STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-7, SUB 1276
DOCKET NO. E-7, SUB 1134

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1276 In the Matter of Application of Duke Energy Carolinas, LLC, For Adjustment of Rates and Charges Applicable to Electric Service in North Carolina and Performance Based Regulation DOCKET NO. E-7, SUB 1134 In the Matter of Application of Duke Energy Carolinas, LLC for Approval to Construct a 402 MW Natural Gas-Fired Combustion Turbine Electric Generating Facility in Lincoln County	)	JOINT PROPOSED ORDER

HEARD: Wednesday, June 21, 2023, at 7:00 p.m., Burke County Courthouse, 201 South Green Street, Courtroom 1A, Morganton, North Carolina

Thursday, June 22, 2023, at 7:00 p.m., Mecklenburg County Courthouse, 832 East 4th Street, Courtroom 5350, Charlotte, North Carolina

Monday, July 24, 2023, at 7:00 p.m., Forsyth County Courthouse, 200 North Main Street, Courtroom 1A, Winston-Salem, North Carolina

Wednesday, July 26, 2023, at 6:30 p.m., videoconference held remotely via Webex

Monday, August 14, 2023, at 7:00 p.m., Durham County Courthouse, 510 South Dillard Street, Courtroom 7D, Durham, North Carolina

Monday, August 28, 2023, at 2:00 p.m., Commission Hearing Room 2115, Dobbs Building, 430 N. Salisbury Street, Raleigh, North Carolina

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

APPEARANCES:

For Duke Energy Carolinas, LLC (DEC):

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Molly M. Jagannathan, Partner, 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 Utility Customers Association, Inc. (CUCA):

Marcus W. Trathen, Matthew Tynan, and Christopher B. Dodd, Brooks, Pierce, McLendon, Humphrey & Leonard, LLP, Wells Fargo Capitol Center, 150 Fayetteville Street, Suite 1700, Raleigh, North Carolina 27601

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

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For North Carolina Sustainable Energy Association (NCSEA):

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For Haywood Electric Membership Corporation (Haywood EMC), Blue Ridge Electric Membership Corporation d/b/a Blue Ridge Energy (Blue Ridge EMC), Piedmont EMC, and Rutherford EMC:

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For the North Carolina League of Municipalities (NCLM):

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For the Commercial Group:

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

For the Sierra Club:

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

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

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

For NC WARN:

Matthew D. Quinn, Partner, Lewis & Roberts, PLLC, Post Office Box 17529, Raleigh, North Carolina 27619

For The Kroger Co. and Harris Teeter LLC, a Division of The 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

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For the Carolinas Clean Energy Business Association (CCEBA):

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For Andale, LLC (Andale):

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For the Using and Consuming Public:

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

BY THE COMMISSION: On September 8, 2022, pursuant to Rule R1-17B(c) of the Rules of Practice and Procedure of the North Carolina Utilities Commission, DEC 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 December 7, 2022, pursuant to Commission Rule R1-17(a), DEC 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 January 19, 2023, DEC filed its Application to Adjust Retail Rates and for Performance-Based Regulation, 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, DEC'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 DEC and the parties, and procedural orders issued by the Commission.

On September 12, 2022, pursuant to N.C.G.S. § 62-69, DEC, Duke Energy Progress, LLC (DEP), the Public Staff, CIGFUR, and the Carolina Industrial Group for Fair Utility Rates II (CIGFUR II), 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 (DEP Rate Case) 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 September 14, 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 November 2, 2022, that DEC should file the information on projected transmission and distribution projects to be included in the PBR Application (T&D Information Filing) no later than October 19, 2022, and that parties would be allowed to file written comments on DEC's T&D Information Filing no later than November 2, 2022.

On September 19, 2022, CIGFUR filed a petition to intervene. The Commission issued an order granting CIGFUR's petition on September 20, 2022.

On October 17, 2022, Haywood EMC and Blue Ridge EMC filed petitions to intervene. On October 28, 2022, the Commission issued orders granting the petitions of Haywood EMC and Blue Ridge EMC.

CIGFUR's notice of intent to participate in the technical conference was also filed on October 17, 2022. The Public Staff filed its notice of intent to participate in the technical conference on October 18, 2022.

On October 18, 2022, Rutherford EMC, Piedmont EMC, NCSEA, and CUCA filed petitions to intervene. Also on October 18, 2022, NCJC et al. filed a petition to intervene and notice of intent to participate in the technical conference. On October 25, 2022, the Commission issued orders granting the petitions of CUCA, NCSEA, and NCJC et al. On October 28, 2022, the Commission issued orders granting the petitions of Rutherford EMC and Piedmont EMC.

On October 19, 2022, DEC filed its T&D Information Filing. On November 2, 2022, the Public Staff, CIGFUR, and NCJC et al. jointly with NCSEA filed comments in response to DEC's T&D Information Filing.

On November 2, 2022, the Commission held a technical conference with Commissioner Kimberly W. Duffley, Presiding; Chair Charlotte A. Mitchell; and Commissioners ToNola D. Brown-Bland; Daniel G. Clodfelter; Jeffrey A. Hughes; Floyd B. McKissick, Jr.; and Karen M. Kemerait.

On December 7, 2022, pursuant to Commission Rule R1-17(a), DEC 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.

The Attorney General's Office (AGO) filed a notice of intervention on December 8, 2022.

On January 19, 2023, DEC filed its Application, Form E-1, and the direct testimony and exhibits of Morgan D. Beveridge, Manager of Rates and Regulatory Strategy for Duke Energy Business Services, LLC (DEBS)[1]; Jonathan L. Byrd, Managing Director of Rate Design and Regulatory Solutions for DEBS; Kendal C. Bowman, North Carolina President for DEC; Janice D. Hager, President of Janice Hager Consulting, LLC; Laura A. Bateman, Vice President of Carolinas Rates and Regulatory Strategy; Phillip O. Stillman, Managing Director of Load Forecasting and Corporate Strategic Regulatory Initiatives for DEBS; Timothy S. Hill, Vice President, Coal Combustion Products (CCP) Operations, Maintenance, and Governance for DEBS; Steven D. Capps, Senior Vice President of Nuclear Operations for Duke Energy; Quynh Pham Bowman, Rates and Regulatory Strategy Director for DEC; Brent C. Guyton, Director, Asset Management in Customer Delivery for DEC; Bradley G. Harris, Rates and Regulatory Strategy Director for DEBS;

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

P. Brandon Lane, Vice President of Real Estate for DEBS; Retha Hunsicker, Vice President, Customer Experience Design and Solutions for DEBS; Justin C. LaRoche, Director of Renewable Development for Duke Energy; Daniel J. Maley, Director of Transmission Compliance Coordination for DEBS; John J. Spanos of Gannett Fleming Valuation and Rate Consultants, LLC (Gannett Fleming); Lesley G. Quick, Vice President of Customer Technology, Advocacy, Regulatory and Business Support within Customer Services for Duke Energy; John R. Panizza, Director, Tax Operations for DEBS; Karl W. Newlin, Senior Vice President, Corporate Development and Treasurer for 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 Duke Energy; Evan W. Shearer, Principal Integrated Planning Coordinator for DEC; Jacob J. Stewart, Director Health and Wellness for DEBS; Bryan P. Walsh, Vice President of Central Operational Services and Oversight for DEBS; Kathryn S. Taylor, Rates and Regulatory Strategy Manager for DEC; Nicolas G. Speros, Director of Accounting for DEBS.

On February 3, 2023, the Public Staff filed a letter in which it asserted the Application was incomplete and requested additional information. On February 8, 2023, DEC filed a responsive letter in which it noted it disagreed with the Public Staff's assertion that the Application was incomplete, but provided the Public Staff with the requested information.

On February 6, 2023, the Commercial Group and the Sierra Club filed petitions to intervene. On February 23, 2023, the Commission issued orders granting the petitions of the Commercial Group and the Sierra Club.

On February 13, 2023, Vote Solar filed a petition to intervene. On February 23, 2023, the Commission issued an order granting the petition of Vote Solar.

On February 16, 2023, the Commission issued an order that 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.

On February 21, 2023, Kroger Co. and Harris Teeter filed a petition to intervene. The Commission entered an order granting Kroger Co. and Harris Teeter's petition on February 28, 2023.

On March 15, 2023, CCEBA filed a petition to intervene. On March 29, 2023, the Commission issued an order granting CCEBA's petition.

On March 16, 2023, 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 Durham, Morganton, Charlotte, Winston-Salem, North Carolina, as well as a virtual hearing, on June 19, June 21, June 22, July 24, and July 26, 2023, respectively. Further, the Scheduling 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 DEC 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. Finally, the Scheduling Order scheduled a hearing for the purpose of receiving expert witness testimony on DEC's Application to begin on Monday, August 21, 2023. Subsequently, on May 23, 2023, the Commission issued its Order Rescheduling Durham County Public Witness Hearing and Requiring Public Notice (Second Scheduling Order) rescheduling the public witness hearing in Durham to August 14, 2023, and instructing DEC to publish a notice of the rescheduled public witness hearing in Durham once a week for two consecutive weeks prior to June 19, 2023.

In June, July, and August of 2023, the Commission held five public hearings as scheduled by the Scheduling Order and Second Scheduling Order for the purpose of receiving public witness testimony.

On April 27, 2023, DEC filed a Transmission Cost Allocation Agreement and Stipulation of Settlement between DEC, DEP, and the Public Staff (TCA Stipulation). On April 28, 2023, DEC filed settlement testimony of witness Bateman to support the TCA Stipulation.

On May 4, 2023, DEC, 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 16, 2023, DEC filed the settlement testimony of Witnesses Conitsha B. Barnes, Director of Energy Policy Management for DEC; Harris; and Quick in support of the Affordability stipulation.

On May 17, 2023, DEC filed a motion to substitute Witness Melissa B. Abernathy, Director of Rates and Regulatory Planning for DEC, as the sponsor of the Direct Testimony and Exhibits prefiled by witness Taylor on January 19, 2023. On May 25, 2023, the Commission issued an Order Accepting Substitution of Witness and Allowing Adoption of Testimony that allowed Witness Abernathy to adopt the testimony of Witness Taylor.

On May 19, 2023, DEC filed the supplemental testimony and exhibits of Witnesses Abernathy; Bateman; Stillman; Beveridge; Q. Bowman; Capps; Guyton; Lane; LaRoche; Maley; Meeks; Shearer; Martin M. Strasburger, Vice President, Chief Security and Information Security Officer for Duke Energy; and Walsh.

On May 19, 2023, DEC also filed a Petition to Amend Certificate of Public Convenience and Necessity (CPCN) in Docket No. E-7, Sub 1134 for a 402 MW combustion turbine (CT) at its existing Lincoln County Combustion Turbine site in Lincoln

County, North Carolina to allow DEC to seek cost recovery of the Lincoln CT. Given the overlap of issues between the issues in DEC's Petition and Application filed in this proceeding, DEC's Petition requested the Commission consolidate E-7, Sub 1134 with this proceeding. On July 11, 2023, the Commission issued an Order Consolidating Dockets that consolidated DEC's Petition filed in Docket No. E-7, Sub 1134 with the general rate case application filed in this proceeding.

On June 15, 2023, DEC filed a motion to substitute witness Donna T. Council, Senior Vice President, Corporate Real Estate, Aviation, and Business Services for DEBS, as the sponsor of the Direct Testimony and Exhibits prefiled by witness Lane on January 19, 2023, and May 19, 2023. On June 28, 2023, the Commission issued an Order Accepting Substitution of Witness and Allowing Adoption of Testimony that allowed witness Council to adopt the testimony of witness Lane.

On June 19, 2023, Andale filed a petition to intervene. On June 28, 2023, the Commission issued an order granting the petition of Andale.

Also on June 19, 2023, DEC filed the second supplemental testimony and exhibits of witnesses Q. Bowman and Abernathy.

On June 29, 2023, NC WARN filed a petition to intervene. On July 11, 2023, the Commission issued an order granting NC WARN's petition.

On July 14, 2023, DEC filed a Motion seeking to delay the evidentiary hearing by seven (7) days to Monday, August 28, 2023. On July 26, 2023, the Commission issued an Order Rescheduling Hearing and Providing Additional Hearing Procedures that rescheduled the expert witness hearing to begin on Monday, August 28, 2023.

On July 18, 2023, DEC filed the third supplemental direct testimony and exhibits of witnesses Q. Bowman and Abernathy; the second supplemental direct testimony and exhibits of witnesses Council, Walsh, LaRoche, and Maley; and the supplemental direct testimony and exhibits of witness Spanos.

On July 19, 2023, NCLM filed a petition to intervene. On July 24, 2023, the Commission issued an order granting NCLM's petition.

Also on July 19, 2023, the North Carolina Electric Membership Corporation (NCEMC) filed a petition to intervene, or in the alternative, motion for leave to file *Amicus Curiae* brief. On August 23, 2023, the Commission issued an order denying NCEMC's petition.

Also on July 19, 2023, the Public Staff filed the direct testimony and exhibits of Dustin Metz, Manager of the Electric Section – Operations and Planning in the Energy Division of the Public Staff; James S. McLawhorn, Director of the Energy Division of the Public Staff; Tommy Williamson, Jr., Engineer with the Energy Division of the Public Staff; David M. Williamson, Engineer with the Energy Division of the Public Staff; Roxie

McCullar, Consultant, William Dunkel and Associates; Jordan A. Nader, Engineer with the Energy Division of the Public Staff; Jay B. Lucas, Engineer with the Energy Division of the Public Staff; Evan D. Lawrence, Engineer with the Energy Division of the Public Staff; Blaise C. Michna, Engineer with the Energy Division of the Public Staff; Christopher C. Walters, Associate, Brubaker & Associates, Inc.; Jeff Thomas, Engineer with the Energy Division of the Public Staff; John W. Chiles, Principal, GDS Transmission Services group at GDS Associates, Inc.; the joint direct testimony and exhibits of David M. Williamson and Jeff T. Thomas, Engineers with the Energy Division of the Public Staff; and the joint direct 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.

Also on July 19, 2023, NC WARN filed the joint direct testimony and exhibits of William E. Powers, Principal, Powers Engineering, and Rao Konidena, President, Rakon Energy LLC; NCJC et al., filed the direct testimony and exhibits of Mark E. Ellis, economic and financial consultant; Genelle Wilson, Senior Associate at RMI; and the joint direct testimony and exhibits of David G. Hill, Managing Consultant at Energy Futures Group, Inc., and Jake Duncan, Southeast Regulatory Director for Vote Solar; Kroger Co. and Harris Teeter filed the direct testimony and exhibits of Justin Bieber, Principal, Energy Strategies, LLC; NCSEA filed the direct testimony and exhibits of Lance D. Kaufman, Consultant, lance Kaufman Consulting; the Commercial Group filed the direct testimony and exhibits of Steve W. Chriss, Senior Director, Utility Partnerships for Walmart Inc.; the Sierra Club filed the direct testimony and exhibits of Michael Goggin, Vice President at Grid Strategies, LLC; CIGFUR filed the direct testimony and exhibits of Brian C. Collins, Managing Principal with Brubaker & Associates, Inc.; CUCA filed the direct testimony and exhibits of Jeffry Pollock, energy advisor and President of J. Pollock, Inc.; David Lyons, Director of Energy for Gerdau, N.A.; and Billie S. LaConte, energy advisor and Associate Consultant at J. Pollock, Incorporated; and the AGO filed the direct testimony and exhibits of Edward Burgess, Senior Director of Integrated Resource Planning with Strategen Consulting; Nikhil Balakumar, Manager with Strategen Consulting; and Caroline Palmer, Manager with Strategen Consulting.

On August 4, 2023, DEC filed the rebuttal testimony and exhibits of DEC's witnesses K. Bowman; Morin; James M. Coyne, Senior Vice President, Concentric Energy Advisors, Inc.; Kevin A. Murray, Vice President of the Project Management and Construction organization for DEBS; Maley; Guyton; Capps; Walsh; LaRoche; Council; the joint rebuttal testimony and exhibits of witnesses Bateman and Stillman; the joint rebuttal testimony and exhibits of witnesses K. Bowman, Quick, and Abernathy; and the joint rebuttal testimony and exhibits of witnesses Meeks and Shearer.

On August 7, 2023, DEC filed a Notice of Intent to Place Temporary Rates into Effect and Request for Expedited Approval of Notice of Undertaking. On August 14, 2023, the Commission issued an Order Approving Public Notice of Temporary Rates Subject to Refund and Financial Undertaking.

On August 18, 2023, DEC filed its Temporary Rates Compliance Filing.

On August 22, 2023, DEC filed an Agreement and Stipulation of Settlement between DEC and CIGFUR on Performance Incentive Mechanisms (the Power Quality Stipulation). DEC also filed an Agreement and Stipulation of Settlement between DEC and the Public Staff (the August 22, 2023 Revenue Requirement Stipulation). DEC also filed an Agreement and Stipulation of Settlement between DEC, CIGFUR, and the Public Staff on Performance Incentive Mechanisms, Tracking Metrics, and Decoupling Mechanism (the PIMs Stipulation).

On August 23, 2023, the Commission issued an Order Denying Petition to Intervene of North Carolina Electric Membership Corporation and Granting Amicus Curiae Status.

On August 24, 2023, the Public Staff filed the Joint Testimony of witnesses Thomas and D. Williamson in Support of the PIMs Stipulation and DEC filed the PBR Policy Panel PIMs Stipulation Testimony. Also on August 24, 2023, DEC filed the Settlement Testimony and Exhibits of witnesses Abernathy, Beveridge, K. Bowman, and Q. Bowman in support of the Revenue Requirement Stipulation.

On August 28, 2023, the expert witness hearing commenced.

On August 25, 2023, DEC and CIGFUR and filed an Agreement and Stipulation of Partial Settlement relating to certain rate design issues (OPT-V-Primary Partial Rate Design Stipulation). DEC, the Commercial Group, and Kroger Co. and Harris Teeter, also filed an Agreement and Stipulation of Partial Settlement relating to certain rate design issues (OPT-V-Secondary Partial Rate Design Stipulation) on this same day. Additionally, DEC filed Settlement Supporting Testimony of DEC witnesses Byrd and Beveridge supporting the two rate design partial stipulations filed on this day. CIGFUR also filed a Motion for Admission of Certain Evidence on August 25, 2023.

On August 28, 2023, the expert witness hearing commenced. Also on August 28, 2023, DEC and the Public Staff filed an Amended Agreement and Stipulation of Partial Settlement (Revenue Requirement Stipulation). DEC also filed a Summary Overview of Stipulations and the Supplemental Settlement Testimony and Exhibits of witnesses K. Bowman, Abernathy, Bateman, and Q. Bowman. CIGFUR also filed the Settlement Testimony of witness Collins. Additionally, NCJC et al. filed a Motion Regarding Stipulating of Certain Evidence and Attachments.

From August 30, 2023, through September 6, 2023, DEC filed five Late-Filed Exhibits.

Jurisdiction

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

Application

In summary, DEC requested in its Application and initial direct testimony and exhibits, a base rate increase of approximately $371.5 million, or 7.1%, in its annual electric sales, offset by a rate reduction of $10.4 million to refund certain tax benefits, for a net revenue increase of $361.1 million, or 6.9% from its North Carolina retail electric operations, including a rate of return on common equity of 10.4% and a capital structure consisting of 47.0% debt and 53.0% equity. DEC's Application and initial direct testimony and exhibits also sought approval of PBR and a series of rate increases based on DEC's proposed three-year MYRP, and other mechanisms required as part of PBR, with the first rate increase effective February 20, 2023. DEC sought increases to the revenue requirement of $511.3 million, $171.5 million, and $150.3 million in Rate Year 1, Rate Year 2, and Rate Year 3, respectively.

DEC 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 July 31, 2023.[2]

DEC, by its supplemental direct testimony and exhibits, revised its requested base revenue requirement increase to approximately $434.5 million, offset by a rate reduction of $10.4 million to refund certain tax benefits, for a net revenue increase of $424.1 million, including an increase to the cost of debt to 4.50% based on the average embedded cost of debt financing as of April 30, 2023. DEC also revised its series of rate increases based on DEC's proposed three-year MYRP. DEC's updated MYRP revenue requirements were $165.8 million, $181 million, and $185.1 million in Rate Year 1, Rate Year 2, and Rate Year 3, respectively.

DEC, by its second supplemental direct testimony and exhibits, revised its requested base revenue requirement increase to approximately $440.3 million, offset by a rate reduction of $10.4 million to refund certain tax benefits, for a net revenue increase of $429.9 million including an increase to the cost of debt to 4.53% based on the average embedded cost of debt financing as of May 31, 2023. DEC also revised its series of rate increases based on DEC's proposed three-year MYRP. DEC's updated MYRP revenue requirements were $165.9 million, $181.2 million, and $185.3 million in Rate Year 1, Rate Year 2, and Rate Year 3, respectively.

DEC, by its June 2023 supplemental direct testimony and exhibits, revised its requested base revenue requirement increase to approximately $466.0 million, offset by a rate reduction of $10.4 million to refund certain tax benefits, for a net revenue increase of $455.6 million, including an increase to the cost of debt to 4.56% based on the average

[2] DEC's Application initially proposed a capital cut-off date of July 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 June 30, 2023. The change in capital cut-off was reflected in DEC's supplemental filings.

embedded cost of debt financing as of June 30, 2023. DEC also revised its series of rate increases based on DEC's proposed three-year MYRP. DEC's updated MYRP revenue requirements were $162.6 million, $180.0 million, and $182.8 million in Rate Year 1, Rate Year 2, and Rate Year 3, respectively.

Whole Record

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

Durham:	Kara Lynn Sanders, Anne Lazarides, Markus Joseph Kitsinger, Keval Khalsa, Donald Macon Nonini, Andrew Silver, Sherri Zann Rosenthal, Dale Evarts, Stacey Freeman, Zyad Habash, Eleanor Weston, Jennifer Griffith, Lib Hutchby, Martha Pentecost, Sally Jernigan-Smith, Felicia Wang, Carley Tucker, and Shawn Murphy.
Morganton:	Gray Jernigan.
Charlotte:	Billie Anderson, Janet Labar, David Julian, Beth Henry, Marcia Colson, Ronald Ross, June Blotnick, Nancy Carter, Maria Portone, Michelle Carr, Jessica Finkel, Juanita Miller, Nikita Williams, and Jerome Wagner.
Winston-Salem:	Debra Demske, Anne Garvey, Lei Zhang, Willie Penn, Paulette Smith, and Matthew Mayers.
Virtual Hearing:	Dennis Testerman, Sophie Loeb, and Fotini G. Katsanos.

In summary, most public witnesses did not support DEC's proposed rate increase, but public witnesses did commend DEC's economic development efforts. *See generally*, Tr. vols. 2-6. More specifically, public witnesses voiced concerns regarding the impact of the rate increase on those living on fixed incomes or experiencing poverty in the current economic environment. Public witnesses also testified regarding DEC's use of fossil fuels, including coal and natural gas power plants, and argued in support of increased renewables. Some public witnesses also voiced concerns regarding DEC's executive compensation. However, the Charlotte Regional Business Alliance testified that DEC's investments to provide reliable, affordable energy, and build utility infrastructure for businesses is nationally regarded, and that DEC has partnered with various universities, including Historically Black Colleges and Universities to intentionally develop a more diverse workforce and advance more diverse talent into strong leadership. Tr. vol. 2, 28-29.

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-7, Sub 1276CS. The public witness testimony and consumer statements of position have been considered by the Commission in its deliberations on DEC'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 August 22, 2023, DEC 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 August 28, 2023, DEC and the Public Staff amended the Revenue Requirement Stipulation, resolving additional revenue requirement issues and leaving as unresolved only the following revenue requirement issues: (1) return on equity, (2) capital structure, and (3) recovery of COVID-19 pandemic-related costs.

2. On September 13, 2022, DEC, DEP, the Public Staff, CIGFUR II, and CIGFUR (the COSS Stipulating Parties) filed the COSS Stipulation. The COSS Stipulation provides that DEC 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, DEC, DEP, 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 the instant proceeding and to decrease the revenue requirement in DEP's rate case proceeding in Docket No. E-2, Sub 1300 (DEP Rate Case).

4. On August 22, 2023, DEC, the Public Staff, and CIGFUR filed the PIMs Stipulation.

5. [ ].

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

7. On August 25, 2023, DEC and CIGFUR filed the OPT-V-Primary Partial

Rate Design Stipulation.

8. On August 25, 2023, DEC, the Commercial Group, and Kroger Co. and Harris Teeter filed the OPT-V-Secondary Partial Rate Design Stipulation.

9. The Revenue Requirement Stipulation, the COSS Stipulation, the TCA Stipulation, the PIMs Stipulation, the Power Quality Stipulation, the Affordability Stipulation, the OPT-V-Primary Partial Rate Design Stipulation, and the OPT-V-Secondary Partial Rate Design Stipulation, are the product of give-and-take settlement negotiations between the respective stipulating parties.

Depreciation

10. As amended by the Revenue Requirement Stipulation, the accelerated retirement dates for coal plants proposed by DEC, except for the Cliffside 5 retirement date, which will move to January 1, 2031, and the Allen 1 and 5 retirement date, which will move to January 1, 2025, consistent with the rebuttal testimony of DEC witness John Spanos filed on August 4, 2023, are reasonable.

11. The deferral of 75.0% of the impact of accelerating the depreciation of DEC's subcritical coal plants from the current retirement dates to a regulatory asset as agreed upon in the Revenue Requirement Stipulation is reasonable.

12. Twenty-five percent of net book value upon the retirement of DEC'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.

13. The corrected depreciation rates set forth by DEC in DEC witness Spanos' rebuttal testimony, subject to an adjustment to decommissioning estimates to use 10% contingency and a 5% indirect cost adder as agreed upon in the Revenue Requirement Stipulation, are reasonable.

Base Period Plant-Related Items

14. DEC's plant-related capital investments during the test year in its general/intangible, 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 DEC's last general rate case, DEC 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 DEC's weighted average cost of capital.

16. DEC proposes to amortize the GIP deferral associated with its GIP

investment over an amortization period of three years.

17. Section III, Paragraph 12 of the Revenue Requirement Stipulation provides that DEC 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. DEC's request to amortize costs associated with its coal combustion residual (CCR) obligations incurred through June 30, 2023, over a five-year period and to continue the deferral of any CCR costs incurred subsequent to June 30, 2023, is reasonable.

Environmental Compliance Cost Recovery

19. Since DEC's last rate general rate case, DEC has deferred certain costs incurred in connection with compliance with federal and state environmental requirements as it relates to CCRs.

20. DEC proposes to amortize $7.284 million of deferred environmental costs related to CCRs over an amortization period of six years, which will result in an annual amortization expense of $1.214 million.

Storm Securitization Over Collections

21. Per DEC's Agreement and Stipulation of Partial Settlement with the Public Staff in Docket No. E-7, Sub 1243, DEC 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.

22. The amortization over three years of the regulatory liability for the over-recovered balance of $0.6 million for storm securitization over collections is just and reasonable.

Cost of Debt

23. The embedded cost of debt of 4.56% as set forth in Section III, Paragraph 1 of the Revenue Requirement Stipulation is reasonable and appropriate for use by DEC in this case.

Accounting Adjustments

24. The accounting adjustments set forth in the Revenue Requirement Stipulation, as further described in detail in Q. Bowman Supplemental Partial Settlement Exhibit 2, are the reasonable product of give-and-take negotiations among the parties.

Nuclear PTC Rider

25. The nuclear PTC rider agreed to in the Revenue Requirement Stipulation, as further described in DEC witness Bateman's settlement testimony, is the reasonable product of give-and-take negotiations among the parties.

Lead Lag Study

26. DEC agrees to perform a Lead Lag Study before the next general rate proceeding and incorporate the results in that general rate case application in accordance with Section IV of the Revenue Requirement Stipulation.

MYRP Capital Investments

27. DEC's proposed MYRP capital investments, reflecting the projected costs associated with the transmission, distribution, fossil/hydro, nuclear, cybersecurity, solar, and storage, 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 DEC's overall Application in this proceeding.

Reporting Requirements

28. The reporting obligations established in Section IV of the Revenue Requirement Stipulation are just and reasonable.

29. DEC also agreed to provide certain information in its quarterly reliability reports filed in Docket No. E-100, Sub 138A.

Storm Normalization

30. The adjustment to DEC's revenue requirement, calculated using the method approved by the Commission in Docket Nos. E-7, Sub 1026, E-7, Sub 1146, and E-7, Sub 1214 to account for anticipated storm expenses based upon a 10-year average of storm costs after removing costs associated with major storms, is approximately $32.225 million.

Payment Navigator

31. DEC 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

32. DEC has proposed to recover approximately $92 million associated with the implementation of the Customer Connect platform, which is DEC's customer engagement platform, and the Customer Information System (CIS).

COSS Stipulation

33. The COSS Stipulation between DEC, DEP, CIGFUR II, CIGFUR, and the Public Staff, requires DEC 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

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

PIMs Stipulation

35. 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 DEC to work with the Public Staff to develop tariffs and programs to estimate and update revenue associated with EV sales.

Power Quality Stipulation

36. [ ].

Affordability Stipulation

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

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

Rate Design

39. [ ]

40. [ ]

41. [ ]

42. [ ]

43. [ ]

44. [ ]

45. [ ]

Capital Structure, Cost of Equity and Overall Rate of Return

46. [ ].

47. [ ].

48. [ ].

COVID Deferral Recovery

49. [ ].

50. [ ].

51. [ ].

52. [ ]

53. [ ].

Storm Balancing Account

54. DEC proposed to create a storm balancing account. DEC agreed to withdraw its storm balancing account proposal as part of the Revenue Requirement Stipulation.

Other Deferrals

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

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

57. DEC 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 proposed to defer its incremental O&M costs associated with the implementation of the customer programs and PIMs. DEC agreed to withdraw its request to defer its incremental O&M costs associated with the implementation of the customer programs and PIMs as part of the Revenue Requirement Stipulation.

Interconnection CIAC Regulatory Liability Recommendation

58. With respect to DEC's recording of contributions in aid of construction (CIAC) in the context of interconnection agreements (IA) between DEC and third-party interconnection customers, the Public Staff identified an issue and proposed that a regulatory liability be established to record any instances in which DEC incorrectly recovered costs associated with interconnection agreements (IAs) from ratepayers. In the Revenue Requirement Stipulation, DEC and the Public Staff agreed that DEC will not establish a regulatory liability at this time for a CIAC.

Quality of Service

59. DEC and the Public Staff presented evidence as to the adequacy of electric service provided by DEC.

Tax-Related Items

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

61. The levelized return rate should reflect a 4.56% embedded cost of debt and the capital structure and rate of return on equity approved by the Commission in this proceeding.

Fuel Cost Voltage Differential

62. It is appropriate for DEC to incorporate fuel cost voltage differential for the prospective billing period fuel rates in DEC's next fuel proceeding to be filed in February, 2024, and to remove line losses from base rates at that time.

Base Fuel and Fuel-Related Factors and Fuel Cost Allocation

63. [ ].

64. [ ].

Residential Decoupling Mechanism and Earnings Sharing Mechanism

65. DEC's PBR Application includes a residential decoupling mechanism, a rate-making mechanism intended to break the link between DEC'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 and Commission Rule R1-17B.

66. DEC proposes as a component of the MYRP an ESM, an annual rate-making mechanism that shares surplus earnings between DEC and its customers during the course of the MYRP, as required by N.C.G.S. § 62-133.16(c) and Commission Rule R1-17B.

Performance-Based Regulation

67. DEC filed its first PBR Application pursuant to N.C.G.S. § 62-133.16 and with Commission Rule R1-17B.

Revenue Requirement

68. [ ].

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-9

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

Revenue Requirement Stipulation

On August 22, 2023, the Public Staff and DEC filed the Revenue Requirement Stipulation resolving a portion of the revenue requirement issues between the parties. On August 28, 2023, DEC and the Public Staff amended the stipulation to resolve among themselves a substantial number of additional revenue requirement issues. As amended, the Revenue Requirement Stipulation identifies only three unresolved revenue requirement issues (return on equity, capital structure, and recovery of COVID-19 pandemic costs) and one unresolved non-revenue requirement issue (equal percentage allocation).

Witness K. Bowman testified that the Revenue Require Stipulation resolves nearly all of the revenue requirement issues between DEC and the Public Staff. She stated that the parties fully resolved the recovery of capital projects and related costs to be included in DEC's MYRP. Tr. vol. 7, 109. 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; the Duke Energy Plaza; lobbying; sponsorships and donations; incentive compensation; reliability assurance operations and maintenance (O&M) spend; vegetation management O&M; aviation expenses; non-residential credit card fees; end of life nuclear reserve; coal inventory; materials and supply inventory; executive compensation; EFC revenue; nuclear levelization costs; production O&M; lighting audit, nuclear production tax credits; and the treatment of various deferrals DEC is requesting to recover. *Id.* at 104, 109. She further testified that certain other additional issues were resolved in a manner consistent with the Commission's August 18, 2023 Order Accepting Stipulations, Granting Partial Rate Increases, and Requiring Public Notice in Docket E-2, Sub 1300 (DEP Rate Case Order), for purposes of settlement only, including: over amortization of regulatory assets, inflation adjustment, deferral of program implementation costs, contributions in aid of construction regulatory liability recommendation, storm balancing account, and rate case expense. *Id.* at 108.

She explained that the Revenue Requirement Stipulation shows these accounting and ratemaking adjustments and the resulting effect on the revenue requirement. Witness K. Bowman also testified to DEC's commitment to perform a lead-lag study before its next rate case application and agreement to various reporting obligations. *Id*. at 104. Witness K. Bowman further testified that the Revenue Requirement 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.* at 103.

