

PUBLIC

INFORMATION SHEET

PRESIDING: Commissioner Duffley, Presiding; Chair Mitchell, and Commissioners Brown-Bland, Clodfelter, Hughes, McKissick, Jr., and Kemerait

PLACE: Raleigh, NC

DATE: Monday, October 30, 2023

TIME: 1:01 p.m. to 4:15 p.m.

DOCKET: E-7 Sub 1134 and E-7 Sub 1276

COMPANY: Duke Energy Carolinas, LLC

DESCRIPTION: In the Matter of Duke Energy Carolinas, LLC Application for Approval to Construct a 402 MW Natural Gas-Fired Combustion Turbine Electric Generating Facility in Lincoln County, and for an Application for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina and for Performance-Based Regulation

VOLUME NUMBER: 17

APPEARANCES

See attached

WITNESSES

See attached

EXHIBITS

None attached

REPORTED BY: Lisa A. DeGroat
TRANSCRIBED BY: Lisa A. DeGroat
DATE FILED: November 1, 2023

TRANSCRIPT PAGES: 160
PREFILED PAGES: 32
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OFFICIAL COPY

Nov 02 2023

PLACE: Dobbs Building, Raleigh, North Carolina
DATE: Monday, October 30, 2023
TIME: 1:01 p.m. - 4:15 p.m.
DOCKET: E-7, Sub 1134 and E-7, Sub 1276
BEFORE: Commissioner Kimberly W. Duffley, Presiding
Chair Charlotte A. Mitchell
Commissioner ToNola D. Brown-Bland
Commissioner Jeffrey A. Hughes
Commissioner Floyd B. McKissick, Jr.
Commissioner Karen M. Kemerait

IN THE MATTER OF:

Duke Energy Carolinas, LLC

Application for Approval to Construct a 402 MW Natural
Gas-Fired Combustion Turbine Electric Generating
Facility in Lincoln County
and

Application for Adjustment of Rates and Charges
Applicable to Electric Service in North Carolina and
for Performance-Based Regulation

VOLUME 17



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4 CITIZENS PURSUANT TO N.C.G.S. § 114-2(8):

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**NORTH CAROLINA UTILITIES COMMISSION
APPEARANCE SLIP**

DATE: 8-28-23 DOCKET NO.: E-7 Sub 1276

ATTORNEY NAME and TITLE: JACK E. JIRAK, DEPUTY GENERAL COUNSEL

FIRM NAME: DUKE ENERGY

ADDRESS: 410 S. WILMINGTON ST.

CITY: RALEIGH STATE: NC ZIP CODE: 27602

APPEARANCE ON BEHALF OF: Duke Energy Carolinas, LLC

APPLICANT: ☒ COMPLAINANT: ☐ INTERVENOR: ☐

PROTESTANT: ☐ RESPONDENT: ☐ DEFENDANT: ☒

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☐ Yes, I have signed the Confidentiality Agreement.

Email: JACK.JIRAK@DUKE-ENERGY.COM

SIGNATURE: _____

(Signature Required for distribution of **CONFIDENTIAL** information)

NORTH CAROLINA UTILITIES COMMISSION
APPEARANCE SLIP

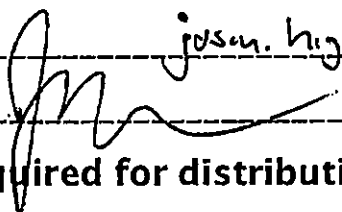
DATE: 6/21/2022 DOCKET NO.: E-7 Sub 1276
ATTORNEY NAME and TITLE: Jason Higginbotham
Associate General Counsel
FIRM NAME: Duke Energy
ADDRESS: _____
CITY: _____ STATE: _____ ZIP CODE: _____
APPEARANCE ON BEHALF OF: Duke Energy Carolinas LLC

APPLICANT: ☒ COMPLAINANT: ___ INTERVENOR: ___
PROTESTANT: ___ RESPONDENT: ___ DEFENDANT: ___

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☒ Yes, I have signed the Confidentiality Agreement.

Email: jason.higginbotham@duke-energy.com
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**NORTH CAROLINA UTILITIES COMMISSION
APPEARANCE SLIP**

DATE: 8-28-23 DOCKET NO.: 16-7 Sub 1274

ATTORNEY NAME and TITLE: JAMES H. JEFFRIES IV, PARTNER

FIRM NAME: MCGUIREWOODS LLP

ADDRESS: 201 N. TRYON STREET, SUITE 3000

CITY: CHARLOTTE STATE: NC ZIP CODE: 28202

APPEARANCE ON BEHALF OF: Duke Energy Carolinas, LLC

APPLICANT: ☒ COMPLAINANT: ☐ INTERVENOR: ☐

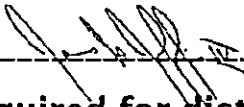
PROTESTANT: ☐ RESPONDENT: ☐ DEFENDANT: ☐

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NORTH CAROLINA UTILITIES COMMISSION
APPEARANCE SLIP

DATE: 8/23/2023 **DOCKET NO.:** E-7 Sub 1276

ATTORNEY NAME and TITLE: Andrea R. Kells, Counsel

FIRM NAME: McGuireWoods, LLP

ADDRESS: 501 Fayetteville St. Suite 500

CITY: Raleigh **STATE:** NC **ZIP CODE:** 27601

APPEARANCE ON BEHALF OF: Duke Energy Carolinas, LLC

APPLICANT: ☒ **COMPLAINANT:** ☐ **INTERVENOR:** ☐

PROTESTANT: ☐ **RESPONDENT:** ☐ **DEFENDANT:** ☐

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☒ **Yes, I have signed the Confidentiality Agreement.**

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Digitally signed by Andrea R. Kells
Date: 2023.08.23 09:43:52 -0400

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**NORTH CAROLINA UTILITIES COMMISSION
APPEARANCE SLIP**

DATE: August 28, 2023 **DOCKET NO.:** E-7 Sub 1276

ATTORNEY NAME and TITLE: Kristin M. Athens, Esquire

FIRM NAME: McGuireWoods LLP

ADDRESS: 501 Fayetteville St. Suite 500

CITY: Raleigh **STATE:** NC **ZIP CODE:**

APPEARANCE ON BEHALF OF: Duke Energy Carolinas, LLC

APPLICANT: x **COMPLAINANT:** **INTERVENOR:**

PROTESTANT: **RESPONDENT:** **DEFENDANT:**

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**NORTH CAROLINA UTILITIES COMMISSION
APPEARANCE SLIP**

DATE: August 22, 2023 **DOCKET NO.:** E-7, Sub 1276

ATTORNEY NAME and TITLE: Brandon F. Marzo, Partner

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CITY: Atlanta **STATE:** GA **ZIP CODE:** 30308

APPEARANCE ON BEHALF OF: Duke Energy Carolinas, LLC

APPLICANT: X **COMPLAINANT:** **INTERVENOR:**

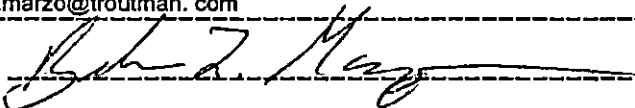
PROTESTANT: **RESPONDENT:** **DEFENDANT:**

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**NORTH CAROLINA UTILITIES COMMISSION
APPEARANCE SLIP**

DATE: 8/22/23 **DOCKET NO.:** E-7, Sub 1276

ATTORNEY NAME and TITLE: Melissa Oellerich Butler, Associate

FIRM NAME: Troutman Pepper Hamilton Sanders LLP

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CITY: Atlanta **STATE:** GA **ZIP CODE:** 30308

APPEARANCE ON BEHALF OF: Duke Energy Carolinas, LLC

APPLICANT: x **COMPLAINANT:** **INTERVENOR:**

PROTESTANT: **RESPONDENT:** **DEFENDANT:**

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x **Yes, I have signed the Confidentiality Agreement.**

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APPEARANCE SLIP**

DATE: 8/22/23 **DOCKET NO.:** E-7, Sub 1276

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APPEARANCE ON BEHALF OF: Duke Energy Carolinas, LLC

APPLICANT: X **COMPLAINANT:** **INTERVENOR:**

PROTESTANT: **RESPONDENT:** **DEFENDANT:**

Non-confidential transcripts are located on the Commission's website. To view and/or print transcripts, go to <https://www.ncuc.net/>, hover over the Dockets tab, select Docket Search, enter the docket number, and click search, select the highlighted docket number and select Documents for a list of all documents filed.

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**NORTH CAROLINA UTILITIES COMMISSION
APPEARANCE SLIP**

DATE: 8/22/2023 **DOCKET NO.:** E-7, Sub 1276

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APPEARANCE ON BEHALF OF: Duke Energy Carolinas, LLC

APPLICANT: ☒ **COMPLAINANT:** ☐ **INTERVENOR:** ☐

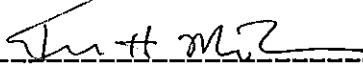
PROTESTANT: ☐ **RESPONDENT:** ☐ **DEFENDANT:** ☐

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NORTH CAROLINA UTILITIES COMMISSION

APPEARANCE SLIP

DATE: August 22, 2023 **DOCKET NO.:** Docket No. E-7, Sub 1276

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CITY: Charlotte **STATE:** NC **ZIP CODE:** 28202

APPEARANCE ON BEHALF OF: Duke Energy Carolinas, LLC

APPLICANT: X **COMPLAINANT:** **INTERVENOR:**

PROTESTANT: **RESPONDENT:** **DEFENDANT:**

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**NORTH CAROLINA UTILITIES COMMISSION
APPEARANCE SLIP**

DATE: August 23, 2023 **DOCKET NO.:** E-7, SUB 1276

ATTORNEY NAME and TITLE: MELINDA L. MCGRATH, PARTNER

FIRM NAME: TROUTMAN PEPPER HAMILTON SANDERS LLP

ADDRESS: 301 S. COLLEGE STREET; 34TH FLOOR

CITY: CHARLOTTE **STATE:** NC **ZIP CODE:** 28202

APPEARANCE ON BEHALF OF: DUKE ENERGY CAROLINAS, LLC

APPLICANT: XX **COMPLAINANT:** ___ **INTERVENOR:** ___

PROTESTANT: ___ **RESPONDENT:** ___ **DEFENDANT:** ___

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SIGNATURE: 

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**NORTH CAROLINA UTILITIES COMMISSION
APPEARANCE SLIP**

DATE: 8-28-23 **DOCKET NO.:** E-7, Sub 1276

ATTORNEY NAME and TITLE: Marcus W. Trathen

FIRM NAME: Brooks Pierce McLendon Humphrey & Leonard, LLP

ADDRESS: 1700 Wells Fargo Capitol Center, 150 Fayetteville St.

