferred expenses include employee safety-related costs, costs for remote work, employee stipends, and other miscellaneous costs. Tr. vol. 13, 197. She explained that because DEP is an essential service provider, it was not an option for some of DEP's employees to remote work. Witness Jiggetts further explained that DEP provided, and will continue to provide, employees with the appropriate personal protective equipment, and incurred additional incremental costs for increased cleaning and sanitation supplies, health care, as well as for testing and temperature checks. *Id.* at 198. For those employees who could work from home, witness Jiggetts testified that DEP incurred additional costs for remote work, including costs for expanded conference line capacity, increased network bandwidth, other required information technology improvements, expanded video conferencing licenses, and increased company cellular telephone and data usage. *Id.* at 198-99. Lastly, for certain eligible employees, witness Jiggetts stated that DEP provided a one-time cash payment of $1,500 to help with unplanned expenses associated with COVID-19. Witness Jiggetts also clarified that DEP seeks to recover other expenses related to overtime costs needed to implement COVID-19 guidelines to ensure employee safety and increased costs due to expected increased call volume at call centers when normal billing practices resume. *Id.* at 199.

Witness Jiggetts testified that the proposed new rates requested in this proceeding include recovery of costs deferred from March 2020 through April 2023, and that the adjustment normalizes revenues for waived late fees that will be collected going forward, amortizes the deferred costs over a three-year period, adjusts test year expenses to include certain incremental employee costs that were previously deferred and includes the deferral balance, net of one year of amortization and deferred taxes, in rate base. *Id.* In her third supplemental direct testimony, witness Jiggetts updated DEP's amortization amount for the COVID deferral to include actual amounts realized through March 31, 2023.[18] Tr. vol. 13, 247.

The Public Staff Direct and Supplemental Testimony

In their direct testimony, Public Staff witnesses Zhang and Boswell recommended that the Commission adjust DEP's revenue requirement to remove DEP's proposed COVID deferral due to significant questions regarding the eligibility, accuracy, and reasonable quantification of the costs included in the deferral and the savings and cost offsets DEP chose not to net against the COVID expenses. Tr. vol. 19, 65. Witnesses Zhang and Boswell commented that during their review of several major O&M expenses they found COVID-related cost savings in employee expenses and printing which were not netted again the deferred COVID costs. They stated that DEP was offsetting these savings against reduction in customer load, unfavorable weather, and excess storm costs, none of which were the causation of the savings. *Id.* at 66.

Witnesses Zhang and Boswell noted that DEP received the following credits and delayed payments as a result of the pandemic: (1) Employee Retention Credit (ERC); (2) delayed payment of employer portion of social security tax; and (3) Accelerated Alternative Minimum Tax (AMT). *Id.* at 67. The witnesses explained that Section 2301 of the federal CARES Act created a refundable ERC of up to $5,000 per eligible employee taken against the employer's share of the Social Security Tax on Qualified Wages paid from March 13, 2020, through December 31, 2020. *Id.* Witnesses Zhang and Boswell

[18] See fn. 2.

further stated that the CARES Act amended Title 26 of the Internal Revenue Code to allow the entire AMT credit carryforwards to be refundable to taxpayers in either the 2018 or 2019 tax year. Witnesses Zhang and Boswell noted that DEP reported that the AMT credits were generated by non-regulated operations of Duke Energy and, as such, were not attributable to DEP. *Id.* at 68.

Witnesses Zhang and Boswell testified that DEP is unable to provide any and all costs savings associated with the pandemic; thus, the Public Staff cannot calculate an appropriate amount for deferral. Additionally, the witnesses expressed concerns regarding the types of charges deferred reiterating the same concerns the Public Staff expressed in its comments filed in the Deferral Docket. *Id.* at 69. With regard to the employee stipends, witnesses Zhang and Boswell testified that this one-time payment, does not appear to include a verification by DEP as to the expenses paid, and constitutes goodwill to some employees on the part of DEP, not a cost that should be borne by ratepayers. *Id.*

Witnesses Zhang and Boswell rebutted DEP's assertion that its call center costs have increased, instead testifying that based on the Public Staff's review of the call center volumes and labor costs, including overtime, over the last five years, the volume and costs has been steady, with costs and volume declining in 2021 and 2022. *Id.* at 69. They testified, concerning costs for remote work, that while DEP incurred some additional costs with the initial rollout, remote work is now part of DEP's regular work offerings, and DEP has not offset any of these increased costs with associated decreases in office expenses. The witnesses removed the costs associated with safety personal protection equipment because DEP indicated that the amount included in the original filing will not be an ongoing amount. *Id.* at 71. Witnesses Zhang and Boswell also removed the overtime for the call center as their review indicated the level sought by DEP was not above the amounts already included in DEP's cost of service. *Id.* They also expressed concern regarding the reserve percentage DEP is utilizing to estimate its bad debt expense because DEP is still collecting a portion of the uncollectible amount through various collection agencies. *Id.* at 70.

In their supplemental and settlement testimony, Public Staff witnesses Zhang and Boswell again recommended removal of DEP's COVID deferral from the revenue requirement and updated their recommended removal amount to account for amounts included by DEP through February 28, 2023. *Id.* at 89. The witnesses again reiterated that the Public Staff opposes DEP's recovery of its deferred expenses because it did not net its COVID-related cost savings against the actual costs incurred. *Id.* at 93.

DEP Rebuttal Testimony

On rebuttal, DEP's COVID Panel, consisting of witnesses Bowman, Quick, Abernathy, and Speros, all testified to provide further detail and context for DEP's pandemic response and COVID-related costs incurred. Tr. vol. 21, 1263-64. The Panel stated that the vast majority of the deferred costs DEP seeks to recover result directly from customer inability to pay and the governmental response to that inability to pay. They explained that non-payment ordinarily would have been met by discontinuance of service, but actions both of the Governor of North Carolina and the Commission removed service disconnection as an option for DEP. *Id.* at 1264.

Witness Bowman detailed DEP's initial and ongoing response as an essential service provider. Witness Bowman explained DEP's actions in response to federal, State, and Commission direction, including Governor Cooper's executive orders and the Commission's moratorium on disconnections. *Id.* at 1266-67. Witness Bowman also provided a brief background on the Deferral Docket and the Commission's Deferral Order, which approved DEP and DEC's request to establish a regulatory asset for the purposes of deferring the incremental costs associated with the COVID-19 pandemic for final determination in a future rate case. *Id.* at 1268. She stated that the Deferral Order also required DEP to periodically file reports to update the Commission concerning the actual amounts deferred. *Id.* DEP witness Quick details the ways in which DEP adapted its customer support operations to serve the unique needs of customers associated with the pandemic. *Id.* at 1272-76.

DEP witness Abernathy included in her portion of the prefiled COVID Panel rebuttal testimony a chart detailing the deferred costs as of March 17, 2023, the date DEP's second supplemental testimony was filed:

Deferred Incremental COVID-19 Costs	**$ in Millions**	**% of total**
Customer fees waived	$27.1	29.1%
Bad debt expense	$57.3	61.6%
Employee safety related costs	$4.0	4.3%
Costs for remote work	$0.6	0.7%
Employee stipends	$0.7	0.8%
Other (primarily call center costs)	$3.3	3.5%
Total Incremental COVID-19 Costs deferred	$93.0	100.0%
Accrued carrying costs	$12.0	
COVID Deferral projected balance as of rates effective	$105.0	

Id. at 1280.

According to DEP, the requested $105.0 million in deferred incremental COVID-related costs translates to approximately 124 basis points, excluding any impacts from lost revenues. *Id.* Witness Abernathy testified that as of the filing of the third supplemental testimony (April 18, 2023) the projected balance as of the date rates would go in effect had grown to approximately $107 million, mainly because of an increase in the amount of bad debt expense. *Id.* at 1307. She commented that the spike in bad debt expense occurred in connection with the expiration in March 2023 of 12-month repayment plans DEP automatically enrolled customers into as of the time (March 2022) when the extended winter moratorium on disconnection finally ended. *Id.* at 1353.

Witness Abernathy explained that over 90% of the deferred costs are attributable to waived customer fees and bad debt expenses. She notes that these incremental costs were primarily the result of government-issued moratoriums imposed on DEP. *Id.* at 1282. Witness Quick explained that DEP waived approximately $27 million in customer fees, launched extensive outreach campaigns to bring awareness to the available customer assistance, expanded the eligibility for the Winter Moratorium and extended its length. *Id.* at 1272-73. The COVID Panel testified that the remaining categories of expense are also clearly pandemic-related, in that they were incurred in order for DEP, as a provider of an essential service, to fulfill its obligation to continue operation 24 hours a day, seven days a week despite the pandemic. Witness Bowman stated that more than 40% of DEP's workforce had to show up, in person, at work, at power plants and other facilities, or to repair damage following storms. *Id.* at 1319. She noted that in doing so those employees had to be furnished with protective gear, cleaning supplies, sanitizing supplies, and COVID testing services and nursing case management. Further, witness Bowman testified that DEP installed barriers at the workstations located at various operating plants so employees would not transmit the coronavirus. *Id.* at 1321. Witness Abernathy stated that these costs are captured in the category "employee safety related costs." *Id.* at 1281.

The COVID Panel testified regarding the challenges faced by DEP's customer service representatives, who ordinarily would work in call centers but had to transform themselves essentially overnight into a virtual workforce working from their homes – homes that in large measure were not set up with home-office facilities – while simultaneously dealing with childcare and other family-related issues exacerbated by the pandemic. They noted that costs associated with these challenges are captured in the employee stipends, which were distributed to hourly-paid call center employees costs related to the pandemic such as increased childcare, home-office equipment, and home internet access.[19] *Id.* at 1282, 1325-26. They explained that the stipends served as an inexpensive means of retaining essential employees, as witness Quick noted, "to try to keep them and help them through this unprecedented time that we were all going through … just a way of really supporting our hourly employees at the call center." *Id.* at 1326. The COVID Panel testified that DEP also incurred costs related to remote work generally, such as expanded conference line capacity, increased network bandwidth, other required information technology improvements, expanded video conferencing licenses, and increased company cellular telephone and data usage. *Id.* at 1281-82.

Regarding regulatory treatment of COVID-19 costs in other jurisdictions, the COVID Panel testified that as of the time the reply comments were filed in the Deferral Docket (November 30, 2020) commissions in 32 states and the District of Columbia had permitted cost deferral in response to requests from regulated utilities subject to their jurisdiction. They stated that since then, several state commissions have begun to allow recovery of deferred costs. They noted that the Georgia Public Service Commission

[19] Call center-related costs are also captured in the "call center" category, which relates to incremental increases in workload and the need to retain outside vendors as the centers began to "return to normal" following the easing of the shutdown moratoriums. Tr. vol. 21, 1277-79.

recently permitted recovery of approximately $25 million in deferred COVID-related costs over a three-year amortization period.[20] *Id.* at 1270.

In response to the Public Staff's testimony that DEP's request for cost recovery of incremental deferred COVID-related costs should be denied because DEP has not offset these costs with COVID savings, the COVID Panel testified that the Deferral Order requires only that DEP track the costs being deferred. The Panel did note that in South Carolina DEP was required to track and report quarterly both COVID-19 related savings and net lost revenues (NLRs) on a South Carolina retail basis in 2020. *Id.* at 1288. The Panel stated that because of this South Carolina requirement, DEP has tracked incremental savings due to COVID and provided these amounts to the Public Staff. They explained that DEP's estimates included two categories of expenses that resulted in financial savings attributable to the COVID-19 pandemic. First, DEP experienced reduced employee expenses as compared to budget, primarily related to reductions or elimination of travel and expenses associated with normal operations while DEP's employees were required to work remotely and adhere to travel restrictions, etc. Second, DEP experienced reduced printing and postage costs while the various government-imposed moratoriums were in place and DEP was not disconnecting customers and thus not mailing required notifications. *Id.* at 1289.

The COVID Panel stated that in 2020, DEP estimated approximately $4.5 million, on a North Carolina retail basis, in O&M expense savings attributable to COVID-19. DEP estimated NLRs in 2020 to be approximately $28 million, on a North Carolina retail basis, compared to budget, more than offsetting the savings reductions that the Public Staff suggests. *Id.* The COVID Panel maintained that the negative impact of NLRs was ignored by the Public Staff in its testimony.

The Covid Panel also addressed the assistance provided by the federal CARES Act. With respect to the accelerated AMT, the COVID Panel maintain that the Public Staff's argument that this credit should impact the COVID-19 deferral is simply incorrect as "not a single dollar of the AMT refunds is attributable to DEP; rather, the refunds all relate to other subsidiaries of Duke Energy Corporation". *Id.* at 1291. Regarding the delay in payment of the social security tax for the period April through December 2020, the COVID Panel noted that this was only a temporary deferral from the government and was fully paid by December 31, 2022. *Id.* They stated that although the Public Staff believes that DEP should have offset the COVID deferral for the working capital impacts of the delay in payment, witnesses Boswell and Zhang did not provide a quantification of their estimate of that amount. The COVID Panel estimates that the carrying cost benefit between April 2020 and December 2022 was approximately $2 million on a North Carolina Retail basis. *Id.* Related to the ERC, the COVID Panel stated that DEP filed for ERCs under the CARES Act and that all claims have been filed attributable to its operations from March 13, 2020, through September 30, 2021. The COVID Panel contended that even if these

[20] See Order Adopting Settlement Agreement as Modified, Docket No. 44280 (December 20, 2022); see also Direct Testimony of Aaron P. Abramovitz, Sarah P. Adams, Adam D. Houston, and Michael B. Robinson, Docket No. 44280, at 46-47 (June 24, 2022).

benefits to DEP (excluding the AMT which is not a benefit attributable to DEP) should be netted against costs, they should in that case also be netted against NLRs. The Panel maintained that these benefits do not overcome NLRs even when added to the $4.5 million DEP estimates is COVID-related savings. *Id.* at 1292.

Witness Abernathy maintained that the Public Staff's recommendation is one-sided and asymmetrical in its focus on DEP's apparent savings but omits any discussion of NLRs. *Id.* at 1271. Witness Abernathy explained that in 2020, DEP faced challenges in addition to the pandemic, such as mild weather that also resulted in substantially lower than projected revenues. She also testified concerning increased expense due to higher-than-normal storm restoration costs. Witness Abernathy testified that when faced with the prospect of revenue loss and in keeping with its focus on managing O&M expenses for the benefit of customers, DEP, as a routine part of its business, identifies and implements a suite of cost mitigation measures. *Id.* at 1271.

Witness Abernathy testified that total O&M cost reductions for 2020 amounted to $62 million on a North Carolina retail basis. *Id.* at 1295. She further testified that revenue impacts from COVID and mild weather amounted to $71 million on a North Carolina retail basis, and when added to an additional impact ($14 million) related to storm costs, the total is $85 million, an amount that was not contested by any party. *Id.* at 1294-95. Witness Abernathy then observed that "revenue impacts plus storm costs on the one hand, and the cost savings on the other, are opposite sides of the same coin – but, as shown by my illustration, the reduced revenues and storm impacts ($85 million) outstrip cost savings ($62 million) by a significant amount – approximately $23 million." *Id.* at 1295.

In response to the Public Staff's testimony regarding incremental call center costs, the DEP COVID Panel explained that, although average workload hours decreased during the Commission-ordered disconnection (Q2 and Q3 2020), DEP could not capture the potential savings associated with reduced workload during this timeframe in light of the uncertainty of when DEP would return to normal, making it such that reducing staffing would not have been prudent; and its view that reducing staffing in the short term, only to have to restaff a few months later, would not have been cost-effective. DEP witness Quick clarified that while overall call volume declined in 2021 and 2022, the average handling time per call increased as DEP's customers experienced changing needs following the return to normal. *Id.* at 1276.

Witness Abernathy also testified regarding the various invoices and ledgers DEP provided the Public Staff of its COVID-related expenses and savings. *Id.* at 1284-86. She described in detail the data DEP provided in response to the Public Staff data requests and in support of its COVID cost recovery request. *Id.* Witness Abernathy stated that the Public Staff did not dispute the actual amounts of the costs deferred and requested for recovery. *Id.* at 1286-87. She noted that for bad debt expense, the Public Staff only expressed concerns with DEP's calculation and the reserve percentages used.

Witness Speros provided additional testimony in support of DEP's bad debt expense and calculation. Witness Speros testified to the process that DEP undertook to develop the reserve percentages, explaining that the reserve percentages are calculated by taking the net charge-off amounts divided by the aged receivable balance utilizing the historical data from 2018 and 2019. *Id.* at 1297. Witness Speros explained that DEP reviews the aging schedules and works with various internal teams to determine if there are any unusual changes or fluctuations in collections and write-offs that could impact the reserve calculation, and that based on these reviews, DEP determines if the balance in the loss reserve is reasonable as stated or if an adjustment is required. Witness Speros also testified that DEP compiles quarterly data on aged receivables, the balance of the loss reserve, and the current write-offs compared to forecast are then summarized and discussed with management. *Id.* at 1298. Witness Speros also clarified how customers on payment plans are treated for purposes of charge-off accounting. *Id.* He stated that customers on payment plans are actively working with DEP and are therefore viewed as having less risk of charging off than the typical delinquent customer. He noted that consistent data is available related to payment plans and a more accurate assessment can be taken by looking at the trends of customer defaults on their payment plans. Witness Speros explained that the percentage is calculated using the dollars defaulted on payment plans divided by total dollars of payment plans. *Id.*

Witness Abernathy testified that DEP has proposed to continue the deferral of bad debt expense until the next rate case. She stated that if the reserve percentages used to calculate bad debt expense do not result in actual charge offs, this will be reflected in future bad debt expense. *Id.* at 1286. Therefore, the continuation of the deferral should resolve any Public Staff concerns about the correct percentages to use. She noted that if the Commission does not approve continuation of the bad debt expense deferral, then test year bad debt expense should be increased by approximately $42 million to reflect a current level of bad debt expense using 2022 actual expense. *Id.* at 1286-87.

Testimony Presented at the Expert Witness Hearing

At the expert witness hearing, Public Staff witnesses Zhang and Boswell responded to questions on cross-examination and from Commissioners about their recommendation to disallow all COVID-related expenses included in DEP's deferral. Witness Boswell testified that part of the reason why the Public Staff removed the expense was because it could not determine what level should be included. Tr. vol. 19, 139. Public Staff witness Boswell stated that the Public Staff struggled to receive information from DEP and that underlying the difference of opinion between the Public Staff and DEP is the respective views on COVID savings. *Id.* Witness Boswell further stated that it is unreasonable to offset COVID-related savings against other costs, such as storm and weather costs, as DEP has proposed. *Id.* at 140. In response to a hypothetical question on deferral approval from Commissioner Duffley, witness Boswell testified that an appropriate amortization period would be around ten or fifteen years, akin to storm recovery, instead of the three years proposed by DEP. *Id.* at 141.

The COVID Panel also responded to questions from Commissioners related to DEP's deferral request. Witness Abernathy began by providing the final amount of the requested deferral in this proceeding – $107 million through DEP's third supplemental update. Tr. vol. 21, 1307. Witness Speros explained that DEP has a structured and well-documented approach for tracking its COVID-related impacts, and further clarified that DEP's bad debt expense consists of two components: actual charge-offs, and a reserve adjustment based on the level of accounts receivable. *Id.* at 1310-11. Witness Abernathy explained DEP's methodology for the quantification of net lost revenues but reiterates that DEP has not requested recovery for lost revenues, *Id.* at 1316, 1343, and witness Bowman provided testimony related to the costs incurred in order for DEP to continue to operate as an essential service provider. *Id.* at 1319. Witness Bowman explained that 40% of DEP's workforce had to continue work as before, even in light of potential nonpayment due to the disconnection moratorium in place at the time, and that in no instance did DEP stop providing its services. *Id.* at 1319-20. Witness Bowman further testified that this period extended from March of 2020 until August of 2022. *Id.* at 1321. Witness Bowman explained that this continuation of service came at a cost to DEP as it ensured safety protocols were in place and followed and procured adequate protective gear for DEP's employees. *Id.*

Concerning the amortization period of the deferred costs, witness Bowman indicated its preference for a shorter amortization period stating DEP's preference for a three-year amortization but stated that DEP would likely be willing to slightly extend the recovery period. She testified that, if extended, DEP would prefer the amortization period be in a three-year increment, such as six years, to keep in sync with the MYRP. *Id.* at 1327.

Public Staff witness Boswell testified that "the Company meticulously … [accounted for] the costs associated with COVID." Tr., vol. 19, 161. Witness Boswell further testified that, while the Public Staff would have liked to provide the Commission with a recommendation on recovery of COVID costs, "[t]ruthfully … we couldn't determine what level should be put in there." *Id.* at 138. Witness Boswell noted that the Public Staff had issued numerous data requests and participated in several teleconferences with DEP seeking to formulate a recommendation. *Id.* She stated that "…since we couldn't come to a number, we thought it was just wiser to remove [the deferred COVID costs] altogether than to put a range for which that we didn't fully have support for." *Id.*

Witnesses Abernathy and Speros addressed the "savings" issue directly. Witness Speros noted that while costs can be (and were) directly tracked, the negative is not true – "savings" are not directly trackable; rather, they must be discerned through data analysis, namely by comparing actual expenditures with budgeted expenditures to get a sense of what DEP did not spend versus what it thought it would spend. Tr. vol. 21, 1345. He stated that at that point, the analyst can make a judgment based upon the type of expense and whether it is COVID-related. *Id.* Witness Abernathy confirmed that is precisely what DEP did to determine that the employee expense and printing/postage reductions discussed in her testimony, in fact, directly related to the pandemic. *Id.* at 1346. The witnesses maintained there is no reason that the Public Staff could not go through the same exercise, had it chosen to do so. They noted that the Public Staff had the data including "[a]nalysis of comprehensive actuals vs. budget information by O&M for function for 2020 (PS DR 138)" and that data was even supplemented outside of the formal discovery process. DEP Redirect COVID Panel Rebuttal Ex. 1, Tr. Ex. vol. 21. When asked by Chair Mitchell if the Public Staff used any of this data provided by DEP to estimate COVID savings, witness Abernathy responded, "[n]o, they have not." *Id.* at 1350.

Concerning DEP's request to continue the COVID deferral for bad debt expenses, witness Abernathy testified (and her testimony is uncontradicted) that were the Commission to side with the Public Staff and refuse cost recovery and continued deferral, test year bad debt expense in this case would increase by approximately $42 million, increasing the revenue requirement in this case by that amount, an amount which no party to this proceeding has challenged. *Id.* at 1354-55; Tr. vol. 22, 13. Witness Abernathy testified that the revenue requirement associated with recovery of the deferred costs in this case is $41 million. Tr. vol. 21, 1307. She maintained that, not only is DEP's proposed approach the most reasonable and equitable, it is also the approach that results in the lower revenue requirement in this proceeding.

Further, as it relates to DEP's request for continuation of the COVID deferral, witness Quick explained that part of this request results from the payment plans that DEP offered at the expiration of the disconnection moratorium and the expansion of the Winter Moratorium. Tr. vol. 21, 1328-29. Witness Quick testified that this provided customers with flexibility and support to make disconnection a last resort. *Id.* at 1330. Witness Abernathy explained that this process has resulted in higher arrearages and testifies that DEP accordingly has not seen the completion or lack of completion of all the authorized payment plans, and therefore is unable to calculate an appropriate level of bad debt expense. *Id.*

Discussion and Conclusions

In the Deferral Order, the Commission expressly granted DEP's request that "estimated incremental costs of utility service that are proximately caused by the pandemic may be deferred pending a final determination on cost recovery in a future rate case," and also held that its decision was "without prejudice to the right of any party to take issue with the amount, if any, of the deferred costs to be allowed for ratemaking purposes, if such costs are included in future rate filings." Deferral Order at 13. Typically, the Commission's customary two-prong deferral test is applied in the context of a deferral request such that the nature of the costs and magnitude thereof need not be litigated in the subsequent cost recovery docket. The COVID deferral request was unique in the sense that the costs were unusually speculative, the length of time totally unknown, and the magnitude indefinite, leaving the Commission unable to evaluate the second prong in a meaningful manner in the COVID Deferral Docket. In its discretion, the Commission may in this proceeding undertake an analysis of the magnitude of the deferred COVID expenses that are now known and measurable, if the Commission determines such analysis is necessary in reaching its conclusion regarding cost recovery of COVID-related costs. The three main factors that the Commission generally finds relevant in its analysis of the second prong are: (1) the amount of the deferred costs; (2) DEP's earnings during the analogous timeframe; and (3) fairness and equity.

In prior deferral orders, the Commission has noted that it does not apply the two-prong test in a vacuum. Rather, the Commission considers all of the pertinent factors involved on a case-by-case basis and weighs the equities to arrive at a decision that is fair to the utility and its ratepayers, and that serves the public interest. The Commission may analyze the merits of deferral using not only the well-established two-prong test but also considering the totality of the underlying facts, circumstances, and equities of this case. In the case of the incremental COVID-related costs, the Commission determines that the two-prong test was met in that these costs are extraordinary in nature and, absent deferral, would have a material impact on the utility's financial condition. The Commission gives significant weight to DEP's calculation in this proceeding that the $105.0 million in deferred costs amount as of DEP's second supplemental filing would have a 124 basis point impact on earnings, excluding any impacts on lost revenues.

In this proceeding, the Public Staff noted that DEP has consistently achieved earnings in excess of its authorized ROE since before the COVID pandemic and maintained that DEP's earnings are a relevant factor for consideration in the Commission's decision concerning cost recovery. The Commission acknowledges that historically in assessing the appropriateness of cost-deferral requests, the Commission has based its decision, in large measure, on the impact that the costs would have on the level of earnings currently being achieved by DEP. The impact on earnings, typically, has been measured and assessed in terms of ROE, considered in conjunction with: 1) the ROEs realized and reported to the Commission in DEP's recent quarterly ES-1 reports, particularly the ROE reflected in DEP's most recent report; and 2) DEP's currently authorized ROE. In this proceeding, the Commission finds that the COVID pandemic was an unprecedented event – truly exceptional – much more so than unusually severe weather and other events for which costs have been allowed to be deferred in the past. In determining fairness and equity between customers and shareholders in this circumstance, the Commission must evaluate the totality of the situation.