Sections III and IV of the Revenue Requirement Stipulation outline several accounting and ratemaking adjustments, as well as reporting obligations, to which DEC and the Public Staff 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 in the instant proceeding and in the DEP Rate Case. Tr. vol. 12, 342. We approved the COSS Stipulation in our DEP Rate Case Order. The COSS Stipulation provides that DEC 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, DEC 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 DEC cases. *Id.* DEC 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 342-43.

TCA Stipulation

On April 27, 2023, DEC, DEP, and the Public Staff filed the TCA Stipulation in the instant proceeding and in the DEP Rate Case. We approved the TCA Stipulation in our DEP Rate Case Order. 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 this proceeding and to decrease the revenue requirement in the DEP Rate Case.

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-

[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 Duke Energy Corporation. Order

firm transmission rate established in the FERC-approved Joint Open Access Transmission Tariff (OATT) of DEC, DEP, and Duke Energy Florida, LLC (DEF).[4] The TCA 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 DEC or DEP. 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 DEC's or DEP's next general rate case or the effective date of a full merger of DEC and DEP, unless the Commission orders otherwise.

DEC witness Bateman testified in support of the TCA Stipulation. Tr. vol 11, 212. 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.* at 214. Public Staff witness Metz also testified in support of the TCA Stipulation. Tr. vol. 12, 864-67. 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 August 22, 2023, DEC, the Public Staff, and CIGFUR filed the PIMs Stipulation. The PIMs Stipulation reflects an agreement between the stipulating parties regarding certain of the PIMs, tracking metrics, and the electric vehicle (EV) adjustment to DEC's decoupling mechanism.

The PBR Policy Panel, consisting of DEC witnesses Bateman and Stillman, provided testimony in support of the PIMs Stipulation. Tr. vol. 11, 197. The PBR Policy Panel testified that the resolution reached among the stipulating parties represents a balanced approach to achieving policy goals in DEC's first PBR Application. *Id.* at 201. DEC witness Stillman testified that the Settled PIMs originated from the North Carolina Energy Regulatory Process (NERP) PBR Working Group,[5] were informed by DEC's pre-filing PIM stakeholder process, and evolved over discussions among the parties in the

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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).

[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. 11, 143.

instant proceeding. *Id.* at 200. Witness Bateman testified that DEC took a conservative approach in this first PBR Application in order for DEC, customers, and the Commission to gain experience with the operation and implementation of PIMs. Tr. vol. 11, 187. DEC witness Stillman explained DEC's approach to designing the PIMs around the 1.0% cap set forth in N.C. Gen. Stat. § 62-133 and stated that DEC was deliberate in choosing to propose only a select number of PIMs that meet the maximum number of policy goals. *Id.* at 271.

Public Staff witnesses D. Williamson and Thomas provided testimony in support of the PIMs Stipulation. Tr. vol. 14, 315-18. 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. *Id.* at 318. 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*.

Power Quality Stipulation

[ ]

Affordability Stipulation

On May 4, 2023, DEC, DEP, Sierra Club, NCJC, et al., and the Public Staff filed the Affordability Stipulation. Tr. vol. 11, 74-75. The Affordability Stipulation obligates DEC to withdraw the affordability PIM proposed in this proceeding. *Id.* at 75. 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. *Id.* at 75-76. In addition, the stipulation obligates DEC 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. *Id.* at 76. Finally, the stipulation obligates DEC 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. *Id.* at 76-77.

OPT-V-Primary Partial Rate Design Stipulation

On August 25, 2023, DEC and CIGFUR filed the OPT-V-Primary Partial Rate Design Stipulation, which provides that any increase in energy charges resulting from an increase in DEC's revenue requirement to be recovered from the OPT-V-Primary sub-class, as determined by final Commission order, shall be limited to a percentage that is less than half of the approved overall increase percentage to OPT-V Primary, exclusive of any decrements for OPT-V-Primary. The OPT-V-Primary Partial Rate Design Stipulation also provides that DEC agrees to modify the Mid-Peak Demand tiers for the

OPT-V-Primary sub-class from 1,000 kW/3,000 kW to 1,000 kW/5,000 kW to better align with the On-Peak Demand tier in the current OPT-V tariff. DEC will also adjust the Mid-Peak Demand Charge prices within OPT-V Primary to achieve similar pricing spreads between the first, second, and third demand tiers. Additionally, DEC agrees to adjust Transmission demand charge pricing in proposed Schedule HLF to achieve a similar pricing spread between voltage classes as compared to Schedule OPT-V, and DEC agrees to set the HLF energy charge equal to the unit cost for OPT-V Large sub-classes. Finally, DEC agrees to modify proposed Rider ED to strike the following words: “The New Load shall exclude any curtailable, back-up, or standby service.”

OPT-V-Secondary Partial Rate Design Stipulation

On August 25, 2023, DEC, the Commercial Group, and Kroger Co. and Harris Teeter filed the OPT-V-Secondary Partial Rate Design Stipulation, which resolves some of the issues in this proceeding among the parties. The OPT-V-Secondary Partial Rate Design Stipulation, entered into by DEC, the Commercial Group, and Kroger Co. and Harris Teeter, provides that the proportion of total revenues recovered through demand charges for the Schedule OPT-V-Secondary sub-class will be increased by 5% (relative to current rates) in Rate Year 1 of the MYRP from 37.9% to 42.9%, with a corresponding revenue neutral decrease to the proposed on-peak, off-peak, and discount energy charges. In Rate Years 2 and 3 of the MYRP, each of the demand and energy charges will be increased by an equal percentage in order to recover the target revenue requirement.

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 Affordability Stipulation, the OPT-V-Primary Partial Rate Design Stipulation, and the OPT-V-Secondary Partial Rate Design 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, and the dearth of evidence in the record opposing any of these stipulations, and concludes, exercising its independent judgment, that it should accept the stipulations, consistent with the specific discussion and resolution of the issues set forth below.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 10-13

Depreciation

The evidence supporting these findings of fact is included in DEC's verified Application and Form E-1; the testimony and exhibits of DEC witness Spanos, Bateman, Bowman, and Kopp, Public Staff witnesses Lucas and McCullar, NCSEA witness Kaufman, and the entire record in this proceeding.

Spanos Direct Exhibit 1 to DEC witness Spanos's direct testimony is the 2021 DEC Depreciation Study prepared by Gannett Fleming (2021 Depreciation Study). Tr. vol. 9, 188-189; see also 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 188. In supplemental testimony, DEC witness Spanos provided the Commission with an updated 2021 Depreciation Study. Tr. vol. 9, 225-26; see also Tr. Ex. vol. 10. The Updated Depreciation Study accounted for changes to the Lee facility, which was retired as of March 2022 but was not consistently reflected in the initially filed 2021 Depreciation Study presented as Spanos Exhibit 1. *Id.* at 226. He also testified that the weighted net salvage calculation for the Lee facility was updated from negative 17% to negative 12% to reflect the more accurate expectation of decommissioning costs. *Id.* at 226-27. Additionally, witness Spanos testified that the updated testimony reflects the proper assignment of the accumulated depreciation to properly match utilization and recovery of assets. *Id.* at 227. Witness Spanos testified that the total depreciation impact for the change in steam production plant is an increase in annual depreciation expense of $11,619,514, which is related to all steam production plants. *Id.* Witness Spanos set forth in his rebuttal testimony the corrected calculation for other Production Plant as of December 31, 2021, and set forth the updated calculation for the Lee steam facility. Tr. Ex. vol. 10.

Section III, Paragraph 2 of the Revenue Requirement Stipulation provides that the Stipulating Parties agree to use DEC's proposed accelerated retirement dates for its coal plants to set depreciation rates, except for the Cliffside 5 retirement date. Tr. Ex. vol. 7. The Cliffside 5 retirement date will move to January 1, 2031, which is consistent with DEC's Carolinas' Resource Plan filed on August 17, 2023. *Id.* Section III, Paragraph 3 of the Revenue Requirement Stipulation provides that the Stipulating Parties also agree to increase DEC's proposed deferral to a regulatory asset from 50% to 75% of the impact of accelerating the depreciation of DEC's subcritical coal plants from the current retirement dates. *Id.* This preserves the ability of DEC to recover 50% of the net book value of the subcritical coal plants through securitization as allowed under House Bill 951. *Id.* The Revenue Requirement Stipulation further provides that for the remaining 25%, it is appropriate to recover those costs with a return over an amortization period to be determined by the Commission in a future rate case. *Id*. Finally, Section III, Paragraph 4 of the Revenue Requirement Stipulation sets forth an agreement by the Stipulating Parties to use the corrected depreciation rates set forth by DEC witness Spanos's rebuttal testimony, subject to an adjustment to the decommissioning estimates to use 10% contingency and a 5% indirect cost adder. *Id*.

Summary of Evidence

Retirement Dates for Coal Plants

DEC 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. 9, 194. Witness Spanos testified that he used these factors to evaluate DEC's recommended retirement dates and agreed that they were reasonable. *Id.* at 194–95. The 2021 Depreciation Study identified the following retirement dates for DEC's coal plants:

Unit	Probable Retirement Date
Allen 1	December 31, 2023
Allen 5	December 31, 2023
Belews Creek 1	December 31, 2035
Belews Creek 2	December 31, 2035

Cliffside 5	December 31, 2025
Cliffside 6	December 31, 2048
Marshall 1	December 31, 2028
Marshall 2	December 31, 2028
Marshall 3	December 31, 2032
Marshall 4	December 31, 2032

Tr. Ex. vol. 10. Witness Spanos testified that since the last approved depreciation rates in DEC's previous rate case, the life spans for the Allen Units were shortened from 2026 to 2023; the Marshall Units were shortened from 2034 to 2028 or 2032; Belews Creek Units were shortened from 2037 to 2035; and Cliffside Unit 5 was shortened from 2032 to 2025. *Id.* at 194–195. Witness Spanos agreed that the new life span for the units are Reasonable and consistent with both DEC's plans as well as industry expectations. *Id.*

In connection with these coal retirement dates, DEC witness Q. Bowman testified that DEC was requesting approval to defer to a regulatory asset 50% of the impact of accelerated depreciation for sub-critical coal plants. Tr. vol 12, 190. Witness Q. Bowman testified that HB 951 allows DEC to securitize 50% of the remaining net book value of the plants at retirement, and DEC wants customers to benefit from the savings that could potentially be provided through securitization. *Id.* at 190–91. Accordingly, witness Bowman testified that DEC seeks to defer to that regulatory asset 50% of the incremental depreciation expense for North Carolina retail customers resulting from the accelerated retirement dates for these coal units in the 2021 Depreciation Study. *Id.* Additionally, witness Q. Bowman testified that DEC seeks permission to defer to this regulatory asset any costs related to obsolete inventory, net of salvage, at the time of retirement. *Id.*

Public Staff witnesses Lucas and McCullar both addressed coal plant retirements and life spans in their testimony. In his direct testimony, witness Lucas recommended using retirement dates from DEC's 2018 Integrated Resource Plan, filed in Docket No. E-100, Sub 157, with the exception of Allen Units 1 and 5. Tr. vol. 13, 126. Witness Lucas testified that he does not dispute the retirement dates established in the Commission's initial Carbon Plan order. Instead, witness Lucas testified that his recommended retirement dates are based on issues of cost and reliability. *Id.* at 127-28. Witness Lucas further testified that if DEC 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 127–28. He also testified that Session Law 2021-165 and Commission Rule R8-74 allow securitization of remaining plant value. *Id.* at 128. Witness Lucas further testified that delaying retirement of the dual fuel optionality (DFO) plants will allow for greater use of DFO capital investment. *Id.*

For Allen Units 1 and 5, witness Lucas recommended that, for ratemaking purposes only (rather than planning purposes), the Commission keep DEC's retirement date of December 31, 2023, for Allen Units 1 and 5 to allow DEC to eliminate fixed O&M

expenses for these units. Accordingly, he recommends the Commission exclude rate recovery of $7,392,797 after December 31, 2023. *Id.* at 129.

Witness McCullar proposed depreciation rates based on the final coal plant retirement years provided by witness Lucas. Tr. vol. 15, 224, 231.

Witness Kaufman did not propose alternative retirement dates from those proposed by DEC, but instead recommended that the Commission authorize a deferral of 50% of DEC's return on rate base associated with subcritical coal-fired electric generating facilities to be retired early and 50% depreciation expense associated with coal-fired electric plants. Tr. vol. 15, 1158. Witness Kaufman testified that, in his view, the total benefits of DEC securitizing early rather than after retirement would save approximately $99 million over ten years. *Id.* at 1160–61. Further, witness Kaufman testified that by deferring 50% of DEC's return on rate base will preserve the Commission's ability to disallow recovery on any cost of capital expense that exceeds the amounts DEC would have incurred had it securitized early. *Id.* at 1164.

In rebuttal, DEC witness Spanos testified that Public Staff witnesses McCullar and Lucas's proposed retirement dates are longer and not consistent with DEC's plans. Tr. vol. 9, 231. Witness Spanos testified that many other DEC coal-fired power plants either have been or are planned to be retired with life spans of around 40-45 years and that the proposed life spans of DEC's plants are consistent with those of other utilities. *Id.* at 233. Witness Spanos testified that the retirement dates for the coal-fired plants are consistent with informed judgement based on each unit and the expectation within the industry. *Id.* at 233. Witness Q. Bowman testified that DEC also proposes, for ratemaking purposes only, to set customer rates in this proceeding as if the coal plant retirement dates were extended for 50% of the plant balances. Tr. vol. 15, 1284. Thus, DEC and the Public Staff are partially aligned in principle but not aligned in methodology. *Id.* DEC believes the depreciation rates at the system level should be set based on the actual planned retirement dates, and that deferrals and regulatory assets should be used thereafter for jurisdictionally specific ratemaking purposes. *Id.* Witness Spanos testified that the methodology is particularly important because securitization of the coal plant balances, which witness Lucas states as a significant reason for his recommendation, is only available for DEC's North Carolina retail jurisdiction. *Id.* Witness Spanos testified, therefore, that deferral and regulatory assets are a more appropriate way to accomplish the effect that witness Lucas is proposing. *Id.* In addition, witness Q. Bowman explained that the retirement dates from DEC's 2018 Integrated Resource Plan utilized by witness Lucas are not reflective of what is included in current customer rates based on DEC's last rate case in Docket No. E-7, Sub 1214, and use of those dates is inappropriate. *Id.* at 1284–85. Finally, witness Q. Bowman explained that HB 951 only permits securitization for 50% 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% of the plant balances. *Id.* at 1285.

Witness Bateman explained that witness Kaufman's proposal has no basis in HB 951's language authorizing securitization of the remaining net book value of early retired subcritical coal generating facilities. Tr. vol. 16, 268. She also explained that it would be inappropriate to have current customers, who are benefitting from coal plant generation, not pay the cost for that generation. *Id.* Finally, she noted that witness Kaufman was unable to provide any examples of where his proposal has been implemented. *Id.*

Net Salvage

DEC witness Spanos testified that net salvage is the salvage value received for an asset upon retirement, less the cost to retire or remove the asset. Tr. vol. 9, 196-97, 234. Witness Spanos testified that net salvage must be incorporated in depreciation, as it represents the future cost that is expected to be incurred by DEC. *Id.* at 236. Witness Spanos testified that this calculation approach is consistent with the Uniform System of Accounts (USOA) as well as positions expressed by NARUC. *Id.* at 236-38. Witness Spanos testified that the net salvage percentages estimated in DEC's 2021 Depreciation Study were based on informed judgment that incorporated factors such as the statistical analyses of historical net salvage data; information provided by DEC's operating personnel and general knowledge and experience of industry practices; and general industry trends. *Id.*

Regarding net salvage, the parties presented three main topics of disagreement: (1) decommissioning costs (including indirect costs and asbestos), (2) contingency, and (3) escalation of decommissioning costs.

Specific Decommissioning Study Recommendations

A. Indirect Costs

In its Decommissioning Study, DEC included a 10% adder for project indirect costs. Witness Lucas recommended that a 5% adder be used instead. Tr. vol. 13, 121. He testified that the previous study filed in DEC's 2019 rate case properly used a 5% adder, and that DEC only stated that its proposed 10% adder was to account for the increase in costs attributable to market conditions. *Id.* Witness Lucas testified that the Decommissioning Study contains a subtotal for dismantlement and environmental costs that is already adjusted for market conditions; thus, an increase in the project indirects percentage amounts to a double counting of these costs. *Id.*

In rebuttal, DEC witness Kopp testified that DEC does have subtotals in decommissioning costs for dismantlement and environmental that are adjusted for market conditions. Tr. vol. 12, 425. However, he further testified that those only reflect the costs and market conditions for the direct costs incurred for each of those subtotals, and project indirect costs include a separate set of cost items. *Id.* This separate set of cost items include those costs expected to be incurred by DEC during the dismantlement process that are in addition to the direct costs paid to demolition contracts, such as obtaining permits, construction services such as water and electricity, security labor and facilities, site vehicles, procurement services, legal services, and environmental monitoring. *Id.* at 425–26. Witness Kopp further testified that a minimum of 5% indirect costs is typically used on decommissioning cost estimates, but that this is simply the starting point. *Id.* at 426. If the project owner (here, DEC) has insights or experience into expected indirect costs, that input would be taken into consideration. *Id.* For the previous study, DEC did not provide any guidance to change the percentage to change the minimum assumption. *Id.* However, since the time of the previous decommissioning study, DEC has decommissioned several power generating facilities, and based on that experience, DEC reported that indirect costs were approximately 11% of the direct costs. *Id.* at 426-27. Thus, witness Kopp testifies that a 10% indirect cost was a more accurate representation of expected costs. *Id.*

B. Asbestos

Witness Lucas recommends that the Commission disallow asbestos removal costs for the Bad Creek and Bridgewater hydroelectric plants. Tr. vol. 13, 119-20. The Bad Creek plant was built in the late 1980s and early 1990s, while Bridgewater was completely dismantled and rebuilt in 2010 and 2011. *Id.* Accordingly, he testifies that neither plant should contain asbestos because the dangers of asbestos were well known before either plant was built. *Id.* at 120.

Further, witness Lucas notes that the asbestos removal cost for the 99 Islands hydro plant is a 73% increase over DEC's previous decommissioning study and recommends that this increase be limited to 16%, which is the average increase for asbestos removal at other hydro plants. *Id.*

In rebuttal, witness Spanos testified that witness Lucas fails to properly consider that, although Bad Creek went into service in 1991, there were many assets that were part of the initial project in 1977. Tr. vol. 9, 240. DEC witness Kopp also noted that exploration and construction occurred throughout the late 1970s and into the 1980s, with some structures constructed in the early 1980s. Tr. vol. 12, 422. Asbestos-containing materials were still used in construction during this time, and therefore, those assets from before 1986 could have asbestos. *Id.*; *see also* Tr. vol. 9, 240. Similarly, witness Spanos testified that the Bridgewater hydro facility, while rebuilt in the 2011-2012 time frame, still maintains some assets from the original plant that were built many years before 1986. Tr. vol. 9, 240; *see also* Tr. vol. 12, 422-423. Witness Spanos testified that these older assets need to be considered when establishing a decommissioning study. Tr. vol. 9, 240. Witness Kopp testified that the proper removal and disposal of that asbestos will be required during decommissioning, so those costs should be included. Tr. vol. 12, 423.

Regarding 99 Islands, witness Kopp testified that some areas that are likely to contain asbestos were not included in the prior decommissioning study. Tr. vol. 12, 424. In addition to the changes in market conditions since the previous study, the quantity of asbestos materials were increased in the current study, reflecting increased asbestos removal and disposal costs at this plant than others. *Id.* Witness Kopp noted that witness Lucas provided no support for his recommended percentage, other than applying an average. *Id.*

C. Contingency

DEC's Decommissioning Study includes a 20% adder for contingency. Tr. Ex. vol. 10. Witness Lucas testified that Commission approved a 10% contingency in its June 22, 2018, Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction in Docket No. E-7, Sub 1146. Tr. vol. 13, 121. He further testified that a 20% contingency as proposed by DEC in this case would require ratepayers to pay an additional amount for unknown future risks far in advance of when DEC will incur the costs. *Id.* at 122. Accordingly, the Public Staff recommended a 10% contingency factor, consistent with the Commission's prior Order in Docket No. E-7, Sub 1146.

In rebuttal, witness Spanos testified that contingency costs are a standard component of decommissioning studies. Tr. vol. 9, 242. He noted that standard decommissioning studies support a 20% contingency factor. *Id.* He also noted that a 10% contingency was agreed upon in the previous case, but this was to be reviewed again if an updated decommissioning study was performed. *Id.* Finally, given that contingencies have approached or exceeded 20% in many instances in recent years, witness Spanos testified that 20% is more appropriate. Witness Kopp also noted that the Decommissioning Study's 20% contingency is well-informed by experience. Tr. vol. 12, 429. Witness Kopp testified that decommissioning involves a greater level of unknowns than new construction, and that it is reasonable to expect that the scope of decommissioning can change once actually executed, which would result in cost increases. *Id.* at 431–32. Witness Kopp testified that contingency estimates could be developed with enough accuracy and precision such that a smaller amount of contingency would be reasonable; however, he testified that the cost at which those detailed estimates are derived can be prohibitive, as it is unreasonable to perform exhaustive investigations during the study phase. *Id.* at 433–34. He testified that DEC's decommissioning estimates are reasonable and accurate for the purpose of determining depreciation rates. *Id.* at 434.

D. Escalation of Decommissioning Costs

NCSEA witness Kaufman recommended that decommissioning costs not be escalated when calculating net salvage values. Tr. vol. 15, 1168. He testified that this practice is unnecessary, is not performed in many depreciation studies, and would result in an excess assignment of decommissioning costs to current customers. *Id.* at 1168-69. He also noted that these costs are uncertain. *Id.* at 1169. Based on this, witness Kaufman testified that net salvage rates be calculated using original decommissioning costs. *Id.* at 1170.

In rebuttal, witness Spanos explained that witness Kaufman's proposal does not properly reflect the definition of depreciation. Tr. vol. 9, 243. He testified that the total service value, which includes the cost to remove and to decommission, must include costs at the time of retirement. He testified that, thus, escalating decommissioning costs, which are in 2022 dollars, to the date of retirement for each generating unit matches the concept of depreciation. *Id.* Finally, witness Spanos noted that this approach meets USOA and NARUC definitions of depreciation, which provides that customers should pay through depreciation expense an appropriate share of the terminal costs of removing the asset. *Id.* As such, he testified that inflation is a component that authoritative texts recognize as needing to be recovered and built into the overall cost or service value of the asset. *Id* at 286–87*.* Additionally, witness Spanos explained that witness Kaufman failed to consider the fact that these assets will be retired in the future and that costs would be as of the date of retirement, which is the definition of "depreciation". *Id.* at 280–81. He further explained that witness Kaufman fails to consider the intergenerational inequities caused by his recommendation or his recommendations' failure to recover cost systematically and rationally. *Id*. at 281. Witness Spanos further explained that, over his 37-year career, there have only been rare exceptions, primarily for unique jurisdictional reasons, that escalating decommissioning cost has not been performed as part of a depreciation study that he has conducted. Tr. Vol. 10, 70-73.

Net Salvage for Mass Property Accounts

Both Public Staff and NCSEA propose different net salvage estimates for some accounts. Public Staff witness McCullar and NCSEA witness Kaufman both propose a different net salvage estimate for transmission plant Account 356. Additionally, witness Kaufman proposes different net salvage estimates for distribution Account 373 and general plant Accounts 390, 392, and 396.

Account 356

In DEC's Depreciation Study, DEC proposes a -40% net salvage percentage for Account 356 – Overhead Conductors and Devices. In contrast, Public Staff witness McCullar proposes a -30% net salvage percentage. Tr. vol. 15, 233. Witness McCullar testified that this is more reasonable than DEC's proposed figures because Public Staff's estimated future net salvage percentages do not result in an under-recovery of the estimated future costs. *Id.* at 239.

NCSEA Witness Kaufman recommended a negative 31% net salvage estimate for Account 356, which is based on a 20-year average of the statistical data, rather than the negative 40% proposed in the 2021 Depreciation Study. Tr. vol. 15, 1171.

In rebuttal, witness Spanos testified that neither witness McCullar nor witness Kaufman considers why the cost of removal is so low for most accounts in the last few years. Tr. vol. 9, 267. Witness Spanos testified that the cost of removal and gross salvage are not always booked/recorded at the same time as the associated retirement. *Id.* Witness Spanos testified that the cost of removal of the associated retirements are not time synchronized. *Id.* As such, witness Spanos testified that witness McCullar's net salvage methodology does not properly assess the true levels of cost of removal. *Id.* Furthermore, witness Spanos notes that the texts cited by witness McCullar support the methodology he uses for DEC's depreciation study. *Id.* at 270. Witness Spanos testified that witness Kaufman's use of a 20-year statistical average fails to consider the proper cost of removal amounts to the associated retirement amounts. *Id.* at 267.

Accounts 373, 390, 392, and 396

For Account 373 – Street Lighting and Account 390 – Structures and Improvements, DEC proposed a -10% net salvage rate. For Account 392 – Transportation Equipment and Account 396 – Power Operated Equipment, DEC proposed a positive 10% net salvage rate. NCSEA witness Kaufman recommends using a 20-year average net salvage cost for these accounts. Tr. vol. 15, 1170-71.

In rebuttal, DEC witness Spanos testified that witness Kaufman conducted a 20-year average analysis without looking over the data available to analyze. Tr. vol. 9, 270-71. For Accounts 373 and 390, witness Spanos explained that the most recent data and the overall trend, even when accounting for data from an anomaly year, strongly supports the use of a -10% net salvage rate. *Id.* at 271-272. For Accounts 392 and 396, witness Spanos reiterated that it is critical to review the data in order to understand the estimate that is most appropriate for future recovery. *Id.* at 272. He testified that a positive 10% rate is much more likely to be recorded into the future for these accounts.

Other Depreciation Recommendations

Interim Net Salvage for Percentage for Steam and Other Production Accounts

NCSEA witness Kaufman proposes a negative 15% interim net salvage rate for steam assets, a positive 35% interim net salvage rate for Other Production assets except Account 343.10, and a positive 49% for Account 343.10. Tr. vol. 15, 1171. DEC recommends negative 18%, negative 5%, and positive 40%, respectively. Tr. Ex. vol. 10.

Witness Spanos testified that the overall net salvage for most accounts exceeds negative 15 percent. Tr. vol. 9, 265. Further, he notes that for the past five years, the net salvage for all steam assets exceeds 20%, and for some accounts exceeds 50%. *Id.* For Other Production accounts, the data shows that -5% is most appropriate except for Account 343.10. *Id.* Thus, he testifies that it is unrealistic to expect over the full life cycle of these asset classes that a positive 35% rate will be recorded, as witness Kaufman proposes. *Id.* Finally, for Account 343.10, witness Spanos testified that the high levels of positive salvage relate only to the first stage of rotable part replacements; this salvage rate will not continue in later stages, so increasing salvage values as assets age is unreasonable. *Id.*

Mass Property Service Lives - Survivor Curves

Witness Spanos testified that a mass property account is typically a group of assets for which there will be a range of service lives. Tr. vol. 9, 243. Service lives of these accounts use survivor curves, which provide an estimate of both an average service life and a dispersion of lives or retirements around the average. *Id.* NCSEA proposes changes to the survivor curves included in the 2021 Depreciation Study for Other Production Account 344.66 – Generators – Solar; transmission Account 354.00 – Towers and Fixtures; distribution accounts 368 – Line Transformers, 368.1 Line Transformers – Storm Securitization, and 369 – Services; and all the Land Rights and Rights of Way accounts. Tr. vol. 15, 1173.

Witness Spanos explained that the primary difference between his analysis and witness Kaufman's analysis in determining the appropriate survivor curves is the understanding of the accounts and the assets within the accounts. Tr. Vol. 10, 73. He explained that fieldwork is key to understanding the nature of the account. *Id.* He testified that, furthermore, survivor curves are more than a mathematical matching of points; they also involve projecting what future occurrences and how the assets in the account are changing. *Id.*

Account 344.66

Witness Kaufman proposed an alternative survivor curve of 30-S3 for small community solar assets and utility scale solar assets when calculating the expected remaining life for Account 344.66 - Solar Generators. Tr. vol. 15, 1173. Witness Kaufman testified that the 30-S3 curve is the best fitting curve for this distribution and provides a reasonable fit for DEC's actual retirement data. *Id.* Further, witness Kaufman testified that DEC's proposed retirement curve is 20-S2.5 for community solar facilities and 25-S2.5 for all other solar facilities, which is an unreasonably high level of expected retirement relative to industry expectations. *Id.*

In rebuttal, witness Spanos testified that he recommends a 20-S2.5 survivor curve for community solar assets and a 25-S2.5 survivor curve for utility scale solar assets. Tr. vol. 9, 254. Witness Spanos testified that the 20-S2.5 survivor curve and 25-S2.5 survivor curve estimate a maximum life for solar assets in Account 344.66 will be 35 and 45 years respectively. *Id.* Further, witness Spanos testified that there are more causes of retirement than degradation of solar panels and the life characteristics of the related assets—such as the inverters, electronic controls, and framing—have an impact. *Id.* Additionally, witness Spanos testified that the capabilities of the solar sites to store energy, the required upgrades, and wear of the elements will affect the ages. *Id.* In his testimony, witness Spanos reiterated that the process for estimating service lives is based on informed judgment that incorporates a number of factors, including the statistical analysis of historical data. *Id.* at 244. Witness Spanos further testified that the original life tables provide an indication of the percentage of assets that have historically survived to each age for which data is available. *Id.*

Account 354

In his direct testimony, witness Kaufman proposed an alternative survivor curve of 75-R2.5 be used when calculating the expected remaining life for Account 354 - Towers and Fixtures. Tr. vol 15, 1175–76. Witness Kaufman testified that DEC's proposed survivor curve is unreasonable because the older ages of DEC's historic survivor curve represent less than 0.2 percent of first year exposures and are unlikely to be recommended. *Id.* at 1175. Instead, witness Kaufman testified that he recommends that the 75-R2.5 curve be used because it fits ages 0 through 60 well, and these ages are more representative of future retirements. *Id.*

In rebuttal, witness Spanos testified that when considering the overall life cycle and the significant statistical points of the account, the 70-R2.5 curve is a better fit for Account 354. Tr. vol. 9, 253. Further, witness Spanos testified that the transmission towers will have changes in the near future as lines are retired due to generation facilities being retired and many of the lattice towers being changed out to tubular poles. *Id.*

Accounts 368 and 368.10

NCSEA witness Kaufman objected to DEC's proposed 45-R1.5 retirement curve for Accounts 368 and 368.10 - Line Transformers. Tr. vol. 15, 1177. Witness Kaufman noted that the curve flattens at age 50 and follows a linear path until age 60, then exhibits a sharp decline to age 63, resulting in the best fitting curve underestimating retirements in early years. *Id.* Instead, witness Kaufman recommended the 50-R1.5 retirement curve. *Id.*

In rebuttal, witness Spanos testified that DEC's proposed 45-R1.5 survivor curve is a good match to the historical data through age 40 and is consistent with the overall life cycle of the assets recorded in the account through age 68. Tr. vol 9, 247. Further, witness Spanos testified that the 45-R1.5 curve reflects DEC's future operational plans for Line Transformers, as there will be high retirements for line transformers for the foreseeable future. *Id.* at 247, 249.

Account 369

NCSEA witness objected to DEC's proposed use of a 55-R1.5 curve for Account 369 - Services. Tr. vol 15, 1178. Instead, witness Kaufman recommended the use of a 65-R1.5 curve. *Id.* at 1178–79. Witness Kaufman notes that the use of a 65-R1.5 curve results in a similar average age as that proposed by DEC, and only deviates marginally from the historical data for ages 40 through 62. *Id.*

In rebuttal, witness Spanos testified that witness Kaufman's statistical analysis is inconclusive, as 70% of Account 369 has lasted 60 years; this cannot be expected to continue with low retirement into the future. Further, witness Spanos testified that many services will have increased retirements as overhead services move to underground services, and the increased customer requests for added load due to electronics in the home will increase service replacements. Additionally, witness Spanos testified that witness Kaufman's 65-R1.5 survivor curve unrealistically has a maximum life of 125 years, given that the currently approved life estimate is a 52-R1.5 survivor curve. Tr. vol 9, 254.

Land Rights and Rights of Way Accounts

In his direct testimony, witness Kaufman proposed an alternative survivor curve of 132-S6 for Accounts 310, 320, 330, 340, 350, 360, 360.2, 389, and 389.2. Tr. vol. 15, 1173. Witness Kaufman testified that the primary cause of retirement for these accounts is abandonment, but rights of way are rarely, if ever, abandoned. *Id.* at 1174. He further testified that the low level of retirements means that historic data cannot be used to reliably predict retirement curves after 115 years of age, but it is reasonable to select a retirement curve that at least has a relatively high survival rate to age 115. *Id.* Witness Kaufman accordingly recommends the 132-S6 curve, as it results in a conservatively short expected life because it assumes the steepest retirement rate of all well-fitting curves. *Id.* Witness Kaufman further recommends that all rights of way accounts be analyzed together. *Id.*

In rebuttal, witness Spanos testified that the land rights and rights of way survivor curves are unrealistic because the land rights and rights of way accounts are not all the same. Witness Spanos noted that there are some functional land rights and rights of way that have historical data that help understand the past for those categories, but the most important factor is the lives of the related assets. Tr. vol. 9, 257. Additionally, witness Spanos testified that the related substation and lines accounts have average lives of 43, 45, 70, 48, and 60 years. *Id.* All of the life cycles are close to or less than the 115 years of the related rights of way. *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 adopt the depreciation rates set forth by DEC in Witness Spanos' rebuttal testimony, subject to the adjustments agreed upon in the Revenue Requirement Stipulation. Specifically, DEC's coal plants will be depreciated based on the accelerated retirement dates proposed by DEC, with the exception of the Cliffside 5 retirement date, which will move to January 1, 2030, consistent with DEC's CPIRP filed on August 17, 2023. Additionally, based on the Revenue Requirement Stipulation and the entire record in this proceeding, the Commission concludes that it is appropriate to increase DEC's proposed deferral to a regulatory asset from 50% to 75% of the impact of accelerating the depreciation of DEC's subcritical coal plants from the current retirement dates. Using the accelerated retirement dates, while also accomplishing the type of rate mitigation that witness Lucas proposed, strikes a reasonable balance. This preserves the ability of DEC to recover the 50% of the remaining net book value of the subcritical coal plants through securitization, as allowed under HB 951, while recovering the remaining amount, with a return, over an amortization period to be determined in a future rate case.