CITY: Raleigh **STATE:** NC **ZIP CODE:** 27601

APPEARANCE ON BEHALF OF: CUCA

APPLICANT: **COMPLAINANT:** **INTERVENOR:** X

PROTESTANT: **RESPONDENT:** **DEFENDANT:**

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To receive an electronic **CONFIDENTIAL** transcript, please complete the following:

☒ **Yes, I have signed the Confidentiality Agreement.**

Email: mtrathen@brookspierce.com

SIGNATURE: /s/ Marcus Trathen

(Required for distribution of CONFIDENTIAL transcript)

**NORTH CAROLINA UTILITIES COMMISSION
APPEARANCE SLIP**

DATE: 8/23/2023 **DOCKET NO.:** E-7 Sub 1276

ATTORNEY NAME and TITLE: Matthew B. Tynan

FIRM NAME: Brooks Pierce LLP

ADDRESS: P.O. Box 26000

CITY: Greensboro **STATE:** NC **ZIP CODE:** 27420

APPEARANCE ON BEHALF OF: Carolina Utility Customers Association

APPLICANT: **COMPLAINANT:** **INTERVENOR:** x

PROTESTANT: **RESPONDENT:** **DEFENDANT:**

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SIGNATURE: Matthew B. Tynan

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**NORTH CAROLINA UTILITIES COMMISSION
APPEARANCE SLIP**

DATE: 8-28-23 **DOCKET NO.:** E-7, Sub 1276

ATTORNEY NAME and TITLE: Christopher B. Dodd

FIRM NAME: Brooks Pierce McLendon Humphrey & Leonard, LLP

ADDRESS: 115 N. 3rd St #301

CITY: Wilmington **STATE:** NC **ZIP CODE:** 28401

APPEARANCE ON BEHALF OF: CUCA

APPLICANT: **COMPLAINANT:** **INTERVENOR:** X

PROTESTANT: **RESPONDENT:** **DEFENDANT:**

Non-confidential transcripts are located on the Commission's website. To view and/or print transcripts, go to <https://www.ncuc.net/>, hover over the Dockets tab, select Docket Search, enter the docket number, and click search, select the highlighted docket number and select Documents for a list of all documents filed.

ONLY fill out this portion if you have signed an NDA to receive CONFIDENTIAL transcripts and/or exhibits:

X **Yes, I have signed the Confidentiality Agreement.**

Email: cdodd@brookspierce.com

SIGNATURE: /s/ Christopher Dodd

(Signature Required for distribution of CONFIDENTIAL information)

NORTH CAROLINA UTILITIES COMMISSION

APPEARANCE SLIP

DATE: August 22, 2023 **DOCKET NO.:** E-7, Sub 1276; E-7, Sub 1134

ATTORNEY NAME and TITLE: Christina Cress, Partner; Douglas "D.C." Conant, Associate (Bailey & Dixon, LLP)

Chris S. Edwards, Partner (Ward & Smith, LLP)

FIRM NAME: Bailey & Dixon, LLP (CDC & DC); Ward & Smith, LLP (CSE)

ADDRESS: 434 Fayetteville St., Ste. 2500 (Bailey & Dixon); 127 Racine Drive (Ward & Smith)

CITY: Raleigh (B&D); Wilmington (W&S) **STATE:** NC **ZIP CODE:** 27601 (B&D); 28403 (W&S)

APPEARANCE ON BEHALF OF: CIGFUR III, Haywood EMC, Blue Ridge EMC, Piedmont EMC, and Rutherford EMC

APPLICANT: ___ **COMPLAINANT:** ___ **INTERVENOR:** X

PROTESTANT: ___ **RESPONDENT:** ___ **DEFENDANT:** ___

Non-confidential transcripts are located on the Commission's website. To view and/or print transcripts, go to <https://www.ncuc.net/>, hover over the Dockets tab, select Docket Search, enter the docket number, and click search, select the highlighted docket number and select Documents for a list of all documents filed.

ONLY fill out this portion if you have signed an NDA to receive CONFIDENTIAL transcripts and/or exhibits:

X **Yes, I have signed the Confidentiality Agreement.**

Email: ccress@bdixon.com

SIGNATURE: Christina D. Cress

Digitally signed by Christina D. Cress
Date: 2023.08.22 13:33:10 -0400

(Signature Required for distribution of CONFIDENTIAL information)

**NORTH CAROLINA UTILITIES COMMISSION
APPEARANCE SLIP**

DATE: 8/28/23 **DOCKET NO.:** E-7 Sub 1276

ATTORNEY NAME and TITLE: Ethan Blumenthal, Regulatory Counsel

FIRM NAME: North Carolina Sustainable Energy Association

ADDRESS: 4800 Six Forks Rd., Suite 300

CITY: Raleigh **STATE:** NC **ZIP CODE:** 27609

APPEARANCE ON BEHALF OF: North Carolina Sustainable Energy Association

APPLICANT: ___ **COMPLAINANT:** ___ **INTERVENOR:** x

PROTESTANT: ___ **RESPONDENT:** ___ **DEFENDANT:** ___

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ONLY fill out this portion if you have signed an NDA to receive CONFIDENTIAL transcripts and/or exhibits:

___ Yes, I have signed the Confidentiality Agreement.

Email: ethan@energync.org

SIGNATURE: Ethan Blumenthal

Digitally signed by Ethan Blumenthal
Date: 2023.08.21 21:17:22 -0400

(Signature Required for distribution of CONFIDENTIAL information)

**NORTH CAROLINA UTILITIES COMMISSION
APPEARANCE SLIP**

DATE: 8-28-23 DOCKET NO.: E-7, sub 1276
ATTORNEY NAME and TITLE: Cassie Garvin, Director of Policy

FIRM NAME: NCSEA
ADDRESS: 4800 Six Forks Rd, suite 300
CITY: Raleigh STATE: NC ZIP CODE: 27609

APPEARANCE ON BEHALF OF: NCSEA

APPLICANT: ___ COMPLAINANT: ___ INTERVENOR: X
PROTESTANT: ___ RESPONDENT: ___ DEFENDANT: ___

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☒ **Yes, I have signed the Confidentiality Agreement.**

Email: CASSIE@energync.org

SIGNATURE: /s/ KTM: Cassie Garvin

(Signature Required for distribution of CONFIDENTIAL information)

**NORTH CAROLINA UTILITIES COMMISSION
APPEARANCE SLIP**

DATE: 8/28/23 DOCKET NO.: E-7, Sub 1276

ATTORNEY NAME and TITLE: Ben Snowden, Partner

FIRM NAME: Fox Rothschild LLP

ADDRESS: 434 Fayetteville St., Suite 2800

CITY: Raleigh STATE: NC ZIP CODE: 27601

APPEARANCE ON BEHALF OF: North Carolina League of Municipalities

APPLICANT: ___ COMPLAINANT: ___ INTERVENOR: x ___

PROTESTANT: ___ RESPONDENT: ___ DEFENDANT: ___

Non-confidential transcripts are located on the Commission's website. To view and/or print transcripts, go to <https://www.ncuc.net/>, hover over the Dockets tab, select Docket Search, enter the docket number, and click search, select the highlighted docket number and select Documents for a list of all documents filed.

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x ___ Yes, I have signed the Confidentiality Agreement.

Email: bsnowden@foxrothschild.com

SIGNATURE: BSnowden

Digitally signed by BSnowden
Date: 2023.04.27 16:52:04 -0400

(Signature Required for distribution of CONFIDENTIAL information)

**NORTH CAROLINA UTILITIES COMMISSION
APPEARANCE SLIP**

DATE: 8/25/2023 **DOCKET NO.:** E-7 Sub 1276

ATTORNEY NAME and TITLE: _____

Alan Jenkins

FIRM NAME: Jenkins at Law, LLC

ADDRESS: 2950 Yellowtail Ave

CITY: Marathon **STATE:** FL **ZIP CODE:** 33050

APPEARANCE ON BEHALF OF: The Commercial Group

APPLICANT: ___ **COMPLAINANT:** ___ **INTERVENOR:** x ___

PROTESTANT: ___ **RESPONDENT:** ___ **DEFENDANT:** ___

Non-confidential transcripts are located on the Commission's website. To view and/or print transcripts, go to <https://www.ncuc.net/>, hover over the Dockets tab, select Docket Search, enter the docket number, and click search, select the highlighted docket number and select Documents for a list of all documents filed.

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_____ **Yes, I have signed the Confidentiality Agreement.**

Email: aj@jenkinsatlaw.com

SIGNATURE: _____

(Signature Required for distribution of CONFIDENTIAL information)

**NORTH CAROLINA UTILITIES COMMISSION
APPEARANCE SLIP**

DATE: August 22, 2023 **DOCKET NO.:** E-7, Sub 1276

ATTORNEY NAME and TITLE: Catherine Cralle Jones

FIRM NAME: Law Offices of F. Bryan Brice, Jr.

ADDRESS: 130 S. Salisbury Street

CITY: Raleigh **STATE:** NC **ZIP CODE:** 27601

APPEARANCE ON BEHALF OF: Sierra Club

APPLICANT: ___ **COMPLAINANT:** ___ **INTERVENOR:** x

PROTESTANT: ___ **RESPONDENT:** ___ **DEFENDANT:** ___

Non-confidential transcripts are located on the Commission's website. To view and/or print transcripts, go to <https://www.ncuc.net/>, hover over the Dockets tab, select Docket Search, enter the docket number, and click search, select the highlighted docket number and select Documents for a list of all documents filed.

ONLY fill out this portion if you have signed an NDA to receive **CONFIDENTIAL** transcripts and/or exhibits:

x Yes, I have signed the Confidentiality Agreement.

Email: cathy@attybryanbrice.com

SIGNATURE: Catherine Cralle Jones

(Signature Required for distribution of **CONFIDENTIAL** information)

NORTH CAROLINA UTILITIES COMMISSION
APPEARANCE SLIP

DATE: August 22, 2023 **DOCKET NO.:** E-7, Sub 1276

ATTORNEY NAME and TITLE: Andrea C. Bonvecchio

FIRM NAME: Law Offices of F. Bryan Brice, Jr.

ADDRESS: 130 S. Salisbury Street

CITY: Raleigh **STATE:** NC **ZIP CODE:** 27601

APPEARANCE ON BEHALF OF: Sierra Club

APPLICANT: ___ **COMPLAINANT:** ___ **INTERVENOR:** x

PROTESTANT: ___ **RESPONDENT:** ___ **DEFENDANT:** ___

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x Yes, I have signed the Confidentiality Agreement.

Email: andrea@attybryanbrice.com

SIGNATURE: 

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**NORTH CAROLINA UTILITIES COMMISSION
APPEARANCE SLIP**

DATE: August 28, 2023 **DOCKET NO.:** E-7, Sub 1276

ATTORNEY NAME and TITLE: David L. Neal, Senior Attorney

FIRM NAME: Southern Environmental Law Center

ADDRESS: 601 West Rosemary Street, Suite 220

CITY: Chapel Hill **STATE:** North Carolina **ZIP CODE:** 27516

APPEARANCE ON BEHALF OF: _____

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

APPLICANT: **COMPLAINANT:** **INTERVENOR:** x

PROTESTANT: **RESPONDENT:** **DEFENDANT:**

Non-confidential transcripts are located on the Commission's website. To view and/or print transcripts, go to <https://www.ncuc.net/>, hover over the Dockets tab, select Docket Search, enter the docket number, and click search, select the highlighted docket number and select Documents for a list of all documents filed.

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x **Yes, I have signed the Confidentiality Agreement.**

Email: dneal@selcnc.org

SIGNATURE:  2023.08.23 12:33:09 -04'00'

(Signature Required for distribution of CONFIDENTIAL information)

**NORTH CAROLINA UTILITIES COMMISSION
APPEARANCE SLIP**

DATE: 08/28/2023 **DOCKET NO.:** E-7, Sub 1276

ATTORNEY NAME and TITLE: Munaashe Magarira, Staff Attorney

FIRM NAME: Southern Environmental Law Center

ADDRESS: 601 W Rosemary Street, Suite 220

CITY: Chapel Hill **STATE:** NC **ZIP CODE:** 27516

APPEARANCE ON BEHALF OF: North Carolina Justice Center, North Carolina Housing Coalition,

Natural Resources Defense Council, Southern Alliance for Clean Energy, and Vote Solar

APPLICANT: **COMPLAINANT:** **INTERVENOR:** x

PROTESTANT: **RESPONDENT:** **DEFENDANT:**

Non-confidential transcripts are located on the Commission's website. To view and/or print transcripts, go to <https://www.ncuc.net/>, hover over the Dockets tab, select Docket Search, enter the docket number, and click search, select the highlighted docket number and select Documents for a list of all documents filed.