The Commission recalls that during the state of emergency government officials were taking all necessary steps to slow the spread of the coronavirus by requiring people to social distance and stay at home to the greatest extent possible. The health and safety of North Carolina communities were affected by the efforts of all residents to stay home and socially distance to slow the spread of the coronavirus. Governmental actions were also implemented to help prevent hospitals from being overwhelmed with patients and to preserve human life. The seriousness of the circumstance was unprecedented. The Commission recognizes that it was crucial for DEP, as a provider of an essential service, to fulfill its obligation to its customers to continue operations 24 hours a day, seven days a week despite the pandemic. This vital requirement for DEP to continue to provide its customers essential electric utility service during this unprecedented event cannot be overemphasized. The Commission recognizes that DEP met its obligation to the Commission and the citizens of North Carolina. The Commission recognizes that for DEP to provide electric utility service to the citizens of North Carolina during the pandemic necessitated certain DEP employees to perform their job duties in the same manner as prior to the declaration of the state of emergency. As a result, many of DEP's employees were not allowed the option to work from home to protect the health and safety of themselves and their families.

Government officials, including this Commission, sought to aid North Carolina citizens amidst a turbulent and challenging economic environment by issuing a state of emergency and various mandates and moratoriums. During the height of the turmoil caused by the pandemic, customers benefitted from the governmental mandates to waive customer fees and discontinue disconnections for non-payment. The pandemic lasted much longer than anyone anticipated. Businesses, families, and individuals benefitted from these mandates, particularly households that were struggling with financial issues resulting from the pandemic. Further, DEP, at this Commission's direction, provided customers with new, more favorable payment options and worked to connect eligible customers with available financial assistance from new and existing federal and state programs.

In reaching its decision concerning cost recovery of the incremental COVID-related expenses, the Commission sought to balance fairness and equity between customers and shareholders when: 1) determining the appropriate size or amount of the deferral for cost recovery in this proceeding; 2) applying the COVID-related savings; 3) determining whether a return should be allowed on the deferred costs during the deferral period and on the unamortized balance during the amortization period; 4) selecting the amortization period for cost recovery; and 5) deciding the timing of when amortization should begin.

In its examination of the deferred COVID-related costs for which to allow cost recovery, the Commission gives significant weight to the fact that the Public Staff, which extensively audited the deferred costs, did not find any of the costs to be unreasonable in amount and did not find that any of the costs were unrelated to the COVID-19 pandemic. As it did in the Deferral Docket, the Public Staff argues that COVID costs should be offset with COVID savings, and that, in its view, DEP has not adequately accounted for savings.

After careful consideration, the Commission concludes based upon the evidence presented that recovery in rates of DEP's deferred COVID-related costs pertaining to customer fees waived, bad debt expense, and employee safety related costs, are just and reasonable and should be approved. The Commission determines that it is appropriate to reduce these allowed costs by certain COVID-related expense savings for employee travel expenses, printing and postage costs, DEP's filed ERCs, and the carrying cost benefit of the delayed payment of the employer portion of social security tax. The Commission concludes that it is not appropriate to recover the carrying costs accrued during the deferral period or a return on the unamortized balance during the amortization period. Further, the Commission determines a six-year amortization beginning when rates become effective for this proceeding is appropriate. The Commission sets forth its reasons for these conclusions below.

Regarding the amount of costs deferred, DEP witness Abernathy testified that as of the filing of the Third Supplemental Testimony filed on April 18, 2023, the projected balance of deferred incremental COVID-19 costs as of the date rates would go in effect increased to approximately $107 million, mainly because of an increase in the amount of bad debt expense that occurred in connection with the expiration in March 2023 of 12-month repayment plans DEP automatically enrolled customers into as of the time (March 2022) when the extended winter moratorium on disconnection finally ended. The Commission acknowledges that no party has challenged the expenses for which DEP now seeks recovery pursuant to the Deferral Order were COVID-related expenses. Instead, the fundamental disagreements between DEP and the Public Staff are: (1) whether certain deferred COVID expenses are appropriate for recovery from ratepayers; (2) whether the deferred COVID expenses should be offset by certain savings, benefits, credits, and overearnings; and (3) whether a return on the deferred costs during the deferral period and on the unamortized balance during the amortization period should be allowed.

The Commission notes that as indicated in the chart above provided by witness Abernathy, over 90% of the deferred costs were incurred from waived customer fees and bad debt expense. The Commission concludes that these two costs resulted directly from governmental action, including mandates from the Commission, and are appropriate for recovery from customers. Specifically, at the onset of the COVID-19 pandemic the Governor issued a proclamation of a state of emergency (Executive Order No. 116), and subsequent orders of the Governor and of the Commission imposed a moratorium upon DEP's ability to disconnect customers for nonpayment and required waiver of customer fees ordinarily imposed in connection with nonpayment, such as late fees, reconnection fees, and return check charges. As a consequence of these governmental actions, DEP was unable to use its customary tools to timely collect payments from customers. DEP's ability to charge certain customer fees such as late fees, reconnection fees, and returned check charges encourage customers to pay their monthly bills. Disconnection of electric service is a strong incentive for the customers to pay their bills timely. The DEP COVID Panel testified that the moratorium on disconnections and the suspension of late fees had an adverse impact on the level of bad debt expense in that DEP realized an increase in the number of past due accounts that ultimately caused a significant increase in bad debt expense.

In this proceeding DEP seeks to recover only the difference between the level of bad debt expense currently in rates and the amount of bad debt expense above that level resulting from actions taken during the pandemic. The Commission acknowledges that denial of the recovery of deferred waived customer fees and bad debt expense would deny DEP recovery of costs incurred for complying with Executive and Commission Orders. DEP was expected to continue to provide normal, uninterrupted electric service 24 hours per day, seven days a week, to all customers during this unprecedented event. Moreover, DEP was expected to continue to provide service to its customers who were not paying for such service for an extended period of time. The Commission concludes that these costs are reasonable for recovery from customers.

With respect to employee safety related costs, the Commission acknowledges that DEP incurred costs to provide its employees with the appropriate personal protective equipment to facilitate the continuation of work for customers in a safe manner. Additionally, DEP incurred incremental costs associated with cleaning supplies, health care, as well as testing and temperature checks. As previously noted, to provide essential electric service, many of DEP's employees were not allowed the option to work from home. DEP witnesses testified that more than 40% of DEP's workforce had to show up, in person, at work, at power plants and other facilities, or to repair damage following storms. The Commission concludes that those employees had to be furnished with protective gear, cleaning/sanitizing supplies, and COVID testing services and nursing case management. Thus, the Commission concludes that these costs are reasonable and prudent costs to recover from customers.

Regarding the costs of remote work, in order to facilitate employees working remotely to protect their health and safety during the pandemic, DEP incurred incremental costs associated with expanded conference line capacity, increased network bandwidth, other required information technology improvements, expanded video conferencing licenses, and increased company cellular telephone and data usage. The Commission recognizes that many other businesses and state agencies in North Carolina were able to shift to fully or nearly full remote work to respond to the Governor's state of emergency and also incurred similar incremental costs to accommodate employees working remotely. The Commission notes that in the post-state of emergency work environment, remote work offerings continue either fully or on a hybrid basis for many businesses, state agencies, and utilities, including DEP. The Commission determines that although the pandemic may have initiated this category of costs, these costs are now largely ongoing in nature and not specific to the pandemic. Moreover, DEP has not offset the deferred costs of remote work with the associated decreases in office expenses such as utilities, office supplies, and other miscellaneous expenses related to employees working from the office. Thus, the Commission concludes that it would not be appropriate to recover the deferred costs of remote work from customers.

DEP provided certain eligible employees a one-time cash payment of $1,500 to help with unplanned expenses associated with COVID-19. DEP testified that the stipends were appropriate to support employees in providing service to customers and to avoid turnover and should be allowed as reasonable and prudent costs. The COVID Panel contended that DEP did not require expense verification associated with the employee stipends to avoid the extra administrative cost of reviewing receipts and validating usage by the employees that received the stipend. The Commission concludes that the one-time $1,500 stipends provided voluntarily by DEP to certain hourly employees should be considered voluntary goodwill and should not be recovered from customers. Usage of the stipends was not verified by DEP and that employees were free to spend the funds as they pleased, without oversight, and thus the Commission determines they should be excluded from cost recovery of deferred COVID expenses.

DEP witness Jiggetts testified that the other category of deferred costs includes overtime to implement COVID-19 guidelines to ensure employee safety and increased costs due to expected increased call volume at call centers when normal billing practices resume. Public Staff witnesses Boswell and Zhang contended that expenses associated with call center overtime should not be included in the ongoing COVID deferral given that the amount sought by DEP for call center overtime was not above the amounts already included in DEP's cost of service. The Commission is persuaded that, because the amount sought by DEP for call center overtime was not above the amount already included in DEP's cost of service, these costs should not be recovered from customers.

Regarding COVID-related cost savings, the COVID Panel contends that the Deferral Order required only that DEP track the costs being deferred, but that nonetheless DEP was required to track and report COVID savings (specifically, reduced employee expenses such as reductions or elimination of travel and expenses associated with normal operations while employees were required to work remotely and adhere to travel restrictions, and reduced printing and postage costs) and NLRs on a South Carolina retail basis for 2020 and therefore did, and provided to the Public Staff, the incremental COVID savings and NLRs at a system level to which it applied allocation factors to derive the South Carolina retail amounts. According to the COVID Panel, DEP's COVID savings were largely realized in 2020 in the amount of approximately $4.5 million on a North Carolina retail basis, while DEP estimated the NLRs related to reduced load and demand in 2020 to have been approximately $28 million on a North Carolina retail basis, thereby more than offsetting the savings reductions that the Public Staff suggests.

Although not presented in filed testimony, in its proposed order the Public Staff maintained that a portion of the O&M savings DEP experienced in 2020 and 2021 – which includes any savings experienced by DEP related to remote work, and reduced expenses in employee travel, printing, and postage – should offset the deferred COVID costs DEP is now seeking to recover. The Public Staff contended that, with few exceptions, DEP stated it did not track how the O&M savings were derived, thus, there is no amount that the Public Staff could definitively identify as strictly COVID-related savings. In light of this, the Public Staff recommended that 50% of DEP's total non-fuel O&M savings in 2020 and 2021 should be offset against the deferred COVID costs sought for recovery. The Commission notes that in its proposed order, the Public Staff also recommended disallowance of the employee stipends and the increased call center costs but did not specifically object to cost recovery of any other category of DEP's deferred COVID-related costs.

The Commission acknowledges that DEP is not requesting rate recovery of the NLRs related to the COVID pandemic. Witness Bateman testified that DEP made a conscious decision not to request deferral of NLRs in the COVID Docket. Witness Bateman further testified that DEP did what it always does when faced with the prospect of lower than budget revenues, DEP absorbs revenue impacts through O&M savings. Witness Bowman explained that when faced with the prospect of revenue loss, DEP as a routine part of its business and in keeping with its focus on managing O&M cost for the benefit of customers, identifies and implements a suite of cost mitigation measures. Witness Abernathy testified that further complicating the picture in 2020, the prospect of revenue loss arose not only from the pandemic but also from mild weather. She noted that DEP responded to twin threats to its revenue stream, both the pandemic and mild weather, by instituting cost efficiency measures, which she described in detail. She testified that none of these "belt tightening measures" were included in the deferred costs. Witness Abernathy maintained that DEP did everything that it could to reduce costs and, as a result, avoided the need to request a deferral of the NLRs. However, DEP was not able to offset both the incremental costs due to COVID-19, and the other unfavorable impacts in 2020, including the NLRs due to COVID. The end result is that deferral of incremental COVID-19 costs was required and requested, and the Commission gave its approval to that deferral. Witness Abernathy contends that none of the cost savings measures discussed above have been – or should be – used to offset the COVID-19 related incremental costs.

When asked by the Public Staff to identify the COVID-related savings, witness Abernathy testified that two categories of savings were identified: 1) reduced employee expense related to reduction in or elimination of travel, and 2) reduced printing and postage costs as a result of the disconnect moratoriums ordered by the Commission. The Commission concludes that these cost savings identified by DEP which were directly attributable to the pandemic should offset the amount of deferred COVID-related expenses. DEP witness Speros noted that while COVID-related costs can be and were directly tracked, the negative is not true – "savings" are not directly trackable; rather, they must be discerned through data analysis, namely by comparing actual expenditures with budgeted expenditures to get a sense of what DEP did not spend versus what it thought it would spend. He stated that the analyst can make a judgment based upon the type of expense as whether it COVID-related. Witness Abernathy confirmed that is precisely what DEP did to determine that the employee expense and printing/postage reductions were, in fact, directly related to the pandemic.

The Commission determines that the issue of COVID-related cost savings is intertwined with the issue cost savings resulting from the mitigation measures taken by DEP to address NLR. Furthermore, various events occurring in 2020 are entwined in the analysis - COVID, mild weather, and storm restoration costs. On the one hand, in its proposed order the Public Staff indicated there was no amount that the Public Staff could definitively identify as strictly COVID-related savings; thus, the Public Staff recommended that 50% of DEP's total non-fuel O&M savings in 2020 and 2021 should be offset against the deferred COVID costs sought for recovery. On the other hand, DEP, through witness Abernathy's testimony, maintained that none of DEP's cost saving measures to mitigate NLRs should be used to offset the incremental COVID-related costs. Witness Abernathy also maintained that savings related to the federal government assistance for which DEP filed ERCs and was granted a carrying cost benefit related to the delayed payment of the employer portion of social security tax. The Commission concludes that these measures taken by the federal government to assist companies and employers in weathering the impacts of the pandemic should inure to the benefit of customers. To balance the fairness and equity between customers and shareholders related to the COVID-19 pandemic and, in part, because the amount of COVID-related savings cannot be definitively identified, the Commission did not approve all deferred COVID-related expenses for cost recovery from customers. The Commission notes DEP's position on savings and the difficulties associated with calculating savings that are directly attributable to the pandemic. However, the Commission determines that the two types of savings identified by witness Abernathy are directly related to the pandemic and that the measures taken by the federal government to assist companies and employers during the pandemic which provided benefits to DEP, directly relate to the pandemic. For these reasons, the Commission concludes that these costs should be netted against deferred COVID-related costs. In reaching this conclusion, the Commission gives weight to the testimony of witness Abernathy that expense savings resulting from DEP's normal cost mitigation measures to offset revenue shortfalls related to mild weather and in this case, the pandemic, should not be used to offset COVID-related expenses.

The Commission declines to approve DEP's request to recover approximately $12 million in accrued carrying costs on the deferred costs or to authorize a return on the unamortized balance of the COVID costs during the amortization period. In reaching this decision, the Commission is conscious of the fairness and equity factors inherently at play in considering how to appropriately balance the difficulties experienced by both the utility and ratepayers throughout the pandemic. DEP contends that inasmuch as the deferred costs are by definition not already in rates and were fronted by DEP's investors, the costs properly bear a return at DEP's weighted average cost of capital so as to ensure that DEP and its investors are made whole. The Public Staff recommends denial of any return on the allowed deferred expenses stating that interest has already been accounted for in the $27 million late payment fees of the deferred expenses at issue in this proceeding, and to allow an additional return would unfairly allow DEP to collect interest upon interest.

Taking into consideration the hardships caused by the pandemic on the residents and businesses in North Carolina, DEP's earnings reported in its E.S.-1 Report during the deferral period which were at or above the utility's authorized rate of return, and the totality of the hardships suffered by customers during the pandemic, the Commission concludes that the approximately $12 million included in DEP's request related to accrued carrying costs on the deferred costs or a return on the unamortized balance during the amortization period should not be recovered from customers through rates.

The Commission concludes that it is appropriate that cost recovery for the approved deferred COVID-related costs occur over a six-year amortization period. Due to the material amount of COVID-related costs approved for recovery, the Commission finds that the three-year amortization period requested by DEP would be burdensome for customers. The 12-year amortization period advocated by the Public Staff in its proposed order is unreasonably long in light of the Commission's decision herein to not allow carrying charges on the deferred costs. The Commission has customarily used a five-year amortization period for recovery of costs from customers for extraordinary events like storms. However, at the expert witness hearing, the COVID Panel stated DEP's preference that the amortization period be in a three-year increment, such as six years, to keep in sync with the MYRP. Thus, the Commission determines that a six-year amortization period reasonably balances the impacts to both DEP's customers and its shareholders.

The Commission determines that amortization of the deferred COVID-related costs should begin upon the effective date of new rates in this proceeding.

Regarding DEP's request to continue its deferral for incremental bad debt expense, the Commission determines that since DEP is still incurring incremental bad debt expense, it is appropriate for DEP to continue to defer those costs incurred after March 31, 2023. The Commission concludes that DEP's request to continue the deferral of the incremental bad debt, for future recovery, is just and reasonable, and should be approved. The Commission acknowledges the positions taken by the Public Staff in its proposed order related to this issue and agrees with the Public Staff's recommendation that any payments associated with the deferred bad debts should be credited on a monthly basis through the next general rate case but declines to accept the Public Staff's other recommendations related to call center overtime costs or an ongoing overearnings analysis during the deferral period. Thus, the Commission concludes that DEP should credit on a monthly basis through the next general rate case any payments associated with the deferred bad debts.

Finally, the Commission notes that its decision on deferral of the COVID-related costs is based on the particular facts of this case, and in particular, the unprecedented circumstances related to the pandemic, and should not be cited or relied on as precedent for future cost deferral decisions. The Commission evaluated the totality of the pandemic, taking into consideration the governmental mandates which removed DEP's tools to control bad debt expense, the necessity for DEP to provide uninterrupted electric service during the duration of the pandemic – even when many customers were not paying their bills, the benefit to customers and North Carolina as a whole of the governmental mandates, and DEP's financial standing as reported in its quarterly E.S.-1 Reports to the Commission for the duration of the deferral period. Considering all these factors and the entire evidence of record, the Commission concludes that its decision set forth herein is the most reasonable, fair, and equitable outcome for both customers and shareholders with respect to the COVID-19 pandemic.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 57

Inflation Adjustment

The evidence supporting this finding of fact is found in DEP's verified Application and Form E-1; the testimony and exhibits of DEP witness Jiggetts and Public Staff witnesses Zhang and Boswell; and the entire record in this proceeding.

Summary of Evidence

DEP Direct and Supplemental Testimony

DEP, through witness Jiggetts' direct testimony and exhibits, adjusted its annual non-labor and non-fuel O&M costs to reflect the increase in costs during the test period that occurred due to inflation. *See* Tr. vol. 13, 185. In supplemental direct testimony, witness Jiggetts testified that this inflation adjustment was updated to reflect inflation factors through December 31, 2022, and to remove the impact of the gains/losses on the sale of by-products. *Id.* at 222-23. This inflation adjustment factor was subsequently updated in Jiggetts' second and third supplemental direct testimony, *Id.* at 232, 243, and finally in Settlement Testimony to arrive at a rate of 12.13%. Jiggetts Partial Settlement Ex. 4 at 109, Tr. Ex. vol. 14.

The Public Staff Testimony

Public Staff witnesses Zhang and Boswell recommend that the Commission adjust DEP's inflation factor to reflect a five-year average inflation rate through December 31, 2022. Tr. vol. 19, 44. Witnesses Zhang and Boswell further recommend that the inflation adjustment be modified to reflect the Public Staff's recommended adjustments removing aviation expenses, Board of Directors expenses, uncollectibles, and sponsorships and donations. *Id*. In supplemental testimony, witnesses Zhang and Boswell applied their recommended inflation adjustment to actuals through February 2023 to reflect the 61-month average recommended by the Public Staff. *Id.* at 90. Witnesses Zhang and Boswell testified that the increasing inflation rates seen in 2021 and early 2022 have already begun to decrease and that DEP's 2021 expenses already reflect some portions of the increase in costs due to inflation. *Id.* at 44-45. They further testified that the Public Staff does not find it appropriate to calculate ongoing rates for a minimum of the next three years based on years in which inflation was abnormally high. *Id.* at 45.

DEP Rebuttal Testimony

In rebuttal, DEP witness Jiggetts opposed the Public Staff's recommended adjustment. Tr. vol. 23, 93-97. Jiggetts testified that DEP's proposal does not project inflation of O&M expenses, but instead accounts for the impacts of inflation that have already been incurred from the test period to the end of the update period. *Id.* at 94. Witness Jiggetts further testified to DEP's methodology for calculating an inflation factor, stating that it has not changed from previous rate cases. *Id.* Witness Jiggetts testified that the Public Staff's assertion that any non-payroll O&M expenses updated beyond December 2021 would include impacts related to inflation is incorrect, and she explained that any O&M expenses that are updated through pro forma adjustments are excluded from the inflation adjustment. *Id.* at 94-95. Witness Jiggetts cited data from the U.S. Bureau of Labor Statistics that shows a continual upward trend for all inflation metrics. *Id.* at 96. Further, witness Jiggetts testified that while DEP disagrees with the Public Staff's adjustments removing certain expenses related to aviation, sponsorships, donations, lobbying, and Board of Directors expenses, DEP agrees that it would be appropriate to adjust the total O&M subject to inflation for that amount, to the extent that there are adjustments made to those expenses. *Id.* at 97.

Testimony Presented at the Expert Witness Hearing

At the hearing, witness Jiggetts testified to DEP's recommended inflation rate factor of 12.13%. Tr. vol. 13, 302. Witness Jiggetts explained that DEP uses a 13-month average to calculate its inflation factor, consistent with its methodology in the previous rate case. *Id.* at 302-03. She further explained that, in calculating the inflation factor, DEP is looking at the actual level of inflation, as reported by the U.S. Bureau of Labor Statistics, through the March 31, 2023 cutoff date. *Id.* at 302. She testified that DEP compares that level of inflation to the costs actually incurred during the test year by looking at the 13-month average of the Bureau of Labor Statistics' data. *Id.* at 302-03. Using this approach, witness Jiggetts explained that inflation has increased to 12.13% through the March 31, 2023, cutoff period. *Id.*

Witness Jiggetts clarified that the test year used in the adjustment is historical, rather than prospective, and that the purpose of the adjustment is to adjust test year expenses to account for inflation as of the March 31 cutoff period. *Id.* at 304. Witness Jiggetts explained that DEP does not project inflation rates or factors. *Id.* at 304. Instead, the test year expenses are adjusted for known and measurable changes through the March 31 cutoff period. *Id.* at 303.

Public Staff witness Zhang testified that the Public Staff calculated its recommended inflation adjustment by averaging the inflation rate over the 61-month period from January 2018 through January 2023. Tr. vol. 19, 116-17. Witness Zhang further testified that averaging the inflation rate over that 61-month period with the average inflation of the consumer producer price index's published inflation resulted in a 61-month average inflation factor of 4.31%. *Id.* at 117. In response to cross examination by DEP, witness Boswell testified that she could not state for certain if the Public Staff's methodology had previously been used in any electric utility rate case. *Id.* at 128.

Discussion and Conclusions

The Commission concludes, based upon the evidence presented, that the rate factor adjustment proposed by DEP is just and reasonable. The Commission declines to adopt the 61-month average method advocated by the Public Staff and notes that per DEP's Late-Filed Exhibit No. 13, the Public Staff has previously proposed the same method that DEP employed in this proceeding. The Commission determines that the adjustment proposed by DEP, at 12.13%, captures actual inflation during the test period updated through March 31, 2023, in substantially the same manner that DEP has historically employed.

Specifically, the inflation adjustment (Adjustment No. NC2110 in witness Jiggetts' schedules) annualizes test period O&M expenses, excluding fuel, purchased power, and labor and benefit costs to reflect the change in test period costs through the March 31, 2023 cutoff date by an actually-experienced inflation factor. The adjustment captures actual inflation during this period in the same manner used in at least DEP's last seven general rate cases. DEP Late-Filed Ex. No. 13. As witness Jiggetts testified, DEP has proposed and the Commission has approved rates that were calculated using the method of determining the inflation adjustment used by DEP in this proceeding for many years, in all kinds of inflationary environments. While the Commission recognizes that, as the Public Staff points out, the period of time during which the updated test year occurred was coincident with unprecedented times, including the pandemic, the Commission is concerned that a departure from historical practice on this issue is not warranted, as adjusting for "known and measurable changes" is consistent with N.C.G.S. § 62-133(c) and produces the just and reasonable result of putting DEP in a position of recovering its costs, and is fair to DEP and to customers regardless of the inflationary environment.

Upon consideration of all the evidence in this proceeding, the Commission concludes that DEP's proposed inflation adjustment to test year non-fuel and non-labor O&M costs is consistent with past practice, consistent with statutory law, derived using a method that is fair to customers and to the utility regardless of the inflationary environment, and is approved.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 58-60

Rate Case Expense

The evidence supporting these findings of fact is found in the verified Application and Form E-1; the testimony and exhibits of DEP witnesses Jiggetts and Bateman; Public Staff witnesses Zhang and Boswell, and the Public Staff's cross exhibits of witness Jiggetts; and the entire record in this proceeding.

Witness Jiggetts testified that, in the current proceeding, DEP has included adjustment NC5020 related to rate case costs, amortizes over a three-year period the incremental rate case costs incurred and projected to be incurred for this docket, as well as costs incurred after the cut-off in the last rate case which have not yet been brought forth for recovery. Her testimony explained that over amortizations associated with rate case costs approved in Docket Nos. E-2, Subs 1023 and 1142 and severance costs approved in the 2019 Rate Case were used to offset the amount requested for recovery in this case. Tr. vol. 13, 176, 194.

With respect to costs associated with the 2019 Rate Case, witness Jiggetts explained that in the first partial settlement in the 2019 Rate Case (2019 First Partial Settlement), entered into by DEP and the Public Staff on June 20, 2020, DEP and the Public Staff settled on an agreed amount of rate case expense that would be recovered from customers. Tr. vol. 13, 332. She explained that the amount of rate case expense was estimated, at that time, to be $3.5 million, which represented the sum of actual expense incurred through February 2020 and estimated to be incurred through August 2020. Tr. vol. 13, 312. Witness Jiggetts testified that the projection of costs through August 2020 was based upon past, normal experience that DEP would have had with a rate case proceeding.