Based upon the evidence presented the Commission rejects the securitization proposal of NCSEA witness Kaufman. For the reasons previously stated, the Revenue Requirement Stipulation is a just and reasonable resolution that preserves the ability of DEC to utilize securitization.

Decommissioning Study Recommendations – Indirect Costs, Asbestos, Contingency, and Escalation of Decommissioning Cost.

Based on the evidence presented by Public Staff witnesses McCullar and Lucas and DEC witnesses Spanos and Kopp, the Commission finds the settled-upon specific decommissioning cost as follows: decommissioning shall utilize a 5% indirect cost as settled upon in Section III, Paragraph 4 (a) of the Revenue Requirement Stipulation, which states that the Stipulating parties agree to adjust decommissioning estimates to use a 5% indirect cost adder. In addition, Section III, Paragraph 4 (a) of the Revenue Requirement Stipulation provides that the stipulating parties agree to adjust decommissioning estimates to use 10% contingency. Tr. Ex. vol. 7. Furthermore, the Revenue Requirement Stipulation does not include adjustments for asbestos or escalation of decommissioning cost. Based on the evidence presented, the Commission finds the resolution of these issues through the Revenue Requirement Stipulation to be just and reasonable.

NCSEA is not a signatory to the Revenue Requirement Stipulation and through witness Kaufman argued for no escalation in decommissioning cost. The Commission finds persuasive the testimony of witness Spanos that the total service value, which includes the cost to remove and to decommission, must include costs at the time of retirement. The escalation of decommissioning cost matches the concept of depreciation supported by authoritative texts like the USOA and NARUC.

Net Salvage For Mass Property Accounts

Account 356

Based on the evidence presented, the Commission finds that the settled-upon net salvage percentage for transmission Account 356 – Overhead Conductors and Devices, established in the depreciation rate in the Revenue Requirement Stipulation, is just and reasonable and should be adopted. With respect to witness Kaufman’s net salvage proposal, the Commission finds that his calculation only uses a 20-year statistical average and fails to consider the proper cost of removal amounts to associated retirement amounts. As such, the Commission concludes that the -40% net salvage estimate proposed in the 2021 Depreciation Study is just and reasonable and appropriate for use in this case.

Accounts 373, 390, 392, and 396

Based upon the evidence presented, the Commission finds that the settled-upon net salvage percentage for Accounts 373, 390, 392, and 396 established in the depreciation rates in the Revenue Requirement Stipulation, are just and reasonable and should be adopted. The Commission finds the testimony of DEC witness Spanos persuasive on this issue and rejects the recommendations of witness Kaufman. As witness Spanos explained, witness Kaufman’s 20-year average analysis fails to fully comprehend the data and the underlying assets in these accounts. When that data is fully understood and evaluated, as witness Spanos did in performing the 2021 Depreciation Study, the net salvage percentage used in the Study and incorporated into the depreciation rates established by the Revenue Requirement Stipulation are appropriate.

Interim Net Salvage for Percentage for Steam and Other Production Accounts

Based on the evidence presented, the Commission finds that that the interim net salvage percentages for steam assets, Other Production assets and account 343.10 (Rotable Parts) used in establishing the depreciation rates in the Revenue Requirement Stipulation, are just and reasonable and should be adopted.

Survivor Curves

Based on the evidence presented, the Commission finds that the survivor curves proposed by DEC, supported through the testimony of witness Spanos, and used in establishing the depreciation rates in the Revenue Requirement Stipulation, are just and reasonable and should be adopted. The Commission finds persuasive the testimony of witness Spanos, especially regarding his knowledge of the accounts at issue and the assets within the accounts in determining the appropriate life characteristics and the survivor curve.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 14

Base Period Plant-Related Items

The evidence supporting this finding of fact appears in DEC's verified Application and Form E-1; the testimony and exhibits of DEC witnesses Q. Bowman, Capps, Guyton, Maley, and Walsh, Public Staff witnesses Metz, Thomas, Michna, Lucas, and T. Williamson, 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

DEC witness Walsh described DEC's fossil/hydro/solar fleet and the operational performance of those assets during the test year. Tr. vol. 12, 634-35, 643-44. Witness Walsh testified as to the major capital projects undertaken by DEC for maintenance of its fossil, renewable, and solar fleets. *Id*. at 640-41. In testifying on the importance of the traditional fossil fleet to customers in North Carolina, witness Walsh 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. Witness Walsh testified that as DEC makes plans to retire its remaining coal fired assets, and replace those assets with other resources, DEC must keep these remaining units in efficient working order to support the energy needs of its customers. Witness Walsh explained that DEC will continue to make investments 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, witness Walsh 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 and continue to provide 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 – DEC 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 DEC customers. *Id*. at 638-39. Witness Walsh also testified regarding DEC's hydro fleet capital maintenance projects, including two uprate projects at Bad Creek, and DEC's completion of the Maiden Creek and Gaston solar facilities. *Id.* at 641. Finally, witness Walsh testified as to his opinion that DEC has reasonably and prudently operated its fossil/hydro/solar fleet during the test period. *Id.* at 644.

DEC witness Capps described DEC's nuclear generation assets and capital additions made to the fleet since the 2019 Rate Case to enhance safety, reliability, and efficiency, preserve performance and reliability of the plants throughout their extended life operations, and address regulatory requirements. Tr. vol. 12, 265-66, 268-70. Witness Capps 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 DEC's customers. *Id.* at 271. Witness Capps testified about the exceptional performance of the nuclear fleet during the test period and initiatives that DEC has undertaken to increase nuclear operational efficiency. *Id.* at 278-80. Witness Capps testified that, in comparison to others in the industry, DEC's nuclear fleet has a history of top performance, including a test period capacity factor of 96.12%, 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 280.

Public Staff witnesses Metz, Thomas, and Michna reviewed aspects of DEC's capital investments in its generation fleet. Public Staff witness Metz described his review of DEC's historic costs associated with projects placed in service for the period July 2020 through April 2023, noting that his investigation included multiple site visits to DEC's fleet of generating stations, as well as numerous meetings with DEC personnel. Tr. vol. 12, 785. Witness Metz did not propose any adjustments to the base case capital investment costs. Public Staff witness Thomas reviewed DEC's capital additions to solar and hydro plant since the 2019 Rate Case. Tr. vol. 14, 159-160, 184-85. Aside from recommendations regarding tax incentives for solar and hydro facilities, addressed in Finding of Fact No. 24, witness Thomas did not recommend any adjustments to the base case capital investment costs for the solar and hydro fleets. Public Staff witness Michna reviewed DEC's capital additions for steam generation since the 2019 Rate Case and did not propose any adjustments to the base case capital investment costs for the steam facilities. Tr. vol. 15, 44, 60.

Lincoln Pipeline

Public Staff witness Lucas recommended removal of $353,067 of plant-in-service expense for natural gas pipeline improvements necessary for Lincoln County Station Unit

17. Witness Lucas testified that the new pipeline project was built to serve Unit 17 and that the existing pipeline to serve Units 1 through 16 did not require a capacity expansion. Tr. vol. 13, 133.

In his rebuttal, DEC witness Kevin Murray testified that the pipeline improvements were for the benefit of the entire Lincoln facility, and not just Unit 17. Tr. vol. 12, 499.

The Revenue Requirement Stipulation provides that no further adjustment is needed to DEC's Lincoln pipeline costs included in the case. Revenue Requirement Stipulation § III.11, Tr. Ex. vol. 7. DEC witness Q. Bowman supported this provision in her settlement supporting testimony. Tr. vol. 12, 255.

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

In their direct testimonies, DEC witnesses Guyton and Maley discussed DEC's distribution and transmission investments since its last general rate case. DEC witness Guyton testified that DEC had invested approximately $1.069 billion in new distribution infrastructure since DEC's last rate case, which included investments in DEC'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. 8, 103. In his direct testimony, witness Maley testified that DEC had spent approximately $463 million in additional transmission infrastructure since its last rate case, the bulk of which was for reliability and capacity improvements. Tr. vol. 8, 267-68.

In their direct testimonies, Public Staff witnesses Lawrence, Metz, and T. Williamson took issue with some of the transmission and distribution capital investments made by DEC since its last case, as discussed in more detail below. Specifically, witness Lawrence took issue with the inclusion in rate base of capital associated with EV charging infrastructure and Public Staff witness T. Williamson discussed the Pleasant Garden Circuit Breaker Replacement project (Pleasant Garden Project).

Pleasant Garden Breaker Replacements

In his direct testimony, Public Staff witness T. Williamson recommended that the Pleasant Garden Project be reclassified from distribution to transmission plant in service. Tr. vol. 15, 129. On rebuttal, witness Guyton testified that he agreed with witness T. Williamson's recommendation to reclassify the Pleasant Garden Project and asserted that DEC had already made the accounting entry necessary to reflect the reclassification. Tr. vol. 8, 190.

Section III, Paragraph 8 of the Revenue Requirement Stipulation specified that reclassification of the Pleasant Garden Project is appropriate. Tr. Ex. vol. 7.

EV Infrastructure

In his direct testimony, witness Lawrence recommended a $886,130.16 disallowance for costs associated with EV charging infrastructure installed in conjunction with DEC's Electrification Charging Infrastructure (ECI) Project. Tr. vol. 15, 99. Witness Lawrence testified that the program was designed to meet corporate goals and exceeded what was necessary to serve customers. *Id*. at 100. Additionally, witness Lawrence testified that he was unable to determine that the EV charging stations were used and useful. *Id*.

On rebuttal, DEC witness Guyton testified that the EV infrastructure costs were appropriately recoverable because the ECI Project responded to customers' clearly articulated demands and the public interest underlying those demands. Tr. vol. 8, 215. Witness Guyton also testified that the charging infrastructure is used and useful. Tr. vol. 8, 193. Specifically, he testified that the infrastructure was being used to charge existing DEC plug-in hybrid and electric vehicles. Id. He asserted that DEC's EV infrastructure would continue to support the growing number of electric fleet vehicles over the next seven years in alignment with DEC's commitment to electrify its internal fleet. Id. Finally, witness Guyton noted that DEP included a similar expense for EV infrastructure in the DEP rate case and the Public Staff did not object to its inclusion in that proceeding. *Id*.

Section III, Paragraph 7 of the Revenue Requirement Stipulation provides that DEC's EV infrastructure in service as of June 2023 that was recommended for removal by Public Staff witness Lawrence should be included in the base period with the limitation that such infrastructure shall only be used for DEC vehicle use. Tr. Ex. vol. 7.

Mount Holly Building and Other Projects

DEC witness Speros testified that the Mount Holly Technology Center is a multifaceted facility where innovations and technology that are intended to benefit customers and the Duke system are modeled, tested, and evaluated for integration and deployment. Tr. vol. 12, 564.

Public Staff witness Metz testified that he was recommending disallowance of nine Mount Holly projects, making up a total disallowance of $8.7 million. Tr. vol. 12, 835. Witness Metz also requested that DEC provide a pro forma adjustment in future rate cases to resolve the cost allocation issue for capital projects relating to Mount Holly initiatives as well as similar initiatives benefitting other affiliate companies. *Id.* Witness Metz also noted that he believed the Mount Holly capital projects are for Duke initiatives and learnings that will likely be applied across multiple Duke entities, and that it was not appropriate for DEC ratepayers to bear 100% of those capital costs. *Id.* at 834-835.

In rebuttal, witness Speros testified that two of the nine projects identified by witness Metz were building renovation projects at Mount Holly. *Id.* at 565. DEC witness Speros testified that two projects identified by Public Staff are building renovation projects comprising $5.1 million of Public Staff's total proposed $8.7 million disallowance. *Id*. Witness Speros testified that these two renovation projects are properly recorded to DEC's books. *Id.* at 566. The Mount Holly facility was previously a generation operations facility that was repurposed when the generation operations were no longer necessary, but because the legacy generation building was constructed and recorded to DEC's books, it could not easily be moved to another entity from an accounting perspective. *Id.* at 565. Therefore, DEC developed a facility rent charge for the building, which is charged to the business units utilizing the facility and then recorded as rent revenue on DEC's books. *Id*. Witness Speros testified that this building rent charge is a reduction in DEC's cost of service, and accordingly, all the Mount Holly building renovation projects are properly recorded to DEC's books. *Id.* at 566.

The remaining seven projects identified by witness Metz, as well as four additional projects identified by DEC, are other non-building related projects. *Id.* Witness Speros testified that the remaining seven projects are non-renovation projects and should be recorded to the books of Duke Energy Business Services, LLC ("DEBS"). *Id*. The impact of this adjustment on DEC's request is approximately $572,930. *Id.* Witness Speros also testified that DEC self-identified four additional projects; two of those projects will be recorded on DEBS books, and the other two projects are meter farm related projects and therefore appropriately recorded on DEC's books. *Id.*

Section III, Paragraph 5 of the Revenue Requirement Stipulation provides that the Mount Holly Building Renovation Project should be included in DEC's base period. Tr. Ex. vol. 7. In addition, Section III, Paragraph 9 of the Revenue Requirement Stipulation provides that the Mount Holly Other Projects will be allocated to all Duke Energy subsidiaries rather than direct assigned to DEC. *Id.*

526 S. Church Street

Public Staff witness Metz testified that the 526 S. Church Street building underwent a $7 million switchgear and generator replacement project. Tr. vol. 12, 813–814. Witness Metz testified that the Public Staff was recommending cost adjustments related to this project. *Id.* at 826.

In rebuttal, DEC witness Speros testified that the switchgear and generator replacement project is not included in DEC's rate request, and therefore, the adjustment proposed by Public Staff is unwarranted. *Id.* at 562. He further testified that Speros Rebuttal Exhibit 1 details the journal entries associated with the sale of the 526 S. Church Street building, and that within the exhibit, the entirety of the 526 S. Church Street plant-in-service was removed in January 2023. *Id.* This removal of the plant-in-service removes all projects, including the projects identified by witness Metz. *Id.* Accordingly, there are no projects associated with the 526 S. Church Street building remaining in DEC's rate request, as all activity concluded prior to the capital cutoff in this case. *Id.*

Section III, Paragraph 6 of the Revenue Requirement Stipulation provides that no adjustment is needed for the 526 S. Church Street Renovation, as this asset was retired prior to the capital cut-off period in this case and is not included in rates. Tr. Ex. vol. 7.

Workstation Project

DEC Witness Speros testified that DEC is undertaking a workstation refresh project that entails the complete replacement of workstation hardware and peripherals across Duke Energy. Tr. vol. 12, 563. One-third of workstation hardware is being replaced each year over a 3-year replacement cycle. *Id.* The refresh replaces out of warranty computers and associated equipment with updated devices and software to improve productivity, enhance security for the benefit of customers, and reduce the level of O&M maintenance support typically associated with maintaining older workstations. *Id.*

Public Staff witness Metz testified that DEC had issued 5,346 out of 14,219 workstations, and recommended disallowance of the workstations not issued to employees—a disallowance of approximately $2.66 million, which would be updated to reflect the number of workstations issued in May and June of 2023. *Id.* at 827.

In his rebuttal testimony, DEC witness Speros noted that witness Metz did not challenge the prudency of DEC's investment in the workstation refresh project, but rather argued that the workstations should not be included in rates until actually issued to employees. *Id.* at 563. Witness Speros testified that there is a delay from time of purchase, to delivery, and to issuance to employees in order to allow DEC to prepare workstations for integration into the DEC network. *Id.* at 564. However, witness Speros noted that there is no accounting requirement that laptops be issued to employees in order to be included in rates in this case, and testified that the Public Staff's recommendation sets an arbitrary standard for inclusion of prudently incurred cost in rates. *Id.*

Pursuant to Section III, Paragraph 10 of the Revenue Requirement Stipulation, DEC and the Public Staff agreed that, for purposes of this proceeding, DEC will remove new laptop devices not issued to employees as of the capital cutoff date from the revenue requirement. Tr. Ex. vol 7. The removal will result in a decrease to Plant in Service of $1,811,000 on a North Carolina retail basis. Public Staff will have the opportunity to assess compliance with this treatment in its audit of DEC's Second and Third Supplemental updates. *Id.*

Discussion and Conclusions

Based on the entire record in this proceeding, the Commission concludes that the costs related to DEC's investments in its fossil, renewable, 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 also concludes that DEC's electric vehicle infrastructure in service as of June 2023 should appropriately be included in the base period, as set forth in the Revenue Requirement Stipulation. The Commission further concludes that the adjustment for the Pleasant Garden Project as the Public Staff and DEC agreed in the Revenue Requirement Stipulation is 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 DEC witnesses Q. Bowman, Guyton, and Maley, Public Staff witnesses Thomas and Zhang and Boswell, the Revenue Requirement Stipulation, and the entire record in this proceeding.

Summary of Evidence

DEC witness Maley testified that DEC'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. 8, 273. 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.* DEC installed approximately 800 relays over the 19 months immediately preceding the date on which DEC filed the Application. In the period starting June 1, 2020, through December 31, 2021, DEC made North Carolina GIP transmission investments totaling $15 million. *Id.* at 274. Witness Maley testified that DEC completed the North Carolina GIP work scope in its three-year plan by December 31, 2022. *Id.* at 275.

DEC witness Guyton testified that DEC 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 121. Witness Guyton also testified about the operational benefits associated with the GIP work that DEC 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 115. 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.*

Witness Guyton 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 $134 million. *Id.* at 119.

DEC witness Q. Bowman 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 DEC's next general rate proceeding. Tr. vol. 12, 178-79. With respect to the specific costs that have been deferred, DEC witness Maley testified that DEC 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 DEC's weighted average cost of capital. Tr. vol. 8, 275. In her initial direct testimony DEC witness Q. Bowman testified that by of the end of 2022, DEC will have placed in service investments of approximately $469.6 million on a North Carolina retail basis. She explained that DEC proposes to amortize the GIP regulatory asset of $100.5 million over a three-year period, which results in an amortization expense of $33.5 million. Tr. vol. 12, 179. In supplemental testimony, DEC witness Q. Bowman updated the GIP-related costs to replace estimated data with actual amounts incurred through April 30, 2023.[6] *Id.* at 205. Witness Maley testified that DEC proposes to roll these costs into base rates in the current rate case. Tr. vol. 8, 275.

While the Public Staff agreed with DEC's assertion that the Commission approved deferral accounting treatment for the GIP programs, the Public Staff took issue with DEC's calculation of the GIP deferral balance. Tr. vol. 12, 1026-30. Specifically, Public Staff witnesses Zhang and Boswell testified that DEC's inclusion of O&M expenses is outside of the allowable expenses envisioned by the Commission's approval in the 2019 Rate Case. Tr. vol. 12, 1029. 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.* Witnesses Zhang and Boswell asserted that some of the O&M expenses included in the deferral were not incremental, that DEC had not determined the amount of any operating benefits, and that the O&M expenses included overhead and administrative and general costs. *Id.* at 1029-30. Public Staff witness Thomas also challenged DEC's inclusion of certain O&M and capital expenses in the GIP deferral balance on these same grounds. Tr. vol. 14, 223-26. As explained by DEC witness Q. Bowman, the Public Staff proposed the following adjustments related to DEC's proposed recovery of the deferred GIP costs: 1) removal of capital and O&M costs, resulting in a reduction to the deferred asset balance of $22.5 million based on the contentions that DEC 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. Tr. vol. 15, 1253.

DEC witness Guyton testified on rebuttal that the labor expense deferred for GIP projects was incremental to base labor included in rates since DEC 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. 8, 196-97. 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 DEC's accounting practices and

[6] The total GIP investment made by DEC as of December 31, 2022, on a North Carolina retail basis is approximately $454 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 Q. Bowman Settlement Exhibit 4.

cost allocation manual. *Id.* at 195-96. DEC witness Q. Bowman also testified on rebuttal as to DEC'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. 15, 1253-55.

Section III, Paragraph 12 of the Revenue Requirement Stipulation provides that DEC 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 DEC, result in a deferred balance on December 31, 2023, of $71.121 million, and annual amortization expense of $3.951 million, as set forth in DEC witness Q. Bowman Supplemental Partial Settlement Exhibit 4. Tr. Ex. vol. 12.

Discussion and Conclusions

The Commission concludes that the evidence presented supports the treatment of the deferred GIP-related costs as agreed to by DEC 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 FINDING OF FACT NO. 18

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 Carolinas, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina,* No. E7, Sub 1214 (March 31, 2021) (CCR Settlement); DEC's verified Application and Form E-1; the testimony and exhibits of DEC witnesses Q. Bowman and Hill, Public Staff witnesses Zhang and Boswell and Lucas; and the entire record in this proceeding.

DEC witness Hill provided testimony as to DEC's activities to close ash basins and landfills along with other CCR management units for the period since DEC's last rate case. Tr. vol. 12, 377. Witness Hill testified that the actual and forecasted activities, as well as costs incurred, were reasonable and prudent. *Id.* Moreover, he testified that DEC 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.* at 378-79. He testified that DEC has also complied with its obligations under the CCR Settlement.

DEC witness Q. Bowman presented DEC's request to amortize deferred costs associated with the CCRs and to continue deferring costs related to compliance with coal ash regulations. Tr. vol. 12, 174. Witness Q. Bowman 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.* at174-77. She explained that the CCR costs sought for recovery are based upon actual costs incurred from February 1, 2020 through June 30, 2022, and updated amounts through May 31, 2023, provided in the supplemental filing made on June 19, 2023. *Id* at 214. She testified that the cost, less the adjustments, totals approximately $661 million on a system basis and $444 million on a North Carolina retail basis. *Id.* at 176. She testified that DEC's adjustment amortizes the net deferred balance over a five-year period. *Id.* at 177. Witness Q. Bowman also testified that DEC proposes to offset the over-amortization for the CCR costs established in the 2017 Rate Case in the amount of $8.1 million against the Coal Ash CCR ARO deferral DEC sought recovery of in this case. Witness Q. Bowman 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 $169.7 million. *Id.* at 176-77.

Public Staff witness Lucas investigated DEC's management of CCRs, construction and operation of DEC's CCR beneficiation projects, and proceeds from DEC's litigation of CCR insurance claims. Tr. vol. 13,104. After performing a thorough review, witness Lucas concluded that DEC's CCR management practices have been sufficient to prevent unnecessary costs to its customers, that DEC has complied with the coal ash beneficiation statute and the Commission's requirements, and that DEC's construction and operation of its beneficiation project since the last rate case have been sufficient to prevent unnecessary costs to customers. *Id.* at 115. Finally, witness Lucas found that DEC properly credited North Carolina retail customers with proceeds from the insurance litigation. *Id.* at 116.

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. 12,1042.

The adjustments recommended by the Public Staff regarding CCR costs were resolved in the Revenue Requirement Stipulation. Section III of the Revenue Requirement Stipulation provides that no further adjustments other than those specifically identified in the stipulation would be made to DEC's base period revenue requirement. In addition, Paragraph 40, subpart a of Section III of the Revenue Requirement Stipulation provides that the Public Staff and DEC agree that the over amortizations related to coal ash will be netted against the coal ash costs included in the case, consistent with our decision in the DEP Rate Case. 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 DEC has complied with the CCR Settlement and has made the agreed-upon adjustments in this case to reflect that settlement. The Commission approves DEC's applying the over-amortization of CCR costs as established in the 2017 Rate Case in the amount of $8.1 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 DEC's request to continue the deferral of any CCR cost DEC incurs subsequent to June 30, 2023, for future recovery consistent with the CCR Settlement.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 19-20

Environmental Compliance Cost Recovery

The evidence supporting these findings of fact is included in the testimony and exhibits of DEC witness Q. Bowman and the entire record in this proceeding.

Summary of Evidence

In her direct testimony, DEC witness Q. Bowman detailed DEC's request to amortize non-ARO environmental costs over a six-year amortization period. Witness Q. Bowman explained that in its Order in Docket No. E-7, Sub 1214, the Commission granted the DEC authority to continue to defer certain costs incurred in connection with compliance with federal and state environmental requirements as it relates to CCRs. Tr. vol. 12, 178. She testified that a portion of the environmental compliance costs associated with coal ash are related to the continued operation of the active plants and are capitalized to plant in service. *Id.* Witness Q. Bowman stated that by July 31, 2023, DEC placed in service non-ARO environmental compliance investments of $40 million on a system basis since February 1, 2020. She explained that DEC is requesting recovery of actuals beginning February 1, 2020. *Id.* Witness Q. Bowman provided updated actuals through June 30, 2023, in her third supplemental direct testimony. *Id.* at 224.

Discussion and Conclusion

No party contested DEC's request to amortize its non-ARO costs related to compliance with federal and state environmental requirements for CCRs over a six-year period. The costs associated with the deferred CCR environmental costs result in a deferred balance through June 30, 2023 of $7.284 million and an annual amortization expense of $1.214 million.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 21-22

Storm Securitization Overcollections

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

In the Agreement and Stipulation of Partial Settlement with the Public Staff filed in Docket No. E-7, Sub 1243, DEC 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, DEC proposed to amortize the regulatory liability of $0.6 million for overcollections associated with storm securitizations over a three-year period. Tr. vol. 12, 186, 215; Tr. Ex. vol. 12. 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 DEC 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. 23

Cost of Debt

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

DEC witness Newlin testified that DEC's long-term debt cost as of September 30, 2022, was 4.31%, which was the value DEC used to determine the revenue requirement in DEC's Application. Tr. vol. 9, 72. Section III, Paragraph 1 of the Revenue Requirement Stipulation establishes that the embedded cost of debt as of June 30, 2023 shall be used to calculate DEC's revenue requirement. Tr. Ex. vol. 7. DEC witness Q. Bowman presented in her supplemental testimony that the embedded cost of debt as of June 30, 2023, is 4.56%. Tr. vol. 12, 131.

No intervenor offered any evidence opposing this provision of the stipulation. The Commission therefore concludes that the use of a debt cost of 4.56% 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. 24

Accounting Adjustments in Revenue Requirement Stipulation

The evidence supporting this finding of fact is included in DEC's verified Application and Form E-1; the testimony and exhibits of DEC witnesses Q. Bowman, Capps, Council, Quick, Speros, Stewart, and Walsh, and Public Staff witnesses Zhang and Boswell, McLawhorn, and Metz; the Revenue Requirement Stipulation; and the entire record in this proceeding.

Incentive Compensation

In his direct testimony, DEC witness Stewart testified that DEC included in its cost of service incentive compensation at target levels that are assigned or allocated to DEC. Tr. vol. 12, 597. 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. *Id*. at 1017.

In rebuttal, DEC witness Stewart refuted these contentions, asserting that metrics such as EPS and TSR are appropriate for recovery, as they benefit customers. *Id.* at 605.

The Revenue Requirement Stipulation establishes that DEC employee incentives should be adjusted to remove incentive pay related to EPS and TSR for the top levels of DEC's leadership, but not for the remainder of the employees. Revenue Requirement Stipulation § III.13, Tr. vol. 7, Ex. 38. No intervenor took issue with this provision of the Revenue Requirement Stipulation, which is consistent with the DEP Rate Case Order. The Commission concludes that the Revenue Requirement Stipulation provides a reasonable resolution of this issue for purposes of this proceeding.

Duke Energy Plaza

In her direct testimony, DEC witness Council testified in support of DEC's investment in the Duke Energy Plaza, the new corporate headquarters building located in Charlotte, North Carolina, and described Duke Energy's overall real estate strategy and how that strategy evolved during the COVID-19 pandemic. Tr. vol. 12, 319-20. The Duke Energy Plaza is approximately one million square feet and has the capacity to house more than 4,000 Duke Energy teammates. *Id.* DEC began occupying the building in first quarter 2023 with phased "move-ins" occurring through the third quarter of 2023. *Id.* at 320. The total estimated cost of the building through July 31, 2023, was estimated to be approximately $644 million, or $439 million on a North Carolina retail basis, offset by rent revenue received from other affiliates using the building. *Id*. Witness Council testified that initially the Duke Energy Plaza was not intended to replace the Duke Energy's headquarters but was needed to consolidate office facilities to provide cost savings, promote a more collaborative workplace environment, accommodate growth, and compete for and retain talent. Id. She explained that Duke Energy's previous real estate portfolio included 40-45 year old facilities which were inefficient and well past their useful life, incurring millions of break/fix maintenance costs year over year. *Id*. at 321. Furthermore, these facilities were not designed with workplaces that promote collaboration, productivity, or wellness and more than two-thirds of Duke Energy teammates were in less than optimal office space with limited lighting, inefficient heating and cooling systems, and furniture, fixtures, and equipment prone to breakage. *Id*. at 321-22. Based on these considerations and supporting analysis, Duke Energy determined that by constructing a new office building, it could consolidate its workforce into the new building and generate annual cash savings of approximately $5 million by 2026. *Id*. at 322. Following the COVID-19 pandemic, Duke Energy further revised its real estate strategy and decided it was most cost effective to fully vacate the prior headquarters, the Duke Energy Center, by year end 2021, and consolidate all uptown Charlotte-based employees in one building, designating the Duke Energy Plaza as the new headquarters. *Id.* By divesting of five facilities, Duke Energy reduced its real estate footprint from 2.5 million to 1.1 million square feet. *Id.* at 328. Duke Energy implemented a new way of working where only about 10% of the workforce reports onsite full-time and are provided dedicated workspaces. *Id.* at 323. Approximately 10% work virtually in a non-company location or work in the field the majority of the time and the remaining 80% of employees are considered hybrid teammates that alternate between remote and Duke Energy facilities, where shared space is reserved as needed. *Id.*

In her supplemental testimony, witness Council supported the inclusion in the MYRP of 11 levels of the Duke Energy Plaza anticipated to be placed in service after June 30, 2023. *Id.* at 331. In her second supplemental testimony, she revised the Duke Energy Plaza MYRP projects to remove one level that was placed in service before the June 30, 2023 capital cut-off date in this proceeding. *Id.* at 336.

Public Staff witness Metz testified that based on his review of the Duke Energy Plaza, DEC did not select the least cost option and selected the most expensive options in terms of projected total project cost and net present value. *Id.* at 797. He testified that the least cost option would have been to move forward with a renovation of Duke's 526 S. Church Street building which he estimated would have been about half as expensive as the Plaza. *Id.* He explained that based on meetings with DEC and targeted discovery he reviewed, including a presentation from the 2016 timeframe, DEC explored four main options for further housing of its Charlotte-area staff: 1) status quo, (2) renovate, (3) re-develop, or (4) build. *Id.* at 797-98. For each option DEC sought competitive proposals, developed an evaluation tool, had internal collaborative discussions, and performed a comprehensive financial analysis, ultimately selecting to build the Duke Energy Plaza. *Id.* at 798. Witness Metz recommended a disallowance for the costs of the Duke Energy Plaza offering three potential ways to calculate the disallowance: 1) calculating a disallowance ratio of 49.4% based on a comparison of the Plaza costs to the renovation project's estimated 2016 cost of $289.2 million, 2) calculating a disallowance ratio of 63.7% based on a comparison of the total cost of the Plaza facility on a market-based rate recovery versus the actual cost of the facility, or 3) an average of multiple data points resulting in a 52.8% disallowance ratio. *Id.* at 805-09. Another option witness Metz offered was for the Commission to apply a general screening criterion and disallow cost recovery for any floors that were not moved into and not meeting their designed or intended purpose(s). *Id.* at 812.

In her rebuttal testimony, DEC witness Council responded to Public Staff witness Metz's proposed disallowance of a portion of the Duke Energy Plaza investment and explained the reasons Duke Energy undertook an evaluation of its real estate portfolio beginning in 2014, and the alternatives Duke Energy considered as part of its real estate optimization strategy over the course of the project development. Tr. vol. 16, 376. She explained that Duke Energy did not consider the Status Quo or Renovate alternatives to be viable options and those options were included in the analysis as the typical "base case" comparisons that the real estate team includes when evaluating real estate alternatives. *Id.* at 377. She explained further that after initial analysis and consultation with construction experts and architects/design experts, Renovation was not deemed a viable option; thus, Duke Energy prudently did not expend valuable resources to further develop and assess the Renovation estimate, which would have required additional scope and engineering/structural analysis at a significant cost. *Id.* The Renovation option was limited and primarily focused on interior cosmetic aspects and the scope did not address many of the infrastructure issues of the building, so expensive repairs and maintenance costs would continue to be incurred. *Id*. at 377-78. She also responded that witness Metz's analysis fails to account for other costs and risks that, when added to the project costs, demonstrate that the entire real estate costs (both capital and ongoing O&M) would have been higher if DEC had selected the Renovation option and would not have achieved most of DEC's real estate strategic objectives. *Id.* at 378. Finally, she rebutted his disallowance methodologies and noted that the majority of the floors in the Duke Energy Plaza are already occupied and in use, with the remaining floors scheduled to be moved into over the next few months, well before the rates effective date in this case. *Id.* at 378.