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x **Yes, I have signed the Confidentiality Agreement.**

Email: mmagarira@selcnc.org

SIGNATURE:  Digitally signed by Munaashe Magarira
Date: 2023.08.22 09:28:18 -0400

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**NORTH CAROLINA UTILITIES COMMISSION
APPEARANCE SLIP**

DATE: 05/04/2023 **DOCKET NO.:** E-2 Sub 1300

ATTORNEY NAME and TITLE: Thomas Gooding, Associate Attorney

FIRM NAME: Southern Environmental Law Center

ADDRESS: 601 W. Rosemary Street, Suite 220

CITY: Chapel Hill **STATE:** NC **ZIP CODE:** 27516

APPEARANCE ON BEHALF OF: North Carolina Justice Center, North Carolina Housing Coalition,

Natural Resources Defense Council, Southern Alliance for Clean Energy, and Vote Solar

APPLICANT: **COMPLAINANT:** **INTERVENOR:** x

PROTESTANT: **RESPONDENT:** **DEFENDANT:**

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x **Yes, I have signed the Confidentiality Agreement.**

Email: tgooding@selcnc.org

SIGNATURE: Thomas Gooding

Digitally signed by Thomas Gooding
Date: 2023.04.29 12:46:38 -0400

(Signature Required for distribution of CONFIDENTIAL information)

OFFICIAL COPY

Nov 02 2023

ATTORNEY NAME and TITLE: Matthew D. Quinn, Partner

ADDRESS: P. O. Box 17529

CITY: Raleigh STATE: NC ZIP CODE: 27619

APPEARANCE ON BEHALF OF: NC WARN

APPLICANT: ___ COMPLAINANT: ___ INTERVENOR: X

PROTESTANT: ____ RESPONDENT: ____ DEFENDANT: ____

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Email: _____

SIGNATURE: _____

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**NORTH CAROLINA UTILITIES COMMISSION
APPEARANCE SLIP**

DATE: 8-28-2023 DOCKET NO.: E-7 Sub 1276

ATTORNEY NAME and TITLE: Kurt Boehm

FIRM NAME: Boehm, Kurtz & Lowry

ADDRESS: 36 East Seventh Street, Suite 1510

CITY: Cincinnati STATE: Ohio ZIP CODE: 45202

APPEARANCE ON BEHALF OF: Kroger Co. and Harris Teeter

APPLICANT: COMPLAINANT: INTERVENOR: x

PROTESTANT: RESPONDENT: DEFENDANT:

Non-confidential transcripts are located on the Commission's website. To view and/or print transcripts, go to <https://www.ncuc.net/>, hover over the Dockets tab, select Docket Search, enter the docket number, and click search, select the highlighted docket number and select Documents for a list of all documents filed.

ONLY fill out this portion if you have signed an NDA to receive **CONFIDENTIAL** transcripts and/or exhibits:

x Yes, I have signed the Confidentiality Agreement.

Email: kboehm@bkllawfirm.com

SIGNATURE: 

(Signature Required for distribution of **CONFIDENTIAL** information)

OFFICIAL COPY

Nov 02 2023

(Signature Required for distribution of CONFIDENTIAL information)

OFFICIAL COPY

Nov 02 2023

(Signature Required for distribution of CONFIDENTIAL information)

**NORTH CAROLINA UTILITIES COMMISSION
APPEARANCE SLIP**

DATE: 8-28-23 **DOCKET NO.:** E-7, Sub 1276

ATTORNEY NAME and TITLE: Marcus W. Trathen

FIRM NAME: Brooks Pierce McLendon Humphrey & Leonard, LLP

ADDRESS: 1700 Wells Fargo Capitol Center, 150 Fayetteville St.

CITY: Raleigh **STATE:** NC **ZIP CODE:** 27601

APPEARANCE ON BEHALF OF: Andale, LLC

APPLICANT: ___ **COMPLAINANT:** ___ **INTERVENOR:** X

PROTESTANT: ___ **RESPONDENT:** ___ **DEFENDANT:** ___

Non-confidential transcripts are located on the Commission's website. To view and/or print transcripts, go to <https://www.ncuc.net/>, hover over the Dockets tab and select Docket Search, enter the docket number and click search, select the highlighted docket number and select Documents for a list of all documents filed.

To receive an electronic **CONFIDENTIAL** transcript, please complete the following:

☒ **Yes, I have signed the Confidentiality Agreement.**

Email: mtrathen@brookspierce.com

SIGNATURE: /s/ Marcus Trathen

(Required for distribution of **CONFIDENTIAL** transcript)

**NORTH CAROLINA UTILITIES COMMISSION
APPEARANCE SLIP**

DATE: 8/28/2023 **DOCKET NO.:** E-7, Sub 1276

ATTORNEY NAME and TITLE: Tirrill Moore

Assistant Attorney General

FIRM NAME: North Carolina Attorney General's Office

ADDRESS: 114 West Edenton Street

CITY: Raleigh **STATE:** NC **ZIP CODE:** 27602

APPEARANCE ON BEHALF OF: The using and consuming public; the State and its citizens

APPLICANT: **COMPLAINANT:** **INTERVENOR:** X

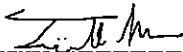
PROTESTANT: **RESPONDENT:** **DEFENDANT:**

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X **Yes, I have signed the Confidentiality Agreement.**

Email: temoore@ncdoj.gov

SIGNATURE: 

(Signature Required for distribution of CONFIDENTIAL information)

**NORTH CAROLINA UTILITIES COMMISSION
APPEARANCE SLIP**

DATE: August 28, 2023 **DOCKET NO.:** E-7, Sub 1276

ATTORNEY NAME and TITLE: Derrick C. Mertz, Special Deputy Attorney General;

FIRM NAME: North Carolina Department of Justice

ADDRESS: 114 W. Edenton Street

CITY: Raleigh **STATE:** NC **ZIP CODE:** 27603

APPEARANCE ON BEHALF OF: The using and consuming public pursuant to N.C.G.S. sec. 62-20, and

on behalf of the State of North Carolina and its citizens pursuant to N.C.G.S. sec. 114-2(8)

APPLICANT: ___ **COMPLAINANT:** ___ **INTERVENOR:** X

PROTESTANT: ___ **RESPONDENT:** ___ **DEFENDANT:** ___

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ONLY fill out this portion if you have signed an NDA to receive **CONFIDENTIAL** transcripts and/or exhibits:

X **Yes, I have signed the Confidentiality Agreement.**

Email: dmertz@ncdoj.gov

SIGNATURE: Derrick Mertz

Digitally signed by Derrick Mertz
Date: 2023.08.23 15:26:03 -0400

(Signature Required for distribution of CONFIDENTIAL information)

NORTH CAROLINA UTILITIES COMMISSION
PUBLIC STAFF - APPEARANCE SLIP

DATE August 28, 2023 DOCKET # : E-7, Sub 1276

PUBLIC STAFF ATTORNEY Lucy E. Edmondson; Robert B. Josey; Nadia L. Luhr; Thomas J. Felling; William E. H. Creech; William S.F. Freeman; Anne M. Keyworth

TO REQUEST A **CONFIDENTIAL** TRANSCRIPT, PLEASE PROVIDE YOUR EMAIL ADDRESS BELOW:

ACCOUNTING _____

CONSUMER SERVICES _____

COMMUNICATIONS _____

ENERGY _____

ECONOMICS _____

LEGAL lucy.edmondson@psncuc.nc.gov; robert.josey@psncuc.nc.gov; nadia.luhr@psncuc.nc.gov; thomas.felling@psncuc.nc.gov; zeke.creech@psncuc.nc.gov; william.freeman@psncuc.nc.gov; anne.keyworth@psncuc.nc.gov

TRANSPORTATION _____

WATER _____

Non-confidential transcripts are located on the Commission's website. To view and/or print, please access <https://www.ncuc.net/>.

COUNSEL/MEMBER(s) REQUESTING A **CONFIDENTIAL** TRANSCRIPT WHO HAS SIGNED A CONFIDENTIALITY AGREEMENT WILL NEED TO SIGN BELOW.

/s/ Lucy E. Edmondson

/s/ Robert B. Josey

/s/ Nadia L. Luhr

/s/ Thomas J. Felling

/s/ William E. H. Creech

/s/ William Freeman /s/ Anne M. Keyworth

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION**DOCKET NO. E-7, SUB 1276**

In the Matter of:	)	
	)	
Application of Duke Energy Carolinas, LLC for	)	SUPPLEMENTAL
Adjustment of Rates and Charges Applicable to	)	AGREEMENT AND
Electric Service in North Carolina and	)	STIPULATION OF
Performance-Based Regulation	)	PARTIAL SETTLEMENT

Duke Energy Carolinas, LLC (“DEC” or the “Company”) and the Public Staff – North Carolina Utilities Commission (the “Public Staff”), collectively referred to herein as the “Stipulating Parties” through counsel and pursuant to N.C. Gen. Stat. § 62-69, respectfully submit the following Supplemental Agreement and Stipulation of Settlement regarding the Company’s May and June Supplemental Update (“Supplemental Revenue Requirement Stipulation”) for consideration by the North Carolina Utilities Commission (“Commission”) in the above captioned docket.

I. BACKGROUND

1. On January 19, 2023, the Company filed its Application to Adjust Retail Base Rates and for Performance-Based Regulation, and Request for an Accounting Order, in Docket No. E-7, Sub 1276, along with supporting direct testimony and exhibits, and Commission Form E-1, Rate Case Information Report – Electric Companies (“Application”).

2. On February 16, 2023, the Commission issued its Order Establishing General Rate Case and Suspending Rates, which declared this proceeding to be a general

rate case and suspended the proposed rates for up to 300 days pursuant to N.C. Gen. Stat. § 62-133.16. On March 16, 2023, the Commission entered an order scheduling hearings, establishing due dates for intervention, discovery, and testimony, and requiring public notice of the Company's Application.

3. On May 19, 2023, the Company filed its First Supplemental Filing, on June 19, 2023, the Company filed its Second Supplemental Filing, covering the month of May, and on July 18, 2023, the Company filed its Third Supplemental Filing, covering the month of June.

4. On July 19, 2023, the Public Staff and the other intervenors in this proceeding filed testimony. On August 4, 2023, the Company filed its rebuttal testimony.

5. The parties to the proceeding conducted substantial discovery on the issues raised in the Application, as well as on the direct, first supplemental, second supplemental, and rebuttal testimonies of the Company and the Company conducted substantial discovery on the direct testimonies of the Public Staff and intervenors.

6. On August 22, 2023, the Stipulating Parties executed and filed an Agreement and Stipulation of Partial Settlement and filed supporting Settlement Testimony on August 24, 2023.

7. On August 28, 2023, the Stipulating Parties executed and filed an Amended Agreement and Stipulation of Partial Settlement (as so amended, the "Revenue Requirement Stipulation"), and the Company filed supporting Supplemental Settlement Testimony.

8. The Revenue Requirement Stipulation specified that it "does not prevent the Public Staff from completing its audit of DEC's Second and Third Supplemental

Updates filed in this docket or making proposed adjustments to the updated revenue requirements based on such audit, which will be presented in the Public Staff's Supplemental Testimony to be filed in this docket." The Public Staff has now completed its audit of all supplemental filings and the Stipulating Parties hereby agree to the additional adjustments identified herein as full resolution of such audit, with the continuing exception of the Unresolved Issues previously identified in the Revenue Requirement Stipulation.