In response to a question from Commissioner Duffley, witness Jiggetts testified that DEP seeks to recover rate case costs in this case which exceed those agreed to in the 2019 First Partial Settlement with respect to rate case expense related to the instant proceeding, Witness Jiggetts updated adjustment NC5020 in her supplemental direct testimony and third supplemental direct testimony to reflect actual rate case expense amounts incurred by DEP. *Id.* at 224, 247.

Witness Jiggetts testified that over-amortizations associated with rate case expenses approved in Subs 1023 and 1142 and severance costs approved in the 2019 Rate Case were used to offset the amount requested for recovery in this case. Tr. vol. 13, 194. She testified that DEP requests that the remaining balance to be amortized over the three-year period. Tr. vol. 23, 78.

Public Staff witnesses Zhang and Boswell explained that they removed: 1) DEP's adjustment to include additional rate case expenses from the 2019 Rate Case that exceed the amount agreed to in the 2019 First Partial Settlement 2) the adjustment to include the unamortized portion of rate case expense in rate base; and 3) DEP's inclusion of over-amortized regulatory assets to offset rate case expense. Regarding the additional costs from the 2019 Rate Case, witnesses Zhang and Boswell testified that the 2019 First Partial Settlement reflected an agreed-upon amount for 2019 Rate Case expenses, and that this amount was ultimately incorporated into the revenue requirement approved by the 2019 Rate Case. As such, the Public Staff asserted that it is inappropriate to include 2019 Rate Case costs beyond those included in the Commission-approved revenue requirement from a general rate case that has been closed, and in which DEP did not request that additional costs be considered before the Commission issued its final order. Tr. vol. 19, 56-57.

Regarding DEP's adjustment to include the unamortized balance of rate case expense in rate base, witnesses Zhang and Boswell testified that the amortization of rate case expense should reflect a normalization of the costs associated with the filing of a rate case, based on an average of the number of years between rate case filings. In this case, witnesses Zhang and Boswell stated that rate case expense does not rise to the level of being extraordinary in nature and, as such, does not require rate base treatment. As with other over-amortizations in this proceeding, witnesses Zhang and Boswell asserted that the over-amortized amounts from the rate case expense and severance costs should be flowed back to ratepayers as a one-year rider and not used to offset other amounts. Tr. vol. 19, 57-58.

In her rebuttal testimony, witness Jiggetts asserted that DEP is not precluded from collecting additional amounts incurred from the 2019 Rate Case based on the 2019 First Partial Settlement. In her view, the 2019 First Partial Settlement does not contain any language capping rate case costs at a maximum amount or prohibiting DEP from asking for additional reasonably and prudently incurred actual expenses in a future rate case. While the amounts agreed to in the 2019 First Partial Settlement were based upon information available at the time the agreement was reached, witness Jiggetts stated that DEP's costs were ultimately higher as the proceedings for that case were delayed and extended, for reasons which could not have been foreseen, and that the Public Staff has made no assertion or forecasted any evidence showing that the additional 2019 Rate Case expenses were not reasonably and prudently incurred. Tr. vol. 23, 79-81.

Rejecting the Public Staff's recommendation that the unamortized rate case costs for this proceeding be removed from rate base, witness Jiggetts explained that DEP's investors have advanced the funds to cover these reasonably and prudently incurred utility costs and, as such, DEP should be allowed to earn a return on this asset to reflect the earnings expected from its investors during the amortization period. Tr. vol. 23, 81-82.

At the expert witness hearing, witness Jiggetts testified that, to the best of her knowledge, DEP did not provide updates of its 2019 Rate Case expenses through May 2020 as the second settlement would have allowed, and that she was not aware of DEP's having requested to recover these amounts during the 2019 Rate Case expert witness hearing or at any point prior to the filing of this proceeding. Tr. vol. 13, 311-18.

Although not presented in prefiled testimony, in is proposed order, the Public Staff provided additional context concerning various events that occurred during the 2019 Rate Case related to the issue of rate case expense. On June 2, 2020, DEP and the Public Staff filed the First Settlement, in which DEP and the Public Staff agreed that certain rate case expenses as set forth in DEP's rebuttal testimony could be recovered (not in rate base) and that these expenses would be amortized over a five-year period. In DEP witness Kim Smith's testimony supporting the 2019 First Partial Settlement, she describes the settled issues (including rate case expense) as "resolve[d] . . . without the necessity of contentious litigation." 2019 Rate Case, Tr. vol. 14, 260. On July 31, 2020, DEP and the Public Staff filed the second partial settlement, in which the two parties agreed that DEP's updates covering expenses through May 31, 2020 (filed on July 2, 2020), could be included for recovery (pending and subject to the Public Staff's audit thereof), up to 75% of the difference (should the difference result in an increase in the revenue requirement) between DEP's February 2020 costs and May 2020 updates in recognition of the uncertainty regarding the effects of COVID. However, in its July 2, 2020 filing, which updated expenses through May 2020, DEP did not seek recovery of any additional rate case expenses. In addition, the Public Staff notes that the expert witness hearing for the 2019 Rate Case took place in August 2020, but the issue of recovery of 2019 Rate Case expense beyond that provided for in DEP's rebuttal testimony does not appear to have been raised to the Commission during the hearing, in DEP's proposed order, or in any other form during the pendency of the 2019 Rate Case.

According to the Public Staff, DEP had a reasonable opportunity in the 2019 Rate Case to come forth with additional rate case expenses, and it failed to do so. If DEP believed there were 2019 Rate Case expenses outside the confines of the 2019 Settlement Agreements, DEP should have raised this issue at the 2019 Rate Case expert witness hearing and sought the Commission's guidance on how to preserve the issue, but it failed to do so. The Public Staff asserts that just because DEP's 2019 Rate Case expenses were ultimately higher than expected due to COVID does not mean that the entire category of 2019 Rate Case expenses were not encompassed in the settlement agreements. Instead, this was an aspect of settlement that DEP did not foresee. However, the Public Staff asserts that the fact that DEP did not foresee the impact of its agreements is not justification to depart from the terms therein or deprive customers of the benefit of the Public Staff's bargain.

In their second supplemental testimony filed on June 27, 2023, Public Staff witnesses Zhang and Boswell updated rate case expenses to reflect the actual rate case expense incurred through March 31, 2023, as reflected in DEP's third supplemental filing.

Discussion and Conclusions

The Commission must decide on three issues relating to rate case expense: (1) recovery of rate case expense from DEP's 2019 Rate Case, as well as the recovery of rate case expense from the current proceeding; (2) whether rate case expense should be reflected in the rate base; and (3) the amortization period over which the expense should be recovered. As discussed below the Commission concludes that (1) DEP's request to recover costs incurred from the 2019 Rate Case which are above and beyond those provided for in the 2019 Settlement Agreements is approved; (2) the unamortized balance of rate case expense should not be reflected in the rate base; and (3) the amortization period over which the rate case expense should be recovered is three years. The issue regarding whether over-amortizations associated with rate case costs approved in Sub 1023 and severance costs approved in the 2019 Rate Case should be used to offset the rate case expense in this proceeding is discussed in other portions of this Order.

The Commission notes that 2019 First Partial Settlement reflected a settlement on the sum of actual rate case expense incurred through February 2020 plus expenses estimated to be incurred through August 2020. The Commission also notes, as DEP witness Jiggetts testified, that DEP did not update its rate case expenses through May 2020, as the second partial settlement in the 2019 Rate Case allowed. However, the Commission also notes the unusual, perhaps unprecedented, trajectory of the 2019 Rate Case. Specifically, the first partial settlement was entered into on June 2, 2020, and the second settlement was entered into on July 31, 2020. The consolidated hearing for DEC and DEP was held in late August 2020. The separate hearing for DEP was held in late September to early October 2020. Between the consolidated hearing and the individual hearing, DEP worked to put interim rates into effect and notified customers of same. On December 11, 2020, the Supreme Court issued its order in *State ex rel. Utils. Comm'n v. Stein*, 375 N.C. 870, 851 S.E.2d 237 (Dec. 11, 2020), effectively remanding the issue of cost recovery for coal combustion residuals (CCRs) back to the Commission. Subsequent to issuance of that decision, DEP engaged in settlement discussions related to CCR cost recovery. On January 25, 2021, the Coal Combustion Residuals Settlement Agreement (CCR Agreement), to which DEP and the Public Staff were parties, was filed in the 2019 Rate Case docket. On February 12, 2021, the Commission issued an order in the 2019 Rate Case docket re-opening the record to accept into evidence supporting testimony filed by DEP and the Public Staff. On February 17, 2021, the Commission issued an order requiring DEP to respond to certain questions from the Commission regarding the CCR Agreement. The final order in the 2019 Rate Case was issued by the Commission on April 16, 2021. Subsequent to the issuance of the order, DEP worked to establish rates in compliance with the Commission's order, provide notice to its customers of new rates and put those rates into effect on June 1, 2021. The 2019 Rate Case, initiated by application filed in August 2019 made by DEP, culminated with rates' taking effect on June 1, 2021. This timing was impacted by events outside of DEP's control, namely the pandemic and the issuance of the Stein order by the North Carolina Supreme Court. As summarized by DEP witness Jiggetts:

> The actual hearings, the consolidated hearings, I believe, happened at the end of August of 2020. We had interim rates that went into effect in September of 2020. The individual hearing for DEP happened, I believe, late September, early October of 2020. The CCR settlement was essentially reached in January of 2021. The Order in that case came out in April of 2021. And then new rates went into effect in June of 2021.
>
> During that time frame, obviously, we had additional discovery that required, you know, questions and responses. We had the prep and the times for the hearings. So all of that, kind of, bled into the costs being more than what we initially estimated at the time of settlement in June of 2020.

Tr. vol. 23, 118.

The Commission understands and respects the Public Staff's strongly held position that the settlement agreements entered into during the rate case should govern and that DEP should be held to the terms of these agreements in order for customers to receive the benefit of the Public Staff's bargain. In general, the Commission agrees with the Public Staff that parties must be held to their agreements made in settlement, particularly in the interest of encouraging future settlements. Nevertheless, the Commission concludes that it would be unreasonable to deny DEP recovery of expenses incurred in the context of the 2019 Rate Case that were not reflected in the 2019 First Partial Settlement The Public Staff asserts that DEP could have raised the issue rate case expense during the August 2020 expert witness hearing, but it is not clear to the Commission that DEP could have reasonably anticipated, at that time, the additional work that would be required in the 2019 Rate Case. Thus, DEP's request to recover costs incurred related to the 2019 Rate Case which are above and beyond those provided for in the 2019 First Partial Settlement is approved. Further, the Commission concludes that these additional rate case costs in the amount of $5.384 million as shown on Public Staff Accounting Second Supplemental Exhibit I, Schedule 3-1(t), Line 4, should be amortized over a three-year period.

Regarding rate case expense for this proceeding, the Commission concludes that it is reasonable and appropriate to allow DEP to recover total costs of $6.551 million as shown on Public Staff Accounting Second Supplemental Exhibit I, Schedule 3-1(t), Line 1. Tr. Ex. vol. 24. As previously stated, the issue regarding whether over-amortizations associated with rate case costs approved in Sub 1023 and severance costs approved in the 2019 Rate Case should be used to offset the rate case expense in this proceeding is discussed in other portions of this Order.

The Commission notes that DEP has projected additional rate case expense to be incurred through the date rates will be effective for this proceeding in the amount of $2.526

million as shown on Public Staff Accounting Second Supplemental Exhibit I, Schedule 3-1(t), Line 6, and has requested that the Commission allow DEP to track these costs for possible recovery in a future general rate case proceeding. Tr. Ex. vol. 24. The Commission determines that, in the ordinary course of ratemaking, the rate case expense amount to be recovered from customers should be established in the current general rate case proceeding and not re-evaluated in a future rate case for recovery from customers. Generally, it has been past practice for the Public Staff and the utility to work together to estimate an appropriate amount of rate case expense for approval by the Commission to reflect the activities occurring after the agreed-upon update cutoff date to the conclusion of the hearing or through the preparation of proposed orders. The Commission finds that this practice has been an efficient and reasonable process with respect to determining the appropriate amount of rate case expense to recover from customers. As previously discussed, the Commission's decision in this case to re-evaluate in this proceeding the 2019 Rate Case costs to be recovered in rates is an exception to the Commission's historic practice due to the unusual circumstances occurring during the 2019 Rate Case. Therefore, the Commission denies DEP's request to track and seek future recovery of rate case costs for the present proceeding above the amounts approved herein.

Concerning DEP's adjustment to include the unamortized portion of rate case expense in rate base, the Commission gives significant weight to the Public Staff's testimony stating that the amortization of rate case expense should reflect a normalization of the costs associated with the filing of a rate case, based on an average of the number of years between rate case filings. The Commission notes that the 2019 First Partial Settlement expressly provided that the unamortized balance of rate case expense would not be included in rate base. The Commission concludes that DEP's request to include the unamortized balance of rate case expense in rate base is denied.

Regarding the amortization period over which the current rate case expense of $6.551 million, as netted against a portion of the over-amortization of rate case expenses approved in Sub 1023, should be recovered, the Commission determines that the amortization period over which the rate case expense should be recovered is three years, as this aligns with the MYRP timeframe. Accordingly, the Commission finds and concludes that the three-year amortization period is just and reasonable and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 61

Over-Amortizations

The evidence supporting this finding of fact is contained in DEP's verified Application and Form E-1; the testimony and exhibits of DEP witness Jiggetts, Public Staff witnesses Zhang and Boswell; and the entire record in this proceeding.

Summary of Evidence

In its Application, DEP requested permission to apply expiring over-amortizations as an offset to the deferral balances of costs that DEP believed were similar in nature, but which may not yet have been approved by the Commission. The requested offsets include: (1) the coal combustion residuals (CCR) asset retirement obligation; (2) rate case expenses; (3) application of the over-amortization of severance costs to rate case expenses; (4) application of the over-amortization of early retired coal plants to the Asheville early retired coal plant; (5) application of the over-amortization of Hurricane Matthew to the Winter Storm Izzy proposed deferral; and (6) regulatory fees. Tr. Ex. vol. 7.

DEP Direct Testimony

In direct testimony, DEP witness Jiggetts supported adjustment NC5010, which removes from Test Period costs the amortization of various regulatory assets or liabilities that have been approved by the Commission in previous general rate case proceedings. Tr. vol. 13, 194. Witness Jiggetts testified that the amortization period for the items removed will expire before proposed new rates are effective, and thus should not be included in Test Period expenses on which new rates are based. *Id.* Witness Jiggetts explained that over-amortizations of the regulatory assets and liabilities have been applied to like kind expense recovery in this case. *Id.* Witness Jiggetts testified that DEP intends to apply the over-amortization of the early retired plant regulatory assets against the Asheville Coal plant regulatory asset allowed in the 2019 Rate Case, as an example, and she also testified that over-amortization associated with rate case costs as approved in Docket Nos. E-2, Subs 1023 and 1142 and severance costs approved in the 2019 Rate Case were used to offset the amount requested for recovery in this case. *Id.*

The Public Staff Testimony

Public Staff witnesses Zhang and Boswell recommended that the Commission remove DEP's proposed over-amortization offsets and return the expiring amortizations to customers as single rider over a period of one year with interest. Tr. vol. 19, 73. Witnesses Zhang and Boswell stated that, due to the complexities involved with the associated adjustments, the Public Staff will work with DEP to verify appropriate accounting for the removal of the regulatory assets from the calculation of rate base and propose their inclusion in a rider in their supplemental filing. *Id.* Witnesses Zhang and Boswell explained that currently, regulatory assets are handled on a case-by-case basis, with the recovery period determined by the Commission based on the specifics of the item to be recovered. *Id.* They testified that by offsetting the expiring amortizations against continuing amortizations, DEP is overriding the Commission's approved terms for recovery of the individual regulatory assets. Thus, witnesses Zhang and Boswell testified that the Public Staff recommends returning the over-amortizations to ratepayers through a one-year rider with interest to allow for the refund to customers while maintaining the terms of the Commission's previous approvals of the remaining regulatory assets. *Id.*

DEP Rebuttal Testimony

In rebuttal, DEP witness Jiggetts described each of the expired amortizations that DEP is proposing to offset against like costs: (1) coal ash;[21] (2) rate case costs;

[21] The over-amortization of coal ash costs is separately addressed earlier in this Order.

(3) severance; (4) early retirement of coal plants; (5) Hurricane Matthew; and (6) regulatory fees. Tr. vol. 23, 101-04. Witness Jiggetts explained how DEP's proposed treatment of the expiring amortizations is consistent with the Commission's 2018 Order in the 2017 Rate Case. *Id.* at 100-01; Order Accepting Stipulation, Deciding Contested Issues and Granting Partial Rate Increase, Docket No. E-2, Sub 1142 (February 23, 2018) at 224. She stated that in that order the Commission previously addressed continuing amortizations of expired regulatory assets and liabilities in the context of coal ash costs. Tr. vol 23, 100. She further stated that in that order the Commission concluded:

> With regard to DEP's CCR costs from 2018 forward, DEP witness Bateman testified that DEP is requesting to establish a regulatory asset/liability account and defer to this account the portion in annual rates that is more than DEP's actual costs, or the amount in annual rates that is less than DEP's actual costs. In essence, the asset/liability account would be a tool used to true-up the difference in DEP's next general rate case. The Commission agrees with DEP's recommended approach, not only for CCR costs, but also for all cost deferral accounts…. [T]he Company should continue to record all amounts recovered as deferred costs in the specific regulatory asset account established for those deferred costs until the Company's next general rate case.

Id. at 100-101.

Witness Jiggetts also disagreed with the Public Staff's assertion that by offsetting the expiring amortizations against continuing amortizations, DEP is overriding the Commission's approved terms for recovery of the individual assets. *Id.* at 100. Witness Jiggetts maintained that DEP has complied with the 2018 DEP Order and has continued the amortization of the expired regulatory assets and liabilities and, in the context of this rate case, is applying those over-amortizations to the deferral balances of costs that are similar in nature, in compliance with the Commission's order. *Id.* at 101.

Witness Jiggetts' also explained the impact upon rates should the Commission adopt DEP's proposed treatment. *Id.* at 104. Witness Jiggetts testified that DEP's approach reduces deferred balances being addressed in the current case, and thereby reduces the base rate revenue requirement, all the while protecting the customers from the rate volatility created by a significant one-year rider. *Id.*

Testimony Presented at the Expert Witness Hearing

At the expert witness hearing, DEP witness Jiggetts answered questions from the Commission regarding the process by which DEP analyzed the rate impact of its proposed treatment of over-amortizations. Tr. vol. 14, 22. Witness Jiggetts walked through DEP's proposal with regard to both coal ash and Winter Storm Izzy. *Id.* at 22-23. Witness Jiggetts explained how applying DEP's proposed treatment to coal ash over-amortizations provides customers a benefit of approximately $3 million. *Id.* at 23. Witness

Jiggetts testified that for - Hurricane Matthew, the over-amortization completely covers what DEP is requesting to defer for Winter Storm Izzy, which means customers would never have to pay for that balance. *Id.* at 23-24.

Discussion and Conclusions

Over-amortization occurs when amortization expense collected in rates (as established in a prior rate case) exceeds the associated regulatory asset or liability. DEP defers such over-amortizations, and the issue in this proceeding is how to utilize such over-amortizations to benefit customers. DEP proposes to apply the over-amortizations to recovery of like kind expenses. The Public Staff proposes to flow the over-amortizations back to customers through a one-year Regulatory Asset/Liability Rider (Rider RAL). The Commission has reviewed the evidence and considered the testimony of the witnesses and determines that, for purposes of this proceeding, it is reasonable and appropriate to offset some, but not all, of DEP's previously approved regulatory assets that have been over-amortized against other regulatory assets.

DEP witness Jiggetts testified that the Commission previously addressed continuing amortizations of expired regulatory assets and liabilities in the context of coal ash costs in the 2018 DEP Order and that DEP's proposal in this proceeding to apply over-amortizations to like kind expenses is consistent with that order. DEP contends that the Commission's conclusion in the 2018 DEP Order that the asset/liability account would be a tool used to account for and subsequently true-up in the next general rate case the difference between the actual amount in annual rates for regulatory assets/liabilities and DEP's actual costs is consistent with its proposal that over-amortizations should be used as a true-up tool with respect to like costs, to be ruled on by the Commission in DEP's next rate case. The Commission disagrees with DEP's interpretation that the 2018 DEP Order approved any sort of offsetting of amortizations between one set of costs that had been approved by the Commission and another set of costs which had not been approved by the Commission for deferral.

The Commission notes that in the 2018 DEP Order cited to by DEP, the Commission allowed DEP to record a specific amount of revenue for its CCR costs as of September 1, 2017, and onward in a deferral account until its next general rate case, with a five-year amortization period. The Commission also stated in the 2018 DEP Order that, if DEP receives revenue for any deferred cost authorized in the 2017 Rate Case proceeding for a longer period of time than the amortization period approved by the Commission for that deferred cost, DEP should continue to record all revenue received for that deferred cost in the specific regulatory asset account established for that deferred cost until DEP's next general rate case. In other words, the Commission directed in its 2018 DEP Order that the asset/liability account utilized for CCR costs be used as a tool to true-up the difference between the portion in annual rates that is more than DEP's actual costs, or the amount in annual rates that is less than DEP's actual costs, in DEP's next general rate case.

The Commission has addressed over-amortizations directly in another docket. In its February 21, 2019 Order Approving Joint Partial Settlement Agreement and Stipulation, Granting Partial Rate Increase, and Requiring Customer Notice, *Application by Carolina Water Service, Inc., of North Carolina for Authority to Adjust and Increase Rates for Water and Sewer Utility Service in All of its Service Areas in North Carolina, Except Corolla Light and Monteray Shores Service Area*, No. W-354, Sub 360 (2019 CWSNC Order), the Commission ordered that federal unprotected EDIT funds (a regulatory liability) should be returned to ratepayers through a levelized rider and not be offset through the remaining unamortized portion of a regulatory asset (in this instance, the overcollection in rates of federal income taxes related to the decrease in the federal corporate income tax rate), as the utility suggested. In ordering as such, the Commission explained that:

> [O]ffsetting [a] known and measurable [liability] against either unknown future regulatory assets, or regulatory assets previously approved by the Commission for recovery over a specified period, presents significant intergenerational issues and constitutes inappropriate ratemaking. . . . [T]he amortization period for each regulatory asset is approved by the Commission based upon its determination of what is fair and reasonable for the ratepayers with regard to the costs associated with that specific regulatory asset, or other specific factors taken into consideration by the Commission at the time of that approval. The Commission finds that choosing to simply offset the new . . . liability with the remaining unamortized portion of any regulatory asset would effectively override the Commission's prior decision as to the appropriate amortization period for the regulatory asset, by equalizing the remaining amortization period and the amortization period for the new . . . regulatory liability. And as CWSNC witness DeStefano testified, he is not aware of a situation wherein the Commission has approved such offsetting treatment. . . .
>
> [D]eparting from this transparent process in the course of a general rate case simply to offset flowing through the benefit of reductions in an entirely separate category of costs (income taxes) is neither fair nor reasonable. Further, the Commission notes that for customers, a rider will be separately identified on their bills so they can see in dollars and cents the impact of the federal unprotected EDIT flow through. This transparency would not occur with the offsetting proposed by DEP.

2019 CWSNC Order at 55-56. The Commission considered the two costs to be in "entirely separate categor[ies] of costs" such that offsetting one with the other was not justified.

In the proceeding now before us, the Commission examines whether offsetting expiring over-amortizations with new or existing regulatory assets or expenses is justified or in the best interests of ratepayers, when the nature of the two events is similar or the same. The Commission notes that the Public Staff did not present any Commission precedent, statutory, or rule that over-amortizations must be flowed back to customers via a one-year rider. DEP argues that its proposed approach reduces deferred balances and thereby reduces the base rate revenue requirement which provides a longer-term benefit to customers than the Public Staff's proposed one-year rider. Further, the Commission gives significant weight to the potential implications of the Public Staff's one-year rider proposal upon DEP's credit metrics. As indicated in DEP LFE No. 10, "[g]iven the magnitude of the reduction in cash flow resulting from the Public Staff's proposed $37 million one-year rider, the accelerated flowback puts additional downward pressure upon DEP's already-stressed credit metrics – specifically, the ratio of Funds from Operations (which is essentially a measure of cash flow) to Debt (FFO/Debt). The downward pressure is all the more acute in light of Moody's very recent decision to increase the FFO/Debt downgrade threshold to 21% (up from 20%)."

The Commission finds that DEP's proposal makes intuitive sense in some specific instances because it applies the over-amortization to an actual, Commission-approved cost of the same nature as identified in the course of a general rate case rather than "returning" the over-amortization only to turn around and collect revenue from customers for costs of the same type. However, the Commission determines that similar to the approval of deferral requests, the manner in which to address the true-ups related to over-amortizations in the utility's next general rate case should be determined on a case-by-case basis based on the specific circumstances existing at the time. The Commission finds that, in this specific rate case, DEP's simpler approach to reduce regulatory assets approved by the Commission in this rate case with over-amortizations related to previously Commission-approved regulatory assets is reasonable and appropriate as follows:

a. The over-amortization of rate case expense from Docket No. E-2, Sub 1023 of $1,112,000 should be applied to the balance of rate case expense in the Commission's Order in the 2017 Rate Case $530,000, which will eliminate that balance. The remaining $582,000 of over-amortization should be applied against rate case costs being requested in this proceeding.

b. The over-amortization of early retired plant in the amount of $13.8 million should be applied against the outstanding rate base balance for the Asheville early retired coal plant authorized in the 2019 Rate Case.

c. The over-amortization of Hurricane Matthew costs from the 2017 Rate Case in the amount of $17 million should be treated as follows: First, to recover 2022 incremental Winter Storm Izzy costs of approximately $15 million, and second, the remaining $2 million credit should be refunded to customers through a one-year rider with interest.