The Revenue Requirement Stipulation provides that the Stipulating Parties agree to remove the DEC North Carolina retail allocation of $50 million system plant in service costs for the Duke Energy Plaza, with $40 million being removed from the base period and $10 million from the MYRP. Revenue Requirement Stipulation § III.14, Tr. vol. 7, Ex. 38. The parties agreed that all other costs associated with Duke Energy Plaza shall be recoverable subject to the following:

> a. The capital adjustment for Duke Energy Plaza will flow through the rent expense proforma NC-2150;
>
> b. $2.86 million (system) will be reflected in the MYRP revenue requirement to account for parking lot revenues for employees and after-hour parking associated with Duke Energy Plaza parking; and
>
> c. This agreed upon adjustment covers the costs sought for recovery in the entire base period and MYRP for the Duke Energy Plaza building in this case. No further adjustments shall be made to the plant in service costs of the Duke Energy Plaza or changes to the operation and maintenance costs based on the Public Staff's continuing audit of the Company's second and third supplemental updates.

Id. DEC witnesses Abernathy and Q. Bowman supported this provision in their respective settlement supporting testimony. Tr. vol. 12, 135, 239-40. 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. Based on the entire record in this proceeding, the Commission concludes that the costs related to DEC's investment in the Duke Energy Plaza through the capital cut-off, as adjusted by the Revenue Requirement Stipulation, were reasonably and prudently incurred and should be recovered. After having carefully reviewed the entirety of the evidence in the record on DEC's MYRP Duke Energy Plaza project, the Commission finds that the Duke Energy

Plaza MYRP project satisfies 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 Duke Energy Plaza MYRP project. The Commission further concludes that the adjustments for the parking lot revenues for employees and after-hour parking associated with the Duke Energy Plaza parking as the Public Staff and DEC agreed in the Revenue Requirement Stipulation are reasonable.

Reliability Assurance O&M Adjustment

In his direct testimony, DEC witness Walsh testified regarding the importance of keeping DEC's remaining coal-fired assets in efficient working order to support customers' energy needs as DEC plans for those units' retirement and explained that DEC will continue to incur costs for these assets as appropriate and prudent to ensure that reliable cost-effective electricity remains available while DEC develops and implements replacement of the coal fleet. Witness Walsh also testified that the fossil units operated efficiently and reliably during the test period. Tr. vol. 12, 638-39, 643.

In his supplemental testimony, witness Walsh explained the rationale for DEC's pro forma adjustment to O&M expenses for reliability assurance. Witness Walsh stated that the adjustment increased by $5.9 million the test period O&M costs related to planned reliability assurance projects. These additional projects are necessary to maintain reliability of the Marshall, Belews Creek, and Cliffside plants and include winterization projects. Witness Walsh also provided additional details regarding this work. Witness Walsh stated that DEC identified the major components/Reliability Threats work as necessary through the Reliability Threats Analysis that DEC conducted in late 2022 and that DEC intends the work to address large items of equipment DEC needs to maintain unit reliability. Witness Walsh testified that the winterization O&M project category is work DEC identified as needed due to winter storm Elliott and represents an estimate of the cost of a study of needed repairs and installation of temporary structures to address freeze issues and those projects, such as additional wind breaks and insulation and updated heat trace systems. Witness Walsh testified that the reliability improvements project category represents a deeper level review of system health at the coal stations and typically addresses smaller items that can impact reliability, particularly when combined with other reliability issues. Witness Walsh stated that the operator workaround category is intended to address projects that are needed due to the challenge of utilizing operators to address deficient equipment as a "workaround" and would permit DEC to address such issues directly. Witness Walsh testified that the staffing project category represents DEC's forward projection of costs, primarily salary, benefits, and overhead, accounting for DEC's current understanding of attrition rates, to enable DEC to have adequate resources to operate the coal units until retirement. Witness Walsh also testified that DEC identified the repair hold project category through the Reliability Threat Analysis and that it represents major components that are currently in a repair hold status, do not have a readily available spare, and have long lead times that supply chain challenges have exacerbated. Tr. vol. 12, 665-69.

Public Staff witness Metz testified regarding DEC'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 DEC'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 DEC'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. Witness Metz clarified that the intent of the review was not to determine reasonableness or prudence of DEC'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 as the generation fleet changes and as DEC removes other generation units from service. Witness Metz also noted DEC's reduction of the level of ongoing generating plant non-fuel O&M expenses, which DEP accomplished in part by reducing staffing, in the years following Commission approval in the last two cases. Tr. vol. 12, 844-54.

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 DEC 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. 12, 861-62.

- Since the majority of the costs related to reliability improvements appeared to be capital-related rather than O&M related, and DEC had included a Winterization Capital project in the MYRP, witness Metz recommended exclusion of the Reliability Improvement costs from the pro forma adjustment. *Id.* at 862.

- Since there is no certainty regarding how the expected upcoming closure of DEC's Allen Steam Station will provide synergies or allow for staff relocation to other stations, witness Metz proposed excluding the Staffing costs from the pro forma adjustment. *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 863.

[7] Pro-forma NC-2160 was filed in DEC's May update.

In his rebuttal testimony, DEC witness Walsh described the challenge of optimizing plant investments and maintaining sufficient staffing for the coal-fired assets that DEP will retire in the near future. Witness Walsh stated that the varied timing of these assets' planned retirement dates introduces complexity as to how DEC reliably serves customers while optimizing investments. Witness Walsh explained that DEC must maintain the continued reliability of these units until replacement generation is in place. Witness Walsh explained further that DEC's strategy for addressing this challenge has evolved as circumstances have changed, but with a consistent focus on optimizing investment in the generation fleet based on which units are the most efficient, reliable, and expected to run the most. Most recently, witness Walsh testified that DEC has evaluated how best to ensure that the coal fleet continues to remain reliable up until these units' anticipated retirement, as these assets have run more days than anticipated and therefore required attention and investment. Tr. vol. 12, 680-81.

Witness Walsh also responded to witness Metz's specific recommendations regarding the Reliability Assurance pro forma NC-2160. With respect to the major components/Reliability Threat Analysis work, he explained that the Reliability Threat Analysis is not winter storm related and that, therefore, DEC would not have identified this work earlier. Witness Walsh stated that the winterization O&M work also could not have already been done as it was identified in early 2023 following Winter Storm Elliott. Witness Walsh clarified that the reliability improvements and operator workarounds work is pure O&M. Witness Walsh also explained that staffing considerations must take location and demographics into account and DEC's staffing models are not based on a percentage allocation between stations but rather on the demographics of the work force at each station. Finally, witness Walsh explained that the repair hold category recognizes the supply chain challenges, and the longer time required to complete repairs, that DEC faces today, and disagreed that this work addresses a backlog, noting that much of the inventory intended to be addressed came into inventory within the past year. Tr. vol. 12, 703-11.

Witness Walsh 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, he stated that DEC'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, 711-12. Witness Walsh testified that DEC economically dispatches the lowest cost units to serve customers and that the units at the top of the dispatch order need to be the most reliable because they are used the most to serve customers. Witness Walsh noted that the addition of dual fuel optionality (DFO) to Cliffside, Belews Creek, and Marshall Stations has increased fuel flexibility for the benefit of customers and that DEC must sufficiently invest in these units to keep the entire fleet reliable. Witness Walsh emphasized that the evaluation of fleet performance and reliability assurance needs has changed over time and will differ between smaller coal units and units with lower gas firing DFO capability as compared to the supercritical coal units, units with higher DFO capability, and natural gas combined cycle units. Witness Walsh concluded that the Reliability Assurance pro forma represents the adjustments that DEC has identified as needed to maintain the coal units in reliable condition. *Id.* at 715-16.

The Revenue Requirement Stipulation provides for inclusion of an additional $4.5 million (North Carolina retail) of annual incremental spend for ongoing O&M for DEC's coal generation fleet for discrete programs and targeted categories that witness Walsh lists in his supplemental and rebuttal testimony and for which he includes supporting workpapers. The parties agreed that DEC 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 DEC and the Public Staff. DEC will record any cumulative underspend to a regulatory liability account accrued through the end of the MYRP period (December 2026) and return it to customers in the next general rate case. Revenue Requirement Stipulation §§ III.15, IV.47, Tr. Ex. vol. 7. DEC witness Q. Bowman supported this provision in her settlement supporting testimony. Tr. vol. 12, 235-36, 243-44.

The Commission concludes that the Revenue Requirement Stipulation provides a reasonable resolution of this issue for purposes of this proceeding. DEC 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 DEC 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. DEC'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 DEC 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 DEC 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, DEC removed 50.0% of corporate-related aviation expenses allocated to DEC in the test period that are not related to aerial patrol. DEC witness Q. Bowman testified that DEC believes these costs were reasonable, prudent, and appropriate to recover from customers, but elected to remove them in this case. Tr. vol. 12, 24–25. Public Staff witnesses Zhang and Boswell recommended, in addition to the 50.0% already removed by DEC, removal from DEC'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. *Id.* at 1018.

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.17, Tr. Ex. vol. 7. No intervenor took issue with this provision of the stipulation, which is consistent with the DEP Rate Case Order. 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, DEC removed 50.0% of the compensation of the five Duke Energy executives with the highest level of compensation allocated to DEC. DEC witness Q. Bowman explained that while DEC believes these costs are reasonable, prudent, and appropriate to recover from customers, DEC has, for purposes of this case, made an adjustment to this item. Tr. vol. 12, 166. Public Staff witnesses Zhang and Boswell recommended an adjustment to include the update to Short-Term Incentive Plan actuals paid to the executives and 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. *Id.* at 1014.

Section III, Paragraph 18 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 DEC removed in the Application. Tr. Ex. vol. 7. No intervenor took issue with this provision of the stipulation, which is consistent with the DEP Rate Case Order. 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, DEC witness Speros certified that DEC'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. 12, 535. 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.* at 534. Witness Speros further explained that he performed additional reviews of DEC's cost of service to ensure that DEC did not include any costs that Commission Rule R12-13 prohibits in the Application. *Id.* at 535.

Public Staff witnesses Zhang and Boswell recommended an adjustment to charitable contributions of approximately $23,000 to exclude expense amounts paid to the Chambers of Commerce and other donations. Tr. vol. 12, 1023; Tr. vol. 23, 59; 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. 12, 1023.

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 DEC's service territory. Tr. vol. 12, 560. In addition, funds DEC paid to Chambers of Commerce that DEC does not specify as a donation or lobbying are in fact supporting business or economic development and DEC properly considers them utility operating expenses and includes them in DEC's cost of providing electric service to customers. *Id*. Finally, witness Speros noted that $23,000 on a North Carolina retail basis was inadvertently charged to above-the-line accounts rather than below-the-line; he testified that these amounts have been charged against the allowance for mischarges included in the case. *Id.* at 561.

The Revenue Requirement Stipulation establishes that base year revenue requirement will be reduced by $23,000 (NC retail) in connection with charitable contributions and sponsorships. Revenue Requirement Stipulation § III.19, Tr. Ex. vol. 7. No intervenor took issue with this provision of the stipulation, which is consistent with the DEP Rate Case Order. 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 DEC, 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 DEC in the test period. Tr. vol. 12, 1015-16. In his response, DEC witness Stewart indicated that the law requires DEC 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. *Id.* at 613. He argued that it is not fair or reasonable to penalize DEC 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.21, Tr. Ex. vol. 7. No intervenor took issue with this provision of the stipulation, which is consistent with the DEP Rate Case Order. 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, DEC witness Speros certified that DEC'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. 12, 535. Witness Speros further explained that he performed additional reviews of DEC's cost of service to ensure that DEC 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 DEC recorded above the line in the test year. *Id.* at 1018–19. 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. *Id.* at 1018-19.

In rebuttal testimony, witness Speros stated that DEC 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. *Id.* at 550–51.

The Revenue Requirement Stipulation establishes that, while DEC maintains its position that its cost of service in this case did not include any lobbying expenses, for the purposes of settlement, DEC accepted the adjustments proposed by the Public Staff (with agreed upon corrections) for lobbying expenses. Revenue Requirement Stipulation § III.20, Tr. Ex. vol. 7. No intervenor took issue with this provision of the stipulation, which is consistent with the DEP Rate Case Order. 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 that a 5.0% salvage value be applied to nuclear materials and supplies (M&S) inventory for purposes of calculating DEC's end of life nuclear reserve. Tr. vol. 12, 842-43.

In his rebuttal testimony, DEC witness Capps testified that if DEC 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 DEC'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. DEC does not expect markets for inventory components at or near market value to exist. Witness Capps indicated that, while DEC 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. Witness Capps concluded that DEC does not support maintaining a particular salvage value going forward until the retirement of the nuclear units because doing so would reduce DEC's ability to adjust the salvage value for M&S inventory as needed in the future based on changed circumstances. Tr. vol. 12, 304.

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.23, Tr. Ex. vol. 7. DEC witness Q. Bowman supported this provision in her settlement supporting testimony. Tr. vol. 12, 237. The Commission concludes that the Revenue

Requirement Stipulation provides a reasonable resolution of this issue for purposes of this proceeding.

Coal Inventory

Based on DEC's historical performance, updated coal inventory analysis, and recent coal inventory holdings, Public Staff witness Michna recommended that DEC maintain its current coal inventory of 35 days of 100.0% full load burn and reduce the corresponding DEC adjustment that increased coal inventory to 40 days by $19,301,577 to account for this change. Tr. vol. 15, 46-47.

DEC witness Walsh opposed witness Michna's adjustment. Witness Walsh 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 DEC's updated average inventory of 38.8 days. Witness Walsh concluded that it is prudent to increase the target from 35 days to 40 days. Tr. vol. 12, 717, 721-22.

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.22, Tr. Ex. vol. 7. DEC witness Q. Bowman supported this provision in her settlement supporting testimony. Tr. vol. 12, 238. The Commission concludes that the Revenue Requirement Stipulation (which is consistent with the DEP Rate Case Order) provides a reasonable resolution of this issue for purposes of this proceeding.

Credit Card Payment Fees

In her direct testimony, DEC 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, 160. In support of DEC's request, she noted that residential customers have a transaction Fee Free program for Card Payments, which the Commission approved in DEC's last general rate case. *Id*. 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 161. DEC's vendor charges the convenience fee and DEC receives no portion of it. *Id.* 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 162-63. DEC, 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. *Id.* at 162.

In their joint testimony, Public Staff witnesses Zhang and Boswell opposed DEC's proposal to socialize the credit card payment fees for nonresidential customers. Tr. vol. 12, 1019-20. 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.* at

1019. Additionally, witnesses Zhang and Boswell distinguished this proposal from the socialization of the residential credit card fees the Commission allowed in DEC'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.* at 1019-20. Therefore, they testified that they found no offsetting benefit of socialization of Card Payment fees for the nonresidential customers to general ratepayers. *Id.* at 1020.

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.24, Tr. Ex. vol. 7. The Commission concludes that the Revenue Requirement Stipulation provides a reasonable resolution of this issue for purposes of this proceeding.

Vegetation Management O&M

In his direct testimony, DEC witness Maley described DEC'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 DEC prioritizing the first two categories based on threat assessments. Witness Maley also indicated that DEC 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. 8, 271-72.

In his direct testimony, DEC witness Guyton testified that DEC utilized a reliability prioritization model to drive its routine IVM program. The other important components of DEC'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 DEC continues to utilize a five-year cycle for distribution vegetation management in urban areas, a seven-year cycle for distribution vegetation management in mountain areas, and a nine-year cycle for distribution vegetation management in areas categorized as "other" consistent with DEC's 2013 Tree Growth Study. Tr. vol. 8, 116-17.

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

Distribution and Transmission vegetation plan reporting requirements. Tr. vol. 15, 130-51.

In his rebuttal testimony, DEC witness Guyton addressed Public Staff witness T. Williamson's vegetation plan recommendations and indicated that DEC would consider the recommendations but noted that immediate implementation of the recommendations would have resource and cost implications that DEC needed to evaluate. Witness Guyton further stated that reductions in Distribution Vegetation Management plan budgets would prevent DEC from trimming its full 5, 7, and 9-year mileage targets because DEC's Vegetation Management costs were already higher than those reflected in the budget. Tr. vol. 8, 199-200. Witness Guyton agreed to witness T. Williamson's reporting recommendation. *Id.* at 201-02.

In his rebuttal testimony, DEC witness Maley addressed Public Staff witness T. Williamson's recommended reductions to the Transmission System Vegetation Management budget. Witness Maley explained his disagreement with two of witness T. Williamson's recommended budget reductions but agreed with one recommendation. Tr. vol. 8 331-34. Witness Maley agreed to witness T. Williamson's reporting recommendation with two exceptions. Tr. vol. 8, 354.

No other party presented evidence on these matters.

The Revenue Requirement Stipulation provides for a $3 million (NC Retail) increase to the test year vegetation management O&M and for adoption of the additional vegetation management reporting requirements recommended by Public Staff witness T. Williamson except as noted in the rebuttal testimony of DEC witness Maley. Revenue Requirement Stipulation §§ III.16 and IV.48, 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.

EFC Revenue

The Public Staff recommended that DEC's revenue be increased by approximately $4.4 million to reflect an increase in EFC revenue. Tr. vol. 15, 1264. In rebuttal, DEC witness Q. Bowman testified that DEC did not include a pro forma adjustment for EFC, as such an adjustment has not been included as a routine pro forma adjustment in past rate cases. *Id*. at 1265. Witness Q. Bowman further testified that DEC typically tries to limit pro forma adjustments to those that are routine (i.e., included in every case) and those that are significant in magnitude. *Id*. An adjustment to annualize EFC revenues did not meet either of these criteria. *Id*. Witness Q. Bowman testified that, should the Commission decide to include this adjustment, the calculation should be modified to account for offsetting incremental EFC O&M expenses, which are approximately 15.7% of the EFC revenue and would result in a reduction in revenue requirement of $3.7 million instead of the $4.4 million proposed by the Public Staff. *Id*. at 1266.

Section III.25 of the Revenue Requirement Stipulation provides that the Stipulating Parties agree to update the EFC revenue to 2023 levels, as adjusted in DEC witness Q. Bowman's rebuttal testimony. Tr. Ex. vol. 7.

Nuclear Levelization Costs

In DEC's 2013 rate case, Docket No. E-7, Sub 1026, the Commission approved an accounting mechanism that levelized certain costs related to nuclear refueling outages. Tr. vol. 12, 169. This adjustment annualizes the amortization expense related to this mechanism incurred during the test period to the latest known and measurable level experienced through the capital cut-off period. Id. For this case, DEC provided updated amounts of these costs through the June 30, 2023 capital cutoff date. See Tr. vol. 12, 223, 225.

Public Staff witness Metz testified that he found two nuclear refueling outages—one at Catawba Unit 2 and the other at Oconee Unit 3—that were atypical, and if not adjusted, would result in an excessive expense being included in rates until DEC files its next general rate case. Tr. vol. 12, 840. Accordingly, he proposed a series of modifications that reduced DEC's associated pro forma by approximately $1.8 million (NC Retail). *Id*. at 841. Witness Metz testified that he was not taking issue with the outage durations for either outage, or the decisions DEC made for the delay; rather, his proposed adjustment reflects his concern with the use of the two outages as the basis for ongoing expected costs for nuclear refueling outage costs in base rates. *Id*.

In rebuttal, DEC witness Q. Bowman testified that DEC disagreed with Public Staff's recommended adjustment because it is inconsistent with the Agreement and Stipulation filed on June 17, 2013, in Docket No. E-7, Sub 1026. Tr. vol. 15, 1266. Witness Q. Bowman testified that this Stipulation set forth a deferral and amortization recovery mechanism for nuclear outage costs, but notes that witness Metz contradicts such earlier stipulation by proposing a normalized level of expense going forward rather than amortizing actual, prudently incurred costs consistent with that stipulation. Id. Witness Q. Bowman testified that DEC's nuclear levelization adjustment complies with the earlier stipulation, while witness Metz's adjustment does not. *Id*. at 1266-1267. She notes that the Public Staff did not take issue with the costs incurred for nuclear outages, but rather only with the calculation of the adjustment. *Id*. at 1267.

Section III.26 of the Revenue Requirement Stipulation provides that the stipulating parties agree to amortize actual nuclear levelization costs incurred with no adjustments. Tr. Ex. vol. 7.

Marshall O&M Costs

Public Staff Witness Michna recommended that the test year non-fuel O&M expense for Marshall Station be adjusted to scale to the 2022 rate of $/MWh of O&M, which would reduce Marshall's test year non-fuel O&M by $7.8 million. Witness Michna stated that because the dual fuel operations upgrades at Marshall Station were used and useful for 2022, the 2022 O&M spending should be used to determine going forward expense instead of the test year. Tr. vol. 15, 58-60.

In his rebuttal, DEC witness Walsh testified that the Company disagreed with this adjustment. Tr. vol. 12, 723. In her rebuttal, DEC witness Q. Bowman testified to a calculation error and stated that DEC would work with the Public Staff to resolve the issue. Tr. vol. 15, 1267.

The Revenue Requirement Stipulation provides that no adjustment shall be made to Marshall O&M costs. Revenue Requirement Stipulation § III.27, Tr. Ex. vol. 7. DEC witness Q. Bowman supported this provision in her settlement supporting testimony. Tr. vol. 12, 243. The Commission concludes that the Revenue Requirement Stipulation provides a reasonable resolution of this issue for purposes of this proceeding.

M&S Inventory

Based on his assessment that W.S. Lee Unit 3 has retired and Allen Units 1 and 5 are planned for retirement on or before December 31, 2023, Public Staff witness Lucas recommended that DEC's inventory return for Lee Unit 3 and Allen Units 1 and 5 not be included in rates. Tr. vol. 13, 123-24.

In her rebuttal testimony, DEC witness Q. Bowman testified that DEC partially agreed with witness Lucas' proposed adjustment. Witness Q. Bowman stated that Materials and Supplies (M&S) Inventory is held at sites until retirement, at which point such Inventory is typically recovered through separate regulatory asset treatment or charged against the cost of removal (COR) reserve. Witness Q. Bowman stated that DEC agreed with the removal of the Lee Unit 3 inventory balance as the plant was retired in March 2022. Because inventory balances were charged to COR and included in the net plant portion of rate base as of the cut-off period, and therefore already included in rate base in a different location, it is appropriate to remove them from inventory so as not to double count. Tr. vol. 15, 1250-51.

Witness Q. Bowman did not agree with witness Lucas' proposal to remove inventory costs related to Allen Units 1 and 5 because the plants were not retired as of the capital cut-off date of June 30, 2023, nor were the units expected to be retired by the time of the hearing in the case. Witness Q. Bowman noted that the dismantlement study included in the case includes estimates of inventory amounts remaining at retirement as part of the COR estimates included in the depreciation study, but since these units are still operational the inventory balances have not been charged to COR. Witness Q. Bowman clarified that once the units are retired, the inventory will be charged against COR, but remain in rate base, just in a different location – net plant. As a result, even if the units retired by the time of the hearing, it would still not be appropriate to remove the inventory from rate base for ratemaking purposes. Tr. vol. 15, 1251-52.

The Revenue Requirement Stipulation provides that the M&S inventory balance associated with Lee Unit 3 as detailed in the testimony of Public Staff witness Lucas and the rebuttal testimony of DEC witness Q. Bowman will be removed. Revenue Requirement Stipulation § III.28, Tr. Ex. vol. 7. The Revenue Requirement Stipulation also provides that no adjustment is necessary to the M&S inventory costs associated with Allen Units 1 and 5. Revenue Requirement Stipulation § III.29, Tr. Ex. vol. 7. DEC witness Q. Bowman supported these provisions in her settlement supporting testimony.

Tr. vol. 12, 238, 242. The Commission concludes that the Revenue Requirement Stipulation provides a reasonable resolution of these issue for purposes of this proceeding.

Allen Unit 4 Costs Deferral

In her direct testimony, DEC witness Q. Bowman testified that in the final order in Docket No. E-7, Sub 1214, the Commission granted DEC authority to establish a regulatory asset for the unrecovered costs associated with Allen Unit 4 at the time of its retirement. Witness Q. Bowman stated that DEC will continue amortization of the regulatory asset at the existing depreciation rates from retirement until an appropriate amortization period is determined in this rate case. Witness Q. Bowman explained that DEC made an adjustment to amortize the remaining regulatory asset, including a reduction for the Buck Coal Plant over-amortization from Docket No. E-7, Sub 1026 and an estimated amount of dismantlement costs, net of salvage, over a six-year period. Tr. vol. 12, 180.

Public Staff witness Lucas recommended that the Commission set the Decommissioning Study adder for project indirects at 5% rather than 10% as proposed by DEC, and require a 10% contingency factor 10%, rather than 20% as proposed. Witness Lucas proposed that his decommissioning study recommendations be reflected for Allen Unit 4. Tr. vol. 13, 121-22. Public Staff witnesses Zhang and Boswell made an adjustment to reflect witness Lucas' recommendation to adjust the costs included in the deferral of Allen Unit 4 and did not recommend any change in DEC's proposed six-year amortization period. Tr. vol. 12, 1041-42.

In rebuttal, DEC witness Jeffrey Kopp testified that based on costs actually incurred by DEC on recently completed decommissioning projects, 10% is an appropriate number to use for project indirect costs in this case. Tr. vol. 12, 424-427. Witness Kopp also testified that based on the types of activities that will take place during decommissioning, the level of unknowns that would result in potential cost increases, and DEC's experience incurring the contingency costs included in its estimates, a 20% contingency is reasonable to use in this case. Tr. vol. 12, 427-435.

In her rebuttal, DEC witness Q. Bowman explained that the balance for amortization represents the net book value of the plant at retirement including dismantlement costs for the retirement of Allen Unit 4 and an offset of over-amortization of the Buck Coal Plant retirement due to the like-kind nature (i.e., both amortizations were due to early retirement of plant). Tr. vol. 15, 1255. Witness Q. Bowman stated that for the reasons discussed in DEC witness Jeffrey Kopp's rebuttal, DEC did not agree with the adjustment for dismantlement expenses. Witness Q. Bowman stated further that it is appropriate to apply the Buck plant over-amortization to the Allen Unit 4 deferral balance because the over-amortization was like-kind in nature. Witness Q. Bowman also testified that the appropriate balance to include in rate base is the estimated balance as of December 31, 2023. This deferred plant balance has been in rate base and amortizing at the existing Allen 4 depreciation rate, and therefore has already been reduced by more than a year's worth of amortization. Tr. vol. 15, 1256.

The Revenue Requirement Stipulation provides for the deferral of Allen Unit 4 costs, subject to adjustment of the decommissioning estimate for contingency and indirect adder for Unit 4, no adjustment to Unit 4 inventory estimate, and to DEC's position on rate base as amortization of Allen Unit 4 is already reflected in the test year. Revenue Requirement Stipulation § III.30, Tr. Ex. vol. 7. The Revenue Requirement Stipulation also provides that the over amortization related to the Buck retired plant regulatory asset will be netted against the Allen 4 retired plant regulatory asset, as proposed by DEC. Revenue Requirement Stipulation § III.40.a.iii, Tr. Ex. Vol. 7 DEC witness Q. Bowman supported these provisions in her settlement supporting testimony. Tr. vol. 12, 238, 242, 256. The Commission concludes that the Revenue Requirement Stipulation provides a reasonable resolution of this issue for purposes of this proceeding.

Lighting Audit

Public Staff witnesses Zhang and Boswell testified that DEC agreed in a settlement agreement filed on June 17, 2013, in Docket No. E-7, Sub 1026, to change its billing system to ensure that all lighting customers received a revised extra facilities charge (EFC) rate of 1.1% instead of the then-existing 1.7%. Tr. vol. 12, 1039. In its September 24, 2013 Order Granting General Rate Increase, this Commission ordered that DEC credit any customers continuing to be charged at the 1.7% EFC rate, and that DEC provide a detailed report of the billing corrections. *Id*. at 1040. In the settlement agreement, DEC and the Public Staff agreed to defer the costs associated with conducting this audit. Id. Now, in this rate case, DEC seeks recovery of the estimated $656,000 in deferred costs associated with the lighting audit that was incurred between 2013 and 2015. *Id*.

Witnesses Zhang and Boswell testified that the customers who benefitted from the lighting audit were those who received credits in the two-year timeframe following the Commission's final order. Tr. vol. 12, 1040. However, they testify that customers since that timeframe have not benefitted from the lighting audit. *Id*. Further, DEC filed rate cases in 2017 and 2019 but did not seek recovery of its lighting audit costs in those cases, both of which were closer in time to when the costs were incurred than the current right case. *Id*. Given how much time has passed, witnesses Zhang and Boswell testified that allowing DEC to recover from current customers the costs incurred between 2013 and 2015 would cause significant intergenerational equity issues. *Id*. at 1040-1041. Thus, while the Public Staff did not take issue with the prudency of the lighting audit costs, the Public Staff recommended denying DEC's request to recover those costs. *Id*. at 1041.

In rebuttal, witness Q. Bowman testified that DEC opposed Public Staff's proposed adjustment and noted that DEC acknowledged that it did not bring its lighting audit costs up for recovery sooner. Tr. vol. 15, 1257. Witness Q. Bowman testified that this delay in seeking recovery does not invalidate the fact that the costs are reasonable, were prudently incurred, and should be recoverable. *Id*. Moreover, she testified that there has been no return accrued on this balance, and thus, the delayed timing has no impact on the amount requested for recovery. Id. Witness Q. Bowman further testified that if intergenerational equity is a concern, Public Staff could have chosen to net the full deferral of $656,028 against the over-amortization amounts which have already been collected from customers to better align the timing, rather than proposing a disallowance of reasonable and prudent costs. *Id*.

In the Revenue Requirement Stipulation, the stipulating parties agree that DEC will remove from rate base $656,028 in deferred costs associated with the lighting audit incurred between 2013-2015 and will not seek to recover those deferred costs. Tr. vol. 12, 251; *see also* Tr. Ex. vol. 7.

IIJA for Hydroelectric Plants

Public Staff witness Thomas recommended that the costs of certain MYRP hydroelectric projects be reduced by the hydroelectric incentives for which those projects were likely eligible under the IIJA. Tr. vol. 14, 186-87. Witness Thomas identified several projects in an exhibit to his direct testimony and recommended a total reduction in costs for those projects of approximately $37.9 million throughout the MYRP. *Id*. at 233.

In her rebuttal testimony, DEC witness Klein opposed witness Thomas's recommendations and described DEC's approach to pursuing IIJA funds. Tr. vol. 15, 1213. Witness Klein testified that IIJA programs are highly competitive, and therefore, it is not possible to project with any degree of confidence whether DEC will be selected for an IIJA award or the amount that will be awarded. *Id*. at 1222. In addition, witness Klein explained that, under DEC's internal prioritization framework, DEC pursues IIJA funds for programs that will provide the greatest benefits to customers, and DEC uses its prioritization framework to identify priority IIJA programs based on the resources and costs that would be required to pursue funds. *Id*. at 1218. With regard to the specific hydroelectric incentive projects identified by Public Staff witness Thomas, Witness Klein testified that, as hydroelectric incentives under the IIJA are subject to cost caps and funds have only been appropriated for fiscal year 2022, it is not certain that funds for these projects will be available after 2022. *Id* at. 1224. Witness Klein also testified that multiple developments within individual FERC-licensed hydroelectric projects are treated a single hydroelectric facility for IIJA-eligibility purposes, and therefore, only one IIJA incentive payment may be made to each hydroelectric facility per fiscal year. *Id*. at 1225.

The Revenue Requirement Stipulation establishes that in the case of certain IIJA funds for certain MYRP hydroelectric projects for which DEC did not apply, that no adjustment shall be made to the MYRP revenue requirement based on Public Staff witness Thomas's testimony that DEC should have applied for such funds. For the hydroelectric projects for which DEC previously submitted IIJA applications, the Revenue Requirement Stipulation provides that DEC will assume receipt of such IIJA grants, net of costs incurred, and incorporate those amounts into the final base period and MYRP revenue requirements for such projects. Furthermore, the Revenue Requirement Stipulation provides that the Public Staff will not seek to disallow costs in DEC's next general rate case for these hydroelectric MYRP projects (identified in Thomas Exhibit 17) that meet both of the following conditions: (i) are either under the Catawba-Wateree FERC license or the East Fork Tuckasegee FERC license; and (ii) have capital cost estimates less than $16.7 million.

Over-Amortizations

In its Application, DEC requested permission to apply expiring over-amortizations as an offset to the deferral balances of costs that DEC 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 (ARO); (2) rate case expenses; (3) application of the over-amortization of severance costs to rate case expenses; and (4) application of the over-amortization of the Buck early retired coal plant to the Allen Unit 4 early retired coal plant. Tr. Ex. vol. 7.

In direct testimony, DEC witness Q. Bowman 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. 12, 177. Witness Q. Bowman 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 Q. Bowman explained that over-amortizations of the regulatory assets and liabilities have been applied to like kind expense recovery in this case. *Id.* Witness Q. Bowman testified that DEC intends to apply the over-amortization of Buck coal plant regulatory assets against the Allen Unit 4 plant regulatory asset allowed in the 2019 Rate Case, as an example. *Id.* at 178.