9. For the benefit of the Commission and all parties, the Stipulating Parties have each prepared an exhibit that will be filed with their respective settlement testimonies presenting a consolidated summary of the adjustments to the base period and MYRP revenue requirements in this case based on the adjustments agreed to in the Revenue Requirement Stipulation and this Supplemental Revenue Requirement Stipulation. Those exhibits also present the impact on the base period and MYRP revenue requirement of the respective Stipulating Parties' positions on the Unresolved issues.

10. The Stipulating Parties agree and stipulate as follows:

II. UNRESOLVED ISSUES

The Stipulating Parties have not reached a compromise on the issues identified in the Revenue Requirement Stipulation as "Unresolved Issues"¹ and therefore continue to agree that such issues should be determined by the Commission.

III. RESOLVED ISSUES

The Stipulating Parties have reached an agreement regarding the following issues specific to the Company's May and June Supplemental Filing. Aside from those

¹ Amended Agreement and Stipulation of Partial Settlement, at § II, Docket No. E-7, Sub 1276 (filed August 28, 2023).

adjustments identified herein and those adjustments identified in the Revenue Requirement Stipulation, no further adjustments will be made to the Company's base period or Multiyear Rate Plan ("MYRP") revenue requirement. The areas of agreement are as follows:

Allen 230 kV Transformer Project (Plant in Service)

1. The Stipulating Parties agree that for purposes of this proceeding only, the Company shall remove from rate base the Allen 230 kV Transformer Project, resulting in a decrease of \$5,024,146 from Plant in Service on a system basis, but shall move such project to MYRP Rate Year 1 and adjust the MYRP revenue requirement accordingly.

Apex Solar Additional Facilities Charge (Revenue)

2. The Stipulating Parties agree to apply annualized extra facilities revenue of \$310,987 related to the Apex Solar facility to the base period revenue requirement.

Durham Main Spill Prevention, Control, and Countermeasure ("SPCC") Project (Plant in Service)

3. The Stipulating Parties agree that DEC will reclassify from distribution to transmission plant the \$2,834,492 system amount related to a portion of the Durham Main SPCC project that is included in the base period.

4. The Stipulating Parties agree to remove from rate base costs related to a portion of the Durham Main SPCC that was prematurely closed to plant, resulting in a decrease of \$751,724 from Plant in Service in the base period on a system basis. The Stipulating Parties further agree that this portion of the Durham Main SPCC project was eligible to have been included in the MYRP; however, as part of settlement, the Stipulating Parties agree that no adjustment will be made to the MYRP revenue requirement in

connection with this portion of the Durham Main SPCC project.

Rosman – SS – Quebec Project (Plant in Service)

5. The Stipulating Parties agree that DEC will reclassify the \$418,751 system amount related to the Rosman SS – Quebec 44 kV OCB Replacement project from Distribution FERC to Transmission FERC.

Misenheimer Solar

6. The Stipulating Parties agree that the Company shall remove \$853,150 from Plant in Service on a system basis related to the Misenheimer Solar project.

Rate Case Expense

7. The Stipulating Parties agree that DEC may update its rate case expense with expense incurred through the date of filing of supplemental proposed orders, with all such expenses subject to audit by the Public Staff. 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.

Ernst and Young (“E&Y”) Contract

8. The Stipulating Parties agree that, for reporting purpose only, DEC, along with Duke Energy Progress, LLC, shall track and report in the next base rate case the following information on a system and allocated basis: (i) test period labor costs included in the revenue requirement in this rate case that were impacted by the E&Y contract, including payroll, labor, fringe benefits, pensions & benefits, incentives, outside services, and employee expenses (for employee expenses, the Stipulating Parties will consult to determine) as well as any additional categories the Company has included in its calculation of the \$15M savings over the next five years; and (ii) the actual costs incurred under the

E&Y contract. For purposes of reporting of both savings and costs, the allocations assumed in this rate case would also be utilized for reporting (*i.e.*, allocations between capital / O&M; service company / operating company; and operating company / retail).

IV. AGREEMENT IN SUPPORT OF SETTLEMENT; NON-WAIVER

1. The Stipulating Parties shall act in good faith and use their best efforts to recommend to the Commission that this Supplemental Revenue Requirement Stipulation be accepted and approved. The Stipulating Parties further agree that this Supplemental Revenue Requirement Stipulation is in the public interest because it reflects a give-and-take of contested issues and results in rates (with respect to the stipulated issues) that are just and reasonable. The Stipulating Parties intend to support the reasonableness of this Stipulation in any hearing before the Commission and any proposed order or brief in this docket.

2. Neither this Supplemental Revenue Requirement Stipulation nor any of the terms shall be admissible in any court or Commission except insofar as such court or Commission is addressing litigation arising out of the implementation of the terms herein or the approval of this Supplemental Revenue Requirement Stipulation. This Supplemental Revenue Requirement Stipulation shall not be cited as precedent by any of the Parties regarding any issue in any other proceeding or docket before this Commission or in any court.

3. The provisions of this Supplemental Revenue Requirement Stipulation do not reflect any position asserted by any of the Stipulating Parties but reflect instead the compromise and settlement among the Stipulating Parties as to all the issues covered hereby. No Party waives any right to assert any position in any future proceeding or docket

before the Commission or in any court.

4. This Supplemental Revenue Requirement Stipulation is a product of negotiation among the Stipulating Parties, and no provision of this Stipulation shall be strictly construed in favor of or against any Party.

V. RECEIPT OF TESTIMONY AND WAIVER OF CROSS-EXAMINATION

The pre-filed testimony and exhibits or portions thereof of the Stipulating Parties on this Supplemental Revenue Requirement Stipulation may be received in evidence without objection, and each Party waives all right to cross examine any witness with respect to such pre-filed testimony and exhibits. If, however, questions are asked by any Commissioner, or if questions are asked or positions are taken by any person who is not a Stipulating Party, then any Stipulating Party may respond to such questions by presenting testimony or exhibits and cross-examining any witness with respect to such testimony and exhibits.

VI. STIPULATION BINDING ONLY IF ACCEPTED IN ITS ENTIRETY

This Supplemental Revenue Requirement Stipulation is the product of negotiation and compromise of a complex set of issues, and no portion of this Stipulation is or will be binding on any of the Stipulating Parties unless the entire Supplemental Revenue Requirement Stipulation is accepted by the Commission. If the Commission rejects any part of this Supplemental Revenue Requirement Stipulation or approves this Supplemental Revenue Requirement Stipulation subject to any change or condition or if the Commission's approval of this Supplemental Revenue Requirement Stipulation is rejected or conditioned by a reviewing court, the Stipulating Parties agree to meet and discuss the applicable Commission or court order within five business days of its issuance and to

attempt in good faith to determine if they are willing to modify the Supplemental Revenue Requirement Stipulation consistent with the order. No Party shall withdraw from the Supplemental Revenue Requirement Stipulation prior to complying with the foregoing sentence. If any Party withdraws from the Supplemental Revenue Requirement Stipulation, each Party retains the right to seek additional procedures before the Commission, including cross-examination of witnesses, with respect to issues addressed by the Supplemental Revenue Requirement Stipulation and shall be bound or prejudiced by the terms and conditions of the Supplemental Revenue Requirement Stipulation.

VII. COUNTERPARTS

This Supplemental Revenue Requirement Stipulation may be executed in one or more counterparts, each of which shall be deemed an original, but all of which together shall constitute one and the same instrument. Execution by electronic signature shall be deemed to be, and shall have the same effect as, execution by original signature.

VIII. MERGER CLAUSE

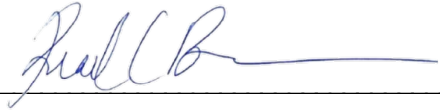
This Supplemental Revenue Requirement Stipulation should be read in concert with the Revenue Requirement Stipulation and all prior understandings between the Stipulating Parties as to the issues discussed herein and may not be changed or terminated orally, and no attempted change, termination, or waiver of any of the provisions hereof shall be binding unless in writing and signed by the parties hereto. Any conflict between this agreement and all prior agreements should be read in favor of the terms in this Supplemental Revenue Requirement Stipulation.

The foregoing is agreed and stipulated this the 13th day of October, 2023.

[Signatures on following page]

IN WITNESS WHEREOF, the Parties have signed and executed as of the date set forth above.

DUKE ENERGY CAROLINAS, LLC

By: _____

PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION

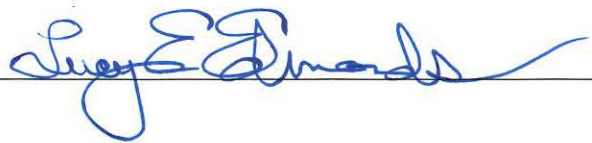
By: _____

IN WITNESS WHEREOF, the Parties have signed and executed as of the date set forth above.

DUKE ENERGY CAROLINAS, LLC

By: _____

PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION

By: _____

DUKE ENERGY CAROLINAS, LLC
SUMMARY OF PROPOSED REVENUE ADJUSTMENTS
FOR EACH RATE YEAR, USING A BASE PERIOD TEST YEAR ENDED DECEMBER 31, 2021
SUPPLEMENTAL REVENUE REQUIREMENT STIPULATION
(Dollars in Millions)

SUPPLEMENTAL REVENUE REQUIREMENT STIPULATION Exhibit 1
Page 1

I/A

Line		NC RETAIL OPERATIONS				
No.	Description	Base Rates	EDIT Rider	Over Amortization Rider	Total Impact	Reference
	<u>Base Rate</u>					
1	Traditional Base Rate Revenue Requirement	\$ 368.5	\$ (10.4) [1]	\$ (0.5)	\$ 357.7	Q. Bowman Exhibit 2 Page 1 Total, Column 5, Line No. 1
2	Rate Year 1 - Incremental Revenue Requirement for MYRP Projects	124.6			\$ 124.6	Abernathy, Exhibit 4, Updated for Settlement
3	Rate Year 1 - Total (L1 + L2)	\$ 493.1	\$ (10.4)	\$ (0.5)	\$ 482.3	
4	Rate Year 2 - Incremental Revenue Requirement for MYRP Projects	\$ 176.4	\$ -	\$ 0.5	\$ 176.9	Abernathy, Exhibit 4, Updated for Settlement
5	Rate Year 3 - Incremental Revenue Requirement for MYRP Projects	\$ 161.2	\$ -		\$ 161.2	Abernathy, Exhibit 4, Updated for Settlement
6	Cumulative Rate year 3 Revenue Increase	\$ 830.7	\$ (10.4)	\$ -	\$ 820.3	Sum Lines 3 - 5

[1] Proposed EDIT rider reduction would expire in June 2026 (part way through Rate Year 3) along with the rest of the EDIT-4 rider.
Note: This table does not include the Nuclear PTC Rider agreed upon in the Supplemental Partial Settlement

-- Some totals may not foot or compute due to rounding.