Based on the circumstances in this proceeding, the Commission concludes this treatment is reasonable and appropriate because the Commission has carefully reviewed and selected specific "same type" regulatory assets for which the over-amortizations are being applied. The Commission is very clear that same type Commission-approved costs are being offset by over-amortizations related to same type previously approved regulatory assets. The specific information related to the same type of regulatory assets/liabilities is set forth herein in a manner that is transparent both to the parties and to customers. The Commission concludes that the approved offsetting of over-amortizations reduces deferred balances being addressed in the current case, and thereby reduces the base rate revenue requirement, provides a longer-term impact on rates to customers, protects customers from the rate volatility created by a significant one-year rider, and addresses the potential unfavorable implications of the Public Staff's significant one-year rider proposal upon DEP's credit metrics.

The Commission denies DEP's proposal to apply the over-amortization of severance costs from the 2019 Rate Case in the amount of $907,000 against the rate case costs being requested in this proceeding because these are two entirely separate categories of costs and as such, offsetting one with the other is not justified. The Commission rejects DEP's argument that the offset should be approved because severance costs are labor related, and the rate case costs primarily consist of labor related dollars. The Commission also rejects DEP's proposal that the over-amortization of regulatory fees in the amount of $68,000 should be addressed in a future proceeding but instead finds the over-amortization should be addressed in the present rate case. Thus, the Commission concludes that the over-amortizations related to the regulatory fees, the severance costs, and the remaining $2 million credit from the Hurricane Matthew amortization that DEP proposed to be used to fund the initial balance in the Storm Balancing Account, should be returned to customers through a levelized rider over a one-year period with a return at the weighted average cost of capital.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 62-66

Winter Storm Izzy and Storm Balancing Account

The evidence supporting these findings of fact is contained in DEP's verified Application and Form E-1; the testimony and exhibits of DEP witness Jiggetts and Public Staff witnesses Zhang and Boswell; and the entire record in this proceeding.

Summary of Evidence

DEP Direct Testimony

DEP witness Jiggetts testified as to the incremental O&M costs incurred as a result of Winter Storm Izzy. Tr. vol. 13, 210. She testified that DEP experienced extraordinary storm costs in response to Winter Storm Izzy in January 2022, incurring approximately $23.8 million on a North Carolina retail jurisdictional basis. *Id.* at 211. Witness Jiggetts testified that these amounts are not finalized and that invoices would continue to be received, validated, and paid over the next several months. *Id.* DEP requested to defer the incremental O&M expenses related to Winter Storm Izzy, less approximately $11 million of "normal storm range expense" as that term was defined in the 2017 Rate Case for a total deferral in this proceeding of approximately $12.8 million. *Id.* Witness Jiggetts testified that, without approval of this deferral request, DEP would face earnings degradation of approximately 35 basis points. *Id.* According to witness Jiggetts, approval of this request would benefit DEP and its customers by helping to ensure investors' confidence in DEP and to assure access to needed capital on reasonable terms and equitable treatment as to deferred costs and revenues. *Id.*

DEP witness Jiggetts also testified as to DEP's request for approval of a new methodology for tracking storm costs incurred. Tr. vol. 13, 212. Witness Jiggetts testified that the regulatory asset approved for Hurricane Matthew storm costs in the 2017 Rate Case was fully amortized as of September 2021, and per the Commission's order in that case, DEP has continued to record the amortization and has a regulatory liability on its books. *Id.* Witness Jiggetts testified that DEP is seeking to use this existing regulatory liability to create a "balancing account" for storm costs going forward, starting with DEP's request to apply the excess amortization from Hurricane Matthew to the deferred costs for Winter Storm Izzy. *Id.* Witness Jiggetts explained that, to this end, Adjustment NC7010 establishes an average amount of incremental storm costs included in customer rates. *Id.* Witness Jiggetts testified that under DEP's proposal, each year, if the incremental storm expenses are over the average amount in rates, the difference would be deferred to the account; if the incremental storm expenses are under the average amount in rates, the difference would be contributed to the account. She testified that if the average amount included in customer rates approximates the average amount of storm expense going forward, the balancing account balance should fluctuate around zero and not require additional funding. *Id.* She further stated that if the account does require additional funding, this could be evaluated in a future rate case or storm securitization proceeding. *Id.* at 212-13. Witness Jiggetts testified that the Storm Balancing Account would allow DEP to recover its actual costs for storm restoration efforts and ensure that DEP does not make or lose money related to its storm restoration efforts. *Id.* at 213.

DEP witness Jiggetts also testified as to how she calculated a storm normal expense amount of $17.8 million based upon a ten-year average of storm costs, after removing costs associated with major storms, to be included in rates consistent with prior Commission orders. Jiggetts Supplemental Ex. 4, Tr. Ex. vol. 14.

The Public Staff Direct Testimony

Public Staff witnesses Zhang and Boswell did not make an adjustment to DEP's storm normalization calculation. Public Staff Accounting Ex. 1, Tr. Ex. vol. 19.

Witnesses Zhang and Boswell disagreed that DEP should be permitted to defer costs associated with Winter Storm Izzy, stating that the Public Staff maintains its position as articulated in its initial comments filed on March 15, 2017, in the 2017 Rate Case and Docket No. E-2, Sub 1131, that it is appropriate and reasonable that DEP only be allowed to defer the difference between its actual incremental O&M expense related to Winter Storm Izzy and a normal amount of $27.4 million on a North Carolina retail jurisdictional basis. Tr. vol. 19, 54. In light of the fact that DEP had, at the time it filed its Application in this proceeding, estimated the costs of Winter Storm Izzy to be approximately $23.8

million on a North Carolina retail jurisdictional basis, the Public Staff stated that the costs associated with this storm would not qualify for a deferral. *Id.* The Public Staff explained that, merely because the storm costs incurred in a given year are greater than $11 million (the normalized level from a prior rate case), it cannot simply be assumed that the larger expense is extraordinary in magnitude and therefore suitable for deferral. *Id.* Witnesses Zhang and Boswell stated that actual storm expenses included in the ten-year average spanned a wide range of annual amounts, from a storm amount as low as $4,901 to as high as $461.974 million, and, as such, at least $27.4 million should be considered an appropriate level of normal storm expense for purposes of consideration of DEP's $23.8 million in deferral costs. *Id.* at 54-55. In the event that the costs associated with Winter Storm Izzy exceed the $27.4 million North Carolina retail amount, the Public Staff suggested that DEP may file for a deferral or securitization, whichever is most beneficial to ratepayers. *Id.*

Additionally, the Public Staff did not agree with DEP's proposal to create a storm balancing account and stated that creating such an account would only serve to transfer all risk from DEP to ratepayers, including placing unaudited costs into a deferral for recovery. *Id.* at 53. The Public Staff stated that DEP already has ample opportunities to recover storm costs, whether that be through storm normalization, securitization, or deferrals, all of which may allow DEP to reasonably and appropriately recover actual audited storm costs. *Id.*

DEP Rebuttal Testimony

DEP witness Jiggetts testified on rebuttal that the Public Staff accurately summarizes DEP's intent in proposing the storm balancing account. Tr. vol. 23, 83. Witness Jiggetts explained that the Commission should implement a mechanism that results in DEP's neither making nor losing money because of storm restoration efforts. *Id.* Witness Jiggetts responded to the Public Staff's assertion that the storm balancing account would transfer risks from the utility to ratepayers and would include unaudited costs for recovery. *Id.* at 83-84. Witness Jiggetts testified that the base level of storm expense that must be exceeded before DEP can request deferral, as established in the 2017 Rate Case, has in practice been inequitable to DEP as the base level of storm expense is greater than the amount of storm normal expense included in base rates, which results in that difference being borne by shareholders. *Id.* at 84. Witness Jiggetts explained that when DEP's linemen repair and replace damaged lines and equipment after a storm event, the outcome is the restoration of utility service for DEP's customers. *Id.* Witness Jiggetts stated that it is DEP's position that these storm restoration expenses are a cost of service of the regulated utility that are reasonably and prudently incurred and should be recovered from customers. *Id.*

Witness Jiggetts also responded to the Public Staff's second assertion and explained that the deferral of the amounts to the balancing account does not preclude those amounts from being subject to audit or review by the Public Staff or the Commission. *Id.* at 86. Witness Jiggetts testified that deferrals, by their nature, are unaudited amounts when initially recorded, but that when the amounts in the balancing account are put forth for recovery or return to customers in a future case or securitization, the activity and related balance will be subject to audit for reasonableness and prudency. *Id.*

In her third and final supplemental testimony, witness Jiggetts updated the storm normalization calculation to $22.2 million. Jiggetts Supplemental Ex. 4, Tr. Ex. vol. 14. In its exhibits to settlement testimony, the Public Staff similarly utilized $22.2 million for DEP's storm normalization calculation. Public Staff Accounting Ex. 1, Tr. Ex. vol. 19.

The Public Staff Supplemental and Settlement Testimony

In its supplemental and settlement testimony, the Public Staff testified that, based upon the updated numbers provided in witness Jiggetts' supplemental filings with regard to the costs of Winter Storm Izzy and other 2022 storms, it recommends that the costs incurred for Winter Storm Izzy be recovered through securitization. Tr. vol. 19, 91.

Testimony Presented at the Expert Witness Hearing

At the expert witness hearing, DEP witness Jiggetts explained the methodology for the calculation of storm normalization of $22.2 million in this case and testified that the Public Staff agreed with her storm normalization calculation. Tr. vol. 14, 29-30; 57-58.

Public Staff witnesses Zhang and Boswell explained at the expert witness hearing that, while the costs contained in DEP's initial filing did not rise to the level of warranting deferral, DEP's inclusion in a supplemental filing of costs associated with Hurricane Ian – when viewed together with Winter Storm Izzy costs – met the threshold warranting deferral or securitization of the costs. Tr. vol. 19, 150-51.

At the expert witness hearing, DEP witness Jiggetts described the mechanics of DEP's proposal for a storm balancing account and how it is accomplished using a visual aid. DEP Redirect Jiggetts Direct and Settlement Ex. 2, Tr. Ex. vol. 14. Witness Jiggetts explained how the exhibit shows that in Year 1 DEP experienced $25.65 million in storm restoration costs (apart from major storms where costs would ordinarily be deferred or securitized). Subtracting that amount from "storm normal" ($22.2 million) leaves an under-recovery of $3.45 million, which is deferred to the Storm Balancing Account, meaning that at its inception in this example, the account is a Regulatory Asset. In Year 2, however, DEP experiences only $10.15 million in storm restoration costs. After accounting for the existing balance in the account ($3.45 million) and Year 2's "storm normal" (again, $22.2 million), the balance in the account has now shifted to a Regulatory Liability of $8.6 million – that is, over the two year period in the example, DEP collected "storm normal" costs in rates amounting to $44.4 million, and experienced restoration costs associated with "normal" storms of $35.8 million, leaving a balance in the account of $8.6 million in favor of customers.

Witness Jiggetts clarified that the initial building block for the storm balancing account is the calculation of the storm normal expense, which is the amount already in rates. Tr. vol. 14, 27-31. Witness Jiggetts testified that, as originally approved by the

Commission in DEP's 2012 Rate Case, Docket No. E-2, Sub 1023, "storm normal" embeds average storm restoration costs in rates over a 10-year period, after excluding costs which would ordinarily be deferred or securitized. She explained that deferral or securitization applies to major storms, so the "storm normal" calculation is designed to have a baseline level of storm restoration cost in rates derived from a 10-year average. *Id.* at 28-30. In this case, the "storm normal" cost to be embedded in rates is $22.2 million, a figure with which the Public Staff agrees. *Id.* at 30.

Witness Jiggetts testified that, as proposed, the account would have a regulatory liability of approximately $2 million (in favor of customers), which would extinguish costs associated with Winter Storm Izzy but also lower returns, since the funds would be in rate base. Tr. vol. 14, 62-63. Witness Jiggetts stated that this regulatory liability position would continue until the next general rate case and, even though the balance in the account would change from year to year based upon storm costs actually experienced from a rates charged to customer perspective that the initial $2.27 million credit, would stay reflected in rates until DEP returns for a rate case proceeding. *Id.* at 63.

Discussion and Conclusions

As noted above, the Commission has approved DEP's calculation in this proceeding for the storm normalization expense to be included in rates.

The Commission stated in its Order in the 2017 Rate Case that both DEP and the Public Staff cite in support of their positions in this case with regard to the issues concerning the recovery of storm costs:

> The Commission's precedents do not require that ratepayers bear the entire cost of repairing the damage to a utility's system resulting from a major storm. Instead, deferrals of storm costs are limited to those costs that are beyond the normal range of fluctuation of storm costs from year (in this case, costs in excess of $27.4 million). In recent general rate cases, the Commission has also included in the utility's rates a storm cost allowance based on the average amount the company has incurred over a period of years (the storm cost allowance approved in Sub 1023 was $12.7 million per year). Costs may exceed an average, or normal, amount used to set rates in a general rate case; however, as long as those excess costs are within a normal range of variation, they should be presumed to be recovered through the utility's rates in effect at that time (given the fact that many expenses fluctuate from year to year).

Order Accepting Stipulation, Deciding Contested Issues and Granting Partial Rate Increase, *Application by Duke Energy Progress, LLC, For Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina*, No. E-2, Sub 1142, at 127 (Feb. 23, 2018) (2017 Rate Case Order).

Based upon DEP's spending of $87.126 million on a North Carolina retail jurisdictional basis in 2022 on annual storm costs, which is above the annual threshold of $27.4 million on a North Carolina retail jurisdictional basis in annual storm costs that the Public Staff agreed is proper for seeking deferral or securitization, the Commission is satisfied that DEP has met the threshold warranting a deferral or securitization for Winter Storm Izzy and Hurricane Ian. As discussed herein, the Commission concludes that DEP should be allowed to recover the 2022 incremental Winter Storm Izzy costs of approximately $15 million, which amount was agreed to by the Public Staff, by applying a portion of the over-amortization of Hurricane Matthew costs in the amount of $17 million from the 2017 Rate Case. As stated elsewhere in this Order, the remaining amount of over-amortization of Hurricane Matthew costs, approximately $2.0 million, should be returned to customers through a levelized rider over a period of one year.

With regard to the proposed storm balancing account, the Commission described the position taken by DEP in the 2017 Rate Case proceeding (that all costs in excess of a normalized annual amount should be considered extraordinary and recovered on a deferred basis) as potentially "set[ting] a dangerous precedent for other categories of costs in the future." 2017 Rate Case Order at 130. More specifically, the Commission stated explicitly that:

> Under this approach, the Company would be assured of recovery of all its storm costs on almost a "true-up" basis, either through the presumed annual allowance in rates or through deferral and amortization. In effect, DEP's proposal would amount to a "tracker" system for storm cost recovery, similar to the riders established by the General Assembly in G.S. 62-133.2, 62-133.8 and 62-133.9 for fuel, REPS, and DSM/EE cost recovery. If DEP is allowed to implement such a system for recovery of its storm costs, other utilities may well seek to adopt a similar approach for any of various other expense items. In light of this concern, and the attendant shifting of more risk to customers, the Commission has generally been reluctant to approve cost tracker systems, except when they are required by statute.

Id.

In this case, and at this time, the Commission is unpersuaded by DEP's contentions that there is any reason to begin allowing, in essence, a true-up of storm costs where such recovery is not explicitly statutorily permitted. Further, the Commission continues to have concerns that DEP's proposed approach might set precedent for other categories of costs in the future. The Commission notes that any storm costs not eligible for securitization or deferral are presumed to be covered by DEP's authorized base rates. For these reasons, the Commission declines to approve a storm balancing account, at this time, as requested by DEP.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 67-69

The evidence supporting these findings of fact is contained in DEP's verified Application and Form E-1; the testimony and exhibits of DEP witnesses Abernathy, Jiggetts, Harris, Quick, Bateman and Stillman, Public Staff witnesses Zhang and Boswell; and the entire record in this proceeding.

IIJA/IRA

By Application and through the direct testimony of witness Abernathy, DEP requests to defer the estimated tax benefits, net of costs, associated with the IRA and IIJA. Tr. vol. 23, 151, 154.

With respect to the IRA, DEP witness Panizza discussed the two solar MYRP projects and six battery energy storage MYRP projects that are eligible for either Investment Tax Credits (ITC) or Production Tax Credits (PTC) made available under the IRA. Tr. vol. 16, 140-44. Witness Abernathy explained how DEP estimated the IRA benefits based on the best information available and that DEP's intention is for customers to receive the full benefit (net of costs) of the tax credits. Tr. vol. 23, 151. Witness Abernathy also testified that "the Company agrees [with the Public Staff] that a deferral of IIJA impacts is appropriate and supports the recommendation for the Commission to approve an accounting order to defer any incremental revenue requirement impacts, including benefits and costs related to IIJA, to be addressed in a future rate case." Tr. vol. 23, 154.

Public Staff accounting panel witnesses Boswell and Zhang, as well as Public Staff witness Thomas, testified in support of the requested deferral treatment of the IRA impacts. Tr. vol. 19, 77, 178-80, 195. Public Staff witness Nader provided similar testimony, recommending that the Commission treat the impacts associated with the IIJA consistent with those related to the IRA. Tr. vol. 21, 114.

Based on foregoing, the Commission concludes that DEP's request for an accounting order authorizing deferral of all IRA and IIJA related impacts, net of costs, as well as any difference between realized and estimated impacts included in DEP's filing is reasonable and should be approved.

Customer Assistance Program, Payment Navigator Program, and the Tariffed On-Bill Program

In her direct testimony, DEP witness Jiggetts explained that DEP has proposed several new programs in this case to benefit customers, including the CAP, Tariffed On-Bill program, and the Payment Navigator program (Customer Programs) and that DEP would incur certain implementation and administration costs that were not included in the test period, and which are not known and measurable at this point. She stated that should the Commission approve the Customer Programs, DEP requests permission to establish a regulatory asset and defer to the account the incremental implementation and administrative O&M costs related to the programs for future recovery in rates. Witness Jiggetts also testified that DEP is proposing PIMs as part of its PBR application and that DEP requests to defer to this regulatory asset the implementation costs for the PIMs, including, without limitation, certain costs relating to marketing, administration, and the PIMs dashboard. Tr. vol. 13, 209.

DEP witnesses Bateman and Stillman testified that the PIMs dashboard had a capital cost estimate of $540,000, with estimated annual O&M costs of approximately $100,000, with DEP proposing to allocate 43.23% of these costs to DEP's North Carolina retail customers. Tr. vol. 14, 112.

Public Staff witnesses Zhang and Boswell testified that the proposed deferral of the costs associated with the implementation of the proposed Customer Programs and PIMs fails to meet either prong of the Commission's two-prong test for deferrals, and therefore DEP's request should be denied. Tr. vol. 19, 75-76. They further testified that because PIMS are designed to protect ratepayers and are required for approval of an MYRP, PIMs are part of DEP's normal course of business and should also be denied on that basis. *Id.* at 75-76.

In her rebuttal testimony, witness Jiggetts responded to the Public Staff's recommendation to deny DEP's request on the basis of the deferral test. Tr. vol. 23, 105. Witness Jiggetts testified that DEP's request is being included as a part of its general rate case proceeding and is not an "out of period" cost subject to the Commission's two-prong deferral test. Witness Jiggetts explained that even though the costs of implementing these programs are known and measurable, DEP did not adjust operating expenses in this case to include these incremental costs which are not captured in the historic test period. *Id.* at 106. Witness Jiggetts clarified that while PIMs will become a part of DEP's normal course of business as a result of the MYRP, the costs of that new normal course of business have not been included in operating expenses for recovery from customers. *Id.* Thus, witness Jiggetts explained that creation of a regulatory asset for deferral of the costs would allow DEP to postpone recovery of these costs until the Customer Programs are implemented and benefitting customers. *Id.*

At the expert witness hearing, responses to the Public Staff discovery requests were entered into the record in which DEP indicated that many of the costs associated with implementation of the PIMs were minimal. Public Staff Cross Examination Bateman Stillman Direct and Settlement Ex. 1, Tr. Ex. vol. 16.

The Commission has historically treated deferral accounting as a tool to be allowed only as an exception to the general rule, and its use has been allowed sparingly. Deferred accounting treatment is generally authorized by the Commission only in those instances where there was a clear and convincing showing that the costs in question were of an unusual or extraordinary nature and that, absent deferral, the costs would have a material impact on the company's financial condition. Requests for the use of deferral accounting have been historically considered by the Commission on a case-by-case basis and such decisions are based on the specific circumstances of the request.

The Commission considers program proposals such as the Customer Programs, to be a normal part of DEP's operations to provide benefits to customers with respect to billing and payment options and other customer service offerings pertaining to the provision of electric utility service. With respect to PIMs, the Commission acknowledges that this is the first time the Commission is considering PIMs in a general rate case proceeding; however, PIMs are now statutorily part of the normal course of business when a utility elects in its discretion to pursue an MYRP. Accordingly, DEP's request to defer these costs is denied. To the extent that there are ongoing O&M expenses associated with implementation of the PIMs and customer programs, DEP may seek cost recovery of actual expenses incurred during a future test period in its next general rate case.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 70

Interconnection CIAC Regulatory Liability Recommendation

The evidence supporting this finding of fact is contained in DEP's verified Application and Form E-1; the Revenue Requirement Stipulation; the testimony and exhibits of DEP witness Speros and Public Staff witnesses Zhang and Boswell; and the entire record in this proceeding.

Public Staff witness Metz explained that in relation to interconnection agreements (IAs), Contributions in Aid of Construction (CIAC) are funds provided to DEP by third party utility customers to pay for capital projects (usually new construction) typically requested by the third party. Tr. vol. 16, 452. Witness Metz testified that during his review of IAs between third party qualifying facilities (QFs) and DEP, he discovered that DEP had historically recorded QF developer CIAC payments as revenue rather than an offset to rate base. *Id.* Witness Metz stated that a QF developer is responsible for the cost of the network upgrades required for interconnection and that the costs are not socialized to all ratepayers unless otherwise permitted by law to ensure that the ratepayers are held harmless. *Id.* He explained that DEP performs a study to determine what network upgrades are necessary for the safe and reliable interconnection of the developer's project. DEP then charges the third-party developer for the construction costs of the identified network upgrades. *Id.* Witness Metz testified that ratepayers should be held harmless if the network upgrades are paid for in whole by the developer, plus any additional true up costs, once the project is online. *Id.* Witness Metz stated that the Public Staff attempted to determine the magnitude and resulting rate impact of this issue; however, more time was needed to audit, validate, and review this issue given the complexity. *Id.*

Witness Metz testified that DEP self-identified errors related to recording CIAC interconnection activity during a 2019 audit but deemed it as not material. *Id.* at 452-53. The audit findings stated that DEP's practice of recording CIAC from developers to the income statement as Other Revenue while charging costs incurred to complete construction to CWIP balance sheet accounts is incorrect. *Id.* at 453. To correct this issue, the audit findings instructed that the CIAC should be recorded to CWIP. *Id.* Witness Metz stated that DEP reviewed this topic again during a 2022 follow-up audit and that the audit findings recognized that DEP's process improvements have strengthened tracking of the interconnection financial activity. *Id.* However, the audit findings determined that a comprehensive process documentation needs to be established to define roles and responsibilities and to ensure sustainability of the financial processes. *Id.* A deadline of June 2023 was established for DEP to prepare this documentation. *Id.*

Public Staff witnesses Zhang and Boswell testified that DEP booked these CIAC payments inconsistently, leaving the Public Staff unable to determine whether ratepayers were held harmless regarding the costs associated with these interconnections. Tr. vol. 19, 39. Witnesses Zhang and Boswell further testified that DEP changed its booking procedures for the fees received for interconnections at the beginning of 2022. *Id.* The Public Staff witnesses asserted that they were unable to determine the magnitude of the error, whether ratepayers have been harmed, and if so by how much or whether DEP's new procedures will alleviate the issues. Tr. vol. 16, 453; Tr. vol. 19, 39. Therefore, the Public Staff recommended that the Commission order DEP to produce all entries related to the IAs for all plant, depreciation, and collections so the Public Staff can determine whether ratepayers have been held harmless. *Id.* Additionally, the Public Staff recommended that a regulatory liability be established to record any instances in which DEP incorrectly recovered costs associated with IAs from ratepayers, to be flowed back to ratepayers with interest at DEP's weighted average cost of capital in the next DEP general rate case. *Id.* at 39-40. Witnesses Zhang and Boswell testified that since DEP had full control over its accounting systems and should have booked the amounts correctly, any items found to have been booked that should have been recovered from ratepayers should not be credited to the regulatory liability. *Id.* at 40. Witnesses Zhang and Boswell recommended that the Commission order DEP to review its CIAC policy and report the results of that review in the next general rate case. *Id.*

DEP witness Speros took exception to the Public Staff's recommendations and argued that the establishment of a regulatory liability has not been justified in this case. Tr. vol. 13, 60. Witness Speros explained that DEP has taken a number of steps to ensure CIAC associated with IAs is appropriately recorded on DEP's books. *Id.* He stated that this process begins with DEP's monthly reconciliation of associated liability accounts. *Id.* For Transmission projects, a monthly journal entry is made to credit capital projects for customer deposits based upon the cost incurred. *Id.* For distribution projects, quarterly journal entries are made to credit the capital projects for customers based upon costs incurred. *Id.* Witness Speros stated that DEP's project controls organization and finance organizations then work together to ensure that the current list of IA projects is appropriately analyzed so that proper journal entries are made, whether a debit or credit to the construction project. *Id.* Moreover, witness Speros explained that DEP continually works to improve its accounting processes, including the process for recording CIAC associated with IAs. *Id.* at 61. He commented that since 2019, DEP has taken steps to improve the processes in place for recording CIAC associated with IAs and made recent modification in 2022. *Id.* Witness Speros also explained that DEP has not been able to identify any interconnection costs associated with CIAC that ratepayers should not have been charged in DEP's last general rate case. Tr. vol. 13, 62.