In their direct testimony, Public Staff witnesses Zhang and Boswell recommended that the Commission remove DEC'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. 12, 1024-25. 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.* at 1042. They testified that by offsetting the expiring amortizations against continuing amortizations, DEC is overriding the Commission's approved terms for recovery of the individual regulatory assets. *Id.* 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.*

In rebuttal, DEC witness Q. Bowman described each of the expired amortizations that DEC is proposing to offset against like costs: (1) coal ash;[8] (2) rate case costs; (3) severance; and (4) early retirement of coal plants. Tr. vol. 15, 1299-1303. Witness Q. Bowman explained how DEC's proposed treatment of the expiring amortizations is consistent with the Commission's 2018 Order in the 2017 Rate Case. *Id.* at 1297-98; Order Accepting Stipulation, Deciding Contested Issues and Granting Partial Rate Increase, Docket No. E-7, Sub 1146 (June 22, 2018) at 24-25. She stated that in that

[8] The over-amortization of coal ash costs is separately addressed later in this Order.

order the Commission previously addressed continuing amortizations of expired regulatory assets and liabilities in the context of coal ash costs. Tr. vol 15, 1297-98. She further stated that in that order the Commission concluded:

> With regard to DEC's CCR costs from 2018 forward, DEC witness McManeus testified that DEC is requesting to establish a regulatory asset/liability account and defer to this account the portion in annual rates that is more than DEC's actual costs, or the amount in annual rates that is less than DEC's actual costs. In essence, the asset/liability account would be a tool used to true-up the difference in DEC's next general rate case. The Commission agrees with DEC's recommended approach, not only for CCR costs, but also for all cost deferral accounts…. Rather, the 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 1298.

Witness Q. Bowman also disagreed with the Public Staff's assertion that by offsetting the expiring amortizations against continuing amortizations, DEC is overriding the Commission's approved terms for recovery of the individual assets. *Id.* at 1297. Witness Q. Bowman maintained that DEC has complied with the 2018 DEC 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 1298-99.

Witness Q. Bowman also explained the impact upon rates should the Commission adopt DEC's proposed treatment. *Id.* at 1299. Witness Q. Bowman testified that DEC'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.*

Section III.40.a of the Revenue Requirement Stipulation provides that (1) the over amortizations related to prior coal ash costs will be netted against coal ash costs included in this case; (2) the over amortizations related to prior rate case costs will be netted with rate case costs included in this case; and (3) the over amortization related to the Buck retired plant regulatory asset will be netted against the Allen Unit 4 retired plant regulatory asset; and (4) the over amortization of the severance regulatory asset established in Docket No. E-7, Sub 1214 will be refunded through a one-year rider with interest. This provision of the stipulation is consistent with our ruling in the DEP Rate Case Order.

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 DEC's previously approved regulatory assets that have been over-amortized against other regulatory assets, in accordance with

Section III.40.a of the Revenue Requirement Stipulation. 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.

Inflation Adjustment

DEC, through witness Q. Bowman's 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. 12, 169. In supplemental direct testimony, witness Bowman testified that this inflation adjustment was updated to reflect inflation factors through April 30, 2023. *Id.* at 203-06. This inflation adjustment factor was subsequently updated in Bowman's second and third supplemental direct testimony, *Id.* at 213, 223, 233, 242, 249, and finally in Settlement Testimony, consistent with the DEP Rate Case Order, to arrive at a rate of 12.58%. *Id*. at 255; Q. Bowman Supplemental Partial Settlement Ex. 4 at 109; Tr. Ex. vol. 12.

In their direct testimony, Public Staff witnesses Zhang and Boswell recommended that the Commission adjust DEC's inflation factor to reflect a five-year average inflation rate through April 30, 2023. Tr. vol. 12, 1011. Witnesses Zhang and Boswell further recommended that the inflation adjustment be modified to reflect the Public Staff's recommended adjustments removing aviation expenses, Board of Directors expenses, rent expense, and sponsorships and donations. *Id*. They further testified that the Public Staff did 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 1012.

In rebuttal, DEC witness Q. Bowman opposed the Public Staff's recommended adjustment. Tr. vol. 15, 1287. Witness Q. Bowman testified that DEC'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 1288. Witness Q. Bowman further testified to DEC's methodology for calculating an inflation factor, stating that it has not changed from previous rate cases. *Id.* Witness Q. Bowman 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 1287-88. Witness Q. Bowman cited data from the U.S. Bureau of Labor Statistics that shows a continual upward trend for all inflation metrics. *Id.* at 1290. Further, witness Q. Bowman testified that while DEC disagrees with the Public Staff's adjustments removing certain expenses related to aviation, sponsorships, donations, lobbying, and Board of Directors expenses, DEC 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 1291.

The Revenue Requirement Stipulation accepts the Company's proposed inflation adjustment. Revenue Requirement Stipulation § III.40.b, Tr. Ex. vol. 7. No intervenor took issue with this provision of the stipulation, which is consistent with the DEP Rate Case

Order. The Commission concludes that the Revenue Requirement Stipulation provides a reasonable resolution of this issue for purposes of this proceeding.

Rate Case Expense

Witness Q. Bowman testified that, in the current proceeding, DEC 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 severance costs approved in Docket No. E-7, Sub 1214 and rate case costs from prior cases were used to offset the amount requested for recovery in this case. Tr. vol. 12, 177, 204.

Public Staff witnesses Zhang and Boswell explained that they removed: 1) DEC's adjustment to include additional rate case expenses from the 2019 Rate Case that exceed the amount agreed to in the first partial settlement entered into by DEC and the Public Staff in the 2019 Rate Case (2019 First Partial Settlement) 2) the adjustment to include the unamortized portion of rate case expense in rate base; and 3) DEC'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. *Id.*

Regarding DEC'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. *Id.* at 1025.

In her rebuttal testimony, witness Q. Bowman asserted that DEC 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 DEC 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 Q. Bowman stated that DEC'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. 15, 1270-72.

In response to the Public Staff's recommendation that the unamortized rate case costs for this proceeding be removed from rate base, witness Q. Bowman explained that DEC's investors have advanced the funds to cover these reasonably and prudently incurred utility costs and, as such, DEC should be allowed to earn a return on this asset to reflect the earnings expected from its investors during the amortization period. *Id.* at 1270.

In the DEP Rate Case Order, the Commission approved DEP's request to recover rate case costs incurred from its 2019 Rate Case which were above and beyond those provided for in its settlement agreements with the Public Staff, denied DEP's request to include the unamortized balance of rate case expense in the rate base, and determined that the amortization period for which the rate case expense should be recovered is three years, which aligns with the MYRP time frame. DEP Rate Case Order, 204-205.

In Section III.40.f of the Revenue Requirement Stipulation, DEC and the Public Staff agreed on the following: (1) that DEC shall recover the remaining unamortized rate case expenses from Docket Nos. E-7, Sub 1146 and E-7, Sub 1214; (2) that DEC shall recover the additional rate case expense requested for the Sub 1214 in this proceeding; (3) that the rate case expense balance shall be net against all rate case expense over amortization from the prior cases; and (4) that the unamortized rate case expense balance will not be included in the rate base. In addition, DEC and the Public Staff agreed that the actual rate case expenses for the present case will reflect prudently incurred costs through the filing of the proposed order, and any remaining costs will not be included for recovery from ratepayers either in a future rate case nor included in the unamortized balance for this case. 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.

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.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 25

Nuclear PTC

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

DEC requested an accounting order to authorize deferral of all impacts associated with the IRA. Tr. vol 12, 95-96. DEC witness Abernathy testified in support of DEC's deferral request. She explained that because there remains uncertainty surrounding the estimated benefits DEC will receive from the IRA, DEC is requesting an accounting order authorizing it to defer any difference between realized and estimated impacts included in this filing, net of costs. *Id.* at 96. Witness Abernathy explained that it is DEC's intent that customers receive the full benefit of the associated tax credits, including nuclear production tax credits (PTCs). *Id.*

DEC witness Panizza's testimony explained how DEC did not account for any impacts associated with nuclear PTCs in the base case due to it being uncertain as to when DEC will be able to monetize nuclear PTCs. *Id.* at 517. Witness Panizza reiterated how DEC's request for an accounting order authorizing a deferral is appropriate.

The Public Staff recommended that DEC begin providing the benefits of the expected nuclear PTCs to customers in Rate Year 1. *Id.* at 927-28. Witness Metz testified that by seeking a deferral of all of the benefits, DEC shifted the full benefit of the nuclear PTCs to the future resulting in current system users (who are benefiting from the nuclear PTCs) not receiving the resulting cost reductions. *Id.* at 927.

In her rebuttal testimony, DEC witness Abernathy testified that none of the MYRP nuclear projects will increase nuclear output during the MYRP period. Witness Abernathy also explained that under N.C.G.S. § 62.133-16(c)(1)a, the MYRP revenue requirement must be based on the costs, net of savings, of specific capital investments. Tr. vol. 16, 228. For this reason, DEC did not include an estimate for nuclear PTCs in DEC's MYRP revenue requirement or adjust the base case revenue requirement to account for nuclear PTCs. *Id.* Further, in his rebuttal testimony DEC witness Panizza noted that the Public Staff's suggestions seemed to overlook the complexities and uncertainties of the IRA's tax credits. In particular, witness Panizza testified that witness Metz's recommendation appeared to be based on a misunderstanding of the nuclear production tax credit and its calculation. Tr. vol. 15, 1198.

In her settlement testimony, DEC witness Bateman testified that the nuclear PTC rider agreed upon in the Revenue Requirement Stipulation provides more structure to DEC's plan to provide the benefits of nuclear PTCs to customers. Tr. vol. 11, 216-17. The rider will be effective beginning January 1, 2025, and flow back $50 million (NC Retail) in 2025 and $100 million in 2026, subject to adjustments from this Commission under certain specified conditions. Witness Bateman explained that the nuclear PTC rider will result in a standardized annual process that will assess and confirm the amount of nuclear PTCs previously generated and monetized or used. *Id.* at 217. Witness Bateman noted that the annual process will allow the benefit of the nuclear PTCs to be distributed in multiple tranches, each over a four-year period, which will extend the timeframe over which the benefit of the nuclear PTCs will be realized by customers. *Id.* She also testified that DEC will track the amounts of nuclear PTCs for inclusion by establishing a regulatory asset/liability account for nuclear PTCs to allow for the deferral of any variance to actuals including a return at DEC's last authorized WACC, net of taxes. She explained that upon monetization or use, the amounts will be deferred to the regulatory asset/liability account, net of costs, and net of any amounts already included in the rider. A return will accrue on the regulatory asset/liability beginning upon the monetization or use of the nuclear PTCs until amounts are included in the rider with a levelized WACC return. *Id.* at 217-18.

At the evidentiary hearing, witness Panizza responded to questions from Commissioners regarding the $50 million and $100 million to be returned to customers in the first two years of the proposed nuclear PTC rider. Tr. vol. 15, 1200. Witness Panizza explained that nuclear PTCs differ from traditional PTCs (like solar) because they include a phaseout of the credit, which is not part of the traditional PTC framework. The phaseout is based upon a calculation of the gross receipts the nuclear producer obtains from the generation of electricity from nuclear sources. The phaseout begins once the gross receipts level hits $25 per megawatt hour, proceeds ratably down to $43.75 per megawatt hour, and then is zero. *Id.* at 1201-1202. Witness Panizza explained that DEC is awaiting IRS guidance to define gross receipts for purposes of calculating the phaseout, if it becomes applicable to DEC under the rules ultimately established by the IRS. Witness Panizza testified that the $50 and $100 million included in the proposed rider was a reasonable estimate that allows DEC to begin the flowback of nuclear PTC's pending finalization of the IRS guidance. He noted that the rider provides for subsequent mechanisms to ensure that customers receive the full amount of the credit. *Id.* at 1203-1204. Witness Panizza also clarified that DEC incurs transactional costs associated with monetizing PTCs, and stated that the rider would return the PTCs to customers net of those costs. *Id.* at 1205-1207.

Discussion and Conclusion

Section III.33 of the Revenue Requirement Stipulation provides that the parties agree to file with the Commission and support a standalone rider to refund deferred benefits of nuclear PTCs to customers. Tr. Ex. vol. 7. The rider will be effective beginning January 1, 2025, and flow back $50 million (NC Retail) in 2025 and $100 million in 2026, subject to adjustments from this Commission. Thereafter, the rider will be updated annually to identify nuclear PTCs generated and monetized in accordance with the IRA to return to customers such amounts evenly over a four-year amortization period with a levelized return at DEC's last authorized weighted average cost of capital (WACC), net of tax. DEC Late Filed Exhibit No. 2. The rider, as proposed, will continue until all nuclear PTCs monetized or used are returned to customers.

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.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 26

Lead Lag Study

The evidence supporting this finding is in the verified Application; the Revenue

Requirement Stipulation, the testimony and exhibits of DEC witness Speros, Public Staff witnesses Zhang and Boswell and the entire record in this proceeding.

As part of its filing in this case, DEC submitted a lead-lag study that was performed by Ernst & Young, LLP, and approved in the Commission's Order in the 2019 Rate Case. Tr. vol. 12, 531; Speros Direct Ex. 2, Tr. Ex. vol. 12. 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). Tr. vol. 12, 532. Public Staff witnesses Zhang and Boswell recommended that DEC prepare and file a fully updated lead-lag study in its next general rate case. Tr. vol. 12, 1011.

In his rebuttal testimony, DEC witness Speros stated that DEC plans to pursue a merger of the DEC and DEP 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. 12, 560.

The Revenue Requirement Stipulation incorporates DEC's agreement to perform a lead-lag study before the next general rate case proceeding and incorporate the results of that study in DEC'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 NO. 27

MYRP Capital Investments

The evidence supporting this finding of fact is included in DEC's verified Application and Form E-1; the testimony and exhibits of DEC witnesses Abernathy, Bateman, Maley, Guyton, Capps, Walsh, LaRoche, Battery Energy Storage Panel witnesses Meeks and Shearer, Strasburger, and Murray; Public Staff witnesses Thomas, Chiles, Metz, Michna, T. Williamson, Nader, Zhang, and Boswell; AGO witness Burgess; NCJC, et al. witnesses Hill and Duncan; Sierra Club witness Goggin; NC WARN witnesses Powers and Konidena; the Revenue Requirement Stipulation; and the entire record in this proceeding.

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

Transmission

DEC witness Maley testified in support of the MYRP transmission projects. Regarding future needs, witness Maley testified that, while DEC 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. 8, 264. Witness Maley testified that DEC designed its MYRP to address those future challenges and opportunities. *Id.* He testified 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 278.

Witness Maley testified that DEC 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 280. He explained that although these seven proposed MYRP investments are the same as those DEC presented in the November 2, 2022, MYRP technical conference, DEC had 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 DEC's proposed MYRP transmission projects. *Id.* at 279.

In his supplemental direct testimony, witness Maley provided an update on the cost estimates applicable to transmission projects that DEC included in its MYRP based on certain criteria agreed upon with the Public Staff. *Id.* at 300. Witness Maley identified additional transmission MYRP project locations that DEC added to the MYRP after filing his direct testimony, and identified those that it removed, along with the reasons behind such changes. *Id.* at 301. He provided updated project cost estimates for certain transmission MYRP projects, including explanations for the basis for such updated cost estimates. *Id.* Witness Maley explained that his direct testimony included 306 transmission projects at the location/task level totaling $1.79 billion and his supplemental direct testimony included 305 projects at the location/task level totaling $2.03 billion, which represented an overall net increase of $246.8 million. *Id.*

In his second supplemental direct testimony, witness Maley provided a further update on the cost estimates applicable to transmission projects that DEC included in its MYRP. *Id.* at 312. Witness Maley also identified those transmission project locations that DEC removed from the MYRP after filing his direct and supplemental direct testimony, along with the reasons behind such changes. *Id.*

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

1. Breakers - $375,814,508;

2. Capacity and Customer Planning - $521,982,230;

3. Substation Hardening and Resilience - $362,637,115;

4. System Intelligence - $136,841,787;

5. Transmission Line Hardening and Resilience - $329,361,344;

6. Transformers - $177,369,201;

7. Vegetation Management - $85,291,177.

Tr. Ex. vol. 9.

The modifications to the proposed MYRP transmission projects described in witness Maley's supplemental direct testimony, second supplemental direct testimony, and accompanying exhibits, resulted in an updated estimated capital cost to DEC's proposed MYRP Transmission projects of $1.99 billion. Tr. vol. 8, 313.

Public Staff Witness Metz testified as to multiple concerns with the transmission MYRP projects, including DEC's provision of project documentation and insufficient staffing levels to complete the projects on schedule. Tr. vol. 12, 790-95, 901. Witness Metz recommended reducing the project estimate contingency components by half, arguing that DEC failed to justify the high contingency amount DEC budgeted for the projects. *Id.* at 912-15. Witness Metz also recommended the removal of certain transmission projects from the MYRP based on the analysis of Public Staff witness Chiles. *Id.* at 867-68. In particular, Witness Chiles recommended removal of the Boyds to Trinity Ridge project. Tr. vol. 15, 207.

AGO witness Burgess critiqued DEC's transmission planning and made several recommendations. AGO witness Burgess recommended that the Commission require DEC to conduct a study on the costs and benefits of grid-enhancing technologies (GETs). *Id.* at 322. Witness Burgess also recommended that DEC engage in regional transmission planning and asserted that regional planning could potentially displace projects in the MYRP. *Id.* at 333-34, 335-36. Finally, witness Burgess recommended that DEC pursue all funding options for transmission projects that are part of the IRA. *Id.* at 328.

Sierra Club witness Goggin recommended that the Commission require DEC 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 the Carbon Plan. *Id.* at 1145. Witness Goggin also recommended that the Commission direct DEC 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…" *Id.* at 1118.

NC WARN witnesses Powers and Konidena expressed concern with the "high apparent cost of" proposed upgrades to several transmission lines that are "listed in Table P-3 of Appendix P to the Carbon Plan." *Id*. at 1094.

Witness Maley addressed testimony from Public Staff witnesses Metz and Chiles. Specifically, he: (1) responded to witness Metz's testimony related to project documentation; (2) spoke of each MYRP project witnesses Metz and Chiles challenged by rebutting the justifications presented for the challenge and explaining why the projects are necessary and appropriate for inclusion in the MYRP; (3) addressed witness Metz's concerns regarding staffing levels; (4) countered the argument that the Commission should reduce contingency components of the estimates for all MYRP transmission projects by 50.0%; and (5) explained the basis for the contingency component of DEC's transmission projects. Tr. vol. 10, 322-35. Witness Maley agreed to remove the Boyds to Trinity Ridge project from DEC's MYRP. *Id.* at 356.

Witness Maley also addressed testimony of witnesses for the AGO, the Sierra Club, and NC WARN. Witness Maley stated that he disagreed with AGO witness Burgess recommendations. *Id.* at 392-93. Witness Maley testified that witness Burgess' recommendation to study GETs is inappropriate in this proceeding because the Commission already considered GETs in the first completed Carbon Plan proceeding. *Id.* at 392. Also, witness Maley disputed witness Burgess' recommendations because they require activities already underway or that should be considered in the CPIRP or in the North Carolina Transmission Planning Collaborative (NCTPC). *Id.* Witness Maley further 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.* at 392-93. 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 CPIRP than within a rate case proceeding. *Id.* at 393. Witness Maley explained that Duke Energy stated in the March 15, 2023, NCTPC Transmission Advisory Group presentation that it is pursuing the integration of a multi-value strategic transmission planning study into the local transmission planning process. *Id.* at 393-94. Since DEC is already pursuing this in the NCTPC, witness Maley testified that any further requirement is unnecessary. *Id.*

Witness Maley testified that the estimated costs included in the MYRP for the projects identified by NC WARN witnesses Powers and Konidena included the most up to date available information and were appropriate based on the scope of work for the projects. He also noted that their concerns would be more appropriately addressed in the CPIRP proceedings. *Id.* at 369.

The Revenue Requirement Stipulation includes a $351 million reduction in DEC's projected MYRP capital on a system basis in connection with the Public Staff's testimony regarding insufficient project documentation. It states that DEC will remove the costs of the Boyds to Trinity Ridge project as agreed to in the rebuttal testimony of witness Maley. It also includes a 50.0% reduction to the contingency amounts of the transmission projects as recommended by Public Staff witness Metz and removal of 50% of corrected one-time installation O&M from the MYRP. The stipulation also establishes that the transmission MYRP projects identified in Exhibits 1 and 2 of DEC witness Abernathy's

August 24, 2023, settlement testimony, and supplemental and rebuttal testimonies of DEC witness Maley are appropriate for inclusion in the MYRP except as modified by the terms of the stipulation. Tr. Ex. vol. 7. Based on the entire record in this proceeding, the Commission finds that DEC's proposed transmission projects as discussed above and adjusted in the Revenue Requirement Stipulation are reasonable and shall be included in the MYRP for recovery.

The only parties that opposed portions of DEC'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 Burgess, the Sierra Club, as indicated by the testimony filed by Sierra Club witness Goggin, and NC WARN, as indicated by the testimony filed by NC WARN witnesses Powers and Konidena.

The Commission agrees with DEC witness Maley's assertion that the recommendations of AGO witness Burgess and Sierra Club witness Goggin regarding transmission planning are designed to change DEC'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. The Commission further finds that the concerns of NC WARN witnesses Powers and Konidena, as addressed by DEC witness Maley do not justify any modifications to the transmission projects in the MYRP.

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.

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

DEC witness Guyton described the discrete and identifiable capital spending projects associated with DEC'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. 8, 100. Witness Guyton testified that DEC's proposed MYRP distribution and other projects covered in his testimony total $2.7 billion and included the $2.3 billion in distribution MYRP projects discussed at the T&D technical conference held on November 2, 2022, as well as $0.4 billion in other non-T&D MYRP projects. *Id.* at 107. The other MYRP project categories include DEC'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 reinforce 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 129. 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*. 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 105. 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*. 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 106.

With respect to reliability, witness Guyton stated that DEC anticipates fewer and shorter outages resulting from programs such as Self-Optimizing Grid (SOG), Targeted Underground (TUG), and distribution automation. *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 Distributed Energy Resources (DERs) and EVs. *Id.* Enhanced automation and control, and situational awareness will enable DEC 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 DEC 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 DEC'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 DEC's Grid Operators but also for its Planning Engineers as they analyze and model DEC's grid for future improvements and capabilities using ISOP toolsets like Morecast and Advanced Distribution Planning. *Id.* He indicated that grid technologies will continue to and will be integrated into new solutions to address changing customer needs. *Id.* at 106-07.

Witness Guyton testified that distribution projects included in the MYRP total $2,718,439,578 in estimated capital investment and fall into four investment categories: (1) Substation and Line MYRP projects, which total estimated capital costs of $1.847 billion and comprise most of the distribution MYRP project costs; (2) Retail and System Capacity Projects, which total estimated capital costs of $0.256 billion and 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 $0.039 billion and consist of the traditional identification and execution of hazard tree removal which is performed in conjunction with normal trimming cycles; (4) the Integrated Volt Var Control (IVVC)/Voltage Regulation Management Projects, which total estimated capital costs of $0.196 billion and represent the work performed to establish control of distribution equipment to optimize delivery voltages and power factors and facilitate addition of DERs and EVs; and (5) non-distribution MYRP projects, which total estimated capital cost of $0.4 billion and include DEC's allocated share of the cost for the Advanced Distribution Management System, enterprise communications and systems, as well as facilities and fleet electrification infrastructure. *Id.* at 107-09.

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 DEC has identified to address the megatrends and support the clean energy transition. *Id.* at 130-31. DEC's Distribution MYRP consists of the following 10 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 $270.8 million.

2. 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 $28.4 million.

3. Capacity Upgrades and Improvements Program consists of the same work that DEC has always performed to serve its new and existing customers. The total capital cost for this program is $522.3 million.

4. 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 $436.5 million.

5. Hardening and Resiliency – Public Interference Program improves reliability by targeting DEC'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 $96.1 million.

6. Hardening and Resiliency – Storm Program consists of improvements to locations of the distribution grid that DEC 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 $51.3 million.

7. Long Duration Interruption 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 $23.1 million.

8. TUG Program improves reliability by strategically identifying DEC'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 $193.7 million.

9. 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 $71.6 million.

10. 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 $447.4 million. *Id.* at 132-36.

Witness Guyton testified that DEC's description of its distribution MYRP programs and associated exhibits reflect the detailed project information required by Commission Rule R1- 17B. *Id.* at 137. 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 138. 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.* DEC 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 DEC either added to or removed from the MYRP period and explained the reasons for such changes. *Id.* at 157. Witness Guyton provided updated project cost estimates applicable to distribution projects that are included in DEC's MYRP based upon certain criteria to which DEC and the Public Staff agreed. *Id.* Witness Guyton testified that his direct testimony included 76 distribution projects (comprised of 602 distribution sub-projects at the location/task level) totaling $2.7 billion, while his supplemental direct testimony included 78 distribution projects (comprised of 680 sub-projects at the location/task level) totaling $3.1 billion representing an overall net increase of $337.6 million across all the distribution MYRP projects. *Id.* at 157-58.

Witness Guyton summarized the supplemental MYRP as follows: (1) DEC added two new Enterprise Application MYRP projects including the Geospatial Information System Replacement project, totaling $30.6 million, and the Grid Hosting Capacity project, totaling $6.7 million; (2) DEC added one project/task, totaling $4.8 million, for Closed Loop Fault Isolation Service Restoration; (3) DEC added 29 project locations, totaling $75.3 million, in the Communications MYRP Projects for a South Carolina location that was added in the supplemental filing; (4) DEC added 15 project locations, totaling $31.3 million, in the Communications MYRP Projects, and removed 9 project locations, totaling $16.3 million, to reflect updates that have occurred in the project development life cycle; (5) DEC added 4 project locations, totaling $1.7 million, in the IVVC MYRP Projects; (6) DEC added 18 project locations, totaling $56 million, to the Retail System Capacity MYRP Projects, while DEC also removed another 18 projects from the Retail System Capacity MYRP Projects; (7) DEC added 6 project locations, totaling $62 million, in the Substation and Line MYRP Projects; and (8) DEC added 1 project location for Hazard Tree. *Id.* at 160-62. Witness Guyton also testified that supply chain constraints on transformers had near-term impacts on DEC's planned TUG work and, consequently, DEC removed TUG work scope from the Substation and Line projects. *Id.* at 168, 230. Witness Guyton described cost updates to 441 total distribution MYRP projects. *Id.* at 164. Witness Guyton also explained that at the time of DEC's Application, the distribution MYRP projects were at various stages of the project management lifecycle under DEC's Project Management Center of Excellence (PMCoE) standards. *Id.* at 165. Under the PMCoE approach, as a project moves through the development cycle, DEC continues to refine the costs and project schedules based on project development, detailed design, and construction planning. *Id.* at 165-66.

Witness Guyton explained that when the Substation and Line 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.* at 167. Planning and engineering activities that occurred after the filing of DEC's Application and engaged in as part of the PMCoE process provided the opportunity to refine the scope of work and cost estimates on 155 of the total 290 Substation and Line sub-projects at the location/task level in the MYRP based on actual circuit and equipment and site conditions. *Id.*

Guyton Supplemental Exhibit 1 identifies the total estimated capital costs of the Distribution MYRP projects to be $3,056,048,092. Tr. Ex. vol. 9.

Public Staff witness Metz testified to multiple concerns with the distribution MYRP projects, including DEC's provision of project documentation and insufficient staffing levels to complete the projects on schedule. Tr. vol. 12, 790-95, 901. Witness Metz recommended reducing the project estimate contingency components by half, arguing that DEC failed to justify the high contingency amount DEC budgeted for the projects. *Id.* at 912-15. Public Staff witness Lawrence recommended removal of the ECI Project that would support the deployment of electric vehicles to DEC facilities and the homes of select DEC employees from the MYRP on the basis that its costs were not sufficiently developed. Tr. vol. 15, 95. Public Staff witness T. Williamson recommended the TUG Program continue to focus on circuit segments that experience a relatively high number of outages, and that DEC use analytics to determine whether TUG is the most cost-effective solution for that segment. *Id.* at 122.

NCJC, et al. witnesses Hill and Duncan made several recommendations related to DEC distribution planning. First, they recommended that the Commission initiate a working group to redesign DEC's CBA methodologies for selection of MYRP projects and that the Commission initiate an investigation into distribution system planning. Tr. vol. 15, 861, 863. Witnesses Hill and Duncan also recommended that the Commission require DEC to conduct non-wire (NW) pilot projects and that DEC update its MYRP cost estimates to account for federal funds available through the IRA and IIJA. *Id.* at 842-43.

In his rebuttal testimony, DEC witness Guyton responded to the Public Staff's distribution related MYRP testimony, and to NCJC, et al. witnesses Hill and Duncan's testimony. Tr. vol. 8, 172-73. Specifically, he: (1) responded to witness Metz's testimony related to project documentation; (2) discussed the methodologies and procedures DEC 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%; (4) addressed witness Metz's concerns regarding staffing levels; (5) responded to witness Lawrence's recommendation to remove the ECI Project from the MYRP; and (6) agreed that DEC would continue to utilize events per mile to determine which circuit segments are appropriate for TUG and that DEC would continue to perform cost benefit analyses on TUG projects with greater than a half mile of overhead conductor removed. *Id.* at 182-86, 204-18, 222-25, 226-27, 238.

The Revenue Requirement Stipulation included certain modifications to DEC's MYRP distribution projects. Those modifications include: (1) a $351 million reduction in DEC's projected MYRP capital on a system basis in connection with the Public Staff's testimony regarding insufficient project documentation; (2) a 50.0% reduction to the contingency amounts of the distribution projects as recommended by Public Staff witness Metz; (3) removal of the costs of the ECI Project; and (4) removal of 50% of corrected one-time installation O&M from the MYRP. The stipulation also establishes that the distribution MYRP projects identified in Exhibits 1 and 2 of DEC witness Abernathy's August 24, 2023, settlement testimony, and supplemental and rebuttal testimonies of DEC witness Guyton are appropriate for inclusion in the MYRP except as modified by the terms of the stipulation. 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. Tr. vol. 8 at 240-41. Witness Guyton asserted that the recommendation of NCJC, et al. that the Commission initiate a working group to update DEC's CBA methodologies is unnecessary since DEC has demonstrated the current methodology, and no other intervenor disputed the current methodology or its usefulness in the current rate case. *Id.* at 241. He contends that witnesses Hill and Duncan also do not acknowledge specific improvements in the CBA methodology DEC used in the current rate case that DEC made in response to stakeholder feedback in DEC's last rate case. *Id.* Witness Guyton also asserted that the NW pilot projects witnesses Hill and Duncan suggest are unnecessary because DEC has already initiated other NW pilot projects. *Id*. 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.* Similarly, witness Guyton asserts that their recommendation to require DEC to update MYRP cost estimates to account for federal funds available through the IRA and IIJA is unnecessary as DEC is actively pursuing grant funding opportunities for the benefit of customers. *Id.* at 242. Witness Guyton also points to DEC witness Abernathy's testimony, in which she testified that DEC requests that the Commission issue an accounting order authorizing deferral of all IRA and IIJA impacts, including benefits and costs, to be addressed 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 DEC'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 DEC to update its distribution MYRP investments to account for available federal funds, the Commission notes that the record demonstrates that DEC is pursuing such funds and re-emphasizes its direction to DEC 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 DEC's distribution MYRP proposal in this docket, and based on that evidence, the Commission finds that DEC's distribution MYRP projects, as adjusted in the Revenue Requirement Stipulation, 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

DEC witness Capps testified in support of the nuclear projects DEC included in the proposed MYRP, the process DEC used to select the projects, and the method by which DEC calculated projected costs for the projects. Tr. vol. 12, 281-86. Witness Capps explained that DEC 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 Capps stated that DEC based the projected costs on its long-range nuclear planning tool, which it updates regularly. *Id.* at 281. Witness Capps presented additional details regarding nuclear fleet-wide projects and the projects DEC planned for each of DEC's nuclear stations. *Id.* at 283-86; Application at 16, Tr. Ex. vol.7. Witness Capps concluded that DEC prudently and reasonably selected these projects as they will enable DEC to maintain the fleet in reliable and efficient condition for customers' benefit. *Id.* at 283. Witness Capps' Direct Exhibit 1 provided additional details regarding projected cost, schedule, scope, and justification for each nuclear MYRP project. Tr. Ex. vol. 12.

In his supplemental direct testimony, DEC witness Capps updated the information on the MYRP nuclear projects. Witness Capps supported nine additional nuclear projects that DEC proposed to include in its MYRP and explained why DEC removed six nuclear projects from the MYRP. Tr. vol. 12, 307-10. Witness Capps explained the basis for updating MYRP project costs as agreed upon with the Public Staff and the method by which DEC developed the updated project costs. *Id.* at 310-12. Witness Capps' Supplemental Exhibits 1 and 2 provided updated in-service dates and projected costs for the nuclear MYRP projects. Tr. Ex. vol. 12.

Public Staff witness Metz discussed the Public Staff's review of DEC'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 DEC on the MYRP. Tr. vol. 12, 867. Witness Metz testified to multiple concerns with the nuclear MYRP projects, including DEC's provision of project documentation and insufficient staffing levels to complete the projects on schedule. Tr. vol. 12, 790-95, 901. Witness Metz recommended reducing the project estimate contingency components by half, arguing that DEC failed to justify the high contingency amount DEC budgeted for the projects. *Id.* at 912-15.

In his rebuttal testimony, DEC witness Capps noted that no individual nuclear MYRP project received objections by the Public Staff or any party on the basis of need, scope, cost, or schedule. Tr. vol. 12, 289, 297. Witness Capps also responded to witness Metz's testimony related to project documentation. *Id*. at 296-302. Finally, witness Capps testified to DEC's ability to execute the nuclear MYRP projects within the three-year time period. *Id*. at 302-03.

Based on the entire record in this proceeding, the Commission finds that DEC's projected nuclear MYRP capital investments as adjusted by the Revenue Requirement

Stipulation, 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 on the basis of need, scope, cost, or schedule. Therefore, the Commission concludes the evidence supports approval of the Revenue Requirement Stipulation's provisions regarding the nuclear MYRP projects.