DUKE ENERGY CAROLINAS, LLC
 OPERATING INCOME FROM ELECTRIC OPERATIONS
 FOR THE TEST PERIOD ENDED DECEMBER 31, 2021
 SUPPLEMENTAL REVENUE REQUIREMENT STIPULATION
 (Thousands of Dollars)

SUPPLEMENTAL REVENUE REQUIREMENT STIPULATION Exhibit 2
 Page 1 Total

Line No.	Description	Total Company Per Books (a)	Traditional Base Rate Revenue Requirement North Carolina Retail Operations				
			Per Books (a)	Accounting Adjustments (c)	Before Proposed Increase (Col. 4) = Col. 2 + Col. 3	Revenue and Expenses from Proposed Increase (e) (Col. 5)	After Proposed Increase (Col. 6) = Col. 4 + Col. 5
		(Col. 1)	(Col. 2)	(Col. 3)			
1	Electric operating revenue	\$ 7,100,634	\$ 4,823,959	\$ 349,350	\$ 5,173,309	\$ 368,540	\$ 5,541,850
	Electric operating expenses:						
	Operation and maintenance:						
2	Fuel used in electric generation	1,504,310	1,023,187	120,669	1,143,856	-	1,143,856
3	Purchased power	97,774	58,933	(25,178)	33,754	-	33,754
4	Other operation and maintenance expense	1,711,413	1,192,866	(57,993)	1,134,872	2,697	1,137,569
5	Depreciation and amortization	1,508,461	1,033,226	186,893	1,220,120	-	1,220,120
6	General taxes	320,410	212,490	(1,045)	211,446	-	211,446
7	Interest on customer deposits (b)	5,907	5,652	-	5,652	-	5,652
8	EDIT Amortization (net of tax)	(258,268)	(204,469)	180,377	(24,092)	-	(24,092)
9	Net income taxes	334,842	220,304	17,672	237,976	85,270	323,246
10	Amortization of investment tax credit	(3,960)	(2,830)	1,026	(1,804)	-	(1,804)
11	Total electric operating expenses	\$ 5,220,889	\$ 3,539,360	\$ 422,421	\$ 3,961,781	\$ 87,966	\$ 4,049,747
12	Operating income	\$ 1,879,745	\$ 1,284,599	\$ (73,070)	\$ 1,211,529	\$ 280,574	\$ 1,492,103
13	Initial cost rate base	\$ 25,767,684	\$ 17,596,163	\$ 1,883,768 (d)	\$ 19,479,931	\$ 31,097 (f)	\$ 19,511,028
14	Rate of return on North Carolina retail rate base		7.30%		6.22%		7.65%

-- Some totals may not foot or compute due to rounding.

Notes: (a) From Form E-1, Item 45a Per Book COS 12 CP Firm

(b) Reclassifies interest on customer deposits to electric operating expense

(c) From Q. Bowman Exhibit 2 Page 3, column (Col.46)

(d) From Q. Bowman Exhibit 2 Page 4, Line 9

(e) From Q. Bowman Exhibit 2 Page 2

(f) From Q. Bowman Exhibit 2 Page 4.4, Line 1. Reflects an increase in operating funds per lead-lag study for the adjusted total requirements in this rate case excluding the portion already adjusted in Col. 5, Line 1.

DUKE ENERGY CAROLINAS, LLC
 OPERATING INCOME FROM ELECTRIC OPERATIONS
 FOR THE TEST PERIOD ENDED DECEMBER 31, 2021
 SUPPLEMENTAL REVENUE REQUIREMENT STIPULATION
 (Thousands of Dollars)

SUPPLEMENTAL REVENUE REQUIREMENT STIPULATION Exhibit 2
 Page 1.1
 Excluding ARO CCR

Line No.	Description	Total Company Per Books (a)	Traditional Base Rate Revenue Requirement North Carolina Retail Operations				
			Per Books	Accounting Adjustments (c)	Before Proposed Increase	Revenue and Expenses from Proposed Increase (e)	After Proposed Increase
		(Col. 1)	(Col. 2)	(Col. 3)	(Col. 4) = Col. 2 + Col. 3	(Col. 5)	(Col. 6) = Col. 4 + Col. 5
1	Electric operating revenue	\$ 7,100,634	\$ 4,799,133	\$ 349,350	\$ 5,148,483	\$ 309,107	\$ 5,457,590
	Electric operating expenses:						
	Operation and maintenance:						
2	Fuel used in electric generation	1,504,310	1,023,187	120,669	1,143,856	-	1,143,856
3	Purchased power	97,774	58,933	(25,178)	33,754	-	33,754
4	Other operation and maintenance expense	1,711,413	1,192,771	(57,993)	1,134,778	2,262	1,137,040
5	Depreciation and amortization	1,508,461	1,013,448	138,913	1,152,361	-	1,152,361
6	General taxes	320,410	212,490	(1,045)	211,446	-	211,446
7	Interest on customer deposits (b)	5,907	5,652	-	5,652	-	5,652
8	EDIT Amortization (net of tax)	(258,268)	(204,469)	180,377	(24,092)	-	(24,092)
9	Net income taxes	334,842	219,148	28,875	248,023	71,494	319,517
10	Amortization of investment tax credit	(3,960)	(2,830)	1,026	(1,804)	-	(1,804)
11	Total electric operating expenses	\$ 5,220,889	\$ 3,518,331	\$ 385,644	\$ 3,903,975	\$ 73,755	\$ 3,977,730
12	Operating income	\$ 1,879,745	\$ 1,280,802	\$ (36,294)	\$ 1,244,508	\$ 235,352	\$ 1,479,860
13	Initial cost rate base	\$ 25,767,684	\$ 17,481,380	\$ 1,818,958 (d)	\$ 19,300,338	\$ 31,097 (f)	19,331,435
14	Rate of return on North Carolina retail rate base		7.33%		6.45%		7.66%

-- Some totals may not foot or compute due to rounding.

Notes: (a) From Form E-1, Item 45a Per Book COS 12 CP Firm less Schedule 2 page 1.2
 (b) Reclassifies interest on customer deposits to electric operating expense
 (c) From Q. Bowman Exhibit 2 Page 3, column (Col. 41) + (Col. 42)
 (d) From Q. Bowman Exhibit 2 Page 4, Line 9 less Schedule 2 page 1.2
 (e) From Q. Bowman Exhibit 2 Page 2.1
 (f) From Q. Bowman Exhibit 2 Page 4.4, Line 1. Reflects an increase in operating funds per lead-lag study for the adjusted total requirements in this rate case excluding the portion already adjusted in Col. 5, Line 1.

DUKE ENERGY CAROLINAS, LLC
 OPERATING INCOME FROM ELECTRIC OPERATIONS
 FOR THE TEST PERIOD ENDED DECEMBER 31, 2021
 SUPPLEMENTAL REVENUE REQUIREMENT STIPULATION
 (Thousands of Dollars)

SUPPLEMENTAL REVENUE REQUIREMENT STIPULATION Exhibit 2
 Page 1.2
 ARO CCR

Line No.	Description	Total Company Per Books (Col. 1)	Traditional Base Rate Revenue Requirement North Carolina Retail Operations				
			Per Books (a) (Col. 2)	Accounting Adjustments (c) (Col. 3)	Before Proposed Increase (Col. 4)	Revenue and Expenses from Proposed Increase (D) (Col. 5)	After Proposed Increase (Col. 6) = Col. 4 + Col. 5
1	Electric operating revenue	\$ -	\$ 24,826	\$ -	\$ 24,826	\$ 59,433	\$ 84,259
	Electric operating expenses:						
	Operation and maintenance:						
2	Fuel used in electric generation	-	-	-	-	-	-
3	Purchased power	-	-	-	-	-	-
4	Other operation and maintenance expense	-	94	-	94	435	529
5	Depreciation and amortization	-	19,778	47,980	67,758	-	67,758
6	General taxes	-	-	-	-	-	-
7	Interest on customer deposits	-	-	-	-	-	-
8	EDIT Amortization (net of tax)	-	-	-	-	-	-
9	Net income taxes	-	1,157	(11,203)	(10,047)	13,776	3,729
10	Amortization of investment tax credit	-	-	-	-	-	-
11	Total electric operating expenses	\$ -	\$ 21,029	\$ 36,777	\$ 57,806	\$ 14,211	\$ 72,017
12	Operating income	\$ -	\$ 3,797	\$ (36,777)	\$ (32,980)	\$ 45,222	\$ 12,242
13	Initial cost rate base		\$ 114,783 (b)	\$ 64,810 (d)	\$ 179,592		\$ 179,592
14	Rate of return on North Carolina retail rate base		<u>3.31%</u>		<u>-18.36%</u>		<u>6.82%</u>

-- Some totals may not foot or compute due to rounding.

Notes:

- (a) Docket E-7 Sub 1214 McManeus Compliance Exhibit 2 CCR ARO page 1 divided by 12, times 7 for the number of months the new rates were in effect.
 (b) Q. Bowman Exhibit 4 NC5080 Remove Expiring Amortizations page NC5080-1 Calculation Line 34
 (c) Q. Bowman Exhibit 2 Page 3, Column (Col. 43) + (Col. 44)
 (d) Q. Bowman Exhibit 2 Page 2.2 (ARO CCR)

DUKE ENERGY CAROLINAS, LLC
 CALCULATION OF ADDITIONAL REVENUE REQUIREMENT
 FOR THE TEST PERIOD ENDED DECEMBER 31, 2021
 SUPPLEMENTAL REVENUE REQUIREMENT STIPULATION
 (Thousands of Dollars)

SUPPLEMENTAL REVENUE REQUIREMENT STIPULATION Exhibit 2
 Page 2 Total

Line No.	Description	Dec. 31, 2021 Amount (Col. 1)	Pro forma Ratio (Col. 2)	Traditional Base Rate Revenue Requirement North Carolina Retail Operations					
				Before Proposed Increase			After Proposed Increase		
				Retail Rate Base (Col. 3)	Embedded Cost/ Return % (Col. 4)	Operating Income (Col. 5)	Retail Rate Base (Col. 6)	Embedded Cost/ Return % (Col. 7)	Operating Income (Col. 8)
1	Long-term debt	(e) \$ 12,260,955	47%	\$ 9,155,567	4.56%	\$ 417,494	\$ 9,170,183	4.56%	\$ 418,242
2	Members' equity	(a) 13,888,337	53%	10,324,363	7.69%	794,035	10,340,845	10.40%	1,073,860 (d)
3	Total	\$ 26,149,292	100%	\$ 19,479,931 (b)		\$ 1,211,529 (c)	\$ 19,511,028 (b)		\$ 1,492,103
4	Operating income before increase (Line 3, Column 5)								1,211,529
5	Additional operating income required (Line 3 minus Line 4)								280,574
6	Calculate income tax on Incremental interest expense due to increase in cash working capital in proposed revenue								(156)
7	Regulatory fee (0.1466%), Uncollectibles Rate (0.5847%)								2,697
8	Income Taxes (23.3503%)								85,425
9	Additional traditional base rate revenue requirement								\$ 368,540

-- Some totals may not foot or compute due to rounding.

Notes: (a) The equivalent of common equity for a limited liability company
 (b) From Q. Bowman Exhibit 2 page 1 Total, Line 13 Columns 4 and 6
 (c) From Q. Bowman Exhibit 2 page 1 Total, Line 12, Column 4
 (d) Note: Per the CCR Settlement agreement, Coal Ash ARO discounts the equity rate by 150 basis points.
 (e) Debt Rate subject to update throughout the proceeding.