Witness Speros also testified that the Public Staff's broad-based recommendation to order DEP to produce all entries related to IAs for all plant, depreciation, and collections is unnecessary to demonstrate that DEP's procedures are working properly. *Id.* at 61. In the alternative, DEP offered to work with the Public Staff in a collaborative fashion to facilitate their review and help identify information that would best provide a reasonable and efficient evaluation. *Id.* at 61-62. DEP also did not oppose in principle reporting to the Commission on its CIAC policy in the next general rate case. *Id.* at 63.

No other intervenors raised an issue regarding DEP's accounting for CIAC associated with IAs.

The initial Revenue Requirement Stipulation identifies as unresolved the issue of whether it is necessary for DEP to establish a regulatory liability to address CIAC for IAs as recommended by the Public Staff. As discussed below, the Commission concludes that the evidence in this case does not support the establishment of a regulatory liability to address CIAC collected by DEP from interconnection customers.

Fundamental to the establishment of a regulatory liability for CIAC related to IAs is a showing that the establishment of a regulatory liability is justified. In this case, the Public Staff offered very little in the way of justification to support the establishment of a regulatory liability. The Public Staff testified that it had found inconsistencies in the financial accounting of the CIAC related to IAs and that it was unable to determine whether ratepayers are being held harmless. Witness Metz acknowledged that the Public Staff needed more time to audit, validate, and review this issue given its complexity. Beyond these statements, the Public Staff witnesses were not in a position to demonstrate to the Commission the magnitude and rate impact on customers of this issue such that the establishment of a regulatory liability would be justified. Instead, the Public Staff requested that the Commission require DEP to produce all entries related to IAs for all plant, depreciation, and collections to allow the Public Staff to continue its audit of this issue beyond the conclusion of the present rate case proceeding.

The explanations provided by DEP witness Speros in his rebuttal testimony are informative as to the steps that DEP has taken to record CIAC for IAs in a manner that does not harm customers. As witness Speros explained, DEP has worked to improve its CIAC accounting procedures since 2019, with additional improvements made as recently as 2022. Further, as a result of the follow-up audit in 2022, a June 2023 deadline was established for DEP to document processes and define roles and responsibilities related to the financial accounting of CIAC related to IAs. The Commission determines that the requirement for DEP to construct this documentation should facilitate sustainability of DEP's improved financial processes. DEP should provide the Public Staff a copy of its documented processes related to this issue once the documentation is completed.

The Commission concludes that the Public Staff's proposal to establish a regulatory liability is not warranted at this time, given the uncertainty regarding the magnitude of the issue. In so concluding, the Commission gives weight to the testimony of witness Speros that

DEP has been unable to identify any interconnection cost associated with CIAC that ratepayers should not have been charged in DEP's last general rate case.

Based upon all of the evidence presented, the Commission concludes that the establishment of a regulatory liability is not justified by the record in this proceeding. DEP shall continue its work with the Public Staff regarding the documentation of its processes related to the recording of CIAC and shall report on the CIAC issue in its next general rate case application as required by the Revenue Requirement Stipulation.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 71

Quality of Service

The evidence supporting this finding of fact is set forth in the testimony of DEP witnesses Guyton, Maley, and Quick and Public Staff witness T. Williamson.

DEP witnesses Guyton and Maley testified to the performance of the DEP transmission and distribution systems during the base period. Witness Maley testified that DEP's transmission system is reliable and well-maintained, and that DEP is seeking to continue transmission investments to facilitate the conversion of the transmission system to meet future demands. Witness Maley further indicated that DEP utilizes the System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) metrics to measure outage durations and that these metrics over the base period showed a downward trend in outages (and therefore an upward trend in reliability). Witness Maley indicated that the transmission system also utilizes an Outages per Hundred Miles per Year – Sustained Automatic (OHMY-SA) metric which has further demonstrated the reliability of the DEP transmission system. Tr. vol. 10, 176-77. Witness Guyton testified that DEP's operational investments since its last rate case have allowed it to meet its operational performance and customer satisfaction goals and that it is providing safe and reliable service. *Id.* at 48. Witness Guyton also cited DEP's SAIDI and SAIFI scores as indicative of increasing system reliability in the form of reduced customer outages. He attributed this improvement in outage experience to ongoing grid improvements such as Self-Optimizing Grid improvements as well as ongoing vegetation management activities. *Id.* at 50.

In his direct testimony, Public Staff witness T. Williamson largely concurred with DEP's conclusions about improving service quality and attributed the stable to improving system performance to DEP's Grid Improvement Plan and vegetation management activities. Tr. vol. 21, 222. Witness T. Williamson also engaged in an in-depth analysis of DEP's service quality in which he examined various aspects of DEP's performance in initiating new service, providing normal day-to-day service, and restoration of service after outage events. *Id.* at 218-33. Witness T. Williamson also summarized various consumer statements of position filed with the Commission relative to this rate case. *Id.* at 233-35.

Regarding the initiation of new service, witness T. Williamson indicated that new service installations had almost doubled from 2015 through 2022 but that DEP's average percentage of installations completed within 20 days had improved in recent years from historic averages and was in the low to mid 90s from 2020 forward. Witness T. Williamson also noted that the sheer number of new connections experienced by DEP in 2022 was having an impact on the ability to complete new installations quickly but that DEP still averaged to meet the 20-day goal 92.6% of the time in 2022. Witness T. Williamson also noted that "[t]he average business days to construct [new connections] has been consistently around the 10-day range and the average percent within 20 days has been consistently around the 95% range since 2019." *Id.* at 219-20. Regarding day-to-day service, witness T. Williamson reiterated that SAIDI and SAIFI scores have been trending downward since 2017 in part because of GIP program implementation which "provides a level of predictability concerning future service levels, to the benefit of customers. *Id.* at 222. Witness T. Williamson further testified that service reliability as measured by ASAI[22] has consistently measured more than 99.97% since 2013. *Id.* at 226. With respect to restoration of service after an outage, witness T. Williamson testified that DEP's Estimated Time to Restoration for service outages was met in 92% of Major Event Day outages. *Id.* at 232.

In her direct testimony, DEP witness Quick testified that in addition to DEP's primary responsibility of providing safe and reliable service, DEP understands that its customer base has diverse service needs and strives to recognize and accommodate them where possible. Tr. vol. 7, 67-68. She outlined the steps that DEP is taking to continue to improve customers' experiences and satisfaction. Tr. vol. 7, 65. With respect to DEP's customer care operations, witness Quick explained that they designed and continuously enhanced to ensure that customer inquiries are answered promptly and accurately. Customer calls are either processed in the Interactive Voice Response (IVR), allowing customers to self-serve, or by a call center specialist. Tr. vol. 7, 67. She also described how DEP uses social media channels to inform customers about reliability updates in their area and changes that could impact their bills. Additionally, in an emergency or major storm, DEP uses social media to communicate essential information to customers, making proactive posts to quickly warn as many customers as possible and engage with customers who have storm- or outage-related questions. Tr. vol. 7, 69-70.

Witness Quick also testified about the programs that DEP supports to help customers with the affordability of electric utility service. She noted the energy efficiency programs that help reduce energy usage and provide weatherization assistance. Tr. vol. 7, 71-73. She also detailed DEP's numerous efforts to support customers during the unprecedented COVID-19 pandemic. One example she gave was DEP's expansion and extension of the Winter Moratorium, a period from November until March every year where qualified customers are protected from disconnection for non-payment. DEP ensured the Winter Moratorium remained in place from November 2020 until March 2022, protecting approximately 48,000 eligible customers from disconnection during the initial and subsequent COVID-19 pandemic waves. Another example was the outreach campaigns to municipal leadership, community stakeholders, Chambers of Commerce, state agencies, food banks, and churches where

[22] ASAI is the ratio of the total number of customer hours that service was available during a given time period to the total number of customer hours demanded. Algebraically, this ratio is represented as follows: ASAI = 1 – (SAIDI/8760).

DEP communicated with customers to promote options for assistance and contacting DEP. Tr. vol. 7, 81-88.

Witness Quick further testified about recent digital enhancements to improve service to customers. She relayed that after receiving customer feedback, DEP improved its website by making interaction operations easier to locate in January 2022. Additionally, she described an interactive Transmission Map that details transmission projects planned across North Carolina, a planned vegetation management map, a feature alerting customers to estimated call wait times, the ability for customers to start and stop service online, and a digital, and a self-service enrollment option for payment arrangements. Moreover, witness Quick highlighted that DEP's digital enhancements made it easier for customers to report service interruptions. She also testified that DEP offers a fee mobile app that allows residential and small business customers to easily manage their account from anywhere in the United States. Witness Quick stated that since making these changes, customers are reporting higher satisfaction with their web experiences. Tr. vol. 7, 96-105.

In recognition of the policy of the State of North Carolina "to promote adequate, reliable and economical utility service" codified at N.C. Gen. Stat. § 62-2(2) and in accordance with the Commission's general supervisory authority established in N.C. Gen. Stat. § 62-32, and recognizing that the Commission found DEP's service quality to be "good" in the 2019 Rate Case and that the performance metrics for service rendered have not declined and, in some cases, have improved since that rate case, as is reflected in witness Williamson's testimony, the Commission concludes, based on the record in this proceeding, that the quality of service provided by DEP's is good. No other party presented evidence on DEP's service quality.

Additionally, no other party presented evidence critical of DEP's quality of service. Based on the foregoing, the Commission concludes that DEP provides adequate service to customers.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 72-73

Tax-Related Items

The evidence supporting these findings of fact is contained in DEP's verified Application and Form E-1; the testimony and exhibits of DEP witness Jiggetts, Public Staff witnesses Zhang and Boswell; and the entire record in this proceeding.

In its Application, DEP proposes to revise the EDIT-4 rider to return an additional $16.2 million for unprotected federal EDIT and $4.5 million for deferred revenues to customers over the remaining 2.7 years of the total five years to return the unprotected federal EDIT approved in the prior rate case. The two-year period for Deferred Revenues under EDIT-3 will expire in June of 2023; therefore, DEP is proposing to flow the additional amounts back to customers over the remaining life of the EDIT-4 rider in lieu of creating a new decrement rider. *Id.*

DEP witness Jiggetts supports this revision to the EDIT-4 Rider in her direct testimony and in Jiggetts Exhibit 3. Tr. vol. 13, 164. The Public Staff agrees with DEP's proposal to flow back the incremental amount to customers on a levelized basis over the remaining EDIT rider term; however, the levelized return rate used by the Public Staff reflects DEP's 3.88% cost of debt rate and a return on equity of 9.25% from December 31, 2022. Tr. vol. 23, 107.

In her third supplemental testimony, witness Jiggetts updated DEP's cost of debt to 4.03% as of March 31, 2023, and recalculated the proposed changes to the EDIT-4 Rider accordingly. Tr. vol. 13, 240, 242. In the initial Revenue Requirement Stipulation, the stipulating parties agree to an embedded cost of debt of 4.03%. Revenue Requirement Stipulation § III.1, Tr. Ex. vol. 7.

Based on the foregoing, the Commission concludes that DEP's proposal to revise the EDIT-4 Rider to return additional unprotected federal EDIT to customers over the remaining life of the EDIT-4 Rider, as supported by the Public Staff, is just and reasonable and should be approved. Further, the Commission finds and concludes that the levelized return rate should be based on the 4.03% embedded cost of debt agreed to by the stipulating parties in the initial Revenue Requirement Stipulation and the capital structure and rate of return on equity approved by the Commission in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 74-75

Equal Percentage Allocation, Base Fuel and Fuel-Related Factors and Fuel Cost Allocation

The evidence supporting these findings of fact is contained in DEP's verified Application and Form E-1; the testimony and exhibits of DEP witnesses Hager, and Jiggetts, the testimony of Public Staff witnesses Lucas, and McLawhorn, and Zhang and Boswell, and the testimony of CIGFUR witness Phillips, and the entire record in this proceeding.

In its Application and Form E-1, the fuel rates presented by DEP were allocated to customer classes utilizing the equal percentage fuel adjustment.

Public Staff witness Lucas testified that DEP currently allocates fuel cost adjustments to customer classes based on an equal percentage change, meaning that fuel and fuel-related costs are recovered using a uniform percent increase or decrease per rate class such that each rate class will, on average, experience the same average monthly percent increase or decrease as the overall fuel and fuel-related cost change. Tr. vol. 20, 28. Public Staff witness Lucas testified that since 2008, DEP has allocated fuel cost increases on an equal percentage basis to each of its five customer classes as allowed by Session Law 2007-397. Tr. vol. 20, 28. He testified that the Public Staff first supported the use of equal percentage allocation in DEP's 2008 fuel adjustment proceeding, Docket No. E-2, Sub 929. He cited several reasons for the Public Staff's agreement to the equal percentage allocation, such as the uncertain economic times and the large increase in fuel costs. *Id.* at 29-30. He noted that the equal percentage method of adjusting rates assisted industrial customers financially during the Great Recession and during a period of unprecedented increases in coal prices at the expense of other customers. Id. at 28-31. He testified that the distortion that can be created by equal percentage fuel adjustments is found in DEP's most recent 2022 fuel rider proceeding, in which fuel costs increased for all customer classes except LGS, which received a fuel rate decrease. Id. at 30-35. He explained that, for this reason, it is the Public Staff's recommendation that the Commission does not allow DEP to make equal percentage fuel adjustments but allow DEP to continue to offer voltage differentiated rates. *Id.*

Witness Lucas stated that N.C.G.S. § 62-133.16(b) requires the Commission to allocate the utility's total revenue requirement among customer classes based on the cost causation principle and minimize cross subsidies "to the greatest extent practicable." *Id.* at 33-35, 53, 103. Witness Lucas noted that the statute defines the cost causation principle to mean "establishment of a causal link between a specific customer class, how that class uses the electric system, and costs incurred by the electric public utility for the provision of electric service." *Id.* at 33.

Witness Lucas presented the current fuel rates adjusted to remove the equal percentage allocation method. *Id*. at 36. As set forth in his Table 4, the rates in cents per kWh, excluding the regulatory fee, are 2.647 for residential customers, 2.654, for SGS customers, 2.609 for MGS customers, 2.516 for LGS customers, and 2.511 for Lighting customers. *Id.* at 36.

In his direct testimony, CIGFUR witness Phillips provided support for the equal percentage methodology. Tr. vol. 21, 487-88. He testified that the methodology has been approved without objection by any party in every annual fuel charge adjustment proceeding since 2008 and that the method has served ratepayers well and should be continued to be utilized. *Id.* He further stated that the methodology levelizes over time any harsh impacts and results in equal percentage increases or decreases to all customers, which are fair, just, and reasonable. *Id.*

The Commission notes that in DEC's annual fuel proceeding, DEC and the Public Staff agreed that DEC should continue to utilize the equal percentage fuel adjustment for purposes of that case. *See* Agreement and Stipulation of Partial Settlement, Docket No. E-7, Sub 1282 (filed May 31, 2023). The Commission further notes that there is not a similar agreement filed in the DEP annual fuel proceeding in Docket. No. E-2, Sub 1321.

Based on all the evidence in this proceeding, the Commission concludes that use of the equal percentage method of allocating fuel and fuel related costs does not follow the cost causation principle. In reaching this conclusion, the Commission gave substantial weight to the testimony of the Public Staff regarding the cost causation principle set forth in N.C.G.S. § 62-133.16, as well as their demonstration of the distortion that can be created by equal percentage fuel adjustments. Further, the Commission finds that this change shall be implemented for fuel rider proceedings filed after the date of this Order, and shall not apply in DEP's pending fuel adjustment proceeding, Docket No. E-2, Sub 1321.

Base Fuel and Fuel-Related Cost Factors

DEP's Application explained that the rates set forth in the exhibits to the Application included a base fuel and fuel-related rate of Residential - 2.126 cents per kWh; SGS - 2.111 cents per kWh; MGS 2.169 cents per kWh; LGS- 2.019 cents per kWh; and Lighting - 1.682 cents per kWh, excluding the Experience Modification Factors as approved in Docket No. E-2, Sub 1272 and excluding regulatory fees.

Witness Jiggetts testified DEP made an adjustment (Adjustment No. NC2010) to test period fuel expense to match the fuel clause revenues included in pro forma Adjustment No. NC1010. Tr. vol. 13, 180-81. She explained that by matching the expenses to the revenue, the adjustment ensures that no increase is requested in this proceeding related to fuel and fuel-related costs that are recoverable through the fuel clause. *Id*. She further stated that DEP intended to update this pro forma adjustment once it received an order in its pending fuel case in Docket No. E-2, Sub 1292. *Id.*

In her supplemental direct testimony, witness Jiggetts explained that DEP had updated pro forma Adjustment No. NC2010 to include revisions to reflect the fuel rates approved under in Docket No. E-2, Sub 1292. Tr. vol. 13, 221.

In her second supplemental direct testimony, witness Jiggetts testified that DEP had made a new adjustment (Adjustment No. NC2020 to adjust the nonfuel component of purchased power expense to reflect the impacts of the Stipulation Regarding the Proper Methodology for Determining the Fuel Costs Associated with Power Purchases from Power Marketers and Others reached with DEP, DEC and the Public Staff in Docket No. E-7, Sub 1282. Tr. vol. 13, 235. She further explained that during the test year, 39% of purchased power energy costs were estimated to be non-fuel expense and appropriate for cost recovery through base rates. *Id.* Based on the stipulation, during the test year, 15% of energy costs from these power purchases is the appropriate percentage to be deemed as non-fuel costs and appropriate for cost recovery through base rates. This pro forma adjustment makes the required reduction to operating expense in the test year as agreed upon with the Public Staff. *Id*.

The Commission issued a final order in the Sub 1292 fuel rider proceeding on November 3, 2022. In the Sub 1292 order, the Commission concluded that, effective for service rendered on and after December 1, 2022, DEP shall adjust the base fuel and fuel-related cost factors in its North Carolina retail rates, as approved in the 2019 Rate Case, amounting to 2.080¢/kWh for the Residential class, 2.126¢/kWh for the SGS class, 2.228¢/kWh for the MGS class, 2.204¢/kWh for the LGS class, and 1.392¢/kWh for the Lighting class (all excluding the regulatory fee), by amounts equal to 0.728¢/kWh, 0.971¢/kWh, 0.352¢/kWh, (0.066¢)/kWh and 1.984¢/kWh, respectively, and further, that DEP shall adjust the resulting approved prospective fuel and fuel-related cost factors by EMF increments/(decrements) of 0.649¢/kWh for the Residential class, 0.449¢/kWh for the SGS class, 0.586¢/kWh for the MGS class, 0.898¢/kWh for the LGS class, and 0.834¢/kWh for the Lighting class (excluding the regulatory fee). The Commission further ordered that the EMF increments are to remain in effect for service rendered through November 30, 2023.

In the direct testimony of Public Staff witnesses Zhang and Boswell, they also used the fuel rates approved in Docket No. E-2, Sub 1292 to update revenues and expenses to May 2023 levels. Public Staff Accounting Ex. 1, Schedule 3-1(b)(1), Tr. Ex. vol. 19. In their Supplemental and Stipulation testimony they included an adjustment to fuel costs to reflect the impact of witness Lucas' recommendation to eliminate the equal percentage change in fuel rates. Tr. vol. 19, 91.

The only party that submitted evidence in this proceeding using fuel rates other than those approved in Docket No. E-2, Sub 1292 was the Public Staff. However, as shown on Public Staff Accounting Supplemental and Settlement Exhibit 1, Schedule 3-1(b), they adjusted fuel expense and revenue by the same amount so that there was no impact on the revenue requirement in this proceeding. *Id.* Also, Public Staff witness Lucas recommended that such rates be implemented effective December 1, 2023. No party offered any evidence contesting the testimony of witness Jiggetts that specifically supported the base fuel and fuel-related cost factor proposed by DEP. Accordingly, the Commission concludes for purposes of this proceeding that the total of the approved base fuel and fuel-related costs factors, by customer class — the sum of the respective base fuel and fuel-related costs factors set in the 2019 Rate Case and the annual non-EMF fuel and fuel-related costs riders approved by the Commission in Docket No. E-2, Sub 1292 — are just and reasonable to all parties in light of all the evidence presented.

Fuel Cost Allocations

In DEP's previous general rate case, the parties agreed on production plant as an appropriate allocation factor for purchased power capacity costs. Tr. vol. 11, 107. Under N.C.G.S. § 62-133.2(a2)(2), the Commission shall determine how these costs shall be allocated in a general rate case for the electric public utility. Therefore, this proceeding is the appropriate forum for the Commission to reconsider the appropriate cost allocation methodology for such costs, which are to be requested for cost recovery in DEP's annual fuel proceeding.

Witness Hager testified that DEP is proposing that the Commission use production demand as the more appropriate factor to allocate purchased power capacity costs to North Carolina retail and across North Carolina retail customer classes. Tr. vol. 11, 107. She testified that allocation based on production demand is more appropriate than production plant because purchased power capacity costs that are not recovered through the fuel clause are allocated on production demand. *Id.* She testified that the change towards allocation based on production demand would align all purchased capacity costs under the same allocator. *Id.* Additionally, most production plant is allocated on production demand, except for jurisdiction-specific amounts that are not related to purchase power costs. *Id.*

No party offered testimony opposing DEP's recommendation.

In DEP's previous general rate case, the parties agreed on production plant as an appropriate allocation factor for purchased power capacity costs. Tr. vol. 11, 107. Under N.C.G.S. § 62-133.2(a2)(2), the Commission shall determine how these costs shall be allocated in a general rate case for the electric public utility. Therefore, this proceeding is the appropriate forum for the Commission to reconsider the appropriate cost allocation methodology for such costs, which are to be requested for cost recovery in DEP's annual fuel proceeding. Based upon the evidence presented in this case, the Commission finds and concludes that the same production demand allocation method approved for production demand costs in this case using the 12 CP methodology at NC retail and the Modified A&E methodology for NC retail classes is the most appropriate methodology for allocating purchased power capacity costs in DEP's annual fuel proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 76-77

Residential Decoupling Mechanism and Earnings Sharing Mechanism

The evidence supporting these findings of fact is contained in DEP's verified Application and Form E-1; the testimony and exhibits of DEP witnesses Abernathy, Bateman and Stillman, Public Staff witnesses D. Williamson and Thomas, AGO witness Nelson, and the entire record in this proceeding.

Summary of Evidence

DEP's PBR Application seeks approval of performance-based regulation through the proposed three-year MYRP beginning on October 1, 2023 and ending September 30, 2026. DEP witness Bateman testified that in addition to the three-year MYRP, which includes an ESM, DEP's PBR Application also includes PIMs a decoupling mechanism for the residential customer class. Tr. vol. 14, 76. Witness Bateman explained that the PBR approach and DEP's PBR Application better aligns customer and state policy goals with utility revenues and performance than traditional ratemaking. *Id.* at 80.

Residential Decoupling Mechanism

DEP witness Abernathy provided direct testimony on the proposed decoupling mechanism. She testified that the "decoupling rate-making mechanism" is intended to break the link between an electric public utility's revenue and the level of consumption of electricity on a per customer basis. She explained that the following Rate Schedules are affected by the decoupling mechanism: RES, R-TOU, R-TOUD, and R-TOU-CPP, along with any new residential rate schedules approved by the Commission during the Plan Period. She testified that the Residential Energy Conservation Discount Rider is also impacted by decoupling. She testified as to how the annual and monthly target revenue per customer would be calculated for Rate Years 1, 2 and 3. She also testified as to estimated number of residential customers for each year and for each month for each rate year. She also explained that the difference between target residential revenues and actual residential revenues would be deferred, which would be adjusted to account for DSM/EE net lost revenues and incremental EV revenues. She also explained how the carrying cost on the deferral would be calculated. She explained how the Decoupling Rider will work and DEP's reporting obligations with respect to the deferred balance. Tr. vol. 13, 102-12.

AGO witness Nelson also supported using a lower carrying cost rate on the decoupling deferral amount and placing a hard cap of 3% on surcharges. Tr. vol. 18, 82-83. Witness Nelson explained that a hard cap would limit rate increases and promote cost containment. *Id*. at 84.

The Public Staff expressed only one concern regarding DEP's proposed decoupling mechanism. Public Staff witness Nader testified that N.C.G.S. § 62-133.16 authorizes the Commission to approve a residential decoupling mechanism designed to break the link between revenues and the consumption of electricity. Witness Nader also testified that the statute also the utility with an opportunity to exclude rate schedules or riders associated with EV charging from sales calculations for purposes of the mechanism. Tr. vol. 21, 110-11. Witness Nader objected to how DEP determined the estimate of EV sales for the calculation and recommended that the decoupling mechanism not include DEP's proposed "Incremental EV Revenue Adjustment". *Id.* Witness Nader asserted that the estimate was "highly speculative" and that the decoupling mechanism should only include the adjustment for EV sales when more accurate EV sales data are available. *Id.* He recommended that DEP use a lower kWh per EV estimate than DEP proposed initially.

AGO witness Nelson asserted that DEP's proposal to exclude EV sales from its decoupling mechanism is not in the public interest. Tr. vol. 18, 72-73. Witness Nelson asserted that there is no link between this proposal and the goal of advancing EV adoption. *Id.* at 74. Witness Nelson further stated that the calculation for EV sales is not accurate and recommended that the Commission reject DEP's proposal. *Id.* at 79.

DoD-FEA witness Blank recommended that the Commission deny DEP's proposal to remove EV sales from the ESM. Tr. vol. 21, 34. Witness Blank stated that the PBR Statute explicitly provides what a utility can exclude from the ESM calculation, and the statute does not list EV sales. Tr. vol. 21, 341.