Fossil/Hydro

In his direct testimony, DEC witness Walsh outlined the projected natural gas, coal, and hydroelectric capital investments DEC included in the MYRP. Witness Walsh described DEC's prioritization process for identification of the projects to include in the MYRP. Tr. vol. 12, 645-46. Witness Walsh explained that DEC applied its project management guidelines for project scope development and cost estimation. *Id.* at 646. Witness Walsh presented additional details regarding the MYRP projects proposed for the natural gas, coal, and hydro generation fleets. *Id.* at 650-55; Application at 16, Tr. Ex. vol. 7. Witness Walsh testified that DEC is undertaking the Clemson Hydrogen project to develop hydrogen generation technology as part of Duke Energy's transition to a cleaner energy future. Tr. vol. 12, 651, 655. Witness Walsh also testified to the importance of keeping DEC's remaining coal fired assets working efficiently to support customers' energy needs as DEC plans for those units' retirement and explained that DEC will continue to incur costs for these assets as appropriate and prudent to ensure that reliable cost-effective electricity remains available while DEC develops and implements replacement of the coal fleet. Witness Walsh noted that due to the continued importance of natural gas to DEC's resource mix, particularly during winter months and while DEC is developing and deploying energy storage capacity, DEC will continue to rely on its natural gas fleet as part of the diverse and dispatchable resource mix. *Id.* at 639. Witness Walsh concluded that DEC's decision to invest in these projects is prudent and reasonable as they will enable DEC to continue to provide safe, reliable, and affordable service to customers. *Id.* at 650. Witness Walsh's Direct Exhibit 1 provided additional details regarding projected cost, schedule, scope, and justification for each fossil/hydro MYRP project. Tr. Ex. vol. 12.

In his supplemental direct testimony, DEC witness Walsh supported the additional fossil and hydro projects that DEC proposed to include in its MYRP. Tr. vol. 12, 658-59. Witness Walsh explained why certain projects that DEC removed from the MYRP were determined to be no longer necessary. *Id.* at 660. Witness Walsh explained the basis for updated MYRP projected costs as agreed upon with the Public Staff and the method by which DEC developed the updated project costs. *Id.* at 661-62. Witness Walsh'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.

In his second supplemental direct testimony, witness Walsh provided an additional update on the fossil and hydro projects included in the MYRP to support DEC's third supplemental update. Witness Walsh explained the removal of one project that had been postponed beyond the MYRP period and updates to cost estimates for three other projects. Tr. vol. 12, 672. Witness Walsh's Second Supplemental Exhibit 1 provided an updated list of the fossil and hydro MYRP projects with these changes reflected. Tr. Ex. vol. 12.

Public Staff witnesses Metz, Thomas, and Michna reviewed DEC's proposed fossil, hydro, and nuclear MYRP projects. Public Staff witness Metz testified that the Public Staff reviewed DEC's initial and supplemental MYRP filings and updates, initiated multiple sets of discovery, and participated in several meetings with DEC on the MYRP. Tr. vol. 12, 867. Witnesses Metz, Michna, and Thomas testified to multiple concerns with the fossil and hydro MYRP projects, including DEC's provision of project documentation and insufficient staffing levels to complete the projects on schedule. Tr. vol. 12, 790-95, 901. Witness Metz recommended removing from the MYRP all projects which did not include supporting documentation sufficient to satisfy Commission Rule R1-17B(d)(2)(j). Tr. vol. 12, 872. Witness Metz also recommended reducing the project estimate contingency components by half, arguing that DEC failed to justify the high contingency amount DEC budgeted for the projects. *Id.* at 912-15. Witness Metz recommended removal of the Clemson Hydrogen Project based on seven factors: lack of a supporting economic analysis; the Company's inability to provide documentation until after the filing of its CPIRP; the Company forcing hydrogen into its 2022 Carbon Plan model; the uncertainty as to whether the project will be approved in South Carolina, were it is located; the cost of energy associated with a hydrogen project; the lack of demonstration of need for the project and its impact on rates; and the fact that only DEC ratepayers would pay all the project costs though the project would benefit other Duke Energy entities . Tr. vol. 12, 880-86.

Public Staff witness Thomas reviewed the proposed hydro MYRP projects. Witness Thomas recommended that the Mountain Island dam seismic project be removed from the MYRP based on the project schedule indicating an in-service date beyond the MYRP period and a lack of cost support. Tr. vol. 14, 190. Witness Thomas also recommended removing some O&M costs associated with hydroelectric plants that had documented cost savings. Tr. vol. 14, 189.

Witness Michna reviewed the proposed coal MYRP projects. Witness Michna agreed with DEC's philosophy of prioritizing unit reliability and resource adequacy in capital spending decisions. Tr. vol. 15, 69.

In his rebuttal testimony, DEC witness Walsh responded to witness Metz's testimony related to project documentation. Tr. vol. 12, 685-693. Witness Walsh testified that the Clemson Hydrogen project is needed for DEC to begin to gain operational experience with hydrogen fuel. Witness Walsh explained that this operational experience will allow DEC to continue to pursue this potentially pivotal fuel option and incorporate hydrogen into the resource mix for the future and to produce benefits for DEC customers. Tr. vol. 12, 694. Witness Walsh also clarified that the modeling completed for the Clemson Hydrogen project was based upon but separate from the 2022 Carbon Plan modeling; described the 2022 Carbon Plan modeling assumption of hydrogen availability for long-term planning purposes; explained that the Clemson modeling process was more complex and took more time than originally anticipated but that DEC subsequently provided production cost information for the project to the Public Staff; and noted that the project will not require a certificate from the Public Service Commission of South Carolina to be constructed. *Id.* at 694-98. Witness Walsh agreed with witness Thomas that the Mountain Island project should be removed from the MYRP as it is not expected to go in service before 2027. Tr. vol. 12, 698-99. Witness Walsh disagreed with witness Thomas' recommendation regarding O&M costs associated with certain hydro MYRP projects, explaining that any initial projections of savings contained in project Evaluator documents were not intended to be relied upon as actual annual ongoing O&M savings. *Id.* at 700. Finally, witness Walsh testified to DEC's ability to execute the fossil/hydro MYRP projects within the three-year time period. *Id*. at 702.

The Revenue Requirement Stipulation provides that the costs of the Clemson Hydrogen project will be removed from the MYRP. Revenue Requirement Stipulation § III.38.b, Tr. Ex. vol. 7. DEC witness Abernathy supported this provision in her settlement supporting testimony. Tr. vol. 12, 134. The Revenue Requirement Stipulation provides that the costs of the Mountain Island Dam Seismic project will be removed from the MYRP as agreed to in DEC's rebuttal testimony. Revenue Requirement Stipulation § III.38.c, Tr. Ex. vol. 7. DEC witness Abernathy supported this provision in her settlement supporting testimony. Tr. vol. 12, 135.

Based on the entire record in this proceeding, the Commission finds that DEC's proposed natural gas, coal, and hydro MYRP projects, as adjusted by the Revenue Requirement Stipulation, satisfy the requirements set forth in N.C.G.S. § 62-133.16(c)(1)(a). DEC 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, DEC 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. Specifically, the Commission concludes that the Revenue Requirement Stipulation provides a reasonable resolution of the Clemson Hydrogen and Mountain Island dam seismic projects for purposes of this proceeding.

Lincoln CT

On May 19, 2023, DEC petitioned the Commission for an Order Amending CPCN to update the commercial operation and cost recovery date for the Lincoln CT Unit 17 to January 1, 2024. *Petition to Amend Certificate of Public Convenience and Necessity*, Docket No. E-7, Sub 1134 (May 19, 2023); Tr. vol. 12, 492. DEC stated that the requested amendment would provide an additional 400 MW of dispatchable generation leading into the 2024 winter season.

The Public Staff opposed DEC's request. Witness Lucas testified that DEC's proposed change would move the warranty expiration date from December 1, 2026, to January 1, 2026. Witness Lucas testified that this change would create disproportionate risks for ratepayers if Lincoln CT Unit 17 were to experience operational problems between those two dates. Tr. vol. 13, 133. Witness Lucas testified that if the Commission did adopt DEC's proposed commercial operation and cost recovery date of January 1, 2024, then the Public Staff's recommendation is that the Commission not allow cost recovery of any repairs or replacements between January 1, 2026 and December 1, 2026. *Id.* at 134.

In his rebuttal testimony, DEC witness Murray testified that DEC's proposal to amend the CPCN is a "creative, efficient, and effective way for DEC to increase generation capacity in time for the winter season through a relatively straightforward administrative process with minimal costs." Tr. vol. 12, 495. Witness Murray also explained that DEC confirmed with Siemens Energy, Inc., the developer of the project, that the unit can be safely placed into service on January 1, 2024. *Id.* at 500-501. Witness Murray noted that Public Staff witness Lucas did not identify any operational issues with Lincoln CT that would support the Public Staff's concerns about changing the commercial operation date. *Id*. at 495. Additionally, witness Murray also noted that the Commission found the Lincoln CT was consistent with DEC's 2016 IRP and will provide enhanced reliability, low turn-down, fast ramp rate, and efficient dispatch capability for the DEC system. *Id.* at 468-70.

Section III.39 of the Revenue Requirement Stipulation provides that the parties agree to recommend that the Commission revise the Lincoln CT CPCN to modify the in-service date to November 1, 2024 for purposes of calculating the MYRP revenue requirement. No intervenor took issue with this provision in the Revenue Requirement Stipulation. The Commission concludes that DEC and the Public Staff's joint recommendation regarding the commercial operation and cost recovery date for Lincoln CT provides a reasonable resolution of this issue. This Commission will issue a revised CPCN Order in accordance with the recommendation.

Cybersecurity

In his Supplemental Direct Testimony, DEC witness Strasburger provided support for DEC's information technology (IT)/operational technology (OT) Cybersecurity project DEC will include in the MYRP. Tr. vol. 12, 617-620. 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*. 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*. The project will also focus on expanding monitoring and threat response capabilities and will introduce proactive elements to reduce cybersecurity risks. Id. 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 DEC continues to see increased cyber threats against operational assets, including potential geopolitical threats, cybersecurity becomes a larger component of DEC'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 DEC's MYRP IT/OT Cybersecurity project, the Commission finds that the IT/OT Cybersecurity MYRP project, as adjusted by the Revenue Requirement Stipulation, satisfies the requirements set forth in N.C.G. S. § 62-133.16(c)(1)(a). DEC 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 DEC put forth a reasonable plan to implement the IT/OT Cybersecurity project within the prescribed time period.

Battery Storage

DEC proposes a portfolio of nine MYRP battery energy storage projects. Tr. Vol. 9, 126. The portfolio consists of nine discrete, and identifiable battery energy storage projects: (1) Lowgap, (2) Monroe, (3) Frieden, (4) Novant Health, (5) Nebo, (6) Rich Mountain, (7) Longtown, (8) Farr's Bridge, and (9) Allen. *Id.* DEC witnesses Meeks and Shearer (the Battery Energy Storage Panel) testified and detailed the projected cost, schedule, and scope for each MYRP project, as well as the rationale supporting each project as required by Commission Rule R1-17B(d)(2)j. *Id.* at 127-28; *see also* Battery Energy Storage Panel Exhibit 1. The Battery Energy Storage Panel submitted supplemental direct testimony explaining that DEC had removed two projects, Novant Health and Rich Mountain, from the proposed MYRP. *Id.* at 140. 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. *Id.* at 125. The Panel explained further that the microgrid projects included in the proposed MYRP provide potential reliability improvement solutions for geographically isolated feeders and circuits facing unique reliability challenges with limited options for traditional mitigation improvements. *Id.* at 127. Evidence contained in Battery Storage Panel Exhibits 1-2 includes detailed information regarding projected cost, schedule, scope, and rationale supporting the investments. *Id.* at 124. Battery Energy Storage Panel Exhibit 2 also contains anticipated project timelines, including projected in-service month and year for each proposed project as required by Commission Rules R1-17B(d)(2)j. *Id.* Battery Energy Storage Panel Exhibit 3 provides a program summary of the battery energy storage project portfolio that were presented at the T&D Technical Conference. *Id.* Battery Energy Storage Panel Exhibit 4 includes the cost benefit analyses (CBAs) for projects presented at the T&D Technical Conference. *Id.* Finally, Battery Energy Storage Panel Exhibit 5 outlines the methodology that DEC employed in developing the CBAs outlined in Battery Energy Storage Panel Exhibit 4. *Id.*

The Battery Energy Storage Panel described the expected benefits associated with each proposed battery project including unique bulk power services. *Id.* at 127-28. The Battery Energy Storage Panel explained further that battery resources are uniquely capable of serving multiple grid functions across generation, transmission, and distribution systems. *Id.* at 125. The Battery Energy Storage Panel testified that the Frieden project allows DEC to provide bulk system benefits from a distribution interconnection point and explore the value of solar smoothing. *Id.* at 127-28. In addition, the proposed Monroe project utilizes existing interconnection infrastructure, thereby reducing development costs and project timelines. The Battery Energy Storage Panel also explained that the Nebo, Longtown, and Farr's Bridge microgrid projects are reliability projects located on feeders and circuits with unique reliability challenges and limited options for traditional outage mitigation improvements; thus, these projects improve reliability and resiliency, and speed restoration times for circuits in those areas. *Id.* at 127. The Battery Energy Storage Panel highlighted that, upon completion, the proposed Allen project will represent the largest battery installation that DEC has installed. The Battery Energy Storage Panel explained further that the proposed Allen project will: (1) provide bulk system services including energy arbitrage and ancillary services with a grid scale battery system; (2) maximize existing interconnection rights and land availability at a retiring coal facility; and (3) capture the added benefit of an additional ten percent Investment Tax Credit adder. *Id.* at 127, 130.

Public Staff witness Thomas examined and provided testimony addressing DEC's proposed battery energy storage portfolio. Witness Thomas did not adjust the cost of battery storage projects included in DEC's proposed MYRP, but recommended removal of certain microgrid projects and recommended allocation of microgrid costs to distribution only. Tr. vol. 14, 174, 179. Witness Thomas questioned whether the microgrid batteries would provide significant production plant services and testified that project costs should therefore "be allocated 100% to distribution." *Id.* at 174. As a further recommendation regarding microgrid projects, witness Thomas recommended removing three projects—the Nebo, Lowgap, and Farr's Bridge projects—from the MYRP because these projects had benefit cost ratios (BCRs) "well below one, indicating that the project tis not cost-effective" *Id.* at 180–82. Finally, witness Thomas recommended that "DEC consider adding additional battery storage at the retired Allen coal plant in the near future." *Id.* at 179.

The Battery Energy Storage Panel submitted rebuttal testimony disagreeing with witness Thomas' recommendations to remove the Farr's Bridge, Lowgap, and Nebo microgrids from DEC's proposed MYRP. Tr. vol. 9, 151, 161. Furthermore, the Battery Energy Storage Panel disagreed with witness Thomas's recommended modifications to DEC's proposed cost allocation methodology for the battery storage projects included in this case. *Id.* at 161. The Battery Energy Storage Panel also contended that Witness Thomas ignored the many qualitative and quantitative benefits that the proposed microgrids can provide to customers: customers benefit from both qualitative and quantitative benefits. *Id.* at 150, 156. To that end, the Battery Energy Storage Panel stated that the proposed microgrids will cost-effectively address difficult reliability challenges and provide bulk system benefits that justify production cost allocation. *See id.* at 157–158.

The Battery Energy Storage Panel highlighted that the projects represent the most optimal solutions for feeders facing unique or chronic reliability challenges with limited options for traditional outage mitigation improvements. *Id.* at 152. The Battery Energy Storage Panel further testified that DEC is open to exploring a second project at the Allen site, but the proposed 50MW project in the MYRP maximizes existing land availability and has already been studied through the large generator interconnection process. *Id.* at 163.

During the hearing, in response to Commissioner questions, the Battery Energy Storage Panel explained DEC's approach to choosing microgrid projects over stand-alone battery projects. *See id.* at 168-70. Specifically, witness Meeks testified that DEC's microgrid projects are strategically sited to solve a grid need that was previously unable to be solved with past technology options, and the microgrids increase reliability and resiliency in areas with reliability needs. *Id.* at 169. Further, when those projects are not needed for local reliability and resiliency, they can be dispatched to the benefit of the bulk system. *Id.* Witness Shearer testified that this also benefits the battery itself, as it allows the battery to "stretch its legs" by providing bulk system benefits on a day-to-day basis rather than sit idly waiting for a reliability event to occur. *Id.* at 170. Witness Shearer also analogized a microgrid to a "Swiss Army knife," testifying that microgrids offer benefits where traditional solutions fall short. *Id.* at 175. Public Staff Witness Thomas testified that the Public Staff would work with DEC to understand the operational benefits of microgrids and would review cost allocation in future general rate cases. Tr. vol. 14, 255-259. Regarding the Allen site project, the Panel testified during the hearing that the Allen battery was sized based on available land and transmission hosting capacity, and the battery's siting at a coal facility derives a higher ITC value to offset the cost to customers. *Id.* at 172.

As part of the Revenue Requirement Stipulation, the Stipulating Parties agreed that, aside from the provisions laid out in the Revenue Requirement Stipulation, no further adjustments will be made to DEC's base period or MYRP revenue requirement based on the Public Staff's positions as presented in its initial testimony. Tr. Ex. Vol. 7. Accordingly, the Stipulating Parties agree to use the allocation factor by plant classification of the microgrid projects as proposed by DEC. *Id.* Additionally, the Stipulating Parties agreed to the removal of the Lowgap project from the MYRP. *Id.* During the expert witness hearing, Public Staff witness Thomas explained that only the Lowgap microgrid costs were removed, but that the allocation of the remainder of the microgrids was as DEC had proposed. Tr. vol. 14, 255. Witness Thomas testified that FERC Order 898 may have an impact on how battery costs are allocated in the future, potentially rendering functional cost allocation discussions moot. *Id.* at 263.

After careful review all the evidence in the record on DEC's MYRP proposal in this docket, and based on that evidence, the Commission finds that DEC's Battery Storage MYRP projects, as adjusted by the Revenue Requirement Stipulation, satisfy the standard set forth in N.C.G.S. § 62-133.16(c)(1)(a). The Commission further finds and concludes that approval of the Revenue Requirement Stipulation's provisions regarding the Battery Storage MYRP projects are appropriate and supported by the preponderance of evidence and that the Battery Storage MYRP costs thereunder are just and reasonable and consistent with the public interest, subject to a prudence review in DEC's next general rate case. Furthermore, while the Commission is also interested in seeing more energy storage deployed at the Allen site, it acknowledges that the 50MW project proposed by DEC in the MYRP is reasonable at this time based on current land availability and interconnection rights.

Solar

DEC witness LaRoche provided testimony supporting the 2026 Solar Procurement Program Investment ("2026 Solar Investment") that is included in DEC's MYRP, as well as in support for DEC's request for a 35-year depreciation life for the 2026 Solar Investment and for future solar facilities. Tr. vol 12, 438-49. Witness LaRoche described the 2026 Solar Investment as a procurement of 165 MWs of solar, which will result in multiple projects being selected as part of the 2022 Solar Procurement Program (2022 SP Program) Request for Proposals (RFP), with projected in-service dates of Jun 1, 2026. *Id.* at 442. Witness LaRoche stated that to identify the 2026 Solar Investment, DEC examined the solar pipeline for discrete and identifiable solar projects that would be placed in service within the MYRP period, and as part of this process, DEC considered the solar investments that will result from the 2022 SP Program. *Id.* at 442-43. Additionally, he testified that DEC's most recent integrated resource plan (IRP) identified the need for new solar resources to reliably serve DEC's projected customer load. *Id.* at 441. Witness LaRoche also stated that HB 951 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.* at 440. Further, witness LaRoche identified that the 2022 Solar Investment aligns with the Carbon Plan solar targets. *Id.* at 441. In addition, DEC's most recent IRP, filed with the Commission and the Public Service Commission of South Carolina, also identified the need for new solar resources to reliably serve DEC's projected customer load. *Id.*

In his first supplemental testimony, witness LaRoche testified to an agreement reached between DEC and the Public Staff describing updates associated with the proposed solar projects contained in DEC's MYRP. Tr. vol. 12, 452. Witness LaRoche's stated that DEC has identified an early winner that is part of the 2026 Solar Investment Project. *Id.* Additionally, witness LaRoche provided the Commission with an update on the 2026 Solar Investment Project to reflect the selection of a proposal from the 2022 Solar Procurement Program RFP. *Id.* Witness LaRoche testified that DEC updated the cost estimate for the 2026 Solar Investment Project to reflect the reduced MW capacity and DEC's revenue requirement. *Id.* at 456.

In his second supplemental testimony, DEC witness LaRoche updated the 2026 Solar Investment to reflect the selection of a market participant and proposal for the 2022 SP Program RFP. *Id.* at 462. Witness LaRoche testified that the market participant selected has (1) performed all required environmental studies; (2) secured required county permit approval; and (3) completed interconnection studies and obtained a fully executed interconnection agreement. *Id.* at 463. Further, the market participant selected has requested and received a CPCN for the 2026 Solar Investment Project and DEC intends on filing a CPCN transfer application by the end of 2023. *Id.* As a result, the 2026 Solar Investment Project cost estimates and revenue requirements for the proposed MYRP have been updated. *Id.* at 463-64. Witness LaRoche testified that the 2026 Solar Investment Project can reasonably be placed in-service by June 2026. *Id.* at 464.

Public Staff witness Thomas recommended reducing the system level in-service costs of the facility and the associated network upgrades to $70,799,273, a reduction of approximately $123 million. Tr. vol. 14, 167. Further, witness Thomas recommended a proportional reduction to the annual O&M, thereby reducing the annual O&M cost to $653,739. *Id.*

DEC witness LaRoche testified in his rebuttal testimony that DEC agrees with Public Staff's solar investment-related recommendations. Tr. vol. 12, 451. Specifically, DEC's supplemental direct testimony updated the projected in-service costs (including associated network upgrade costs) and projected annual net O&M to reflect selected winners resulting from the 2022 solar procurement. *Id.* Consistent with witness Thomas' recommendation, DEC updated the projected in-service costs to $70,799,273. Furthermore, witness LaRoche testified that the projected annual O&M was updated to $481,246, an amount lower than Public Staff's recommended value. *Id.*

After having carefully reviewed the evidence in the record on DEC's Solar MYRP proposal in this docket, and based on that evidence, the Commission finds that DEC's solar MYRP projects, as adjusted by the Revenue Requirement Stipulation, satisfy the requirements set forth in N.C.G.S. § 62-133.16(c)(1)(a).

MYRP Implementation

Public Staff witness Metz testified to his concern regarding DEC's ability to complete the proposed MYRP projects within the three-year MYRP period. Based on his review of DEC's historic and projected 2023 staffing, witness Metz asserted that DEC does not have a plan to increase staffing for planned MYRP projects while continuing to perform traditional work of the utility. Tr. vol. 12, 901-10.

In his rebuttal testimony, DEC witness Murray overviewed DEC'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. 12, 481. 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 DEC has successfully implemented prudent management processes historically. *Id.* at 482-83.

While acknowledging that MYRP project execution will not be easy and that there likely will be unforeseen challenges that require DEC 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 DEC's historic capital project implementation. Witness Murray disagreed with the Public

Staff's suggestion that DEC is not well prepared to successfully execute these projects. *Id.* at 481.

DEC witness Bowman also responded to witness Metz's concerns regarding DEP's ability to execute on certain MYRP projects. Tr. vol. 7, 98. Witness Bowman testified that DEC is confident in its ability to execute the MYRP projects and acknowledged DEC'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.* Witness Bowman explained that although DEC will encounter unforeseen challenges and circumstances, in all instances DEC will leverage its execution experience to maximize benefits for customers. *Id.*

After review of the evidence presented by DEC's various generation, transmission, and distribution witnesses, as well as the evidence presented by DEC regarding its processes, procedures, and project management experience the Commission finds that DEC 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 DEC 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 DEC has demonstrated a reasonable plan to complete the MYRP projects within the prescribed time periods.

MYRP Project Documentation

DEC provided support for its MYRP projects through its Application, direct, supplemental, settlement, and rebuttal testimony of the DEC witnesses discussed below, as well as at the November 2022 Transmission and Distribution Technical Conference. Furthermore, the Public Staff conducted substantial discovery regarding the projects DEC proposed in its MYRP.

The Public Staff critiqued DEC's project documentation for MYRP projects. Specifically, witness Metz testified that the Public Staff implemented a screening process to review and identify project documents received. Tr. vol. 12, 872. Witness Metz stated that the Public Staff received insufficient or no project documentation for a number of MYRP projects, which raised concerns of undue risk placed on customers if projects lacking full documentation are being planning and included in rates. *Id.* at 873-79. Witness Metz recommended removing projects from DEC's MYRP that did not include supporting documentation sufficient to satisfy Commission Rule R1-17B(d)(2)(j). Tr. vol. 12, 872. Witness Thomas also recommended the removal of approximately $63 million of hydroelectric projects from the MYRP, citing a failure to satisfy Commission Rule R1-17B(d)(2)(j) due to a lack of documentation. Tr. vol. 14, 189. Witness Michna further recommended the removal of approximately $41 million of steam generation projects from the MYRP, citing a failure to satisfy Commission Rule R1-17B(d)(2)(j) due to a lack of documentation. Tr. vol. 15, 67.

The various DEC operational witnesses all provided testimony supporting their respective projects. DEC witness Murray specifically responded to the Public Staff's critiques regarding the level and amount of project documentation DEC provided. Witness Murray testified that DEC has in place well-defined project management practices, and that the complexity of a project drives the level of project documentation, with more complex projects generating much more documentation than reoccurring, routine projects. *Id.* at 487. As it relates to the timing, witness Murray testified that project documentation is created in the ordinary course of business. He explained that as a project advances through DEC's Project Stage Gating process, associated documents also advance and develop to include greater detail and a more defined scope. *Id.* Witness Murray also testified that it was reasonable to expect a range of project documentation available based on the factors noted above—namely, timing, complexity, and gating stage. *Id.* at 488.

During the hearing, Public Staff witness Metz testified that the Revenue Requirement Stipulation included a commitment between the Public Staff and DEC to work on a project documentation framework for MYRP projects in future rate cases, as first mentioned above. Tr. vol. 12, 983-5. He agreed with counsel for DEC that the goal of that commitment in the Revenue Requirement Stipulation is to develop an agreed upon structure for making the audit process of MYRP projects more efficient. *Id.* at 985. He further agreed that he felt reasonably comfortable that DEC and the Public Staff can come up with an efficient structure for review of project documentation that will aid the Public Staff in its review in future MYRP cases. *Id.*

Paragraph 42 of the Revenue Requirement Stipulation requires DEC to work with the Public Staff before filing its next PBR application to attempt to establish agreed-upon MYRP project documentation guidelines.

Section III, Paragraph 34 of the Revenue Requirement Stipulation provides that the projected MYRP capital should be reduced by $351 million on a system basis in connection with the Public's Staff's disallowance based on the Public Staff's contention of insufficient project documentation. Tr. Ex. vol. 7. No intervenor took issue with these provisions of the Revenue Requirement Stipulation. The Commission concludes that the Revenue Requirement Stipulation provides a reasonable resolution of these issues for purposes of this proceeding.

MYRP Project Contingency

In his testimony, Public Staff witness Metz recommended the Commission reduce DEC's project contingency by half for all projects not identified for removal by the Public Staff by the appropriate rate year. Tr. vol. 12, 914-15. Witness Metz testified that DEC provided a detailed list, by project, of total project contingency costs. Witness Metz noted that each project type had a different percentage of contingency costs applied. *Id.* at 913. He explained that the Public Staff's recommended adjustment would include project contingencies in rates for prospective years, which would incentivize DEC to complete projects at or under budget. *Id.* at 915.

DEC witness Murray addressed witness Metz's contingency recommendation. Witness Murray testified that the projects included in DEC's MYRP include contingency amounts that are prudent and in line with industry practice and noted that contingency only represents 9.91% of DEC's total planned project spend. *Id.* at 490. Witness Murray also testified that DEC's Project Management Centers of Excellence (PMCoE) provides guidance on project contingency and contingency levels are set for each project based specific execution risks and vary based on the project development timeline. *Id.* at 490-91.

Section III.35 of the Revenue Requirement Stipulation provides that DEC will reduce its total contingency amounts included in the MYRP by 50%. Tr. Ex. vol. 7. No intervenor took issue with this provision of the Revenue Requirement Stipulation, which is consistent with the DEP Rate Case Order. The Commission concludes that the Revenue Requirement Stipulation provides a reasonable resolution of this issue for purposes of this proceeding.

AFUDC

Public Staff witnesses Zhang and Boswell testified that DEC appeared to include AFUDC as part of its costs for MYRP projects. Tr. vol. 12, 1048. They expressed concern that DEC may recover AFUDC while simultaneously recovering capital costs from customers. *Id.* at 1047. Witnesses Zhang and Boswell recommended removal of DEC's AFUDC for MYRP projects and requested that DEC provide in its rebuttal testimony 1) its methodology and supporting calculations for AFUDC included in projects; 2) a detailed description of how DEC calculated AFUDC amounts for each MYRP project, including how DEC accounted for the recovery of projects in given Rate Years; and 3) supporting workpapers for accrual amounts for each project. *Id.* at 1048-49.

DEC witness Abernathy clarified that DEC's MYRP estimates include an amount of AFUDC that is expected to accrue on each capital project from the project start date until the in-service date. Tr. vol. 16, 221. Witness Abernathy explained that there is no overlap of the AFUDC accrual, and the return is included in DEC's revenue requirement calculation because the revenue requirement calculation starts with the in-service date and is based on the total balance projected to be placed in-service. *Id.* at 222.

Section III.36 of the Revenue Requirement Stipulation provides that DEC's AFUDC calculation will be included in the MYRP. 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.

Installation O&M

In her direct testimony, DEC witness Abernathy testified that DEC included one-time, incremental O&M costs in the revenue requirement calculation. Tr. vol. 12, 93. Witness Abernathy explained that these costs, provided by the respective operations witnesses, flow through the revenue requirement calculation according to the date of the one-time O&M expense, not a project's in-service date. *Id.*

Public Staff witness Metz recommended removal of all DEC's one-time, incremental O&M expenses from the MYRP. *Id.* at 922. Witness Metz stated that the test year also included a level of O&M expenses associated with the completion of capital projects, and he expressed concern that DEC overestimated its level of one-time O&M. *Id.* at 918-19.

In her rebuttal testimony, DEC witness Bateman responded to witness Metz's recommendation. Witness Bateman testified that the Public Staff's proposal seeks to adjust test year expenses in a manner that is neither authorized by the PBR Statute nor consistent with the Commission's rules. Tr. vol. 16, 255-57. Witness Bateman explained that as some test year costs will decrease, others will increase, and that it is on DEC to balance non-MYRP impacts. *Id.* at 257.

Section III, Paragraph 37 of the Revenue Requirement Stipulation provides that 50% of corrected, one-time installation O&M should be removed from the MYRP revenue requirement. 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.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 28-29

Reporting Requirements

The evidence supporting this finding is in the verified Application and Form E-1, the testimony and exhibits of DEC witnesses Maley, Guyton, Abernathy and Byrd, the testimony and exhibits of Public Staff witnesses Metz, Thomas, T. Williamson, Lawrence, and Nader, the Revenue Requirement Stipulation, and the entire record in this proceeding.

AFUDC on MYRP Capital Projects Reporting

In her Settlement Testimony, DEC witness Abernathy explained that the Revenue Requirement Stipulation provides that the DEC-calculated AFUDC is included in the MYRP, subject to reporting obligations agreed to with the Public Staff. Tr. vol. 12, 135. These reporting requirements were included in the Revenue Requirement Stipulation.