DUKE ENERGY CAROLINAS, LLC
 CALCULATION OF ADDITIONAL REVENUE REQUIREMENT
 FOR THE TEST PERIOD ENDED DECEMBER 31, 2021
 SUPPLEMENTAL REVENUE REQUIREMENT STIPULATION
 (Thousands of Dollars)

SUPPLEMENTAL REVENUE REQUIREMENT STIPULATION Exhibit 2
 Page 2.1
 Exclude ARO CCR

Line No.	Description	Dec. 31, 2021 Amount (Col. 1)	Pro forma Ratio (Col. 2)	Traditional Base Rate Revenue Requirement North Carolina Retail Operations					
				Before Proposed Increase			After Proposed Increase		
				Retail Rate Base (Col. 3)	Embedded Cost/ Return % (Col. 4)	Operating Income (Col. 5)	Retail Rate Base (Col. 6)	Embedded Cost/ Return % (Col. 7)	Operating Income (Col. 8)
1	Long-term debt	(d) 12,260,955	47%	\$ 9,071,159	4.56%	\$ 413,645	\$ 9,085,775	4.56%	\$ 414,311
2	Members' equity	(a) 13,888,337	53%	10,229,179	8.12%	830,863	10,245,661	10.40%	1,065,549
3	Total	26,149,292	100%	\$ 19,300,338 (b)		1,244,508 (c)	\$ 19,331,435 (b)		\$ 1,479,860
4	Operating income before increase (Line 3, Column 5)								1,244,508
5	Additional operating income required (Line 3 minus Line 4)								235,352
6	Calculate income tax on Incremental interest expense due to increase in cash working capital in proposed revenue								(156)
7	Regulatory fee (0.1466%), Uncollectibles Rate (0.5847%)								2,262
8	Income Taxes (23.3503%)								71,649
9	Additional revenue requirement								\$ 309,107

-- Some totals may not foot or compute due to rounding.

Notes: (a) The equivalent of common equity for a limited liability company
 (b) From Q. Bowman Exhibit 2 Page 1.1 (Exclude ARO CCR), Line 13, Columns 4 and 6
 (c) From Q. Bowman Exhibit 2 Page 1.1 (Exclude ARO CCR), Line 12, Column 4
 (d) Debt rate subject to update throughout the proceeding.

DUKE ENERGY CAROLINAS, LLC
 CALCULATION OF ADDITIONAL REVENUE REQUIREMENT
 FOR THE TEST PERIOD ENDED DECEMBER 31, 2021
 SUPPLEMENTAL REVENUE REQUIREMENT STIPULATION
 (Thousands of Dollars)

SUPPLEMENTAL REVENUE REQUIREMENT STIPULATION Exhibit 2
 Page 2.2
 ARO CCR

Line No.	Description	Dec. 31, 2021 Amount (Col. 1)	Pro forma Ratio (Col. 2)	Traditional Base Rate Revenue Requirement North Carolina Retail Operations					
				Before Proposed Increase			After Proposed Increase		
				Retail Rate Base (Col. 3)	Embedded Cost/ Return % (Col. 4)	Operating Income (Col. 5)	Retail Rate Base (Col. 6)	Embedded Cost/ Return % (Col. 7)	Operating Income (Col. 8)
1	Long-term debt	(f) 	48% (e)	\$ 86,204	4.56%	\$ 3,931	\$ 86,204	4.56%	\$ 3,931
2	Members' equity	(a) 	52% (e)	93,388	-39.52%	(36,911)	93,388	8.90% (d)	8,312
3	Total	 	100%	\$ 179,592 (b)		\$ (32,980) (c)	\$ 179,592 (b)		\$ 12,242
4	Operating income before increase (Line 3, Column 5)								(32,980)
5	Additional operating income required (Line 3 minus Line 4)								45,222
6	Calculate income tax on Incremental interest expense due to increase in cash working capital in proposed revenue								
7	Regulatory fee (0.1466%), Uncollectibles Rate (0.5847%)								435
8	Income Taxes (23.3503%)								13,776
9	Additional revenue requirement								\$ 59,433

-- Some totals may not foot or compute due to rounding.

Notes: (a) The equivalent of common equity for a limited liability company
 (b) From Q. Bowman Exhibit 2 Page 1.2 (ARO CCR), Line 13, Columns 4 and 6
 (c) From Q. Bowman Exhibit 2 Page 1.2 (ARO CCR), Line 12, Column 4
 (d) Per the CCR Settlement agreement, Coal Ash ARO discounts the equity rate by 150 basis points.
 (e) Per the CCR Settlement agreement, Capital structure for CCR is 48% debt 52% equity
 (f) Debt rate subject to update throughout the proceeding.

DUKE ENERGY CAROLINAS, LLC
 DETAIL OF ACCOUNTING ADJUSTMENTS
 NORTH CAROLINA RETAIL
 SUPPLEMENTAL REVENUE REQUIREMENT STIPULATION
 FOR THE TEST PERIOD ENDED DECEMBER 31, 2021
 (Thousands of Dollars)

SUPPLEMENTAL REVENUE REQUIREMENT STIPULATION Exhibit 2
 Page 3.1 of 3.8

	Revenue Annualization NC1010 (Col. 1)	Eliminate unbilled NC1020 (Col. 2)	Adjust other Revenue NC1030 (Col. 3)	Customer Growth* NC1040 (Col. 4)	Weather Normalization NC1050 (Col. 5)	Update Fuel costs to approved rates NC2010 (Col. 6)	Adjust Purchase Power NC2020 (Col. 7)	Adjust for costs recovered through Non Fuel riders NC2030 (Col. 8)	Adj Executive Comp NC2040 (Col. 9)	Labor Annualization* NC2050 (Col. 10)	Benefits Adjustment NC2060 (Col. 11)	Vegetation Management NC2070 (Col. 12)	Adjustments to test year expenses NC2080 (Col. 13)	Adjust Aviation Expense NC2090 (Col. 14)
1 Sales of Electricity	220,249	8,126	(3,748)	53,669	4,807	-	-	25,150	-	-	-	-	3,992	-
2 Other Revenue	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3 Electric operating revenue	\$ 220,249	\$ 8,126	\$ (3,748)	\$ 53,669	\$ 4,807	\$ -	\$ -	\$ 25,150	\$ -	\$ -	\$ -	\$ -	\$ 3,992	\$ -
4														
5 Electric operating expenses:														
6 Operation and maintenance:														
7 Fuel used in electric generation	-	-	-	8,715	891	140,824	-	(29,761)	-	-	-	-	-	-
8 Purchased power	-	-	-	-	-	(42,101)	(1,860)	(968)	-	-	-	-	19,749	-
9 Other operation and maintenance expense	1,611	-	(27)	2,767	110	(18,112)	-	(81,295)	(4,463)	(883)	(641)	3,011	(4,015)	(1,865)
10 Depreciation and amortization	-	-	-	-	-	-	-	14,321	-	-	-	-	(1,429)	-
11 General taxes	-	-	-	-	-	-	-	(940)	-	1,553	-	-	-	(34)
12 Interest on customer deposits	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13 EDIT Amortization (net of tax)	-	-	-	-	-	-	-	180,377	-	-	-	-	-	-
14 Net income taxes	51,053	1,898	(869)	9,851	888	(18,823)	434	30,336	1,042	(156)	150	(703)	(2,408)	443
15 Amortization of investment tax credit	-	-	-	-	-	-	-	945	-	-	-	-	-	-
16 Total electric operating expenses	\$ 52,663	\$ 1,898	\$ (896)	\$ 21,333	\$ 1,890	\$ 61,788	\$ (1,426)	\$ 113,015	\$ (3,421)	\$ 513	\$ (492)	\$ 2,308	\$ 11,897	\$ (1,455)
17 Operating income	\$ 167,586	\$ 6,229	\$ (2,852)	\$ 32,337	\$ 2,917	\$ (61,788)	\$ 1,426	\$ (87,864)	\$ 3,421	\$ (513)	\$ 492	\$ (2,308)	\$ (7,905)	\$ 1,455
18 Operating Income revenue requirement impact	\$ (220,247)	\$ (8,186)	\$ 3,748	\$ (42,498)	\$ (3,833)	\$ 81,204	\$ (1,874)	\$ 115,474	\$ (4,496)	\$ 675	\$ (646)	\$ 3,033	\$ 10,389	\$ (1,913)

* Subject to update throughout the proceeding.

DUKE ENERGY CAROLINAS, LLC
 DETAIL OF ACCOUNTING ADJUSTMENTS
 NORTH CAROLINA RETAIL
 SUPPLEMENTAL REVENUE REQUIREMENT STIPULATION
 FOR THE TEST PERIOD ENDED DECEMBER 31, 2021
 (Thousands of Dollars)

SUPPLEMENTAL REVENUE REQUIREMENT STIPULATION Exhibit 2
 Page 3.2 of 3.8

	Adjust Nuclear Outage levelization*	Annualize non labor O&M*	Adjust EOL Nuclear Costs	Adjust for change in NCUC Regulatory fee	Adjust for Non- Residential Credit Card Fees	Adjust for Duke Energy Plaza	Adjust O&M for Reliability Assurance	Annualize Depreciation on Test Year End Plant	Annualize Property Tax on Test Year End Plant	Adjust for Post Test year additions*	Adjust Depreciation for new depreciation rates	Transmission Merger*	Remove Expiring Amortizations*	Amortize Rate case Costs*	CCR Non ARO*
	NC2100 (Col. 15)	NC2110 (Col. 16)	NC2120 (Col. 17)	NC2130 (Col. 18)	NC2140 (Col. 19)	NC2150 (Col. 20)	NC2160 (Col. 21)	NC3010 (Col. 22)	NC3020 (Col. 23)	NC3030 (Col. 24)	NC3040 (Col. 25)	NC3070 (Col. 26)	NC5010 (Col. 27)	NC5020 (Col. 28)	NC5030 (Col. 29)
1 Sales of Electricity	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2 Other Revenue	-	-	-	-	-	22,513	-	-	-	-	-	-	-	-	-
3 Electric operating revenue	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 22,513	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
4															
5 Electric operating expenses:															
6 Operation and maintenance:															
7 Fuel used in electric generation	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8 Purchased power	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9 Other operation and maintenance expense	5,013	52,823	-	857	-	1,403	4,500	-	-	-	-	-	(22,142)	6,485	-
10 Depreciation and amortization	-	-	(7,091)	-	-	-	-	(3,970)	-	75,360	106,849	(40)	(5,220)	-	1,214
11 General taxes	-	-	-	-	-	-	-	-	4,514	13,575	-	-	-	-	-
12 Interest on customer deposits	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13 EDIT Amortization (net of tax)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14 Net income taxes	(1,170)	(12,334)	1,656	(200)	-	4,929	(1,051)	927	(1,054)	(20,767)	(24,950)	9	6,389	(1,514)	(283)
15 Amortization of investment tax credit	-	-	-	-	-	-	-	81	-	-	-	-	-	-	-
16 Total electric operating expenses	\$ 3,842	\$ 40,489	\$ (5,435)	\$ 657	\$ -	\$ 6,332	\$ 3,449	\$ (2,962)	\$ 3,460	\$ 68,168	\$ 81,900	\$ (31)	\$ (20,973)	\$ 4,971	\$ 930
17 Operating income	\$ (3,842)	\$ (40,489)	\$ 5,435	\$ (657)	\$ -	\$ 16,181	\$ (3,449)	\$ 2,962	\$ (3,460)	\$ (68,168)	\$ (81,900)	\$ 31	\$ 20,973	\$ (4,971)	\$ (930)
18 Operating Income revenue requirement impact	\$ 5,050	\$ 53,212	\$ (7,143)	\$ 864	\$ -	\$ (21,266)	\$ 4,533	\$ (3,892)	\$ 4,547	\$ 89,589	\$ 107,635	\$ (40)	\$ (27,564)	\$ 6,533	\$ 1,223

* Subject to update throughout the proceeding.