In response to AGO witness Nelson's suggestion to institute a 3% hard cap on the amounts the utility is able to collect from customers, "decoupling cap," witness Abernathy testified that there is no basis for a cap in the statute, that a cap has only been authorized in a few states, and that there is no cap on the recovery of DSM/EE net lost revenues. Tr. vol. 23, 149-50. Witness Bateman's rebuttal testimony offered further support for the exclusion of EV sales from the decoupling mechanism. Tr. vol. 23, 161-62. Witness Bateman testified that adjusting the decoupling mechanism for EV sales allows the utility to retain incremental net revenues driven by EV growth, thereby directly connecting EV growth with net revenues. Witness Bateman explained that if the Commission precluded DEP from including an EV adjustment within the decoupling and ESM calculations, DEP's residential EV sales would be decoupled from the utility's margin, thus eliminating an important incentive for the utility to encourage EV adoption and grow EV sales in between rate case filings. *Id.*

The PIMs Stipulation provides that the parties thereto agree to allow DEP to exclude all EV sales from the decoupling mechanism subject to the following two conditions: (1) that the parties work together to develop and file EV tariffs and/or programs to estimate and update the revenue associated with residential EV sales in DEP's service territory, within 90 days of the Commission's order in this docket, and (2) that DEP updates the kWh per EV estimate proposed by Public Staff witness Nader with actual, DEP-specific EV usage data in each future decoupling rider proceeding.

Witness Bateman explained that the PIMs Stipulation clarified how DEP will obtain data that will help it to better estimate revenue associated with incremental residential EVs. Tr. vol. 14, 155. Witness Bateman explained that the agreed-upon method entails using DOT data to derive the number of residential EVs in DEP's service territory, using 180 kWh per vehicle as the electric usage (a value DEP measured within the EV Make-Ready Program), and then applying the flat residential tariff rate to the average monthly EV usage amount to derive the amount of residential EV sales to exclude from the decoupling mechanism. Tr. vol. 23, 234. Thereafter, within 90 days of a Commission order in this proceeding, DEP will file tariffs or programs, and using the data from those tariffs and programs, will refine the analytics to update the number of EVs and the usage assigned to each vehicle. *Id.* at 233. Witness Bateman also stated that DEP will also use this agreed-upon method to exclude EV sales from the ESM. *Id*. at 234-35.

Earnings Sharing Mechanism

DEP witnesses Abernathy and Bateman testified in support of the ESM, which is a component of the MYRP. Tr. vol. 13, 112; Tr. vol. 14, 81. Witness Abernathy explained that if DEP's adjusted earnings exceed the authorized ROE established by the Commission in this rate case plus 50 basis points, those excess earnings, including a return calculated at the weighted average cost of capital, must be distributed to customers over a 12-month period via the annual ESM Rider. Tr. vol. 13, 112.

Witness Abernathy testified that, for purposes of the ESM calculation, DEP will adjust earnings for weather, DSM/EE incentives, PIMs, and EV sales. Tr. vol. 13, 113.

Witness Bateman that the ESM allocates risk away from customers and onto DEP, noting how the ESM distributes to customers 100% of earnings in excess of 50 basis points above the authorized ROE on an annual basis, without a corresponding ability for DEP to collect additional revenue from customers if the utility is underearning. Tr. vol. 14, 81.

Also, as noted above, witness Bateman explained that if the Commission precluded DEP from including an EV adjustment within the ESM calculations, DEP's residential EV sales would be decoupled from the utility's margin, thus eliminating an important incentive for the utility to encourage EV adoption and grow EV sales in between rate case filings.

During the expert witness hearing DEP witness Stillman also provided support for DEP's proposal to exclude EV sales from the ESM where he stated that the adjustment would further support the increased adoption of EVs. Tr. vol. 13, 151. Witness Bateman further explained that this is consistent with the policy goals in N.C.G.S. § 62-133, Commission Rules R1-17B(g)(1)(f) and R1-17B(g)(2), and Governor Cooper's Executive Order 246. *Id.* at 162.

In response to Commission questions, DEP witness Jiggetts, noted that the reports DEP currently files to show annualized return on equity for each quarter is a very high level report. Tr. vol. 13, 327. Currently, DEP provides the Commission with a quarterly surveillance report, the ES1, that shows the Commission approximately where DEP's earnings are as compared to what it is allowed to earn. Tr. vol. 13, 324. Witness Jiggetts explained that in preparing that report, DEP makes numerous simplifying assumptions in order to be able to provide the report to the Commission within the required timeframe. *Id.* Witness Jiggetts confirmed that the quarterly surveillance reports provide a "snapshot" at a high level that does not include several ratemaking adjustments that would be necessary to arrive at DEP's actual return on rate base. *Id.* at 327. DEP provides qualifying language in the quarterly reports indicating that the figures do not accurately reflect DEP's earnings. *Id.* at 329.

Commissioner Clodfelter followed up with witness Jiggetts by asking how the Commission and the Public Staff can obtain actual annualized historical returns on equity that DEP has achieved, not for ratemaking purposes. Tr. vol. 14, 35. Witness Jiggetts explained that to reach a figure that represents DEP's true earnings, the Commission would need to ask DEP to do more detailed reporting and make certain adjustments to reflect the expected ongoing earnings, rather than using the high-level assumptions DEP employs for the quarterly ES1 reports. *Id.* at 35-36. Commissioner Clodfelter noted that the Commission, in evaluating the ESM Rider, needs to know a baseline number of what DEP actually earned in order to determine whether DEP over-earned or under-earned, or whether the Commission should increase or decrease the rate of return, or leave it the same. *Id.* at 37.

Discussion and Conclusion

In general, the Commission concludes that the residential decoupling mechanism and the ESM proposed by DEP are consistent with the PBR Statute and with Commission rule. Further, the Commission concludes that DEP's proposal to exclude EV sales from the decoupling mechanism and the ESM, as modified by the PIMs Stipulation, is reasonable and should be approved. The Commission does not find it appropriate, for the reasons advanced by DEP witnesses Bateman and Abernathy, to impose a decoupling cap, or authorize a lower carrying cost on the decoupling deferral amount. The Commission notes that the TCA Stipulation provides that the $20 million adjustment in the revenue requirement agreed to in the stipulation will be included in the ESM for DEP.

The Commission notes that the current ES1 reports were not intended to be used as a method to evaluate the ESM Rider. The Commission further notes that Commission

Rule R1-17B(h)(1) provides for the filing of quarterly earnings reports that require certain enumerated information. The Commission directs DEP to work with the Public Staff to develop a quarterly reporting form for DEP's earnings that will enable the Commission to analyze the information and determine the appropriate application and operation of the ESM Rider. As part of this review, DEP and the Public Staff shall review the requirements of Commission Rule R1-17B(h)(1) and recommend any necessary changes.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 78

Performance Based Regulation

The evidence supporting this finding of fact is contained in DEP's verified Application and Form E-1; the testimony and exhibits of DEP witnesses Abernathy, Bateman and Stillman, Public Staff witnesses D. Williamson and Thomas, AGO witness Nelson, and CUCA witness O'Donnell; and the entire record in this proceeding.

Summary of Evidence

DEP's PBR Application seeks approval of performance-based regulation through the proposed three-year MYRP beginning on October 1, 2023, and ending September 30, 2026. DEP witness Bateman testified that in addition to the three-year MYRP, which includes an ESM, DEP's PBR Application includes a residential decoupling mechanism, PIMs, and tracking metrics. Tr. vol. 14, 76. Witness Bateman explained that the PBR approach, in general, and DEP's proposed MYRP better aligns customer and state policy goals with utility revenues and performance than does traditional ratemaking. *Id.* at 80.

The Commission notes, as the Public Staff points out, that the PBR Statute represents a substantial supplement to the existing law related to electric public utilities, such as DEP, and provides DEP with a cost recovery framework that represents fairly significant departure from the traditional cost recovery paradigm that has served North Carolina's electric utilities and their customers well for many decades. Discussed below are four new concepts allowed for the first time in North Carolina under the PBR Statute.

First, electric public utilities in North Carolina are entitled to file a MYRP, which is "a rate-making mechanism under which the Commission sets base rates for a multiyear period that includes authorized periodic changes in base rates without the need for the electric public utility to file a subsequent general rate application …" N.C.G.S. § 62-133.16(a)(5). This approach is a departure from the adjusted historic test year and authorizes certain projections of cost in the setting of rates.

Second, electric public utilities, such as DEP, are now allowed to utilize a decoupling mechanism. Under the PBR Statute's decoupling mechanism, DEP is authorized to "defer to a regulatory asset or liability account the difference between the actual revenue and the target revenue for the residential class" and this variance will result in an annual adjustment to the residential customer classes' bills. N.C.G.S. § 62-133.16(c)(2).

Third, the PBR Statute creates an ESM, which allows the electric public utility to elect to file a new rate case under N.C.G.S. § 62-133 in the event its weather-normalized earnings fall below the authorized rate of return on equity and requires the utility to refund to customers all weather-normalized earnings in excess of the authorized rate of return plus 50 basis points. N.C.G.S. § 62-133.16(c)(1).

Fourth, the PBR Statute requires that the utility implement at least one performance incentive mechanism, which is “a rate-making mechanism that links electric public utility revenue or earnings to utility performance in target areas consistent with policy goals …” N.C.G.S. § 62-133.16(a)(6). PIMs are intended to encourage the types of behavior about which customers care, provide DEP with the opportunity to earn a reward to be collected from customers, and expose DEP to payment of penalties which are refunded to customers (subject to a cap). N.C.G.S. § 62-133.16(c)(4).

While certain of the mechanisms established in the PBR Statute are new to North Carolina, aspects of the law are familiar and well-known to the Commission. For example, the responsibility “[t]o make reasonable and just rates” has been the obligation of the Commission’s predecessors since the 19th century. *See, e.g.*, 1899 N.C. Session Laws, Chapter 164, § 2. The requirement that rates be “fair both to the electric public utility and to the customer,” set forth in N.C.G.S. § 62-133.16(d)(1)(a) mirrors the charge in N.C.G.S. § 62-133(a) that “the Commission shall fix such rates as shall be fair both to the public utilities and to the consumer.” Moreover, N.C.G.S. § 62.133-16 explicitly preserves the Commission’s existing rate-making authority, providing: “[n]othing in this section shall be construed to [ ] limit or abrogate the existing rate-making authority of the Commission …” N.C.G.S. § 62-133.16(g) (omission denoted via brackets and ellipses). And, significantly, the Commission has long been required to consider risks both to the electric utility and to its customers, as it is well-established policy in North Carolina “to provide fair regulation of public utilities in the interest of the public” as well as "to promote adequate, reliable and economical utility service to all of the citizens and residents of the State.” N.C.G.S. § 62-2(1), (3).

When reviewing a PBR application, the PBR Statute requires the Commission must consider whether a PBR application:

a. Assures that no customer or class of customers is unreasonably harmed and that the rates are fair both to the electric public utility and to the customer.

b. Reasonably assures the continuation of safe and reliable electric service.

c. Will not unreasonably prejudice any class of electric customers and result in sudden substantial rate increases or "rate shock" to customers.

N.C.G.S. § 62-133.16(d)(1).

Elsewhere in this Order the Commission has ruled upon the specific requests of DEP regarding costs to be recovered, as well as the rate of return that DEP has an opportunity to earn. In approving costs for recovery and establishing the rate of return, the Commission has applied well-established law in attempt to put the utility in a position to maintain its system and level of service, in view of the very real challenges that lie ahead for DEP, to earn a fair return, in view of current economic conditions, and to compete in the marketplace for capital on reasonable terms and at times when a capital need arises. The Commission has considered the impact of changing economic conditions on customers, recognizing that certain of the utility's customers will struggle to afford electric utility service, and has endeavored to establish rates that achieve the foregoing objectives most economically. In addition, elsewhere in this Order, the Commission has considered the potential for prejudice to customer classes and accepts the cost allocation methods, as well as certain of the rate designs, proposed by the utility and modified by the various stipulations to be reasonable and not prejudicial to any customer class.

In addition to the requirements for consideration by the Commission set forth in N.C.G.S. § 62-133.16(d)(1), the PBR Statute provides guidance on other considerations the Commission may undertake, including, for example, whether the PBR application "reduces low-income energy burdens;" whether the PBR application "encourages DERs"; whether the PBR application "encourages utility-scale renewable energy and storage"; and whether the PBR application "encourages peak load reduction or efficient use of the system." N.C.G.S. § 62-133.16(d)(2). The Commission notes, for example, that the PIMs Stipulation, discussed in detail elsewhere in this Order, involves PIMs that are intended to increase numbers of customers enrolled in time-differentiated rates, to increase the number of net-metered interconnections, to encourage the interconnection of utility scale generation above DEP's estimated annual limits, and to enable large commercial and industrial customers to achieve clean/carbon free energy objectives. Each of these PIMs aligns with the considerations established in N.C.G.S. § 62-133.16(d)(2). The tracking metrics, agreed upon by the parties to the PIMs Stipulation, pertain to customer service, reliability and "beneficial electrification," all of which should inform the future development of PIMs that align with the guidance set forth in N.C.G.S. § 62-133.16(d)(2). In addition, elsewhere in this Order, the Commission discusses the CAP's proposed by DEP in this proceeding, aimed at proving customers in need of assistance with bill payment, as well as the Affordability Stipulation, which is intended to provide additional relief for customers who will struggle to afford the cost of electricity. These provisions of the PBR Application, as modified by the stipulations, align with the considerations of § 62-133.16(d)(2). Throughout the course of this proceeding, DEP has worked with parties to the proceeding to refine the elements of its PBR Application to better conform to the requirements of N.C.G.S. § 62-133.16(d)(1) and to more closely align with the guidance set forth in N.C.G.S. § 62-133.16(d)(2).

The PBR Statute provides that the Commission is authorized to approve a utility's PBR application "so long as the Commission allocates the electric public utility's total revenue requirement among customer classes based upon the cost causation principle . . . and interclass subsidization of ratepayers is minimized to the greatest extent practicable by the conclusion of the MYRP period." N.C.G.S. § 62-133.16(b). As previously explained, the PBR Statute also requires that the Commission consider whether a PBR application: 1) assures that no customer or class of customers be unreasonably harmed and that the rates are fair both to the electric public utility and to the customer; 2) reasonably assures the continuation of safe and reliable electric service; and 3) will not unreasonably prejudice any class of electric customers and result in sudden substantial rate increases or "rate shock" to customers. N.C.G.S. § 62-133.16(d). During cross-examination by CIGFUR II, DEP witness Reed acknowledged that the PBR Statute requires DEP to minimize interclass subsidization. Tr. vol. 11, 330. However, witness Reed emphasized that the PBR Statute requires the minimization of interclass subsidization "to the greatest extent practicable," which, the Commission concludes, DEP has achieved. The Commission concludes that DEP's approach of gradually reducing the subsidies between classes by utilizing a variance reduction of 10% is reasonable and that the 10% variance reduction approach moves towards eventual rate parity/minimization of interclass subsidization while, at the same time, balancing the other requirements of the PBR Statute including that no class of customer is unreasonably harmed or faces a sudden and substantial increase in rates resulting in rate shock. The Commission agrees with DEP witness Reed who testified that DEP appropriately considered "competing priorities" such as cost causation, rate shock, and gradualism in proposing the 10% variance reduction. Tr. vol. 11, 320-21. The Commission does not agree with the recommendation of CIGFUR II witness Phillips' argument that a greater variance reduction is warranted in this proceeding, primarily in light of the harm that such a reduction would cause to certain customer classes. Specifically, DEP witness Reed explained that if DEP had employed a 25% subsidy reduction, as recommended by CIGFUR II witness Phillips, the proposed increase to the Residential class would increase from 9.9% to 10.4% and the proposed increase to the Lighting class would increase from 19.9% to 24.9%. Tr. vol. 11, 265. Thus, balancing its obligations under the PBR Statute to ensure allocation of revenue requirement based on cost causation, minimization of interclass subsidization, equitable treatment of customer classes, and avoidance of unreasonable prejudice and rate shock, the Commission concludes that DEP's PBR Application as amended by the stipulations and the various provisions of this Order, is in alignment with cost causation or reasonably headed that way, avoids unreasonable harm to any class of customers, and does not unreasonably prejudice an class of customers or otherwise result in rate shock.

For the foregoing reasons, and as discussed in greater detail throughout this Order, the Commission concludes that DEP's PBR Application, as modified by the stipulations and this Order, results in just and reasonable rates, is in the public interest, and is consistent with the criteria established in N.C.G.S. § 62-133.16.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 79

Revenue Requirement

The evidence supporting this finding of fact is found in DEP's verified Application and Form E-1; the Revenue Requirement Stipulation; the TCA Stipulation; and the

Supplemental Revenue Requirement Stipulation; the testimony and exhibits of the witnesses, including DEP witness Jiggetts and Abernathy and Public Staff witness Zhang and Boswell; and the entire record in this proceeding.

The Revenue Requirement Stipulation, the TCA Stipulation, and the Supplemental Revenue Requirement Stipulation provide for certain accounting adjustments that parties have agreed upon and the Commission has approved in this Order. The stipulation issues that impact the revenue requirement in the Revenue Requirement Stipulation and the TCA Stipulation are detailed in in Jiggetts Partial Settlement Exhibit 2 (Tr. Ex. vol, 14) and the Public Staff Accounting Supplemental and Settlement Exhibit 1 Schedule 1 (Tr. Ex. vol 19), which provide sufficient support for the annual revenue required on the issues agreed to in the Revenue Requirement Stipulation. The stipulation issues that impact the revenue requirement in the Supplemental Revenue Requirement Stipulation are in the Supplemental Revenue Requirement Stipulation Exhibit 1 (Tr. Ex. vol 7).

After giving effect to the approved stipulations and the Commission's decisions on the Unresolved Issues, as discussed herein, the Commission finds that DEP should recalculate the required annual revenue requirement consistent with the Commission's findings herein withing 10 days of the issuance of this Order. DEP is further directed to file with the Commission the final revenue requirements for Rate Years 1, 2, and 3 in the same format as Jiggetts Partial Settlement Exhibit 1. The Commission directs DEP to work with the Public Staff to verify the accuracy of the calculations, and the filing should reflect the corrections identified by DEP and agreed upon by the Public Staff.

The Commission concludes the annual revenue requirement for DEP for Rate Years 1, 2, and 3 which reflect the approved stipulations and the Commission's decisions on the Unresolved Issues will allow DEP a reasonable opportunity to recover its operating costs and earn the overall rate of return on its rate base that the Commission has found just and reasonable upon consideration of the findings in this Order.

IT IS, THEREFORE, ORDERED as follows:

1. That the Revenue Requirement Stipulation, the COSS Stipulation, the TCA Stipulation, the PIMs Stipulation, the Affordability Stipulation, the MGS Partial Rate Design Stipulation, the LGS Partial Rate Design Stipulation, and the Supplemental Revenue Requirement Stipulation are accepted and approved, as detailed in this Order. The Power Quality Stipulation is not approved as detailed in this Order;

2. That the depreciation rates proposed by DEP in this case, which are based on the 2021 Depreciation Study and amended by the Revenue Requirement Stipulation, with such agreed upon amendments proposed by the Public Staff including the amortization periods for General Plant accounts 391 and 397, and the 70-year life of Transmission FERC account 356, shall be, and is hereby approved;

3. That DEP's request for an accounting order for approval to defer to a regulatory asset 75% of the impact of accelerating the retirement of DEP's Mayo and

Roxboro Units 3 and 4, as agreed upon in the Revenue Requirement Stipulation, preserving DEP's ability to recover 50% of the net book value of the subcritical plants through securitization, shall be, and is hereby approved;

4. That the remaining net book value of DEP's Mayo and Roxboro Units 3 and 4 at retirement shall be recovered with a return over the amortization period determined by the Commission in a future rate case;

5. DEP's plant-related capital investments in the base period fossil, renewable, storage, and nuclear fleet assets as adjusted in the Revenue Requirement Stipulation, shall be included in rates for the base period;

6. DEP's transmission and distribution investments made during the test period, as adjusted by the Revenue Requirement Stipulation, shall be included in rates for the base period;

7. That DEP's GIP investments shall be included for recovery in DEP's rates;

8. That in accordance with the Revenue Requirement Stipulation, DEP is permitted to recover the full balance of its GIP deferral over an 18-year amortization period, with a debt-only return during the deferral period and rate base treatment during the 18-year amortization period;

9. That DEP shall recover the balance of the CCR deferral, net of the over amortization, over a five-year amortization period with reduced financing costs during the amortization period calculated based on (1) DEP's cost of debt as approved in this Order adjusted as appropriate to reflect the deductibility of interest expense, (2) an ROE 150 basis points lower than the 9.8% ROE as approved in this Order, and (3) a capital structure of 48% debt and 52% equity as set forth in the CCR Settlement;

10. That in accordance with the Revenue Requirement Stipulation, DEP shall flowback to customers over a three-year period the liability related to the gains on Harris land sales;

11. That in accordance with the Revenue Requirement Stipulation, DEP shall continue to defer any gains on any future Harris land sales to return to customers in a future general rate case;

12. That DEP shall amortize the Roxboro Wastewater Treatment Facility regulatory asset over a period of twelve years and the unamortized balance shall be included in rate base;

13. That DEP shall amortize the regulatory liability for overcollections associated with storm securitization over a three-year period;

14. That the agreed-upon accounting adjustments outlined in the Revenue

Requirement Stipulation shall be, and are hereby, approved;

15. That DEP shall track and report on an annual basis the actual spend and employee head count for each coal generation station over the MYRP period in a manner to be agreed upon by DEP and the Public Staff. DEP shall update the Commission on the manner upon which DEP and the Public Staff have agreed to the tracking and reporting of the actual spend and employee head count for each coal generation station;

16. That DEP shall record any cumulative underspend less than $6 million (North Carolina retail) of annual incremental spend for ongoing O&M for DEP's coal generation fleet for discrete programs and targeted categories to a regulatory liability account accrued through the end of the MYRP period (September 2026) and return the underspend to customers in the next general rate case;

17. That DEP shall perform a lead-lag study before its next general rate proceeding and incorporate the results of that study in its next general rate case filing;

18. That DEP's proposed MYRP, reflecting the projected costs associated with the Transmission, Distribution, Fossil/Hydro, Nuclear, Cybersecurity, Solar, and Storage capital investments, as adjusted by the Revenue Requirement Stipulation, as reflected in Abernathy Partial Settlement Exhibits 1 and 2, is just and reasonable and adopted in its entirety;

19. That DEP has demonstrated a reasonable plan to timely complete the MYRP projects;

20. That DEP shall consult with the Public Staff to develop a report on Rider EC. DEP shall file its first report on Rider EC no later than one year from the date of this Order;

21. That DEP shall report on the issue of CIAC related to IAs in its next rate case application;

22. That DEP shall consult with the Public Staff to develop a report on reliability O&M as the Public Staff proposed. DEP shall file its first report on reliability O&M no later than one year from the date of this Order;

23. That DEP shall consult with the Public Staff to develop its Vegetation Management Program Performance report as provided in this Order;

24. DEP shall, in consultation with the Public Staff, file a report on the Hot Springs Cost Benefit Analysis;

25. That DEP may to recover through base rates DEP's costs associated with its DSDR program;

26. That DEP's request to establish the Payment Navigator program shall be, and is hereby approved;

27. That DEP shall be allowed to recover its costs to implement Customer Connect;

28. That the COSS Stipulation shall be, and is hereby approved;

29. That in its next general rate case, DEP shall provide a comprehensive justification for the use of a NCP demand instead of a coincident peak demand for any cost allocation purpose;

30. That the PIMs Stipulation is consistent with N.C.G.S. § 62-133.16 and Commission Rule R1-17B, achieves a measured balance between encouraging behavior and risk/reward to utility shall be, and is hereby approved;

31. That the Power Quality Stipulation, or the pilot program addressed therein, are not approved, but that DEP may file an application for such a pilot program in a separate proceeding;

32. That, consistent with the Affordability Stipulation, DEP's proposed CAP is hereby approved as a three-year pilot;

33. That DEP's proposed CAP and CAR Riders shall be, and is hereby approved;

34. That the shareholder financial contributions, detailed in the Affordability Stipulation, shall be, and is hereby approved;

35.; That DEP shall convene a stakeholder group to meet at least quarterly to consider data and reporting issues related to the CAP. The stakeholder group is directed to develop an annual report on the CAP as provided in this Order;

36. DEP is directed to file a report on the feasibility and proposed structure of a tiered customer assistance program the later of (i) 18 months after the date of this Order, or (ii) when there is one year of data from the CAP Rider;

37. DEP is directed to report on the Affordability Metrics established in this Order in the same manner as it reports on the tracking metrics agreed to in the PIMS Stipulation;

38. That DEP shall consult with the Public Staff to develop a report on the CAP including the number of CAP recipients, CAP administration costs, and the observed impacts of CAP on arrearage management and disconnections for nonpayment;

39. That the revisions to rate schedules, as proposed by DEP or as otherwise modified herein shall be, and is hereby approved;

40. That the revisions to the service riders, as proposed by DEP or otherwise specifically modified herein, including Rider EC and Rider NSC shall be, and is hereby approved;

41. DEP shall notify all SGS customers that customers may now elect the residential rate schedule for detached garages, barns, and other structures on the same residential premise currently served under a residential rate schedule;

42. That DEP shall inform all Schedule SLR customers that the schedule will not be open to new customers as of October 1, 2023;

43. That DEP shall provide via bill insert or separate mailing amendments to its Outdoor Lighting Service Regulations to all customers subject to those Regulations;

44. That DEP shall, before the next rate case, analyze the impacts of transferring customers receiving service under Riders 7 and 57 to other standby service riders and, if that analysis reveals viable options for transferring these customers, DEP shall propose a transition period in its next general rate case to move these customers to other standby service riders over a reasonable period and in a manner that lessens or avoids rate shock;

45. That DEP's rates during the MYRP Rate Period shall reflect a rate of return on equity of 9.8% and embedded cost of debt of 4.03% based on a capital structure consisting of 53% common equity and 47% long-term, for a rate of return of 7.09%;

46. That DEP's shall be allowed to recover certain COVID-related costs that have been deferred, including customer fees waived, bad debt charge-offs, and costs related to employee safety, netted against the COVID-related savings related to printing, postage, employee travel, and certain measures taken by the federal government that benefitted DEP during the pandemic, over a six-year period with no return on the unamortized balance during the amortization period, which shall begin on the effective date of the rates approved in this proceeding;

47. That DEP's request to continue the deferral of bad debt expenses related to the impact of the COVID-19 pandemic is hereby approved. That any payments associated with bad debt amounts should be credited on a monthly basis through the next general rate case proceeding. That DEP should report on a semiannual basis the actual amounts recorded to the deferral and the payments received;

48. That the inflation adjustment proposed by DEP shall be, and is hereby approved;

49. That DEP's request to recover costs incurred related to the Commission's Order in the 2019 Rate Case in the amount of $5.384 million, which are above and beyond the rate case costs provided for in the 2019 First Partial Settlement is hereby approved. Such costs shall be amortized over a three-year period;

50. That DEP is hereby allowed to recover over a three-year period rate case costs in the amount of $6.551 million related to the present proceeding;

51. That DEP's request to include the unamortized balance of rate case expense in rate base shall be, and is hereby denied;

52. That DEP's request to track actual rate case costs from the March 31, 2023 update cutoff date in this proceeding through the date rates become effective for possible recovery in a future rate case proceeding shall be, and is hereby denied;

53. That the following treatment with respect to over-amortizations of regulatory assets shall be, and hereby is approved for purposes of this proceeding:

a. The over-amortization of rate case expense from Docket No. E-2, Sub 1023 of $1,112,000 should be applied to the balance of rate case expense from the Commission's Order in the 2017 Rate Case of $530,000, which will eliminate that balance. The remaining $582,000 of over-amortization should be applied against rate case costs being requested in this proceeding.

b. The over-amortization of severance costs from the Commisioner's Order in the 2019 Rate Case in the amount of $907,000 should not be applied against the rate case costs being requested in this proceeding but instead should be refunded to customers through a one-year rider with interest.

c. The over-amortization of early retired plant in the amount of $13.8 million should be applied against the outstanding rate base balance for the Asheville early retired coal plant authorized in the 2019 Rate Case.

d. The over-amortization of Hurricane Matthew costs from the Commission's Order in the 2017 Rate Case in the amount of $17 million should be treated as follows: first, to recover 2022 incremental Winter Storm Izzy costs, and second, the remaining $2 million credit should be refunded to customers through a one-year rider with interest.

e. Over-amortization of regulatory fees in the amount of $68 thousand should be refunded to customers through a one-year rider with interest.