EV Reporting

In his testimony, Public Staff witness Lawrence recommended the following reporting requirements for EV charging stations installed by DEC: 1. Location (site name and address). 2. Installation date. 3. Charging station type (L2, DCFC, etc.). 4. Maximum charging station output rating. 5. Capital cost per charging station. 6. Number of uses. 7. Average duration of use. 8. Average energy delivered per use. Tr. vol. 15, 101-2. In addition to this reporting, DEC should also maintain the load profile for each station. DEC should make the first report beginning no later than 180 days after the Commission's final order in this docket and subsequent report every six months thereafter until the Commission's final order in DEC's next rate case. *Id.*

In his rebuttal testimony, DEC witness Guyton stated that DEC agrees in part with the reporting items. He stated items 1-5 are part of the normal project documentation and DEC can provide them. Tr. vol. 8, 218. However, for items 6, 7, and 8, as well as the request of a load profile per station, such reporting items are not achievable. *Id.* DEC witness Guyton explained that charging infrastructure varies in technology and capabilities as well as installation set up. Not all charging stations have the capability to record and transmit number of sessions, time of use, or energy delivered before developing a load profile. *Id.* Further, DEC cannot rely upon meter data to provide an overall look as installation approach varies from site to site. For example, leveraging existing building panel capacity when available to reduce installation costs places charging stations on the building meter. *Id.* At 218-9. In cases where building capacity is not available, a separate transformer and meter specific for the charging stations is installed. However, a separate meter cannot provide individual station data as recommended. *Id.*

Rider ED

In his direct testimony, DEC witness Byrd explained that DEC is proposing a new rider that will improve competitiveness for attracting and retaining customers that are adding jobs and making capital investments in DEC's service territory, Rider ED. Tr. vol. 10, 106. He testified that this new Economic Development Rider, Rider ED, affords greater flexibility to tailor benefits based on both electric grid and regional economic benefits associated with the participant's investment and load characteristics. *Id.*

In his testimony, Public Staff witness Nader stated that DEC's Rider ED adheres to the principals of the Commission's Order Adopting Guidelines for Job Retention Tariffs issued December 8, 2015 in Docket No. E-100, Sub 73. Tr. vol. 13, 766-69. He stated that the Public Staff is reasonably satisfied that the costs and benefits of Rider ED are balanced, fair and in the public interest. *Id.* Public Staff witness Nader recommended that the Commission require annual reporting of the impacts of Rider ED to ensure the rider remains in the Public Interest. *Id.* at 769. At a minimum, he testified that DEC 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 ED to determine if the gross level of incentives paid exceeds the marginal cost to serve the gross pool of participants. *Id.*

In his rebuttal testimony, DEC witness Byrd testified that within certain limits, DEC agrees that some annual reporting is reasonable with respect to the impacts of Rider ED. Tr. vol. 10, 214. For example, DEC could report on the total number of jobs, total capital investment, or other such characteristics contained in the applications for customers currently taking service under Rider ED, provided such information can be appropriately anonymized to preserve confidentiality. *Id.*

CIAC Reporting

In their joint direct testimony, Public Staff witnesses Zhang and Boswell stated that DEC was booking contributions in aid of construction (CIAC) related to interconnection agreements (IA) inconsistently. Witnesses Zhang and Boswell recommended that the Commission order DEC to review its CIAC policy to ensure that DEC properly accounts for CIAC and report the results of that review in the next general rate case. Tr. vol. 12, 1005-6. In rebuttal, DEC witness Speros testified in opposition to the Public Staff's contention that DEC was booking its CIAC related to IAs inconsistently but stated that DEC did not oppose in principle reporting to the Commission on its CIAC policy in the next general rate case. Tr. vol. 13, 545-50.

Quarterly Reliability Reporting

In his testimony, Public Staff witness T. Williamson recommended the Commission require DEC to include the number of Major Event Days (MEDs) and non-MEDs that DEC experiences during a reporting period in its quarterly reliability report filed in Docket No. E-100, Sub 138A. Tr. vol. 15, 171.

In his rebuttal testimony, DEC witness Guyton testified that DEC agreed to add the information requested by Public Staff witness T. Williamson to its quarterly reports. Tr. vol. 8, 239.

Vegetation Management Reporting Requirement

In his testimony, Public Staff witness T. Williamson recommended the Commission extend DECs vegetation management-related semi-annual filing requirement that is already in effect through the end of DEC's proposed MYRP period, aligning with DEP's report sunset in 2026. Tr. vol. 15, 149-50. He also recommended the Commission require DEC to include additional metrics in its semi-annual Vegetation Management Program Performance report. Witness T. Williamson's recommended additions included the following for distribution-related vegetation management reporting: (1) for distribution vegetation management herbicide, add actuals, target, and variance for spending and miles; (2) for distribution vegetation management Hazard Tree Programs, add actuals for spending and tree counts; and, (3) for distribution vegetation management reactive/demand events, add the number of events worked annually. Tr. vol. 15, 150-51. In his rebuttal testimony, DEC witness Guyton agreed with these reporting requirements. Tr. vol. 8, 202.

In addition, Public Staff witness T. Williamson recommended the Commission require the following changes to DEC's report on its Vegetation Management Performance filed semi-annually in the 2019 Rate Case docket: (1) for Transmission vegetation management trimming, add actuals, target, and variance for spending and miles; (2) for Transmission vegetation herbicide, add actuals, target, and variance for spending and miles; (3) for Transmission vegetation management hazard tree programs, add actuals for spending and tree counts for removal; (4) for Transmission vegetation management reactive/demand events, add the number of events worked annually. Tr. vol. 15, 150-51.

In his rebuttal testimony, witness Maley stated that DEC did not take issue with these reporting requirements, subject to two clarifications, those being that (1) the Transmission vegetation management trimming program focuses on removal as the primary function, and that DEC interprets this reporting requirement as requesting the O&M portions of planned corridor work, and (2) that Transmission vegetation herbicide is tracked as the amount of vegetation sprayed in acres as opposed to miles due to varying corridor widths and shared corridors, and that DEC therefore proposes to report by acres rather than miles. Tr. vol. 8, at 354.

Discussion and Conclusions

The Revenue Requirement Stipulation establishes certain reporting obligations. Specifically, in Paragraph 43, DEC agrees to track and report on AFUDC accrued on MYRP capital projects and for the Public Staff and DEC to discuss the scope and content of such reporting. In Paragraph 44, DEC agrees to report the EV reporting requirements discussed by Public Staff witness Lawrence, but to further discuss with the Public Staff those items noted by DEC witness Guyton as unfeasible, with the understanding that those items will be reported by DEC when doing so becomes possible. Paragraph 45 obligates DEC to report on Rider ED, subject to agreement of the Revenue Requirement stipulating parties regarding the scope and content of the report. Paragraph 46 obligates DEC to report on the CIAC issue in its next general rate case application. Paragraph 47 addresses a reporting on reliability O&M as discussed by Public Staff witness Metz and above in this Order, and Paragraph 48 obligates DEC to report on certain Vegetation Management reporting requirements as discussed by Public Staff witness T. Williamson, except for reporting on the two issues noted in the rebuttal testimony of DEP witness Maley. Additionally, witness Guyton agreed to add information to DEC’s reliability reporting.

No other party offered any evidence addressing the reporting obligations outlined in the Revenue Requirement Stipulation or addressed above. The Commission concludes that the reporting obligations agreed-upon in § IV of the Revenue Requirement Stipulation and addressed above 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 § IV of the Revenue Requirement Stipulation are approved, as well as the additional reporting requirement addressed herein.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 30

Storm Normalization

The evidence supporting this finding of fact is in DEC’s verified Application and Form E-1; the testimony and exhibits of DEC witness Q. Bowman; and the entire record in this proceeding.

In prior DEC rate cases, including Docket Nos. E-7, Sub 1026, E-7, Sub 1146, and E-7, Sub 1214, 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 Q. Bowman 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 DEC's calculation is approximately $32.225 million. Q. Bowman Supplemental Partial Settlement Ex. 4, Tr. Ex. vol. 12.

No party disputes DEC's methodology for calculation of storm normal expenses to include in rates, and DEC witness Q. Bowman testified that the Public Staff's calculation is consistent with the methodology used by DEC. Tr. vol. 15, 1276.

Accordingly, the Commission finds that the appropriate North Carolina retail normalized annual level of storm costs to include in DEC's rates in this case is $32.225 million.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 31-32

Payment Navigator

The evidence supporting this finding is in the verified Application; the Revenue Requirement Stipulation, the testimony and exhibits of DEC witnesses Q. Bowman and Quick; and the entire record in this proceeding.

In her direct testimony, DEC witness Q. Bowman stated that DEC 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 DEC witnesses Harris and Quick also discussed in their testimony. If the Commission approves each program, DEC 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. 12, 191-92.

DEC witness Quick described DEC'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, 130-31. Consistent with DEC's Affordability Ecosystem, witness Quick requested approval of the Payment Navigator program, which DEC 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 133. The Payment Navigator program is based on a pilot that DEC tested with customers seeking support in paying their electric bills. *Id*. at 133-34. As witness Quick described, in accordance with the Payment Navigator program, DEC 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.* 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 134.

DEC witness Quick also testified that Payment Navigator would complement the CAP that DEC 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, DEC 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. *Id.* at 135-36.

Witness Quick concluded by requesting that the Commission approve the Payment Navigator program and associated costs, which she estimated to be $4 million over the next three years. She noted that the deferral request that DEC witness Q. Bowman describes in her testimony addresses the associated incremental O&M costs that the $4 million estimate includes. Witness Quick testified that DEC would not defer any capital costs associated with the program. *Id*. at 136.

No party contested the implementation of the Payment Navigator program.

Customer Connect

In its Application, DEC requested recovery of the approximately $92 million North Carolina retail allocated capital investment associated with implementation of its Customer Connect project, the new customer engagement platform, and CIS. Tr. vol. 12, 407, 417. DEC witness Hunsicker testified that in November 2021, DEC implemented the Customer Connect platform including a CIS, which is a system that manages the billing, accounts receivable, and rates for DEC as a central repository for all customer information. *Id.* at 407-08. She explained that a 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. A 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 408-09. Witness Hunsicker explained that DEC 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 407.

Witness Hunsicker explained that Customer Connect benefits customers by providing a modern, configurable billing system that allows DEC 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 DEC 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, DEC 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 408.

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

Discussion and Conclusions

No parties opposed DEC's requests related to 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 DEC has met its burden of showing that its proposals related to Payment Navigator and Customer Connect are just and reasonable.

Further, the Commission concludes that DEC'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 DEC 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 DEC (and its affiliates) apply their specialized knowledge and resources in direct support of the customers. The Commission encourages DEC 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. 33

COSS Stipulation

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

Summary of Evidence DEC Direct Testimony

Cost of Service Study Overview

In her testimony, DEC 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 DEC in the test period with the jurisdictions and customer classes responsible for those costs. Tr. vol. 12, 344. Using the principle of cost causation, the COSS assigns or allocates DEC's revenues, expenses, and rate base to the regulatory jurisdictions and to customer classes that caused such costs to be incurred. *Id.* at 344-45. Costs are first grouped according to their function. *Id.* at 346. 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 346–47. Once all costs and revenues are assigned, the COSS identifies the return on investment that DEC has earned for each customer class during the test period, and these returns can then guide rate design. *Id.* at 345.

The COSS Stipulation

On September 13, 2022, DEC, DEP, the Public Staff, CIGFUR II, and CIGFUR (the COSS Stipulating Parties) filed the COSS Stipulation with the Commission. Tr. vol. 12, 342. 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, DEC 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 DEC cases. *Id.* DEC 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 342–43. The COSS Stipulating Parties urge the adoption of the stipulation in this case as a fair and reasonable methodology for the allocation of costs. 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. Tr. Ex. vol. 7. Witness Hager testified that in its previous rate case, DEC recommended, and the Commission approved, the summer coincident peak (Summer CP) method to allocate the fixed portion of production and transmission demand-related costs. Tr. vol. 12, 351. However, DEC 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 DEC'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. *Id.* at 351–52. 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 352.

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. Tr. Ex. vol. 7. DEC 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. 12, 358. The excess demand is the excess of a rate class's 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 358. A rate class's coincident peak demand is the class's load at the time of the system's peak demand, while a rate class's NCP is the maximum demand regardless of the time of occurrence. *Id.* Witness Hager explained that each customer class's non-coincident demand likely occurs at different times. *Id.* She noted that the A&E method is a commonly accepted method of allocating demand-related production costs used in several jurisdictions and is a reasonable method for allocating demand-related production costs to the North Carolina retail classes in this case. *Id.* at 359. However, DEC modified the method to conform the A&E allocators to the 12 CP method used at the North Carolina retail jurisdictional level. *Id.*

Removal of Certain Curtailable/Interruptible Loads

DEC witness Hager testified that, historically, DEC has allocated production fixed costs based on the demands served at its peak hour. *Id.* at 360. 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.* DEC does not plan for, and does not purchase capacity for, the curtailable load of customers. *Id.* Since DEC 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.* at 360–61. Accordingly, DEC has removed non-curtailed non-firm load present during the test year peaks where its presence would create a mismatch with revenues. *Id.* at 361. 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 363.

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.* The demand-related transmission costs were allocated to rate classes based on 12 CP demand, without adjustment for curtailable load. *Id.*

Distribution Costs

DEC witness Hager testified that most distribution investments are identified and then directly assigned to the state in which they are located. *Id*. at 363. 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.* at 364. 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.*

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.* 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

DEC 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 365. She testified that these costs are allocated using DEC'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

DEC 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. 12, 365. DEC 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.* at 365–66.

While DEC had no battery storage units in plant-in service in the 2021 test year, DEC projections for the MYRP years include the costs to install battery storage facilities. *Id.* at 366. DEC witness Hager testified that storage battery equipment functionalized to production (FERC Account 348) is allocated across customer classes using the production demand allocator. Battery storage equipment that is 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 electrical 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 366. 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.* at 367. 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 DEC incorporated the Minimum System Method into its COSS and testified that this was appropriate for the allocation of customer-related distribution costs. *Id.* She explained that the Zero-Intercept Method is a more complex and time-consuming methodology. *Id.* 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.* DEC's Minimum System Study allowed DEC to classify the distribution system into customer- related and demand-related portions. *Id.* at 367–68. She testified that because every customer requires some minimum amount of wires, poles, and other distribution infrastructure, every customer "causes" DEC to install some amount of distribution assets. *Id.* at 368. The concept used by DEC 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 DEC 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 368–69.

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. 12, 739. The Sub 1214 Partial Settlement provided for an analysis of various cost of service methodologies in which DEC and DEP 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 DEC filed its next rate case. *Id.* at 739–40. As witness McLawhorn described, the stakeholders met several times throughout 2021, holding the final meeting on November 16, 2021. *Id.* at 740. On January 25, 2022, DEC and DEP filed the results of the COSS in Docket Nos. E-2, Sub 1219 and E-7, Sub 1214, as the Commission required. *Id.* 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 DEC's base rate charges will reflect the requested revenue requirement changes. Tr. vol. 13, 16. 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 34–35. 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 38. In sum, witness D. Williamson recommended approval of the COSS Stipulation and DEC's use of the methodologies to which the parties agreed in the COSS Stipulation. *Id.* at 51.

CIGFUR Testimony

CIGFUR witness Collins filed testimony in support of the COSS Stipulation. Witness Collins testified that the COSS Stipulation is reasonable and that the Commission should approve it in its entirety. Tr. vol. 15, 957. Witness Collins 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 951–52, 957. Witness Collins further testified that DEC 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 952. Witness Collins additionally testified about the relation between the excess component of the A&E method as it relates to additional capacity requirements. *Id.* at 960.

CUCA Testimony

CUCA is not a party to the COSS Stipulation and was not involved in the settlement negotiations. Tr. vol. 15, 444. Witness Pollock testified that he disagreed with the use of the A&E method for allocation of production plant and related expenses and the 12 CP method for allocation of transmission plant and related expenses because DEC has been, and will continue to be, a summer-peaking utility. *Id.* Nevertheless, CUCA witness Pollock testified that CUCA was accepting the results of DEC's COSS consistent with the COSS Stipulation for the purpose of this proceeding only. Tr. vol. 15, 444.

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 DEC's proposed production capacity cost allocation methodology. Tr. vol. 15, 1010, 1020.

Discussion and Conclusions

Although the COSS Stipulation is not unanimous, no other party to this proceeding has proposed an alternative cost of service methodology. The Commission notes that the methodology laid out in the COSS Stipulation was approved for use by DEP in Docket No. E-2, Sub 1300.

Based upon the evidence presented in this case, including the evidence offered in support of the stipulation 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 DEC as well as the A&E method applied in South Carolina. Therefore, the Commission directs DEC to provide a more detailed justification for the use of an NCP demand over a coincident peak demand for any cost allocation purpose in future rate cases.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 34

TCA Stipulation

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

As explained by DEC witness Maley, the Red Zone Expansion Plan transmission projects (RZEP Projects) included in DEC's MYRP consist of transmission upgrades needed to enable interconnection of additional solar generation on the DEC transmission system. Tr. vol. 8, 294-96. DEC witness Abernathy testified as to the revenue requirement sought by DEC for the RZEP Projects, which involved allocation of all RZEP costs to DEC. 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, DEC 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. 12, 97-99. Witness Abernathy testified that DEC 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.*

While the Public Staff found merit in DEC's alternative proposal, Public Staff witness Metz recommended a different proposal that focused on the net energy transfers between DEP and DEC. Tr. vol. 12, 864-67. Public Staff witness Metz explained that the Public Staff's alternative proposal utilizes the non-firm transmission rate from the FERC-approved OATT of DEC, DEF, and DEP, which incorporates capital and ongoing O&M costs of the DEC and DEP transmission systems. He testified that DEC'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.*

DEC, 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 instant proceeding and a corresponding decrease to the revenue requirement in the DEP Rate Case.

DEC, 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 DEF. 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 DEC or DEP. The TCA Stipulation provides that the adjustment will become effective on October 31, 2023, for both DEC and DEP and will terminate at the sooner of the effective date of rates in DEC's or DEP's next general rate case or the effective date of a full merger of DEC and DEP, unless the Commission orders otherwise. TCA Stipulation § II, Tr. vol. 7, 23.

DEC witness Bateman testified in support of the TCA Stipulation. Tr. vol. 11, 212. 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.* at 214. In her supplemental direct testimony, DEC witness Abernathy also supported the update to the RZEP Alternative Allocation Method, consistent with the TCA Stipulation. Tr. vol. 12, 122.

At the evidentiary hearing, DEC witness Bateman explained that the TCA Stipulation was agreed to by DEC, DEP, and the Public Staff to address concerns of cross subsidization and rate disparity between DEP and DEC. Tr. vol. 11, 231. DEC witness Bateman testified that the TCA Stipulation supports that goal and results in rate that are just and reasonable and that reduce cross subsidization. *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. The Commission notes that this holding is consistent with our decision on this issue in the recent DEP Rate Case Order. 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 DEC's Application in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING FOR FACT NO. 35

PIMs Stipulation

The evidence supporting these findings and conclusions is contained in DEC's verified Application and Form E-1; the testimony and exhibits of DEC witnesses Bateman and Stillman, Public Staff witnesses D. Williamson and Thomas, AGO witness Balakumar, NCJC et al. witness Wilson, CUCA witness Pollock, and CIGFUR witness Collins; the PIMs Stipulation; and the entire record in this proceeding.

PIMs

DEC 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. 11, 162-70.

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

The Company testified that the Low-Income/Affordability PIM provided incentives for DEC 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.*

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

DEC testified that the Renewables Integration and Encouragement PIM involved three metrics to incent and reward DEC. The Distributed Energy Resource (DER) Integration Metric A provided graduated rewards to DEC for exceeding targets for the number of net-metered DER customers interconnected to the DEC system. *Id.* at 168. The Large Customer Renewable Program Encouragement Metric B provided an incentive for DEC 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 169. The Residential Customer Shared Solar Program Encouragement Metric C encouraged DEC to subscribe residential customers to new shared solar programs. *Id.* at 170.

In addition to the PIMs, DEC explained that it was proposing 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 184. 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 184-85. Finally, the third metric proposed to report on incremental load from EVs. *Id.* at 185.

In supplemental testimony filed by the PBR Policy Panel on May 19, 2023, DEC witnesses Bateman and Stillman withdrew DEC's Low-Income/Affordability PIM. Tr. vol. 11, 193.

Public Staff witnesses D. Williamson and Thomas expressed concerns with each PIM, beginning with the metric DEC proposed in the Peak Load Reduction PIM. Tr. vol. 14, 287. The Public Staff testified that 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 DEC's footprint. The Public Staff noted that DEC'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.*

Regarding the Reliability PIM, which targets reliability by tracking DEC's SAIDI score, the Public Staff expressed support for the Reliability PIM as revised by DEC witnesses Bateman and Stillman's May 19, 2023 supplemental testimony. Public Staff testified to their concern with the Reliability PIM as originally filed, explaining that the benchmarking for the tiered performance structure proposed by DEC was based on five years of historical SAIDI data and 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 included data that was collected before DEC's GIP investments were placed into service. *Id.* at 290-91. The Public Staff acknowledged that the Revised Reliability PIM addressed these concerns. *Id.* at 291.

Finally, the Public Staff testified as to concerns with the Renewables Integration and Encouragement PIM. *Id.* at 291-94. With respect to Metric A, the Public Staff testified that DEC's revised incentive tier structure that incorporates a three-year rolling average of net metered interconnections measured in each Rate Year of the MYRP alleviated the Public Staff's concerns. The Public Staff explained that Net Energy Metering (NEM) adoption is largely outside of DEC'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 DEC 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 291-92.

With respect to Metrics B and C, the Public Staff expressed concerns that DEC 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 DEC 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 Metrics B and C are based are linked to new programs and there is therefore insufficient data for determining whether a financial incentive is necessary. *Id.* at 293-94.

The Public Staff proposed two modified PIMs in response to the PIMs DEC proposed. The Public Staff proposed a Time-Of-Use Enrollment PIM and a Renewable Interconnections PIM, which involve a modification to DEC's proposed Peak Load Reduction PIM and a new PIM proposal, respectively. *Id*. at 294.

CIGFUR witness Collins' direct testimony expressed concern regarding DEC's proposed Reliability PIM. Tr. vol. 15, 986. Witness Collins 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.*at 987.

AGO witness Balakumar proposed a Carbon Reduction PIM as an alternative to Metrics B and C of the Renewables and Integration PIM. *Id.* at 292. Witness Balakumar expressed concern that the PIMs Stipulation does not incentivize DEC to lower emissions at least cost. *Id*. at 292-93.

NCJC, et al. witness Wilson proposed a conceptual fuel cost PIM. Tr. vol. 15, 919-25. Witness Wilson's proposed fuel cost PIM would attempt to manage and reduce fuel costs and volatility and incent DEC to reduce its reliance on fuel over time. *Id*. at 924.

CUCA witness Pollock proposed a rate competitiveness PIM. Tr. vol. 15, 438-41. Witness Pollock's proposed rate competitiveness PIM would reward or penalize DEC for changes in the competitive ranking of its electric service rates as compared to peer utilities in the Southeast region. *Id.* at 438. Witness Pollock testified that the PIM would address all of the costs that directly impact electricity rates and not simply fuel. *Id.* at 441.

DEC 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 DEC to independently reduce its CO2 emissions by 70.0%. Tr. vol. 16, 306-307. In addition, DEC witness Stillman noted a number of concerns with a Carbon Reduction PIM in his rebuttal testimony, namely that it is inconsistent with S.L. 2021-165. *Id.* at 304-305.

DEC, the Public Staff, and CIGFUR resolved their differences of opinion on PIMs proposed in this proceeding, for the purpose of settlement, in the PIMs Stipulation. PIMs Stipulation, Tr. vol. 7, 23.

DEC's PBR Policy Panel provided testimony in support of the PIMs Stipulation. Tr. vol. 11, 198. The PBR Policy Panel testified that the resolution reached with the Public Staff and CIGFUR represents a balanced approach to achieving policy goals in DEC's first PBR Application. *Id.* at 201. DEC witness Stillman testified as to how the settled PIMs originated from the NERP PBR Working Group, were informed by DEC's prefiling PIM stakeholder process, and evolved over discussions with the stipulating parties. *Id*. at 200. DEC witness Stillman explained DEC's approach to designing the PIMs around the 1.0% cap in N.C.G.S. § 62-133.16 and stated that DEC deliberately chose only a select number of PIMs that meet the maximum number of policy goals. Tr. vol. 16, 271.

Public Staff witnesses D. Williamson and Thomas also provided testimony in support of the PIMs Stipulation. Tr. vol. 14, 314-15. 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. *Id.* at 318. 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 PIMs Stipulation contains 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. 7.

Time Differentiated and Dynamic Rate Enrollment PIM

DEC 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 DEC with a $5 incentive for every new customer enrolled in an eligible program. Tr. vol. 11, 202-203. Witness Stillman testified that this PIM targets and advances operational efficiency and cost savings and encourages DEC to design and seek approval of dynamic and time-differentiated rate designs. *Id*. 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 DEC and 70.0% to customers. *Id.* at 189.

At the expert witness hearing, witness Stillman further explained that the purpose behind this PIM is to encourage DEC to expand the use of TOU rates to help address peak load growth. *Id.* at 260-63. This PIM should encourage customers to adapt to new rate designs and subsequently shift their usage from high to low usage periods. *Id.* at 260. Witness Stillman testified that current subscribership to these programs is low so one of the purposes behind this PIM is to encourage more customers to subscribe to TOU programs. *Id.* at 165. 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 DEC will conduct a broader Evaluation, Measurement, and Verification study on system benefits once there is sufficient participation in DEC's TOU rate schedules to achieve statistical significance. Tr. vol. 16, 278.

Reliability PIM

DEC witness Stillman offered direct settlement testimony in support of DEC'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. 11, 203-204. DEC's Reliability PIM would be measured by SAIDI, excluding MEDS. As originally proposed, DEC's Reliability

PIM provided for graduated penalties based on DEC'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. *Id.* at 174.

In the PBR Policy Panel's supplemental testimony, witness Stillman presented a revised metric for the Reliability PIM that accounts for projected SAIDI improvement during the MYRP period due to expected grid investments. *Id.* at 192-93.

Renewables Integration and Encouragement PIM

DEC witness Stillman testified that DEC designed Metric A of the Renewables Integration and Encouragement PIM to incent rooftop solar and to provide DEC with an incentive to determine the most effective way to encourage adoption. *Id.* at 168-69. 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. *Id.* at 205. Metric A would provide an incentive of up to $6 million to DEC if the number of net metered interconnections for each rate year exceeds the applicable preceding three-year rolling average by at least 25.0%. *Id.* at 176-77.

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. *Id.* at 169; Tr. vol. 16, 288-89. 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. 11, 169. DEC witness Stillman testified that the only difference between Metric B as proposed by DEC and finalized in the PIMs Stipulation is the revised incentive tiers. *Id.* at 199.

Metric C of the Renewables Integration and Encouragement PIM in the PIMs Stipulation is based on the recommendations of the Public Staff. Metric C addresses utility-scale interconnections and is designed to increase operational efficiency by incentivizing interconnections above DEC's estimated annual limits. Tr. vol. 11, 206. This PIM includes incentive tiers and minimum MW thresholds for utility-scale interconnections for each MYRP rate year. *Id*. The Public Staff explained that Metric C's performance thresholds were revised to correspond with the most recent data provided in the 2023-2024 Carbon Plan and Integrated Resource Plan, filed in Docket No. E-100, Sub 190 on August 17, 2023. Tr. vol. 14, 316.

Tracking Metrics

DEC witness Stillman provided direct testimony stating that DEC 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 DEC's progress in furthering important policy goals. He further stated that tracking metrics can provide useful information in evaluating potential future PIMs. Tr. vol. 11, 158.

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 DEC proposed in its initial testimony. DEC witness Stillman testified that under the customer service tracking metric DEC 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. 11, 208*.* Witness Stillman testified that this tracking metric is appropriate because customers often communicate with DEC 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 beneficial electrification of EVs, as DEC initially proposed. Witness Stillman explained that this metric requires DEC to report beneficial electrification from estimated incremental load from EVs and that it will provide data in an area of material public policy interest. *Id.*at 208-209.

The third tracking metric in the PIMs Stipulation requires DEC to provide an annual Circuit Performance Report that identifies ten circuits with the worst combined score of SAIDI, SAIFI, and CAIDI and include an analysis of the cause of each circuit's performance. *Id.* at 209. DEC witness Stillman testified that this tracking metric will provide information and analysis that supports the importance of DEC's reliability to its customers and to DEC *Id.*

Discussion and Conclusions

Upon review of the testimony of DEC, the Public Staff, and CIGFUR witness Collins regarding the PIMs Stipulation, the Commission concludes that the PIMs Stipulation is the product of give-and-take negotiations between DEC, CIGFUR, and the Public Staff to achieve PIMs and tracking metrics that are consistent with N.C.G.S. § 62-133.16 and that it strikes 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 annual Circuit Performance Report 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 second PBR application considered by the Commission and, therefore, the second 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 will provide meaningful operational and financial benefits to customers. Therefore, the Commission concludes that the PIMs Stipulation is entitled to substantial weight and that the PIMs and tracking metrics set forth in the PIMs Stipulation should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 36

Power Quality Stipulation

[ ].

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

Affordability Stipulation/CAP

The evidence supporting these findings of fact is in DEC's verified Application and Form E-1; the testimony and exhibits of DEC witnesses Barnes, Harris, Bateman, Stillman and Quick, Public Staff witness D. Williamson and Thomas; the Affordability Stipulation; and the entire record in this proceeding.

Summary of Evidence

Low-Income/Affordability PIM

DEC's PBR Policy Panel testified in support of DEC's proposed Low-Income/Affordability PIM. Tr. vol. 11, 140, 162. 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 165-66. The PBR Policy Panel testified that the proposed PIM would advance the identified policy goals by providing DEC with an incentive to promote voluntary contributions to the Share the Light Fund. *Id.* at 166. However, pursuant to the Affordability Stipulation filed with the Commission on May 4, 2023, DEC formally withdrew its proposal for a Low-Income Affordability PIM. *Id.* at 75-76. The parties to this Stipulation include DEC, DEP, Sierra Club, NCJC et al., and the Public Staff

Public Staff witnesses Thomas and D. Williamson testified that the Public Staff was a party to the Affordability Stipulation and supports DEC's withdrawal of the Low-Income/Affordability PIM. Tr. vol. 14, 282.

Customer Assistance Program

In its Application, DEC requested approval of the CAP and two new tariffs, the CAP Rider and the Customer Assistance Recovery Rider (CAR Rider). DEC witnesses Harris and Quick provided testimony addressing the CAP proposal. DEC witness Quick described DEC's Affordability Ecosystem as a multi-pronged approach to assist customers who face electric utility bill affordability challenges. Tr. vol. 7, 130. Witness

Quick explained that bill payment assistance represents one product or service that can be used as part of the Affordability Ecosystem. *Id* at 130–131. Witness Quick further testified that the CAP program proposal will be a critical component in the Affordability Ecosystem. *Id.* at 131.

Witness Harris testified that the CAP proposal, initially developed as part of the Low-Income Affordability Collaborative (LIAC), is designed to assist low-income customers who face affordability challenges. Witness Harris described the program structure, framework, and reasoning behind the program. Tr. vol. 11, 114–17. Under the CAP, eligible customers would automatically receive a $42 monthly bill credit for a 12-month period. *Id.* at 115.

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. Tr. vol. 11, 115. DEC would automatically enroll eligible customers into CAP using a list of customers provided by the North Carolina Department of Health and Human Services (DHHS). *Id.* at 119. Moreover, DEC could re-enroll customers in CAP for another twelve bill cycles if they are re-certified as LIEAP or CIP eligible after expiration of the initial enrollment. *Id.* at 125.

Witness Harris testified that in addition to the $42 bill credit on their next twelve monthly bills, DEC will also refer CAP customers to other income-qualified weatherization and energy efficiency services that can assist customers with reducing energy usage. Tr. vol. 11, 114. DEC would spread the costs for the $42 CAP credit among all customer classes, excluding lighting schedules, through the CAR Rider. *Id.* at 121. 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. *Id.* The CAR Rider would have a rolling recovery factor that DEC would true-up annually to reflect the actual amount of CAP credits paid. *Id.* at 117.

Public Staff witness D. Williamson testified that the proposed CAP would provide a direct subsidy to qualifying low-income customers to reduce their electric bills, on the premise that these customers will be more likely to avoid chronic arrears and eventual service disconnection. Tr. vol. 13, 27. Witness Williamson acknowledged that the CAP proposal would create a subsidy from non-participating customers to an estimated 64,000 low-income residential customers. However, witness Williamson highlighted that this Commission has, in the past, found some cross-subsidies to be reasonable when it serves to preserve load and customers for the overall benefit of the utility system. *Id.* at 28. Furthermore, witness Williamson noted that the Commission placed a special focus on affordability issues in the 2019 DEC and DEP rate cases – this was the basis for the LIAC and comprehensive rate design study that produced the CAP proposal. *Id.* at 28-29. Witness Williamson also acknowledged that DEC has attempted to address this cross-subsidy by applying a design principle that customers receiving the CAP should still, on average, pay more than the marginal cost of service. *Id.* at 29. He testified that he reviewed the supporting information on this applied design principle and confirmed that it has modeled the monthly credit to, on average, ensure that CAP recipients will pay an amount above their marginal cost of service. *Id.* Witness Williamson further testified that he believes the Commission continues to have the same level of discretion as it did in the 2019 DEC rate case to determine whether a rate or program offering is just and reasonable and within the public interest, including the ability to determine if a certain level of cross-subsidy is allowable. *Id.* at 29–30.

Affordability Stipulation

On May 4, 2023, DEC, DEP, Sierra Club, NCJC, et al., and the Public Staff filed the Affordability Stipulation. Tr. vol. 11, 74–75. Pursuant to the terms of the Affordability Stipulation, DEC 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. 11, 75–76. In addition, DEC and DEP 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. DEC and DEP will file this data annually in Docket No. M-100, Sub 179. *Id.* at 76. Furthermore, pursuant to the terms of the Affordability Stipulation, DEC would establish its CAP program as a three-year pilot. *Id.* If the Commission approves CAP, DEC agrees to convene a stakeholder engagement process to consider CAP data, metrics, and future CAP program features. *Id.* at 77. The Affordability Panel of DEC witnesses Harris, Barnes, and Quick and Public Staff witness D. Williamson each provided testimony supporting the Affordability Stipulation. Tr. vol. 11, 71-78; Tr. vol. 13, 31–33.

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 DEC witnesses Harris, Barnes, and Quick, and Public Staff witness D. Williamson regarding the Affordability Stipulation and DEC's CAP proposal. As Public Staff witness D. Williamson and DEC witness Harris highlighted in their testimony, the Commission has broad authority to set rates in the public interest. Tr. vol. 13, 30; Tr. vol. 11, 85-86, 94. 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 DEC 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 DEC 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 DEC 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, DEC, 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 DEC 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 DEC 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. DEC 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.

DEC 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, DEC and DEP 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.

Specifically, DEC shall seek to procure from the Commission any waivers necessary or required to obtain or provide the zip code-related data set forth in this Order, in addition to any zip code level data necessary or required to comply with the directives outlined in this Order.