DUKE ENERGY CAROLINAS, LLC
 DETAIL OF ACCOUNTING ADJUSTMENTS
 NORTH CAROLINA RETAIL
 SUPPLEMENTAL REVENUE REQUIREMENT STIPULATION
 FOR THE TEST PERIOD ENDED DECEMBER 31, 2021
 (Thousands of Dollars)

SUPPLEMENTAL REVENUE REQUIREMENT STIPULATION Exhibit 2
 Page 3.3 of 3.8

	Grid next tranche*	Amortize Allen NBV	Adjust for approved regulatory assets and liabilities	COVID Deferral*	Customer Connect Amortization	Amortize Deferred Billing	Adjust Coal Inventory	Cash working Capital - Present*	Interest Sync*	NC Tax Rate and Franchise Tax Rate changes	Correct Lead Lad	Unprotected EDIT - Remove from Rate base	Storm Normalization*	Storm Securitization Regulatory Asset*	Exclude CCR ARO
	NC5040 (Col. 30)	NC5060 (Col. 31)	NC5080 (Col. 32)	NC5090 (Col. 33)	NC5120 (Col. 34)	NC5130 (Col. 35)	NC6010 (Col. 36)	NC6020a I'll	NC6030 (Col. 38)	NC6040 (Col. 39)	NC6050 (Col. 40)	NC6090 (Col. 41)	NC7010 (Col. 42)	NC7040 (Col. 43)	Subtotal (Col. 44)
1 Sales of Electricity	-	-	-	-	-	-	-	-	-	-	-	-	-	-	\$ 286,851
2 Other Revenue	-	-	-	14,591	-	-	-	-	-	-	-	-	-	-	62,499
3 Electric operating revenue	\$ -	\$ -	\$ -	\$ 14,591	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 349,350
4															
5 Electric operating expenses:															
6 Operation and maintenance:															
7 Fuel used in electric generation	-	-	-	-	-	-	-	-	-	-	-	-	-	-	120,669
8 Purchased power	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(25,178)
9 Other operation and maintenance expense	-	-	-	1,680	-	-	-	-	-	-	-	-	(4,810)	-	(57,993)
10 Depreciation and amortization	3,951	4,697	(969)	60,967	1,215	-	-	-	-	-	-	-	-	(199)	249,656
11 General taxes	-	-	-	-	-	-	-	-	-	(19,712)	-	-	-	-	(1,045)
12 Interest on customer deposits	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13 EDIT Amortization (net of tax)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	180,377
14 Net income taxes	(923)	(1,097)	946	(11,221)	(284)	-	-	(116)	(13,773)	4,603	-	-	1,113	46	3,017
15 Amortization of investment tax credit	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,026
16 Total electric operating expenses	\$ 3,029	\$ 3,600	\$ (23)	\$ 51,426	\$ 932	\$ -	\$ -	\$ (116)	\$ (13,773)	\$ (15,109)	\$ -	\$ -	\$ (3,697)	\$ (152)	\$ 470,528
17 Operating income	\$ (3,029)	\$ (3,600)	\$ 23	\$ (36,835)	\$ (932)	\$ -	\$ -	\$ 116	\$ 13,773	\$ 15,109	\$ -	\$ -	\$ 3,697	\$ 152	\$ (121,178)
18 Operating Income revenue requirement impact	\$ 3,980	\$ 4,732	\$ (30)	\$ 48,409	\$ 1,224	\$ -	\$ -	\$ (153)	\$ (18,102)	\$ (19,857)	\$ -	\$ -	\$ (4,859)	\$ (200)	\$ 159,256

* Subject to update throughout the proceeding.

DUKE ENERGY CAROLINAS, LLC
 DETAIL OF ACCOUNTING ADJUSTMENTS
 NORTH CAROLINA RETAIL
 SUPPLEMENTAL REVENUE REQUIREMENT STIPULATION
 FOR THE TEST PERIOD ENDED DECEMBER 31, 2021
 (Thousands of Dollars)

SUPPLEMENTAL REVENUE REQUIREMENT STIPULATION Exhibit 2
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	Remove Expiring Amortizations NC5010-CCR (Col. 45)	Amortized Deferred Environmental Cost* NC4010 (Col. 46)	Adjust for approved regulatory assets and liabilities NC5080-CCR (Col. 47)	CCR ARO Subtotal (Col. 48)	Total (Col. 49)	Cash working Capital - Proposed* NC6020b (Col. 50)
1 Sales of Electricity	\$ -	\$ -	\$ -	\$ -	\$ 286,851	-
2 Other Revenue	-	-	-	-	62,499	-
3 Electric operating revenue	\$ -	\$ -	\$ -	\$ -	\$ 349,350	\$ -
4						
5 Electric operating expenses:						
6 Operation and maintenance:						
7 Fuel used in electric generation	-	-	-	-	120,669	-
8 Purchased power	-	-	-	-	(25,178)	-
9 Other operation and maintenance expense	-	-	-	-	(57,993)	-
10 Depreciation and amortization	(110,743)	33,853	14,127	(62,763)	186,893	-
11 General taxes	-	-	-	-	(1,045)	-
12 Interest on customer deposits	-	-	-	-	-	-
13 EDIT Amortization (net of tax)	-	-	-	-	180,377	-
14 Net income taxes	25,859	(7,905)	(3,299)	14,655	17,672	(156)
15 Amortization of investment tax credit	-	-	-	-	1,026	-
16 Total electric operating expenses	\$ (84,884)	\$ 25,948	\$ 10,829	\$ (48,108)	\$ 422,421	\$ (156)
17 Operating income	\$ 84,884	\$ (25,948)	\$ (10,829)	\$ 48,108	\$ (73,070)	\$ 156
18 Operating Income revenue requirement impact	\$ (111,558)	\$ 34,102	\$ 14,231	\$ (63,225)	\$ 96,032	\$ (205)

* Subject to update throughout the proceeding.

DUKE ENERGY CAROLINAS, LLC
 DETAIL OF ACCOUNTING ADJUSTMENTS
 NORTH CAROLINA RETAIL

SUPPLEMENTAL REVENUE REQUIREMENT STIPULATION Exhibit 2
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	Revenue Annualization*	Eliminate unbilled	Adjust other Revenue	Customer Growth*	Weather Normalization	Update Fuel costs to approved rates*	Adjust Purchase Power	Adjust for costs recovered through Non Fuel riders	Adj Executive Comp	Labor Annualization*	Benefits Adjustment	Vegetation Management	Adjustments to test year expenses	Adjust Aviation Expense
	NC1010 (Col. 1)	NC1020 (Col. 2)	NC1030 (Col. 3)	NC1040 (Col. 4)	NC1050 (Col. 5)	NC2010 (Col. 6)	NC2020 (Col. 7)	NC2030 (Col. 8)	NC2040 (Col. 9)	NC2050 (Col. 10)	NC2060 (Col. 11)	NC2070 (Col. 12)	NC2080 (Col. 13)	NC2090 (Col. 14)
Rate Base														
19 Electric plant in service	-	-	-	-	-	-	-	(109,454)	-	-	-	-	(42,468)	-
20 Accumulated depreciation and amortization	-	-	-	-	-	-	-	10,601	-	-	-	-	1,140	-
21 Net electric plant in service (L19 + L20)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (98,854)	\$ -	\$ -	\$ -	\$ -	\$ (41,328)	\$ -
22 Materials and supplies	-	-	-	-	-	-	-	(69,176)	-	-	-	-	(809)	-
Other Working Capital														
23 Customer deposits	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24 Cash Working Capital	-	-	-	-	-	-	-	-	-	-	-	-	-	-
25 Unamortized debt	-	-	-	-	-	-	-	-	-	-	-	-	-	-
26 Required Bank Balance	-	-	-	-	-	-	-	-	-	-	-	-	-	-
27 SFAS-158	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28 Prepayments	-	-	-	-	-	-	-	-	-	-	-	-	-	-
29 Average Taxes Accrual	-	-	-	-	-	-	-	-	-	-	-	-	-	-
30 Injuries and Damages	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31 ARO-related CCR regulatory assets and liabilities	-	-	-	-	-	-	-	-	-	-	-	-	-	-
32 Adjustments to EDIT	-	-	-	-	-	-	-	-	-	-	-	-	-	-
33 Other	-	-	-	-	-	-	-	79,196	-	-	-	-	-	-
34 Total Working Capital	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 79,196	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
35 Accumulated deferred income taxes	-	-	-	-	-	-	-	(18,545)	-	-	-	-	-	-
36 Operating reserves	-	-	-	-	-	-	-	-	-	-	-	-	-	-
37 Construction Work in Progress	-	-	-	-	-	-	-	-	-	-	-	-	-	-
38 Total Initial cost rate base	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (107,379)	\$ -	\$ -	\$ -	\$ -	\$ (42,138)	\$ -
39 Rate Base revenue requirement impact	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (10,097)	\$ -	\$ -	\$ -	\$ -	\$ (3,962)	\$ -
40 Income Tax on Interest Expense	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (706)	\$ -	\$ -	\$ -	\$ -	\$ (277)	\$ -
41 Total Revenue requirement impact (L18+L39+L40)	\$ (220,247)	\$ (8,186)	\$ 3,748	\$ (42,498)	\$ (3,833)	\$ 81,204	\$ (1,874)	\$ 104,671	\$ (4,496)	\$ 675	\$ (646)	\$ 3,033	\$ 6,150	\$ (1,913)

* Subject to update throughout the proceeding.

DUKE ENERGY CAROLINAS, LLC
DETAIL OF ACCOUNTING ADJUSTMENTS
NORTH CAROLINA RETAIL

SUPPLEMENTAL REVENUE REQUIREMENT STIPULATION Exhibit 2

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	Adjust Nuclear Outage levelization*	Annualize non labor O&M (Inflation)*	Adjust EOL Nuclear Costs	Adjust for change in NCUC Regulatory fee	Adjust for Non- Residential Credit Card Fees	Adjust for Duke Energy Plaza	Adjust O&M for Reliability Assurance	Annualize Depreciation on Test Year End Plant	Annualize Property Tax on Test Year End Plant	Adjust for Post Test year additions*	Adjust Depreciation for new depreciation rates	Transmission Merger*	Remove Expiring Amortizations*	Amortize Rate case Costs*	CCR Non ARO
	NC2100 (Col. 15)	NC2110 (Col. 16)	NC2120 (Col. 17)	NC2130 (Col. 18)	NC2140 (Col. 19)	NC2150 (Col. 20)	NC2160 (Col. 21)	NC3010 (Col. 22)	NC3020 (Col. 23)	NC3030 (Col. 24)	NC3040 (Col. 25)	NC3070 (Col. 26)	NC5010 (Col. 27)	NC5020 (Col. 28)	NC5030 (Col. 29)
Rate Base															
19 Electric plant in service	-	-	-	-	-	-	-	-	-	2,654,622	-	(562)	-	-	-
20 Accumulated depreciation and amortization	-	-	-	-	-	-	-	-	-	(560,835)	(145,786)	471	-	-	-
21 Net electric plant in service (L19 + L20)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 2,093,787	\$ (145,786)	\$ (91)	\$ -	\$ -	\$ -
22 Materials and supplies	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other Working Capital															
23 Customer deposits	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24 Cash Working Capital	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
25 Unamortized debt	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
26 Required Bank Balance	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
27 SFAS-158	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28 Prepayments	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
29 Average Taxes Accrual	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
30 Injuries and Damages	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31 ARO-related CCR regulatory assets and liabilities	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
32 Adjustments to EDIT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
33 Other	-	-	-	-	-	-	2,920	-	-	-	38,937	-	-	(7,687)	6,070
34 Total Working Capital	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 2,920	\$ -	\$ -	\$ -	\$ 38,937	\$ -	\$ -	\$ (7,687)	\$ 6,070
35 Accumulated deferred income taxes	-	-	-	-	-	(682)	-	-	-	-	(9,092)	-	-	1,795	(1,417)
36 Operating reserves	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
37 Construction Work in Progress	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
38 Total Initial cost rate base	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 2,238	\$ -	\$ -	\$ -	\$ 2,093,787	\$ (115,941)	\$ (91)	\$ -	\$ (5,892)	\$ 4,652
39 Rate Base revenue requirement impact	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 210	\$ -	\$ -	\$ -	\$ 196,880	\$ (10,902)	\$ (9)	\$ -	\$ (554)	\$ 437
40 Income Tax on Interest Expense	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 15	\$ -	\$ -	\$ -	\$ 13,771	\$ (763)	\$ (1)	\$ -	\$ (39)	\$ 31
41 Total Revenue requirement impact (L18+L39+L40)	\$ 5,050	\$ 53,212	\$ (7,143)	\$ 864	\$ -	\$ (21,041)	\$ 4,533	\$ (3,892)	\$ 4,547	\$ 300,240	\$ 95,971	\$ (49)	\$ (27,564)	\$ 5,940	\$ 1,691

* Subject to update throughout the proceeding.