54. 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, DEP shall continue to record all revenue received for that deferred cost in the specific regulatory asset account established for that deferred cost until DEP's next general rate case for a determination of the appropriate ratemaking treatment of such over-amortizations;

55. That DEP is allowed to collect in rates its North Carolina Retail normalized annual level of storm costs in the amount of approximately $22.2 million;

56. That DEP's request for an accounting order for approval to establish a regulatory asset to defer the incremental costs incurred as a result of Winter Storm Izzy shall be, and hereby is approved;

57. That DEP shall be allowed to recover the 2022 incremental Winter Storm Izzy costs of approximately $15 million applying a portion of the over-amortization of Hurricane Matthew costs in the amount of $17 million from the Commission's Order in the 2017 Rate Case;

58. That the remaining amount of over-amortization of Hurricane Matthew costs of approximately $2.0 million, shall be returned to customers through a levelized rider over a period of one year;

59. That DEP's request for an accounting order for the storm balancing account shall be, and is hereby denied;

60. That DEP's request for an accounting order to defer any incremental revenue requirement impacts, including benefits and costs, associated with the IRA and the IIJA, shall be, and is hereby approved;

61. That DEP's request for an accounting order to defer implementation and administration costs associated with the CAP, Payment Navigator Program, and the Tariffed On-Bill program, and PIMs, shall be, and is hereby denied;

62. That the establishment of a regulatory liability as recommended by the Public Staff to address CIAC collected by DEP related to interconnection agreements is not warranted at this time, however, DEP shall report on the issue of how CIAC is recorded in the context of interconnection agreements in its next general rate case application as required by the Revenue Requirement Stipulation;

63. That the Commission finds DEP's provision of electric service to be adequate;

64. That DEP's proposed revisions to its previously approved North Carolina excess EDIT rider (EDIT-4) to reflect additional amounts due to customers, shall be, and is hereby approved, and that the leveled return rate shall be based on a capital structure consisting of 47% long-term debt and 53% equity, an embedded cost of debt of 4.03% and a rate of return on equity of 9.8%;

65. That DEP shall use the base fuel rates, exclusive of the equal percentage allocation, established above in the current (2023) annual fuel adjustment proceeding;

66. That the approved base fuel and fuel-related cost factors by customer class are as follows: 2.808 cents/kWh for the Residential class, 3.097 cents/kWh for the SGS class, 2.580 cents/kWh for the MGS class, 2.138 cents/kWh for the LGS class, and 3.376 cents/kWh for the Lighting class;

67. The production demand allocation method approved for production demand costs using the 12 CP method at NC retail and the modified A&E method for NC retail classes is the most appropriate method for allocating purchased power capacity costs in DEP's annual fuel proceedings;

68. That DEP's proposed residential decoupling mechanism is consistent with N.C.G.S. § 62-133.16 and Commission Rule R1-17B, and the proposed tariff for the associated rider, shall be, and is hereby approved;

69. That DEP's proposed ESM, as modified by the TCA Stipulation, is consistent with N.C.G.S. § 62-133.16 and Commission Rule R1-17B, and the proposed tariff for the associated rider, shall be, and is hereby approved;

70. That DEP shall file the final annual revenue requirements for Rate Years 1, 2, and 3 consistent with the Commission's findings and rulings herein within 10 days of the issuance of this Order in the same format as Jiggetts Partial Settlement Exhibit 1. DEP shall work with the Public Staff to verify the accuracy of the calculations;

71. DEP shall file schedules (North Carolina Retail Operations – Statement of Rate Base and Rate of Return, Statement of Operating Income, and Statement of Capitalization and Related Costs) with the Commission within 10 days of the issuance of this Order, summarizing the gross revenue and the rate of return that DEP should have the opportunity to achieve based on the Commission's findings and determination in this proceeding;

72. That DEP is authorized to adjust its rates and charges in accordance with the Revenue Requirement Stipulation, the TCA Stipulation, and the Supplemental Revenue Requirement Stipulation and findings in this Order effective for service rendered on and after the following date after the Commission issues an Order accepting the calculations required by Ordering Paragraph No. 70;

73. That within 30 days of this Order, DEP shall file for Commission approval all rate schedules designed to comply with this Order, accompanied by calculations showing the revenues that will be produced by the rates for each schedule; and

74. That DEP shall submit a proposed customer notice to the Commission for review and approval, and upon approval of the notice by the Commission, shall give appropriate notice of the approved rate increase by mailing the notice to each of its North Carolina retail customers during the billing cycle following the effective date of the new rates.

ISSUED BY ORDER OF THE COMMISSION.

This the 18th day of August, 2023.

NORTH CAROLINA UTILITIES COMMISSION

A. Shonta Dunston

A. Shonta Dunston, Chief Clerk

Chair Charlotte A. Mitchell dissents in part. Commissioner Kimberly W. Duffley joins in Chair Mitchell's dissent in full. Commissioner Karen M. Kemerait joins in Chair's Mitchell's dissent with respect to the sections on rate of return of equity and the recovery of the deferred COVID-related costs.

Commissioner Daniel G. Clodfelter dissents in part and concurs in part.

DOCKET NO. E-2, SUB 1300

Chair Charlotte A. Mitchell, dissenting in part:

For the reasons set forth below, I dissent from the Order's resolution of the following three issues: rate of return on equity, the recovery of deferred COVID-related costs, and affordability – next steps.

I. Rate of Return on Equity

DEP requested a rate of return on equity (ROE) of 10.4%, and DEP witness Morin testified on cross examination that, due to a tapering in interest rates between the time of filing of his supplemental testimony and the hearing, his recommended rate of return on equity would have been 0.2% lower if recalculated. Tr. vol. 8, 324. The Order concludes that substantial evidence supports the reasonableness of a rate of return on equity ranging from 9.75% to 10.0%, without a downward adjustment due to the MYRP, and ultimately approves 9.8%. I would have approved an ROE of 10.0% for the following reasons.

First, I question whether the Commission regards 10.0% as a Rubicon across which the Commission must not go. I note that in a 2013 general rate case proceeding, DEP and the Public Staff entered into a settlement agreement which, among other things, included agreement on the ROE at 10.2%. Moreover, a historical review of Commission decisions in general rate cases reveals that this Commission has awarded ROEs in excess of 10.0% in many cases in the past. I do not point this out to indicate that an ROE of 10.2% then makes appropriate an ROE of 10.2% now, rather I point this out only to illustrate that the Commission, in the not-too-distant past, has crossed that "symbolic" threshold. *See* Order Granting General Rate Increase, *Application of Progress Energy Carolinas, Inc., for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina*, No. E-2, Sub 1023 (May 30, 2013).

Second, I am concerned that the results of the DCF models are inconsistent with the current capital market environment and bias downward the range of reasonableness presented in the Order. The three models most cited by the expert witnesses in this case – DCF, CAPM, and RPM – involve different approaches to estimating the cost of equity. However, there is a crucial difference between the DCF model and the other two models. While RPM and CAPM involve borrowing costs as a direct input to the model, DCF does not involve borrowing costs as a direct input. Thus, the outcome of the DCF is not directly affected or informed by borrowing costs. Rather, borrowing costs are considered only indirectly in the DCF model. Many of the experts relied on analyst estimates to inform the dividend growth rate, which is a key input to the DCF model, and while some unknown but correlated factor between dividend growth rates and borrowing costs could impact the outcome of the model, there is no input for borrowing costs. Although utility stocks can act somewhat like long-term fixed income securities, causing their prices to fall (and dividend yields to rise) when bond yields rise, that does not necessarily happen in lock-step. Too, the higher betas presently observed indicate that utility stocks are relatively more correlated to stocks and less so to bonds than they were in the past. The point is that there are structural (i.e., as a result of the model inputs) reasons why the output of the CAPM and RPM will rise due to rising interest rates, when the DCF might not necessarily respond in the same way or to the same extent.

Undisputed in the record of this case is that long-term borrowing costs, both for DEP as well as the U.S. Treasury, have risen significantly and are at multi-year highs. During the pendency of this rate case, DEP's borrowing costs have risen from 3.7% to 4.03%, and since the Commission's decision in the Sub 1219 rate case, 30-year Treasury yields have increased from 2.16% to nearly 3.84% as of May 1, 2023. *See, e.g.,* Tr. vol. 9, 41; tr. vol. 22, 196.

The range of reasonableness identified by the Commission in this case equally weights the DCF, CAPM, and RPM, but of the three, only the DCF model produced results below the range and indicated the cost of equity is lower now than it was in the prior rate case, when the Commission ordered rates to be set using an ROE of 9.6%. Given that the record in this case reflects an increase in borrowing costs and given that the consensus of the DCF models remains below the approved ROE in the last rate case, the results deserve a certain amount of skepticism.

The Commission has at various times in the past placed more or less emphasis on a given model in order to reflect its conclusion as to whether the results of that model accurately reflect the utility's cost of equity. *See, e.g.*, Order Approving Partial Settlement Agreement and Stipulation, Deciding Contested Issues, Granting Partial Rate Increase, Approving Water and Sewer Investment Plan, and Requiring Customer Notice, *Application by Carolina Water Service, Inc. of North Carolina for Authority to Adjust and Increase Rates and Charges for Water and Sewer Utility Service in All Service Areas of North Carolina and Approval of a Three-Year Water and Sewer Investment Plan*, No. W-354, Sub 400, at 44 (Apr. 26, 2023); Order Granting Partial Rate Increase, *Application by Carolina Water Service, Inc. of North Carolina for Authority to Increase Rates for Water and Sewer Utility Service in All Its Service Areas in North Carolina*, No. W-354, Sub 128, at 77-78 (June 10, 1994). Because of the very clear signal sent by the bond market that the cost of capital has risen significantly, an ROE at the top end of the range of reasonableness, implicitly giving the DCF result less weight, is both warranted and necessary at this time.

Third, while the Order gives some acknowledgement to DEP's stressed credit metrics, I am concerned that the decision to approve an ROE of 9.8% will ultimately prolong that stress, leading, potentially, to a downgrade. A downgrade will cost customers. Tr. vol. 22, 186.

DEP witness Newlin explained that credit quality (or creditworthiness) is a term used to describe a company's overall financial health and its willingness and ability to repay all financial obligations in full and on time. Tr. vol. 9, 88. He went on to explain that two major credit rating agencies, Standard & Poor's (S&P) and Moody's Investors Service (Moody's), establish credit ratings for DEP.

Witness Newlin testified that DEP must be in a position to operate and maintain its business without interruption and to refinance maturing debt on time, regardless of financial market conditions. He noted that the financial markets can experience periods of volatility and that DEP must be able to finance its needs throughout such periods. He concluded that strong investment-grade credit ratings provide DEP with greater access to the capital markets on reasonable terms during such periods of volatility. *Id.*

In explaining the qualitative and quantitative factors that rating agencies would consider when assessing DEP's creditworthiness, he testified:

> Quantitative measures are primarily based on operating cash flow and focus on the level at which DEP maintains debt leverage in relation to its generation of cash and its ability to meet its fixed obligations (interest expense in particular) based on internally-generated cash. The percentage of debt to total capital is another example of a quantitative measure. Creditors and credit rating agencies view both qualitative and quantitative factors in the aggregate when assessing the credit quality of a company.

Tr. vol. 9, 90.

He also testified that investors, investment analysts and credit rating agencies, in assessing a utility company's financial strength, consider the allowed rate of return, the cash quality of earnings, the timely recovery of capital investments, the stability of earnings, and the strength of its capital structure*. Id*. at 91. Specifically with respect to ROE, he testified that the allowed return on equity is a key component in the generation of earnings and cash flows and that an adequate return on equity helps ensure equity investors receive fair compensation for their investment while also helping to protect the interests of debt investors. *Id.* at 96. He testified further that a strong capital structure and an adequate return on equity provide balance sheet protection and cash flow generation to support high credit quality. Moreover, he testified that high credit quality creates financial flexibility by providing more readily available access to the capital markets on reasonable terms, and ultimately lower debt financing costs, while a weak capital structure and an inadequate allowed return on equity produces lower earnings and cash flows, lowers credit quality, and may limit financial flexibility. *Id.*

On this record, I am persuaded that ROE is a critical component of creditworthiness. I am also persuaded that high credit quality serves the public interest by putting the utility in a position to compete for capital on the most reasonable terms available and by increasing the potential that the utility will be able to access the capital markets on reasonable terms during all types of market cycles, including periods of high volatility, which, ultimately, lowers borrowing costs passed through to customers.

The Order discusses DEP's stressed credit metrics in the context of capital structure and notes:

> Specifically regarding DEP, Moody's has taken two very recent actions, both of which highlight the immediate credit metric challenges DEP faces. First, in April 2023 Moody's published a "Ratings Action" report (DEP Redirect Newlin Direct Exhibit 1) affirming DEP's A-level rating but at the same time issuing an explicit warning with regard to the principal credit metric utilized by Moody's, the ratio of Funds From Operations (FFO) to debt (FFO/Debt)[1]. In its April 2023 Ratings Action Moody's indicated that it was raising its FFO/Debt downgrade threshold for DEP from 20% to 21% (*Id.* at 4), meaning that while it had in the past forecast a potential downgrade in DEP's credit rating if the FFO/Debt metric stayed below 20% on a sustained basis, it was now forecasting a potential downgrade if the metric stayed below 21% on a sustained basis. This is a particularly worrisome development because, as Company witness Newlin pointed out during his direct testimony, DEP's FFO/Debt ratio has been below 21% for a number of years. Tr. vol. 9, 17-18. In other words, DEP is already operating below the Moody's raised downgrade threshold and has already been doing so on a sustained basis. *Id.* at 18-19.
>
> Between witness Newlin's appearance on direct (May 5) and his appearance on rebuttal (May 16), Moody's issued its May 2023 updated Credit Opinion regarding DEP (DEP Redirect Newlin Rebuttal Exhibit 1), replacing its Credit Opinion issued in March 2022 (introduced into evidence as both Public Staff Cross-Examination Morin Direct and Rebuttal Exhibit No. 15 and DEP Redirect Newlin Direct Exhibit 2). In the updated Credit Opinion, Moody's explicitly referenced as factor that could lead to a downgrade the FFO/Debt ratio "remaining below 21% in 2023." DEP Redirect Newlin Rebuttal Exhibit 1, 2; *see also* Tr. vol. 23, 36-37. Accordingly, Moody's not only alluded to its raised download threshold, but pointedly referenced 2023—this very year.

The Order goes on to note that "the potential for downgrade is not a theoretical issue" and characterizes the Moody's actions as "a series of escalating warnings."

However, I do not agree that an ROE of 9.8%, on this record and at this time, takes those warnings seriously. Even with an equity layer of 53.0%, an ROE of 9.8% does not put the utility in a position to address the challenges it faces.

As was testified to extensively in this proceeding, in November 2022, Moody's placed the entire electric sector on negative outlook as a result of a number of factors including higher fuel costs, higher interest rates, large capital spends, and inflation.

[1] In Moody's parlance FFO/Debt is called "preworking capital cash flow to debt," Tr. vol. 9, 115, or "CFO pre-WC to debt." Both FFO and CFO pre-WC mean the same thing and are a measure of cash flow. *Id.*

Tr. vol. 10, 23. In doing so, Moody's noted that financial metrics for the industry at large are already under pressure with little cushion entering 2023. Subsequent to that action, as mentioned above, Moody's took action with respect to DEP specifically, changing the downgrade threshold from 20% to 21%. *Id.* at 15. The evidence of record demonstrates that DEP is below the downgrade threshold now. Tr. vol. 9, 112.

DEP faces substantial capital needs over the next several years to comply with environmental requirements, to replace and upgrade aging infrastructure, to construct or acquire new generation resources, to upgrade the transmission system, and to satisfy its debt maturities. DEP's capital requirements, including MYRP projects, for the next five years (2022-2026) are projected to be approximately $13.6 billion, which includes $1.3 billion in debt retirements. *Id.* at 98. In the very near term, DEP must retire $300 million of first mortgage bonds, which are due in September 2023. DEP Redirect Newlin Direct Ex. 1, Tr. Ex. vol. 23. DEP witness Newlin testified that DEP's capital requirements, including MYRP projects, are expected to be funded from internal cash generation, the issuance of debt, and equity funding from Duke Energy, as needed. Tr. vol. 9, 98. He explained further that DEP is in a growth cycle, due to the Carbon Plan, and that, while not unusual for utilities in a growth cycle, DEP is a cash flow negative company, which means that its source of funds will not necessarily be limited to debt issuance but must include other sources, such as retained earnings from lowering the dividends paid to the parent or even equity injections from the holding company. *Id.* at 110.

Recognizing some of the challenges ahead for DEP, in a May 2023 credit opinion, Moody's noted that recovery of ongoing coal ash remediation costs and storm costs, along with elevated spending for grid modernization, will maintain pressure on credit metrics. DEP Redirect Newlin Rebuttal Ex. 1, Tr. Ex. vol. 23.

DEP witness Newlin testified that the heightened level of market volatility and uncertainty created by events of recent years have led to an unprecedented number of zero issuance days in the primary debt capital markets. Specifically, he testified that there were 48 zero issuance days in 2022 and already 11 such days to start 2023. Tr. vol. 22, 196. During the hearing, he testified as to a specific recent example, which occurred during the week of the Silicon Valley Bank collapse and sale of Credit Suisse to UBS. He explained that while DEP teed up with two other issuers within the Duke complex to issue that week, the market was very unsettled and they were unable to or decided not to issue into that market. *Id.* at 206. Additionally, evidence in the record, which was not rebutted, shows that borrowing costs increase as credit quality decreases. DEP Redirect Newlin Rebuttal Ex. 2, Tr. Ex. vol. 23. Anticipating the refinancing of low-cost debt the DEP must manage in the coming years – $1.3 billion over the term of the MYRP – potentially impacting DEP's credit quality, such that it might be frozen out of the market or have its borrowing costs significantly increase, is a risk that the Commission should not take. I am concerned that 9.8% takes this risk.

On the record and in light of the very real and complex challenges facing DEP in the coming years – including, to name a few, retirement and/or refinancing of debt in a higher interest rate environment, continued coal ash remediation efforts, construction of

MYRP projects, construction of other transmission and distribution system upgrades necessary to ensure reliability and facilitate the transition, retirement of existing generation, construction of new generation, restoration of system damage caused by extreme weather as a consequence of DEP's being a "storm prone service territory,"[2] fuel price volatility, and labor and materials price volatility – I am not persuaded that an ROE of 9.8%, even with a 53.0% equity layer, particularly given several of the other decisions in this proceeding, will give DEP the cushion it needs to remain consistently above its 21.0% FFO-to-debt downgrade threshold to protect against a downgrade. And, again, I am persuaded that a downgrade will cost customers. As DEP witness Newlin explained in response to cross-examination by the Public Staff, sequential drops in the (Moody's) rating translates to an additional cost to the utility to access capital – each drop can amount to additional incremental borrowing costs of 5-10 basis points but perhaps more given market conditions. Tr. vol 23, 23-24. DEP witness Newlin warns that while allowing DEP to recover less for its cost of equity capital may save customers in the short term, over time as debt matures and must be refinanced, such a measure will impose more cost on customers. *Id.* at 27. Moreover, I note that evidence in the record shows that Georgia Power Company has a credit rating of Baa1, which is two notches below DEP's current credit rating. *Id.* at 24. This lower credit rating results in a higher cost of equity capital of 10.5% for Georgia Power Company and, ultimately, its customers.

DEP witnesses also testified to cost-saving measures, O&M savings, undertaken by DEP since its last rate case. Specifically, DEP witness Abernathy testified:

> We did, you know, implement a series of routine cost-cutting measures to address not only COVID impacts, also mild weather, increased storm costs, things we do in normal course of business when faced with revenue pressures.

Tr. vol. 21, 1332.

While I expect DEP to find every efficiency in the provision of service to its customers and mitigate costs it incurs in providing service to the greatest extent practical, cost-cutting in the face of financial pressure, at a certain point, becomes a concern as it has the potential to impact the reliable operation of the electric system. Given the dynamics of the electric system, including changes in the generating mix, as well as the increasingly extreme summer and winter weather in North Carolina, now is not the time to put DEP in a position to cut to the extent that could impair the reliable operation of the system.

Based on the foregoing, I conclude that the Order's lack of enthusiasm for or lack of consideration of the largely unrebutted testimony of DEP witness Newlin as to credit quality and other evidence of record cited in this dissent is ill-founded. The decision to authorize an ROE of 9.8% has the very real potential to further stress DEP's credit

[2] *See* Moody's Credit Opinion for Duke Energy Progress, LLC, 2 (May 11, 2023); DEP Redirect Newlin Rebuttal Ex. 1, Tr. Ex. vol. 23.

metrics, which will cost customers. Given the real-world challenges that DEP must tackle in the coming years, unlike the majority, I am not willing to take that risk.

Fourth, I note that the Commission recently allowed an ROE of 9.8% for the two largest water and wastewater public utilities in North Carolina. Order Approving Partial Settlement Agreement and Stipulation, Deciding Contested Issues, Granting Partial Rate Increase, Approving Water and Sewer Investment Plan, and Requiring Customer Notice, *Application by Carolina Water Service, Inc. of North Carolina for Authority to Adjust and Increase Rates and Charges for Water and Sewer Utility Service in All Service Areas of North Carolina and Approval of a Three-Year Water and Sewer Investment Plan*, No. W-354, Sub 400 (Apr. 26, 2023); Order Approving Motion on Wastewater Rate Design and Approving Schedules of Rates, Schedules of Connection Fees, and Customer Notices, *Application by Aqua North Carolina, Inc. for Authority to Adjust and Increase Rates for Water and Sewer Utility Service in All Its Service Areas in North Carolina and for Approval of a Water and Sewer Investment Plan*, No. W-218, Sub 573 (July 31, 2023). DEP witness Morin testified that when viewing authorized returns on water utilities versus the authorized returns on vertically integrated electric utilities over a long time period, there is a difference typically on the order of 20 to 30 basis points lower for the water utilities. Tr. vol. 9, 32. My review of the record reveals that no party contested or otherwise rebutted this evidence. While I take no issue with and support the Commission's decisions in the recent CWSNC and Aqua cases, I note that at least in recent history, the trend for ROEs for the water/wastewater utilities and electric utilities has more or less mirrored that testified to by DEP witness Morin – until this Order. I must give this evidence some weight in forming my view that 9.8% is not an accurate reflection of DEP's cost of equity capital.

II. COVID Deferral

I dissent as to the Order's treatment of the deferred COVID-related costs. The Order: (1) approves DEP's recovery of the deferred COVID-related costs pertaining to customer fees waived, incremental bad debt expense, and employee safety; (2) reduces these allowed costs by certain COVID-related expense savings for employee travel expenses, printing and postage costs, DEP's filed ERCs, and the carrying cost benefit of the delayed payment of the employer portion of social security tax; (3) does not allow DEP to recover the carrying costs accrued during the deferral period or a return on the unamortized balance during the amortization period; and (4) requires that these costs be amortized over a six-year period.

The Order notes that approximately 90% of the deferred costs incurred are waived customer fees and incremental bad debt expense and concludes that these two costs resulted directly from governmental action, including mandates from the Commission. For this reason, the Order concludes that the costs associated with waived customer fees and incremental bad debt expense are appropriate for recovery from customers. With respect to employee safety costs, the Order concludes that these costs are appropriate for recovery from customers because to provide essential electric service, many of DEP's employees were not allowed the option to work from home and instead had to show up, in person, at work, at power plants and other facilities, or to repair damage following storms. I agree with these conclusions.

The Order reduces the costs to be recovered by certain COVID-related expenses. I agree that the amount of deferred COVID-related costs should be offset by savings identified by DEP that were directly attributable to the pandemic, which include: (1) reduced employee expense related to reduction in or elimination of travel, and (2) reduced printing and postage costs as a result of the disconnect moratoriums ordered by the Commission. I do not agree with the Order that costs to be recovered should be offset by the carrying cost benefit related to the delayed payment of the employer portion of social security tax, as the benefit received by DEP was simply a temporary deferral from the government and was fully paid by December 31, 2022. Tr. vol. 21, 1291.