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, DEC 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. DEC 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. As mentioned above regarding zip code level data, DEC shall seek from the Commission any waivers necessary or required to design a tiered customer assistance program.

Tracking Metrics

The Commission further finds that in order to inform future PIMs, DEC 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. 39-45

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EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 46-48

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EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 49-53

[ ]

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NO. 54

Storm Balancing Account

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

Summary of Evidence

DEC witness Q. Bowman testified as to DEC's request for approval of a new methodology for tracking storm costs incurred. Tr. vol. 12, 192. Witness Q. Bowman explained that Adjustment NC7010 establishes an average amount of incremental storm costs included in customer rates. *Id.* Witness Q. Bowman testified that under DEC's proposal, each year, if the incremental storm expenses are over the average amount in rates, the difference would be deferred to a "storm balancing 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*. Witness Q. Bowman testified that the storm balancing account would allow DEC to recover its actual costs for storm restoration efforts and ensure that DEC does not make or lose money related to its storm restoration efforts. *Id.*

Public Staff witnesses Zhang and Boswell disagreed with DEC's proposal to create a storm balancing account and stated that creating such an account would only serve to transfer all risk from DEC to ratepayers, including placing unaudited costs into a deferral for recovery. *Id.* at 1021-23. The Public Staff stated that DEC already has ample opportunities to recover storm costs, whether that be through storm normalization, securitization, or deferrals, all of which may allow DEC to reasonably and appropriately recover actual audited storm costs. *Id.* at 1022.

DEC witness Q. Bowman testified on rebuttal that the Public Staff accurately summarized DEC's intent in proposing the storm balancing account. Tr. vol. 15, 1277. Witness Q. Bowman explained that the Commission should implement a mechanism that results in DEC's neither making nor losing money because of storm restoration efforts. *Id.* Witness Q. Bowman 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 1278. Witness Q. Bowman testified that the base level of storm expense that must be exceeded before DEC can request deferral has in practice been inequitable to DEC 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.* Witness Q. Bowman stated that it is DEC'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.* at 1279.

Witness Q. Bowman 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 1280. Witness Q. Bowman 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.*

Discussion and Conclusions

In Section III.40.e of the Revenue Requirement Stipulation, DEC agreed to withdraw its request for a storm balancing account in this proceeding. 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 FINDINGS OF FACT NOS. 55-57

The evidence supporting these findings of fact is contained in DEC's verified Application and Form E-1; the testimony and exhibits of DEC witnesses Abernathy, Bateman and Stillman, Q. Bowman, Panizza, and Klein, Public Staff witnesses Zhang and Boswell; the Revenue Requirement Stipulation; and the entire record in this proceeding.

IIJA/IRA

By Application and through the direct testimony of witness Abernathy, DEC requests to defer the estimated tax benefits, net of costs, associated with the IRA and IIJA. Tr. vol. 12, 95-956; Tr. vol. 16, 231.

With respect to the IRA, DEC witness Panizza discussed the solar MYRP project and the 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. 12, 507. Witness Abernathy explained how DEC estimated the IRA benefits based on the best information available and that DEC's intention is for customers to receive the full benefit (net of costs) of the tax credits. *Id.* at 95-96.

Public Staff accounting panel witnesses Boswell and Zhang testified in support of the requested deferral treatment of the IRA impacts. Tr. vol. 12, 1049-50. Similarly, Public Staff witness Nader provided testimony recommending that the Commission treat the impacts associated with the IIJA consistent with those related to the IRA. *Id.* at 760.

Regarding the IIJA, DEC witness Klein responded to the Public Staff's recommendations and provided an overview of DEC's approach to identifying and pursuing federal loans and grants that may be available under the IIJA, including under the Grid Resilience and Innovative Partnerships (GRIP) Program. Witness Klein also described DEC's rigorous prioritization methodology for determining which opportunities it should pursue, and Witness Klein reiterated that DEC pursued every available opportunity to obtain funds under the IIJA as directed by the Commission. Tr. vol. 15, 1213, 1222. Witness Klein responded to Public Staff witness Thomas' testimony about the status of funding for DEC's hydroelectric projects and clarified the eligibility requirements provided in the IIJA. *Id.* at 1224. Witness Abernathy also testified that DEC "agrees [with the Public Staff] that a deferral of IIJA impacts is appropriate and support[s] the recommendation for the Commission to approve an accounting order to defer any incremental revenue requirement impacts, including benefits and costs related to IIJA, and that they be addressed in a future rate case." Tr. vol. 16, 231.

Based on the foregoing, the Commission concludes that DEC'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 DEC's filing is reasonable and should be approved.

Customer Assistance Program, Payment Navigator Program, and the Tariffed On-Bill Program

In her direct testimony, DEC witness Q. Bowman explained that DEC 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 DEC 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. Tr. Vol. 12, 191-92. She stated that should the Commission approve the Customer Programs, DEC 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. *Id.* Witness Q. Bowman also testified that DEC is proposing PIMs as part of its PBR application and that DEC 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. *Id.*

DEC 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 DEC proposing to allocate 56.77% of these costs to DEC's North Carolina retail customers. Tr. vol. 11, 183.

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 DEC's request should be denied. Tr. vol. 12, 1045. They further testified that because PIMs are designed to protect ratepayers and are required for approval of an MYRP, PIMs are part of DEC's normal course of business and should also be denied on that basis. *Id.* at 1045-46.

In her rebuttal testimony, witness Q. Bowman responded to the Public Staff's recommendation to deny DEC's request on the basis of the deferral test. Tr. vol. 15, 1304-05. Witness Q. Bowman testified that DEC'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. *Id.* at 1305. Witness Q. Bowman explained that even though the costs of implementing these programs are known and measurable, DEC did not adjust operating expenses in this case to include these incremental costs which are not captured in the historic test period. *Id.* Witness Q. Bowman clarified that while PIMs will become a part of DEC'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.* at 1305-06. Thus, witness Q. Bowman explained that creation of a regulatory asset for deferral of the costs would allow DEC to postpone recovery of these costs until the Customer Programs are implemented and benefitting customers. *Id.* at 1306.

In Section III.32 of the Revenue Requirement Stipulation, DEC agreed that it would not defer costs relating to the Customer Programs or costs associated with PIMs. The Commission notes that this resolution is consistent with the resolution of the issue in the recent DEP rate case. The Commission accepts the agreement reached in the Revenue Requirement Stipulation. To the extent that there are ongoing O&M expenses associated with implementation of the PIMs and customer programs, DEC may seek cost recovery of actual expenses incurred during a future test period in its next general rate case. No intervenor took issue with this provision of the Revenue Requirement Stipulation, and the Commission concludes that the Revenue Requirement Stipulation provides a reasonable resolution of this issue for purposes of this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NO. 58

Interconnection CIAC

The evidence supporting this finding of fact is contained in DEC's verified Application and Form E-1; the Revenue Requirement Stipulation; the testimony and exhibits of DEC witness Speros and Public Staff witnesses Metz and Zhang and Boswell; and the entire record in this proceeding.

Public Staff witnesses Zhang and Boswell testified that, during the course of Public Staff's investigation into both the DEC and DEP rate cases, Public Staff discovered that DEC was booking Contributions in Aid of Construction (CIAC) related to interconnection agreements (IAs) inconsistently. Tr. vol 12, 1005. Zhang and Boswell testified that, in general, an IA developer is responsible for network upgrades when connecting to DEC's network, not the ratepayer. *Id.* Witnesses Zhang and Boswell further testified that DEC 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 whether ratepayers have been harmed, and if DEC's new procedures will alleviate the issues. *Id.* Therefore, the Public Staff recommended that the Commission order DEC 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.* at 1005–06. Additionally, the Public Staff recommended that a regulatory liability be established to record any instances in which DEC incorrectly recovered costs associated with IAs from ratepayers, to be flowed back to ratepayers with interest at DEC's weighted average cost of capital in the next DEC general rate case. *Id.* at 1006. Witnesses Zhang and Boswell testified that since DEC 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*. Witnesses Zhang and Boswell recommended that the Commission order DEC to review its CIAC policy and report the results of that review in the next general rate case. *Id.*

DEC 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. 12, 546–47. Witness Speros explained that DEC has taken a number of steps to ensure CIAC associated with IAs is appropriately recorded on DEC's books. *Id.* at 547. He stated that this process begins with DEC'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 DEC'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 DEC continually works to improve its accounting processes, including the process for recording CIAC associated with IAs. *Id.* at 61. He commented that since 2019, DEC has taken steps to improve the processes in place for recording CIAC associated with IAs and made recent modification in 2022. *Id.* at 547–48. Witness Speros also explained that DEC has not been able to identify any interconnection costs associated with CIAC that ratepayers should not have been charged in DEC's last general rate case. *Id.* at 549. Witness Speros testified that if the Commission were to adopt a regulatory liability for the purpose of reconciling any instances where IA costs have been incorrectly booked, that regulatory liability should record both credits and debits. *Id.* at 549. Witness Speros testified that any amounts related to Public Staff's CIAC concerns are not material in this case, given that the vast majority of DEC customers opt for a monthly facilities charge. *Id.*

Witness Speros also testified that the Public Staff's broad-based recommendation to order DEC to produce all entries related to IAs for all plant, depreciation, and collections is unnecessary to demonstrate that DEC's procedures are working properly. *Id.* at 548. In the alternative, DEC 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*. DEC also did not oppose in principle reporting to the Commission on its CIAC policy in the next general rate case. *Id.* at 550.

No other intervenors raised an issue regarding DEC's accounting for CIAC associated with IAs.

The Revenue Requirement Stipulation identifies the CIAC issue as resolved. Per the Stipulation, the Stipulating Parties agree to settle this issue on the same terms as it was resolved in the DEP Rate Case Order. In the DEP Rate Case Order, the Commission directed DEP to continue its work with the Public Staff regarding the documentation of its processes related to the recording of CIAC and to report on the CIAC issue in its next general rate case. Accordingly, the Stipulating Parties in this case agree that it is not necessary to establish a regulatory liability at this time for CIAC in this case. See Tr. Ex. Vol. 7.

Based upon all of the evidence presented, the Commission concludes that the Revenue Requirement Stipulation is just and reasonable with respect to the CIAC issues. Accordingly, DEC will not be required to establish a regulatory liability for the recording of IA-related CIAC. DEC 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. 59

Quality of Service

The evidence supporting this finding of fact is set forth in the testimony of DEC witnesses Guyton, Maley, Quick, and K. Bowman and Public Staff witness T. Williamson.

DEC witnesses Guyton and Maley testified to the performance of the DEC transmission and distribution systems during the base period. Witness Maley testified that DEC's transmission system is reliable and well-maintained, and that DEC is seeking to continue transmission investments to facilitate the conversion of the transmission system to meet future demands. Witness Maley further indicated that DEC 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 DEC transmission system. Tr. vol. 8, 269-71. Witness Guyton testified that DEC'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 113-16. Witness Guyton also cited DEC'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 114-16.

In his direct testimony, Public Staff witness T. Williamson testified that overall, the quality of service provided by DEC to its North Carolina retail customers, on average, is adequate given minor improvements in shorter-term non-MED SAIDI. Tr. vol. 15, 170. Witness T. Williamson also engaged in an in-depth analysis of DEC's service quality in which he examined various aspects of DEC's performance in initiating new service, providing normal day-to-day service, and restoration of service after outage events. *Id.* at 151-70. Witness T. Williamson also summarized various consumer statements of position filed with the Commission relative to this rate case. *Id.* at 168-70.

Regarding the initiation of new service, witness T. Williamson indicated that new service installations has steadily increased from 2015 through 2022 and that DEC's average percentage of installations completed within 20 days averaged 94.7%. Witness T. Williamson also noted that DEC was completing new residential service installations in a consistent manner and is providing customers with a reasonable expectation as to the amount of time it will take DEC to provide initial service to new residential dwellings. Tr. vol. 15, 152-153. Regarding day-to-day service, witness T. Williamson testified that from 2017 through 2022, non-MED SAIDI shows a downward trend (the lower the SAIDI score, the shorter the outage duration for customers) and the non-MED SAIFI trend is relatively flat with a slight upward move (the higher the SAIFI score, the more frequently customers experience outages). Witness T. Williamson also testified that while DEC has seen improvements in non-MED SAIDI and SAIFI during the 2017-2022 timeframe, DEC's longer-term trend from 2014-2022 demonstrates a relative decrease in service quality and a less favorable trend for ratepayers. He testified that these trends may be reflective of the initiation of the GIP and continued investments in DEC's transmission and distribution systems, though it is too soon to draw broad conclusions. *Id.* at 155.

Witness T. Williamson further testified that service reliability as measured by ASAI[922] during the 2014 through 2022 timeframe, has held steady at 99.97%. *Id.* at 159. With respect to restoration of service after an outage, witness T. Williamson testified that DEC's Estimated Time to Restoration for service outages was met in 96% of Major Event Day outages. *Id.* at 167.

In her direct testimony, DEC witness Quick testified that in addition to DEC's primary responsibility of providing safe and reliable service, DEC understands that its customer base has diverse service needs and strives to recognize and accommodate them where possible. Tr. vol. 7, 122-123. She outlined the steps that DEC is taking to continue to improve customers' experiences and satisfaction. *Id*. With respect to DEC's customer care operations, witness Quick explained that they are 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. *Id*. She also described how DEC 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, DEC 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, 124.

Witness Quick also testified about the programs that DEC supports to help customers with the affordability of electric utility service. She noted the energy efficiency

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[9] 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).

programs that help reduce energy usage and provide weatherization assistance. Tr. vol. 7, 125-126. She also detailed DEC's numerous efforts to support customers during the unprecedented COVID-19 pandemic. One example she gave was DEC'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. DEC ensured the Winter Moratorium remained in place from November 2020 until March 2022, protecting approximately 53,000 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 DEC communicated with customers to promote options for assistance and contacting DEC. Tr. vol. 7, 139-144.

Witness Quick further testified about recent digital enhancements to improve service to customers. She relayed that after receiving customer feedback, DEC 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 DEC's digital enhancements made it easier for customers to report service interruptions. She also testified that DEC offers a free 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, 155-166.

In her supplemental settlement testimony, DEC witness K. Bowman testified that the Revenue Requirement Stipulation is a fair compromise that serves customers' interests by allowing DEC to recover the investments required to safely and reliably provide high quality electric service to our customers, all while advancing the state's energy policy goals. Tr. vol. 7, 111.

Discussion and Conclusions

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 DEC'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 DEC's is good. No other party presented evidence on DEC's service quality.

Additionally, no other party presented evidence critical of DEC's quality of service. Based on the foregoing, the Commission concludes that DEC provides adequate service to customers.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 60-61

Tax-Related Items

The evidence supporting these findings of fact is contained in DEC's verified Application and Form E-1; the testimony and exhibits of DEC witness Q. Bowman, Public Staff witnesses Zhang and Boswell; and the entire record in this proceeding.

In its Application, DEC proposes to revise the EDIT-4 rider to return an additional $16.217.1 million for unprotected federal EDIT and $4.55.9 million for deferred revenues to customers over the remaining 72.4 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 expired in June of 2023; therefore, DEC 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.*

DEC witness Q. Bowman supports this revision to the EDIT-4 Rider in her direct testimony and in Q. Bowman Exhibit 3. Tr. vol. 12, 188. The Public Staff agrees with DEC's proposal to flow back the incremental amount to customers on a levelized basis; however, the Public Staff proposed to flow back the incremental amount to customers over three years instead of over the remaining EDIT rider term. Additionally, the levelized return rate used by the Public Staff reflects DEC's 4.53% cost of debt rate and a return on equity of 9.35% with a 48% debt and 52% equity capital structure. Tr. vol. 15, 1306.

In her third supplemental testimony, witness Q. Bowman updated DEC's cost of debt to 4.56% as of June 30, 2023, and recalculated the proposed changes to the EDIT-4 Rider accordingly. Tr. vol. 12, 220, 222. In the Revenue Requirement Stipulation, the stipulating parties agreed to update the cost of debt to the actual cost of debt as of June 30, 2023, 4.56%. Revenue Requirement Stipulation § III.1, Tr. Ex. vol. 7.

Based on the foregoing, the Commission concludes that DEC'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 4.56% embedded cost of debt agreed to by the stipulating parties in the Revenue Requirement Stipulation and the capital structure and rate of return on equity approved by the Commission in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 62

Fuel Cost Voltage Differential

The evidence supporting this finding is in the verified Application and Form E-1, the testimony and exhibit of DEC witnesses Sykes, the testimony and exhibits of Public Staff witness Lucas, the Revenue Requirement Stipulation, and the entire record in this proceeding.

Public Staff witness Lucas recommended in his testimony that voltage differentiated fuel rates be used by DEC, as they are used by DEP. He stated that such rates reflect the fact that less generation and fuel consumption is required for customers that receive service at higher voltages. He further testified that recent changes in North Carolina law, that being the passage of N.C.G.S. § 62-133.16 regarding performance-based regulation, support the Public Staff's position with regard to the cost causation principle. Tr. vol. 13, 140-142. Specifically, Public Staff witness Lucas recommended DEC incorporate voltage differential for the prospective billing period fuel rates in DEC's next fuel proceeding to be filed in February 2024, with rates taking effect on September 1, 2024; however, he clarified that this recommendation should not affect the Experience Modification Factor fuel rates established in the 2024 fuel proceeding. *Id.* at 143-147.

In his rebuttal testimony, DEC witness Sykes stated that DEC did not agree with Public Staff witness Lucas's recommendation, and instead proposed to incorporate voltage differential into fuel rates prior to a merger of the two utilities in a future general rate case proceeding. Tr. vol. 12, 624-626. In support for DEC's proposal, DEC witness Sykes explained that DEC's affiliate, DEP, followed this same approach in its 2012 general rate case proceeding in Docket No. E-2, Sub 1023, where DEP proposed, and the Commission approved, to begin recovering voltage differential through the annual fuel proceeding simultaneously with the effective date for new rates in that general rate case. In the case of DEP, the timing of the transition of voltage differential from the general rate case and the annual fuel proceeding aligned, which is what witness Sykes therefore proposed to do in a future general rate case prior to a merger of DEC and DEP. *Id.*

In the Revenue Requirement Stipulation, DEC agreed to incorporate fuel cost voltage differential for the prospective billing period fuel rates in DEC's next fuel proceeding to be filed in February, 2024, and to remove line losses from base rates at that time. No intervenor took issue with this provision of the stipulation. The Commission concludes that the Revenue Requirement Stipulation provides a reasonable resolution of the fuel cost voltage differential rate issue for purposes of this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 63-64

Equal Percentage Allocation, Base Fuel and Fuel-Related Factors and Fuel Cost Allocation

[ ]

Equal Percentage Allocation

[ ]

Base Fuel and Fuel-Related Cost Factors

[ ]

Fuel Cost Allocations

[ ]

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 65-66

Residential Decoupling Mechanism and Earnings Sharing Mechanism

The evidence supporting these findings of fact is contained in DEC's verified Application and Form E-1; the testimony and exhibits of DEC witnesses Abernathy, Bateman and Stillman, Public Staff witnesses D. Williamson and Thomas, AGO witness Palmer, and the entire record in this proceeding.

Summary of Evidence

DEC's PBR Application seeks approval of performance-based regulation through the proposed three-year MYRP beginning on January 1, 2024 and ending December 31, 2026. DEC witness Bateman testified that in addition to the three-year MYRP, which includes an ESM, DEC's PBR Application also includes PIMs and a decoupling mechanism for the residential customer class. Tr. vol. 11, 146. Witness Bateman explained that the PBR approach and DEC's PBR Application better align customer and state policy goals with utility revenues and performance than traditional ratemaking. *Id.* at 148.

Residential Decoupling Mechanism

DEC witness Abernathy provided direct testimony on DEC's proposed decoupling mechanism, which is a rate-making mechanism intended to break the link between an electric public utility's revenue and the level of consumption of electricity on a per customer basis. The following Rate Schedules are affected by the decoupling mechanism: RS, RE, ES, RT, RSTC, and RETC, along with any new residential rate schedules approved by the Commission during the Plan Period. Tr. vol. 12, 100. Witness Abernathy explained how the annual and monthly target revenue per customer would be calculated for Rate Years 1, 2 and 3, as well as how DEC plans to estimate the number of residential customers for each month for each rate year. Witness Abernathy's testimony also discussed how the difference between target residential revenues and actual residential revenues would be deferred and include a carrying charge, and that deferral amount would be adjusted to account for DSM/EE net lost revenues and incremental EV revenues. Lastly, witness Abernathy testified about how the Decoupling Rider will work and DEC's reporting obligations with respect to the deferred balance. *Id.* at 100-109.

AGO witness Palmer advocated for applying a lower carrying cost rate on the decoupling deferral amount and placing a hard cap of 3% on surcharges. Tr. vol. 15, 409-10. Witness Palmer explained that a hard cap would limit rate increases and promote cost containment. *Id*. at 409. AGO witness Palmer asserted that DEC's proposed to exclude EV sales from its decoupling mechanism is not in the public interest. *Id.* at 398-400. Witness Palmer asserted that there is no link between this proposal and the goal of advancing EV adoption. *Id.* at 399-400. Witness Palmer further stated that DEC's method for calculating EV sales is not accurate and recommended that the Commission reject DEC's proposal. *Id.* at 401-406.

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 provides 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. 12, 772. The Public Staff expressed only one concern regarding DEC's proposed decoupling mechanism. Witness Nader objected to how DEC determined the estimate of EV sales for the calculation and recommended that the decoupling mechanism not include DEC's proposed "Incremental EV Revenue Adjustment". *Id.* at 774. Witness Nader asserted that the estimate was 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 the estimated monthly kWh per EV should be updated regularly based on the data collected within the Commission-approved EV Make-Ready Program. In the interim, witness Nader recommended that DEC use metered data that is filed in DEC's First Status Report on Make Ready Credit Programs. *Id.* at 775.

In response to AGO witness Palmer's suggestion to institute a 3% hard cap on the amounts the utility is able to collect from customers, "decoupling cap," witness Bateman 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. 16, 265-66. Witness Bateman offered further support for the exclusion of EV sales from the decoupling mechanism. *Id.* She 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 DEC from including an EV adjustment within the decoupling and ESM calculations, DEC'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.* at 264-65

The PIMs Stipulation provides that the parties thereto agree to allow DEC 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 DEC's service territory, within 90 days of the Commission's order in this docket, and (2) that DEC update the kWh per EV estimate proposed by Public Staff witness Nader with actual, DEC-specific EV usage data in each future decoupling rider proceeding.

In her supplemental direct testimony, witness Abernathy explained that the PIMs Stipulation (also approved in the DEP Rate Case) agreed and clarified how DEC and DEP will obtain data that will help them to better estimate revenue associated with incremental residential EVs. Tr. vol. 12, 124. Witness Abernathy explained that the agreed-upon method entails using DOT data to derive the number of residential EVs in DEC's service territory 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. 12, 123. Thereafter, within 90 days of a Commission order in this proceeding, DEC 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. Tr. vol. 11, 201-202. Witness Bateman also stated that DEC will use this agreed-upon method to exclude EV sales from the ESM. Tr. vol. 16, 265.

Earnings Sharing Mechanism

DEC witnesses Abernathy and Bateman testified in support of the ESM, which is a component of the MYRP. Tr. vol. 11, 145-47; Tr. vol. 12, 109-110. Witness Abernathy explained that if DEC'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, will be distributed to customers over a 12-month period via the annual ESM Rider. Tr. vol. 12, 109.

Witness Abernathy testified that, for purposes of the ESM calculation, DEC will adjust earnings for weather, DSM/EE incentives, PIMs, and EV sales. *Id.* at 110.

At the evidentiary hearing, witness Bateman that the ESM allocates risk away from customers and onto DEC, since 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 DEC to collect additional revenue from customers if the utility is underearning. Tr. vol. 11, 150.

Also, as noted above, witness Bateman explained that if the Commission precluded DEC from including an EV adjustment within the ESM calculations, DEC'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.

Discussion and Conclusion

In general, the Commission concludes that the residential decoupling mechanism and the ESM proposed by DEC are consistent with the PBR Statute and with the Commission's rules. Further, the Commission concludes that DEC'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 articulated by DEC 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 TCA Stipulation will be included in the ESM for DEC.

The Commission notes that Commission Rule R1-17B(h)(1) provides for the filing of quarterly earnings reports that require certain enumerated information. The Commission directs DEC to work with the Public Staff to develop a quarterly reporting form for DEC'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, DEC 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. 67

Performance Based Regulation

The evidence supporting this finding of fact is contained in DEC's verified Application and Form E-1; the testimony and exhibits of DEC witnesses Abernathy, Bateman and Stillman, Public Staff witnesses D. Williamson and Thomas, AGO witness Balakumar, NCJC et al. witness Wilson, and CUCA witness Pollock; and the entire record in this proceeding.

Summary of Evidence

DEC's PBR Application seeks approval of performance-based regulation through the proposed three-year MYRP beginning on January 1, 2024, and ending December 31, 2026.[10] DEC witness Bateman testified that in addition to the three-year MYRP, which includes an ESM, DEC's PBR Application includes a residential decoupling mechanism, PIMs, and tracking metrics. Tr. vol. 11, 145. Witness Bateman explained that the PBR approach, in general, and DEC's proposed MYRP better align customer and state policy goals with utility revenues and performance than under a traditional ratemaking construct. *Id.* at 148.

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 DEC, and provides DEC with a cost recovery framework that represents a 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.

[10] DEC seeks MYRP cost recovery for capital projects which will be placed into service during the so-called "Gap Period"; that is, the time period between the capital cut-off (June 30, 2023) and the start of Rate Year 1 (January 1, 2024). For the reasons articulated by DEP in its post-hearing brief filed in the DEP rate case proceeding, the Commission concludes that it has the authority to approve cost recovery for MYRP projects entering service during the Gap Period and that DEC properly included a full year's revenue requirement for MYRP projects that are placed in service during the Gap Period.

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 DEC, are now allowed to utilize a decoupling mechanism. Under the PBR Statute's decoupling mechanism, DEC 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 DEC with the opportunity to earn a reward to be collected from customers, and expose DEC 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 to 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 DEC regarding costs to be recovered, as well as the rate of return that DEC 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 DEC, 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 DEC'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 DEC 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, DEC 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, DEC witness Beveridge acknowledged that the PBR Statute requires DEC to minimize interclass subsidization. Tr. vol. 10, 253. However, witness Beveridge emphasized that the PBR Statute requires the minimization of interclass subsidization "to the greatest extent practicable," which, the Commission concludes, DEC has achieved. *Id.* The Commission concludes that DEC'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 DEC witness Beveridge who testified that DEC appropriately considered "competing priorities" such as cost causation, rate shock, and gradualism in proposing the 10% variance reduction. Tr. vol. 10, 252-53. The Commission does not agree with the recommendation of CIGFUR witness Collins 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, DEC witness Beveridge explained that if DEC had employed a 25% subsidy reduction, as recommended by CIGFUR witness Collins, the proposed increase to the Lighting class would increase from 28.0% to 38.0%. Tr. vol. 10, 187-88. 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 DEC'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 any 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 DEC'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. 68

Revenue Requirement

[ ]

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 OPT-V-Primary Partial Rate Design Stipulation, the OPT-V-Secondary Partial Rate Design Stipulation, and the Power Quality Stipulation are accepted and approved, as detailed in this Order.

2. That the depreciation rates proposed by DEC 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 intervenors—including (1) accelerated retirement dates for coal plant assets except for Cliffside 5; and (2) corrected depreciation rates set forth in DEC witness Spanos' rebuttal testimony, subject to an adjustment to decommissioning estimates to use 10% contingency and a 5% indirect cost adder—shall be, and are hereby approved;

3. That DEC's request for an accounting order for approval to defer to a regulatory asset 75% of the impact of accelerating the retirement of DEC's subcritical coal plants, as agreed upon in the Revenue Requirement Stipulation, preserving DEC'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 DEC's subcritical coal plants at retirement shall be recovered with a return over the amortization period determined by the Commission in a future rate case;

5. That DEC's plant-related capital investments in the base period fossil, renewable, storage, nuclear fleet assets, as adjusted in the Revenue Requirement Stipulation, shall be included in rates for the base period;

6. That DEC'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 DEC's GIP investments shall be included for recovery in DEC's rates;

8. That in accordance with the Revenue Requirement Stipulation, DEC 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 DEC 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) DEC'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 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 DEC shall amortize non-ARO environmental compliance costs over a six-year period;

11. That DEC shall amortize the regulatory liability for overcollections associated with storm securitization over a three-year period;

12. That the agreed-upon accounting adjustments outlined in the Revenue Requirement Stipulation shall be, and are hereby, approved;

13. That DEC shall establish the nuclear PTC rider, effective January 1, 2025, as provided in the Revenue Requirement Stipulation;

14. That DEC 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 DEC and the Public Staff. DEC shall update the Commission on the manner upon which DEC and the Public Staff have agreed to the tracking and reporting of the actual spend and employee head count for each coal generation station;

15. That DEC shall record any cumulative underspend less than $4.5 million (North Carolina retail) of annual incremental spend for ongoing O&M for DEC's coal generation fleet for discrete programs and targeted categories to a regulatory liability account accrued through the end of the MYRP period (December 2026) and return the underspend to customers in the next general rate case;

16. That DEC 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;

17. That DEC's proposed MYRP, reflecting the projected costs associated with the Transmission, Distribution, Fossil/Hydro, Nuclear, Cybersecurity, Solar, and Storage and DE Plaza capital investments, as adjusted by the Revenue Requirement Stipulation, as reflected in Abernathy Supplemental Settlement Exhibits 1 and 2, is just and reasonable and adopted in its entirety;

18. That DEC has demonstrated a reasonable plan to timely complete the MYRP projects;

19. That DEC shall consult with the Public Staff before filing its next PBR Application to attempt to establish agreed-upon MYRP project documentation guidelines;

20. That DEC shall track and report on AFUDC accrued on MYRP capital projects and consult with the Public Staff regarding the scope and content of the report;

21. That DEC shall develop and file EV tariffs and/or programs to estimate and update the revenue associated with residential EV sales in DEC's service territory within 90 days of the Commission's order in this docket and that DEC shall update the kWh per EV estimate proposed by Public Staff witness Nader with actual, DEC-specific EV usage data in each future decoupling rider proceeding.

22. That DEC shall consult with the Public Staff to develop a report on Rider ED. DEC shall file its first report on Rider ED no later than one year from the date of this Order;

23. That DEC shall report on the issue of CIAC related to IAs in its next rate case application;

24. That DEC shall consult with the Public Staff to develop a report on reliability O&M as the Public Staff proposed. DEC shall file its first report on reliability O&M no later than one year from the date of this Order;

25. That DEC shall report on Vegetation Management as agreed upon in the Revenue Requirement Stipulation;

26. That DEC's request to establish the Payment Navigator program shall be, and is hereby approved;

27. That DEC 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, DEC 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 is approved, and DEC shall file an application for such a pilot program, or agreed upon alternative, in a separate proceeding within six months of this Order;

32. That, consistent with the Affordability Stipulation, DEC's proposed CAP is hereby approved as a three-year pilot;

33. That DEC's proposed CAP and CAR Riders shall be, and are hereby approved;

34. That the shareholder financial contributions, detailed in the Affordability Stipulation, shall be, and are hereby approved;

35. That DEC 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. That DEC shall 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. That DEC shall 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 DEC 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. [ ];

40. [ ];

41. [ ];

42. [ ];

43. [ ];

44. [ ]

45. [ ];

46. [ ];

47. That DEC is allowed to recover the remaining unamortized rate case expenses from Docket Nos. E-7, Sub 1146 and E-7, Sub 1214 as well as the additional

rate case expense requested for the Sub 1214 in this proceeding. Such costs shall be netted against all rate case expense over amortization from the prior cases and amortized over a three-year period, and shall not be included in rate base;

48. That DEC is hereby allowed to recover over a three-year period rate case costs related to the present proceeding, including actual rate case costs through the date that the proposed order is filed;

49. 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 DEC's prior rate cases should be applied against rate case costs being requested in this proceeding.

b. The over-amortization of severance costs from the Commission's Order in the 2019 Rate Case should be refunded to customers through a one-year rider with interest.

c. The over-amortization of early retired plant should be applied against the outstanding rate base balance for the Allen early retired coal plant authorized in the 2019 Rate Case.

50. That if DEC receives revenue for any deferred cost for a longer period of time than the amortization period approved by the Commission for that deferred cost, DEC shall continue to record all revenue received for that deferred cost in the specific regulatory asset account established for that deferred cost until DEC's next general rate case for a determination of the appropriate ratemaking treatment of such over-amortizations;

51. That DEC is allowed to collect in rates its North Carolina Retail normalized annual level of storm costs in the amount of approximately $32.225 million;

52. That DEC'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;

53. That the agreement in the Revenue Requirement Stipulation that it is not necessary to establish a regulatory liability at this time for CIAC is reasonable, however, DEC 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;

54. That DEC's provision of electric service to be adequate;

55. That DEC'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 levelized return rate shall be based on an embedded cost of debt of 4.56% and a capital structure and rate of return on equity approved by the Commission in this proceeding;

56. [ ]

57. That 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 DEC's annual fuel proceedings;

58. That DEC'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;

59. That DEC'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;

60. That DEC 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 Q. Bowman Supplemental Partial Settlement Exhibit 1. DEC shall work with the Public Staff to verify the accuracy of the calculations;

61. That DEC 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 DEC should have the opportunity to achieve based on the Commission's findings and determination in this proceeding;

62. [ ];

63. That within 30 days of this Order, DEC 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

64. That DEC 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 [__] day of December, 2023.

NORTH CAROLINA UTILITIES COMMISSION

A. Shonta Dunston, Chief Clerk