I would have allowed recovery of costs associated with remote work, employee stipends and call center costs because I am persuaded that these costs were incurred as a result of the pandemic and facilitated DEP's seamless, uninterrupted and undiminished provision of service to customers during the pandemic. I am persuaded that the call center costs should be recovered, primarily as a result of DEP witness Quick's testimony as to the efforts DEP went to during the pandemic to serve those customers in need who called in seeking assistance. *Id.* at 1276-77. I suspect and anticipate that these efforts are the foundation for a new approach, going forward, to reaching and serving customers in need that will have real, direct impacts on those customers' bills.

In addition, I would have allowed DEP to recover its carrying costs on the deferred balance during the deferral period as well as on the unamortized balance during the amortization period. Evidence in the record indicates that DEP had accrued carrying costs of $12 million on the total incremental deferred costs of $93 million as of March 17, 2023. *Id.* at 1280.

Finally, I would have allowed DEP to recover these costs over a three-year amortization period, coincident with its MYRP.

At the onset of the pandemic, DEP took immediate action to mitigate the hardship to customers and to ensure the continued provision of the essential electric service to all of its customers in North Carolina. Those actions included waiving all disconnections for customers who did not pay their electric bills and waiving customer late payment fees, return check charges, reconnection fees, and residential customers' electronic payment fees. As I see it, DEP took extraordinary action to provide customer support though efforts initiated on its own, ordered by the Commission, and/or resulting from State of Emergency executive orders. Customers were served, even when unable to pay, and DEP carried those balances for customers for many months, now years, in some cases. This provision of service enabled its customers to work from home, attend school from home, and otherwise remain in the home minimizing risk to others. As the AGO pointed out,

> The health and safety of communities are affected by the efforts of all residents to stay home and socially distance to slow the spread of the

coronavirus. Accordingly, entire communities benefit from efforts to keep electric service turned on in households that are struggling.

Reply Comments of the Attorney General's Office, *Joint Petition of Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC, for Approval of Accounting Order to Defer Incremental Expenses as a Result of COVID-19*, Nos. E-2, Sub 1258, E-7, Sub 1241 (Nov. 30, 2020).

I agree strongly with the AGO that DEP's actions during the pandemic benefitted all customers, not just those who were unable to pay. In addition, DEP's provision of service during the pandemic and disconnect moratorium periods, without the ability to disconnect for non-payment and with the obligation to enter into longer-term payment arrangements, goes to the heart of the regulatory compact.

In my view, the regulatory compact can be framed as follows. In exchange for an exclusive service area sanctioned by the State, the utility accepts an obligation to serve all customers within that service area, subject to regulatory oversight. Additionally, in return for agreeing to commit the necessary capital for the provision of service, the utility must be given the opportunity to earn a fair and reasonable return on that capital. *See generally*, Charles F. Phillips, Jr., The Regulation of Public Utilities, 21, 3d ed. (1993).

I conclude that the record in this proceeding demonstrates that DEP met its obligation under the regulatory compact. It served customers throughout the pandemic-related moratorium period, regardless of whether those customers paid. It had to carry the amounts owed by the customers who could not pay throughout the moratorium, during a period of time when, as the record demonstrates, DEP faced revenue pressures. Tr. vol. 21, 1332. And, DEP was directed by this Commission to enroll automatically customers who had been unable to pay into extended repayment plans. The late fee moratorium, which I view as an incentive for the payment of bills and which was in effect by order of this Commission, was not lifted until September 2022 coincident with the lifting of the State of Emergency declaration related to the pandemic.

Thus, the actions of this Commission obligated DEP: (1) to provide service even to those customers that were not able to pay their bills: (2) to cease to use its approved tools that are incentives for bill payment for a prolonged period of time; and (3) to enter into extended payment plans with customers. The record reflects that DEP complied with the orders of this Commission. No party to this proceeding took issue with DEP's provision of service during this period of time or with the prudency of the costs incurred by DEP to this end. While the Order reflects a balancing of equities to arrive at the final decision, I do not agree with the balance struck. Customers who were unable to pay benefitted during the pandemic and during the extended period of time for repayment of any amounts owed to DEP. All customers benefitted as DEP's actions allowed households in need to continue to have service in their homes during a time when remaining at home was essential to the health and well-being of all. Denying DEP an opportunity to recover all of its costs does not recognize the value that DEP provided to all of its customers. In addition, I note that the denial of the carrying costs is roughly equivalent to 10 basis points, perhaps more. Thus, I am concerned that this decision compounds the majority's decision to authorize an ROE of 9.8% and that it will erode DEP's financial health, to the detriment of all customers.

The public health situation presented by the pandemic was an unforeseen, unimaginable crisis that impacted the lives of all North Carolinians in many, difficult and, often heart-breaking ways. DEP's efforts to continue the provision of service to all customers during this time and to provide assistance to those who were unable to pay were critical to the health and general well-being of North Carolina. Tr. vol. 21, 1273-74. In my view, aptly captured by the Attorney General's Office, DEP provided service that benefitted all North Carolinians. I do not believe it is appropriate to deny DEP an opportunity to recover all of its costs, including its carrying costs. This Commission ordered DEP to take action, which included carrying costs for customers who could not pay. DEP upheld its obligations under the regulatory compact. This Commission should have done the same.

III. Affordability – Next Steps

As explained in the Order, DEP requested approval of a CAP and two new tariffs, the CAP Rider and the CAR Rider. DEP witness Harris testified that the CAP proposal, initially developed in the LIAC docket, is designed to assist low-income customers who are facing affordability challenges. Under the CAP, eligible customers would automatically receive a $42.00 monthly bill credit for a 12-month period. Customers who are eligible for and receive funds from either the Low Income Energy Assistance Program (LIEAP) or the Crisis Intervention Program (CIP) would qualify for assistance under the CAP. DEP would automatically enroll eligible customers into CAP using a list of customers provided by the North Carolina Department of Health and Human Services (DHHS). The Order also explains that in addition to the $42.00 bill credit on their next 12 monthly bills, DEP will refer CAP customers to other income-qualified weatherization and energy efficiency services that can assist customers with reducing energy usage.

Public Staff witness D. Williamson testified that the concept of the CAP emanated in the LIAC stakeholder meetings, during which a diverse group of stakeholders met over the course of a year to discuss affordability challenges being experienced by low-income customers to propose ways to address those challenges. He testified that one particular proposal (Proposal 24) contained within the LIAC Final Report combined proposals submitted by the NCJC and by Duke and that Proposal 24 received broad support among the LIAC stakeholders. He testified that DEP estimated 60,000 eligible customers would participate and developed its costs associated with the program based on that estimate. Public Staff witness D. Williamson testified regarding the Public Staff's concerns with the cross-subsidization issues created by the CAP, tr. vol. 20, 144, as well as the Public Staff's preference that there be a clear legislative directive for the development and deployment of assistance programs like the CAP. *Id.* at 146. Ultimately, the Public Staff recommend approval of the CAP for a three-year pilot term, running concurrently with the MYRP, on the basis of the uncertainty of CAP-related costs resulting from the unknown number of potential recipients and the potential for the CAP to be more impactful to non-participating customers than anticipated. He also testified as to concern that once an affordability program is initiated, it would be difficult to end the program regardless of the costs, benefits, or impacts on CAP recipients and non-participating customers. He testified that the three-year pilot period would provide the Commission with an opportunity to evaluate the performance of the CAP. *Id.* at 147.

Sierra Club witness Howat endorsed and advocated for the reporting of certain data at a zip code level primarily to inform program design and targeting of effective energy efficiency and other affordable energy programming. Tr. vol. 18, 201-02. He advocates that the CAP bill credit be tiered based on zip code level data. *Id.* at 219.

As the Order points out, DEP took issue with the recommendation related to the disclosure of zip code level data. Specifically, DEP witness Barnes testified that DEP opposed the sharing of non-public customer information data aggregated at a zip-code level, noting that DEP's Code of Conduct, approved by the Commission in its Order Approving Merger Subject to Regulatory Conditions and Code of Conduct, *Application of Duke Energy Corporation and Piedmont Natural Gas, Inc., to Engage in a Business Combination Transaction and Address Regulatory Conditions and Code of Conduct*, Nos. E-2, Sub 1095, E-7, Sub 1100, and G-9, Sub 682 (Sept. 16, 2016), prohibits the disclosure of aggregated non-public customer data. Tr. vol. 22, 87.

The Order notes that on May 4, 2023, DEP, DEC, Sierra Club, NCJC, et al., and the Public Staff filed the Affordability Stipulation, pursuant to which DEP agreed to withdraw the Low-Income/Affordability PIM it had initially proposed and instead would ensure that a shareholder contribution of $16 million to benefit income-eligible customers would be made as follows: $10 million in support of health and safety repairs that would allow for energy efficiency and weatherization upgrades to homes; and $6 million for the Share the Light Fund, which offers customers bill payment assistance. In addition, DEP agreed to implement the CAP as a three-year pilot, on the Public Staff's recommendation, and to convene a stakeholder engagement process to consider CAP data, metrics, and future CAP program features. The Order also notes that the Affordability Stipulation provides that parties agree to explore "a tiered customer assistance program based on income levels if that feature can be incorporated into the design of the CAP."

The Order approves the Affordability Stipulation but, problematically in my opinion, directs DEP to take action beyond that required by the Affordability Stipulation. Specifically, in a section entitled Affordability – Next Steps, the Order directs DEP to convene a stakeholder group which includes the stipulating parties to the Affordability Stipulation within 90 days of issuance and to invite members of the LIAC to join that stakeholder group. The Order further directs that the group meet quarterly and file a report within six months on the data and information that is to be reported to the Commission annually during each of the three years of the CAP pilot. The Order also directs the stakeholder group to develop a tiered program and directs DEP to file a report relating to the feasibility and proposed structure of a program the later of (i) 18 months after the entry of the order in this proceeding, or (ii) when there is one year of data from the CAP.

As a general matter, I note that the Affordability Stipulation represents the give and take of the parties and that the terms and conditions of the stipulation reflect the compromise each was willing to make, as well as resolution of issues disputed in this proceeding. Among the disputed issues was the term of the CAP, which the Public Staff advocated should be limited, at least initially, to a three-year term in order to provide the Commission with an opportunity to examine the impacts of the program. Whether the CAP should be tiered was also disputed, as the Sierra Club advocated that DEP's proposal for a flat credit be modified to a tiered credit. In addition, the disclosure of zip code level data was a contested issue in this proceeding, with the Sierra Club's advocating that all data be reported at the zip code level and with DEP's opposing that recommendation. Going farther than the settlement of issues between the parties to the Affordability Stipulation upsets the balance the parties struck in the resolution of disputed issues and deprives the Public Staff, and the Commission, of the years of data the Public Staff anticipated would be necessary to make meaningful examination of the CAP before having to design a tiered program.

In addition, well beyond the scope of work envisioned in the Affordability Stipulation, the Order directs that the annual report shall include certain data points at the zip code level and directs that DEP report, on a semi-annual basis, certain data regarding health and safety repairs that are made with shareholder funds, again at the zip code level.

While the Order requires DEP to seek from the Commission any waivers necessary to comply with the Order, it is not clear, based on what the Order requires, whether the Code of Conduct and policies underlying the specific provisions of the Code of Conduct will receive the examination they deserve in any such waiver proceeding. In addition, the Order provides DEP no additional funding for the additional work it directs. The majority directs the collection and reporting of this data, as well as the additional time and effort in a quarterly stakeholder process, without any evidence of record indicating what such effort will cost.

Section III of DEP's Code of Conduct prohibits the disclosure of any "Customer Information" without customer consent, and the Commission has determined in a previous decision that the Code does not even allow for the release of aggregated data except as allowed by the Commission. Order Approving Limited Waiver of Code of Conduct, *Application of Duke Energy Carolinas, LLC, for a Waiver of Code of Conduct Section III A. 2(b) and (f)*, No. E-7, Sub 997 (Feb. 29, 2012). Customer Information is defined, in Section I of the Code, as "Non-public information or data specific to a Customer or a group of Customers, including, but not limited to, electricity consumption, natural gas consumption, load profile, billing history, or credit history that is or has been obtained or compiled by DEC, DEP, or Piedmont in connection with the supplying of Electric Services or Natural Gas Services to that Customer or group of Customers." The fact that a customer has been late, is on a payment plan, or is on a particular rate tariff, including enrollment in CAP and the bills for those CAP customers, seem to fall within the definition of Customer Information.

On this record, which is underdeveloped, I cannot agree with the requirement that DEP disclose to the stakeholder group and report to the Commission the zip code level data required by the Order. There is no evidence in the record as to why the Code of Conduct prohibits the disclosure of this type of information or the policy served by the prohibition. There is no evidence in the record as to why this specific information is necessary for understanding the efficacy and impacts of the CAP pilot. In addition, before directing this type of action, I must be persuaded that customers whose data are being collected and shared, or the communities in which they live, will not be inadvertently harmed by such action. Specifically, I would want to be certain that there is no opportunity, once disclosed to stakeholders or otherwise made public, for such data to be used against a customer in a way that might increase affordability challenges for that customer. I recognize that the data will be anonymous and it may be that collecting and disclosing zip code level data poses no risk in this regard, but the record is not developed on these issues, in particular risks to the customers that the majority is trying to serve. Because I agree that the Code of Conduct adopted by the Commission deserves more respect than that shown by the Order, I would not have imposed additional obligation on DEP.

Finally, I agree with the Public Staff that addressing affordability for the most vulnerable customers is, and must continue to be, a critical focus of the utility and the Commission. However, given the concerns expressed by the Public Staff, as well as by CIGFUR witness Phillips, regarding cross-subsidization, the reduction of customer usage through energy efficiency – actually reducing the amount of electricity that a customer must use and pay for – better serves customers. While I support the give and the take, as well as the outcome, of the Affordability Stipulation, I would not have gone beyond the stipulation, as the majority does, for this reason. In my view, DEP and its stakeholders' resources and efforts are well-spent identifying and developing programs that maximize the deployment of federal funding available for weatherization and energy efficiency, particularly funding that results from recent federal legislation, to the advantage of those customers in need. I see DEP's Residential Income-Qualified Energy Efficiency and Weatherization Program, Order Approving Program, *Application by Duke Energy Progress, Inc. for Approval of Residential Income-Qualified Energy Efficiency and Weatherization Program*, No. E-2, Sub 1299 (Mar. 1, 2023), as the type of program that better addresses energy burden and intensity. I also see the availability of federal dollars available for weatherization as a significant and real opportunity to expand the reach of this program to customers in need and to provide longer term assistance to these customers. My hope is that DEP's resources and attention remain on this program and on the opportunity for its customers created by the availability of the federal funding.

/s/ Charlotte A. Mitchell
Chair Charlotte A. Mitchell

DOCKET NO. E-2, SUB 1300

Commissioner Daniel G. Clodfelter, concurring in part and dissenting in part:

I am in agreement with the Commission's Order in all respects save one, and as to that lone issue I dissent. With respect to all other matters I concur, but I write separately to elaborate two points, one concerning performance incentive measures and the second relating to recovery of rate case expense associated with DEP's prior general rate case, the 2019 Rate Case. I address first the issue as to which I dissent.

I. Revenue Decoupling and Electric Vehicles

It is all very well that DEP's proposal for estimating revenues derived from residential electric vehicle (EV) charging would potentially support and encourage increased adoption of EVs by residential customers.[1] But first, before that worthy objective can be considered, the proposal must fit within the actual language of N.C.G.S. § 62-133.16(c)(2). It does not do so, based on a plain reading of the statute. The statute requires that EV revenues eligible for exclusion from the residential revenue decoupling mechanism are those derived from DEP's EV-specific riders or tariffs, not revenues that are derived from some method of estimation, however reasonable the process of estimation may be. The arguments on this point – and the defects in DEP's methodology for estimation even if estimation were proper in the first place – are well developed in the AGO Post-Hearing Brief at 9-18, and I adopt them here.[2]

II. Performance Incentive Measures

On the matter of performance incentive mechanisms (PIMs), N.C.G.S. § 62-133.16 is not especially demanding, requiring only that "one or more" PIMs be included in a rate application under that section. Even by that modest standard, I find the PIMs offered up pursuant to the PIMs Stipulation underwhelming.[3] Largely if not entirely based on the proposed reliability PIM, however, I am willing to accept that DEP's Application complies with the minimum requirements of the statute.[4] The reliability PIM establishes a target that

[1] AGO witness Nelson challenged whether this claimed linkage actually holds, but for the present I am willing to accept the claim.

[2] I acknowledge that in the PIMs Stipulation DEP agrees to work with the Public Staff and file within 90 days "EV tariffs and/or programs to estimate and update" revenues from EV charging. I do not consider this "and/or" commitment to be sufficient. After DEP has filed and has received approval for specific tariffs for residential EV charging, the decoupling mechanism can be revisited and modified as appropriate.

[3] I will not discuss the PIMs presented in DEP's original rate application since they are no longer before the Commission, except to say that I found the analysis and critique of those proposals by Public Staff witnesses Thomas and D. Williamson, by AGO witness Nelson, by CIGFUR witness Gorman, and by NCJC, et al. witness Posner to be highly persuasive.

[4] I am content to accept, for this first round of ratemaking under the new paradigm, the revised Time Differentiated and Dynamic Rate Enrollment PIM and the Renewables Integration and Encouragement PIM as they are set forth in the PIMs Stipulation, though I do not place much weight on them. I agree with several of the non-stipulating intervenors that those PIMs are not especially well-designed and that they address matters that likely do not require the "push or pull" of a PIM incentive to move the issue forward. Directives and initiatives

responds to the policy goals set forth in N.C.G.S. § 62-133.16(d)(2)(j) and likely also (d)(2)(i); it is well-defined and objectively measurable; and it is primarily, though not solely, under DEP's control. These are all necessary elements for a PIM pursuant to N.C.G.S. § 62-133.16(c)(3).

Though the requirement that it do so is not expressly spelled out in the enabling statute, the reliability PIM is also well-integrated with the other elements of DEP's MYRP application. It will provide some evidence, albeit indirect, of the success of DEP's proposed MYRP investments in transmission and distribution infrastructure over the period of the MYRP. Since these investments lie at the core of the MYRP, it is especially valuable that at least one of the proposed PIMs is linked to that core. Given the new ratemaking environment created by the multi-year ratemaking structure, with the many attendant and new forms of risk and reward for both DEP and ratepayers, I would have preferred to be grappling with PIMs that more directly spoke to the challenges that new ratemaking environment presents. For example, PIMs that would reward DEP for realizing reductions in operating costs and expenses, in order to balance the upward pressure on rates from year-to-year, or PIMs that would incentivize DEP to deliver the capital projects identified and included in the MYRP investment plan on time or under budget, in order to protect against the risk that revenues would have been earned on projects never completed, or delayed, or cancelled due to cost, could have more closely aligned the risks and rewards of the PIMs themselves with the potential risks and rewards of the MYRP.[5]

I do not fault DEP that this did not happen. With no prior history in designing and structuring PIMs and with little specific direction from the statute or from the Commission's rule about how to do so, DEP understandably defaulted to measures that were readily at hand and could be set up and proposed without great effort. Nor do I fault the Commission for not providing, in Rule R1-17B, more explicit guidance for DEP with respect to such things as the preferred or desired policy goals for PIMs and the methods for structuring PIMs to best achieve those goals. The Commission was given the task of implementing the new ratemaking paradigm established by the PBR Statute on a short timetable that simply did not permit an extended process of analysis, review, and stakeholder involvement on such matters. One thing that has been apparent from conversations with commissioners in other jurisdictions, from academic literature on the topic, from presentations on the topic of performance-based ratemaking at conferences, and from the work of the NERP task forces in North Carolina is that successful implementation of a robust system of performance-based incentives requires considerably more time and more stakeholder involvement than was available in the present circumstance. Put

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stemming from the Carbon Plan, the recently approved revised residential NEM tariff, and the revised non-residential NEM tariff approved in this case are likely to provide more than sufficient incentives for interconnection of new renewable resources, for expanded adoption of net metering, and for migration to time-differentiated rate structures. As several intervenors also note, the financial rewards proposed for these PIMs are modest, far less individually and collectively than the statutory cap, and are therefore unlikely to drive any significantly different behavior by the utility than what would otherwise occur without the PIMs.

[5] The reporting requirements set forth in Rule R1-17B(h)(2) and (3) do permit tracking of performance relative to capital projects included in the MYRP, including such matters as project substitutions, delays, and costs relative to projections, but they lack the incentive element that would have been provided by a PIM.

another way, the development of a sound policy and regulatory basis for PIMs – most especially the process for prioritizing and selecting goals for PIMS that are supportive of and integrate well into the larger framework of regulatory policy initiatives – is just not something that could be done in a hurry. In the present instance DEP, the various intervenors and interested parties, and the Commission have done the best that could be done in the time that has been available.

First time attempts to tackle any new challenge – or to take up an old challenge in a new way – may prove rocky and will most likely produce surprises and disappointments. This first MYRP rate case effort has not proved otherwise. What is most important now is that we build upon this experience and spend the time we collectively have between now and when DEP's next MYRP rate case is expected to be filed working to build out a more robust structure for selecting, developing, evaluating, and implementing PIMs. In particular, I believe it would be valuable for DEP and interested stakeholders to engage in a deeper discussion concerning the priority among the various optional policy goals set forth in N.C.G.S. § 62-133.16(d)(2) in order to ensure that the PIMs incorporated into an MYRP reinforce and build upon the policies embodied in the Carbon Plan and in related regulatory initiatives. To this end, I believe the Commission should revisit the recommendations made by the Public Staff and by a number of other intervenors in the original rulemaking docket that the Commission initiate a more extended and in-depth proceeding to put more "flesh on the bones" of the statute and of existing Rule R1-17B.[6] As we noted in our Order adopting Rule R1-17B, "the Commission may choose to initiate dockets to set policy goals for PBRs if it determined in the future that such dockets would be useful."[7] This is our opportunity to build out a more meaningful platform to enable DEP and its ratepayers to benefit from the potential contained in the performance-based ratemaking elements in the PBR Statute. We need to take that opportunity while we have time to do so and before the next MYRP is upon us.

III. Recovery of Additional Rate Case Expense Associated with 2019 Rate Case

The Commission has allowed recovery through the rates established in this case of certain additional rate case expenses associated with and arising out of DEP's prior

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[6] E.g., Initial Comments and Proposed Rule of the Public Staff, Rulemaking Proceeding to Implement Performance-Based Regulation of Electric Utilities, No. E-100, Sub 178 (Nov. 9, 2021); AGO Reply Comments, Rulemaking Proceeding to Implement Performance-Based Regulation of Electric Utilities, No. E-100, Sub 178 (Dec. 17, 2021); Comments and Partial Proposed Rules Submitted on Behalf of North Carolina Justice Center et al., Rulemaking Proceeding to Implement Performance-Based Regulation of Electric Utilities, No. E-100, Sub 178 (Nov. 21, 2021); Reply Comments of CIGFUR I, II and III, Rulemaking Proceeding to Implement Performance-Based Regulation of Electric Utilities, No. E-100, Sub 178 (Dec. 17, 2021). The position taken by these parties is also supported by the PBR Regulatory Guidance document issued by the NERP working group, which noted the process of developing, monitoring, and evaluating PIMs is best considered an "iterative" process. See PBR Regulatory Guidance - Implementation Suggestions for the NCUC from the North Carolina Regulatory Process at 19 (Dec. 22, 2020).

[7] Order Adopting Rule, Rulemaking Proceeding to Implement Performance-Based Regulation of Electric Utilities, No. E-100, Sub 178, at 14 (Feb. 10, 2023).

general rate case, (2019 Rate Case).[8] It has done so over the strong objection of the Public Staff, and it has acknowledged the justice of the Public Staff's position. But for one overriding factor, I would be inclined to deny recovery of the additional 2019 Rate Case expense for the reasons well stated by the Public Staff.

At the time of the Second Agreement and Partial Stipulation of Settlement between DEP and the Public Staff on July 31, 2020, DEP already knew that due to the Covid-19 pandemic the hearing of its 2019 Rate Case would be conducted under considerably different circumstances than were customary – that the hearing would be conducted remotely, that portions of the hearing would be consolidated with the hearing of common issues in the then-pending general rate case involving DEC, and that there would likely be delay in hearing those portions of the case that were specific only to DEP. In addition, DEP knew at that time that the Commission's Order in the 2017 Rate Case was on appeal and that there was a risk that order would be reversed in whole or in part and remanded for further proceedings. In its negotiations with the Public Staff, DEP could have taken steps to protect itself from these "known unknowns" affecting rate case expenses, but it did not do so.

The Supreme Court's action to remand to the Commission for further proceedings the order in the 2017 Rate Case came after the close of evidence in the 2019 Rate Case and after the parties had submitted their post-hearing briefs and proposed orders. One possible result of that remand could have been extended re-litigation of issues from the 2017 Rate Case and, even quite possibly, re-opening of the record in the 2019 Rate Case to permit the parties to offer additional evidence or argument concerning the effect of the Supreme Court's ruling on coal ash cost recovery issues in the 2019 Rate Case. In the end, DEP, the Public Staff, the AGO, and others were able to resolve the issues arising from the remand of the 2017 Rate Case in a settlement agreement that was comprehensive in nature and eliminated the risk of prolonged and expense continuing litigation. I consider the result obtained by this resolution to be far less costly for ratepayers in both the short term and in the long run than that alternative. For that reason, and that reason alone, I concur in the Commission's disposition of the issue of supplemental rate case expense associated with the 2019 Rate Case. As does the Commission in its Order, I find the circumstances to be unusual and wish to emphasize that I do not consider this disposition to be precedential for future cases.

/s/ Daniel G. Clodfelter
Commissioner Daniel G. Clodfelter

[8] Strictly, a good portion of these additional expenses can also be said to relate to DEP's next previous general rate case, the 2017 Rate Case, since they were incurred as a result of the Supreme Court's partial reversal and remand of the Commission's Order in the 2017 Rate Case.