DUKE ENERGY CAROLINAS, LLC
DETAIL OF ACCOUNTING ADJUSTMENTS
NORTH CAROLINA RETAIL

SUPPLEMENTAL REVENUE REQUIREMENT STIPULATION Exhibit 2

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	Grid next tranche* NC5040 (Col. 30)	Amortize Allen NBV NC5060 (Col. 31)	Adjust for approved regulatory assets and liabilities NC5080 (Col. 32)	COVID Deferral* NC5090 (Col. 33)	Customer Connect Amortization NC5120 (Col. 34)	Amortize Deferred Billing NC5130 (Col. 35)	Adjust Coal Inventory NC6010 (Col. 36)	Cash working Capital - Present* NC6020a (Col. 37)	Interest Sync* NC6030 (Col. 38)	NC Tax Rate and Franchise Tax Rate changes NC6040 (Col. 39)	Correct Lead Lad NC6050 (Col. 40)	Unprotected EDIT - Remove from Rate base NC6090 (Col. 41)	Storm Normalization NC7010 (Col. 42)	Storm Securitization Regulatory Asset* NC7040 (Col. 43)	Exclude CCR ARO Subtotal (Col. 44)
Rate Base															
19 Electric plant in service	-	-	-	-	-	-	-	-	-	-	-	-	-	-	\$ 2,502,137
20 Accumulated depreciation and amortization	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(694,410)
21 Net electric plant in service (L19 + L20)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 1,807,727
22 Materials and supplies	-	-	-	-	-	-	(19,302)	-	-	-	-	-	-	-	(89,287)
Other Working Capital															
23 Customer deposits	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24 Cash Working Capital	-	-	-	-	-	-	-	23,220	-	-	(2,435)	-	-	-	20,785
25 Unamortized debt	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
26 Required Bank Balance	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
27 SFAS-158	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28 Prepayments	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
29 Average Taxes Accrual	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
30 Injuries and Damages	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31 ARO-related CCR regulatory assets and liabilities	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
32 Adjustments to EDIT	-	-	35,058	-	-	-	-	-	-	-	-	17,079	-	-	52,137
33 Other	67,170	(15,727)	(58,587)	121,934	(6,531)	-	-	-	-	-	-	-	-	(398)	227,298
34 Total Working Capital	\$ 67,170	\$ (15,727)	\$ (23,529)	\$ 121,934	\$ (6,531)	\$ -	\$ -	\$ 23,220	\$ -	\$ -	\$ (2,435)	\$ 17,079	\$ -	\$ (398)	\$ 300,219
35 Accumulated deferred income taxes	(15,684)	3,672	5,494	(28,472)	1,525	-	-	-	-	-	-	(3,988)	-	93	(65,301)
36 Operating reserves	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
37 Construction Work in Progress	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
38 Total Initial cost rate base	\$ 51,486	\$ (12,054)	\$ (18,035)	\$ 93,462	\$ (5,006)	\$ -	\$ (19,302)	\$ 23,220	\$ -	\$ -	\$ (2,435)	\$ 13,091	\$ -	\$ (305)	\$ 1,953,358
39 Rate Base revenue requirement impact	\$ 4,841	\$ (1,133)	\$ (1,696)	\$ 8,788	\$ (471)	\$ -	\$ (1,815)	\$ 2,183	\$ -	\$ -	\$ (229)	\$ 1,231	\$ -	\$ (29)	\$ 183,675
40 Income Tax on Interest Expense	\$ 339	\$ (79)	\$ (119)	\$ 615	\$ (33)	\$ -	\$ (127)	\$ 153	\$ -	\$ -	\$ (16)	\$ 86	\$ -	\$ (2)	\$ 12,847
41 Total Revenue requirement impact (L18+L39+L40)	\$ 9,160	\$ 3,519	\$ (1,845)	\$ 57,812	\$ 721	\$ -	\$ (1,942)	\$ 2,183	\$ (18,102)	\$ (19,857)	\$ (245)	\$ 1,317	\$ (4,859)	\$ (231)	\$ 355,779

* Subject to update throughout the proceeding.

DUKE ENERGY CAROLINAS, LLC
DETAIL OF ACCOUNTING ADJUSTMENTS
NORTH CAROLINA RETAIL

SUPPLEMENTAL REVENUE REQUIREMENT STIPULATION Exhibit 2
Page 3.8 of 3.8

	Remove Expiring Amortizations NC5010-CCR (Col. 45)	Amortized Deferred Environmental Cost* NC4010 (Col. 46)	Adjust for approved regulatory assets and liabilities NC5080-CCR (Col. 47)	CCR ARO Subtotal (Col. 48)	Total (Col. 49)	Cash working Capital - Proposed NC6020b (Col. 50)
Rate Base						
19 Electric plant in service	\$ -	\$ -	\$ -	\$ -	\$ 2,502,137	-
20 Accumulated depreciation and amortization	-	-	-	-	(694,410)	-
21 Net electric plant in service (L19 + L20)	\$ -	\$ -	\$ -	\$ -	\$ 1,807,727	\$ -
22 Materials and supplies	-	-	-	-	(89,287)	-
Other Working Capital						
23 Customer deposits	-	-	-	-	-	-
24 Cash Working Capital	-	-	-	-	20,785	31,097
25 Unamortized debt	-	-	-	-	-	-
26 Required Bank Balance	-	-	-	-	-	-
27 SFAS-158	-	-	-	-	-	-
28 Prepayments	-	-	-	-	-	-
29 Average Taxes Accrual	-	-	-	-	-	-
30 Injuries and Damages	-	-	-	-	-	-
31 ARO-related CCR regulatory assets and liabilities	(175,343)	135,411	(50,858)	(90,790)	(90,790)	-
32 Adjustments to EDIT	-	-	-	-	52,137	-
33 Other	-	-	-	-	227,298	-
34 Total Working Capital	\$ (175,343)	\$ 135,411	\$ (50,858)	\$ (90,790)	\$ 209,429	\$ 31,097
35 Accumulated deferred income taxes	40,943	(31,619)	11,876	21,200	(44,102)	-
36 Operating reserves	-	-	-	-	-	-
37 Construction Work in Progress	-	-	-	-	-	-
38 Total Initial cost rate base	\$ (134,400)	\$ 103,792	\$ (38,983)	\$ (69,590)	\$ 1,883,768	\$ 31,097
39 Rate Base revenue requirement impact	\$ (11,138)	\$ 9,760	\$ (3,666)	\$ (5,044)	\$ 178,631	\$ 2,924
40 Income Tax on Interest Expense	\$ (884)	\$ 683	\$ (256)	\$ (458)	\$ 12,390	\$ 205
41 Total Revenue requirement impact (L18+L39+L40)	\$ (123,580)	\$ 44,544	\$ 10,309	\$ (68,726)	\$ 287,052	\$ 2,924

* Subject to update throughout the proceeding.

DUKE ENERGY CAROLINAS, LLC
Initial COST RATE BASE-ELECTRIC OPERATIONS
FOR THE TEST PERIOD ENDED DECEMBER 31, 2021
(Thousands of Dollars)

SUPPLEMENTAL REVENUE REQUIREMENT STIPULATION Exhibit 2
Page 4.0 of 4.4

Line No.	Description	Page Reference	Total Company Per Books (Col. 1)	North Carolina Retail Operations		
				Per Books (Col. 2)	Accounting Adjustments (Col. 3)	As Adjusted (Col. 4)
1	Electric plant in service	4.1, Line 8	46,562,505	31,450,540	\$ 2,502,137	\$ 33,952,678
2	Less: Accumulated depreciation and amortization	4.2, Line 6	<u>(17,621,458)</u>	<u>(11,946,920)</u>	<u>(694,410)</u>	<u>(12,641,330)</u>
3	Net electric plant		28,941,047	19,503,621	1,807,727	21,311,348
4	Add: Materials and supplies	4.3, Line 5	1,099,948	758,618	(89,287)	669,331
5	Working capital investment	4.4, Line 13	(28,393)	253,217	209,429	462,646
6	Less: Accumulated deferred taxes		(4,013,932)	(2,769,097)	(44,102)	(2,813,199)
7	Operating reserves		(230,986)	(150,195)	-	(150,195)
8	Construction work in progress		-	-	-	-
9	Total		<u>\$ 25,767,684</u>	<u>\$ 17,596,163</u>	<u>\$ 1,883,768</u>	<u>\$ 19,479,931</u>

-- Some totals may not foot or compute due to rounding.

DUKE ENERGY CAROLINAS, LLC
 ELECTRIC PLANT IN SERVICE AT Initial COST
 FOR THE TEST PERIOD ENDED DECEMBER 31, 2021
 (Thousands of Dollars)

SUPPLEMENTAL REVENUE REQUIREMENT STIPULATION Exhibit 2
 Page 4.1 of 4.4

Line No.	Description	Total Company Per Books (Col. 1)	North Carolina Retail Operations		
			Per Books (Col. 2)	Accounting Adjustments (Col. 3)	As Adjusted (Col. 4)
1	Production Plant	\$ 24,018,560	\$ 16,108,722	\$ 354,761	\$ 16,463,484
2	Transmission Plant	4,963,954	2,488,550	\$ 312,648	2,801,198
3	Distribution Plant	14,480,906	10,727,737	\$ 1,416,251	12,143,988
4	General Plant	1,424,450	970,940	\$ 365,095	1,336,034
5	Intangible Plant	<u>1,206,177</u>	<u>838,443</u>	<u>\$ 53,383</u>	<u>891,826</u>
6	Subtotal	46,094,047	31,134,393	2,502,137	33,636,530
7	Nuclear Fuel (Net)	<u>468,458</u>	<u>316,148</u>	<u>\$ -</u>	<u>316,148</u>
8	Total electric plant in service	<u>\$ 46,562,505</u>	<u>\$ 31,450,540</u>	<u>\$ 2,502,137</u>	<u>\$ 33,952,678</u>

-- Some totals may not foot or compute due to rounding.

DUKE ENERGY CAROLINAS, LLC
 ACCUMULATED DEPRECIATION AND AMORTIZATION - ELECTRIC PLANT IN SERVICE
 FOR THE TEST PERIOD ENDED DECEMBER 31, 2021
 (Thousands of Dollars)

SUPPLEMENTAL REVENUE REQUIREMENT STIPULATION Exhibit 2
 Page 4.2 of 4.4

No.	Description	Total Company Per Books (Col. 1)	North Carolina Retail Operations		
			Per Books (Col. 2)	Accounting Adjustments (Col. 3)	As Adjusted (Col. 4)
1	Production Reserve	\$ (9,872,952)	\$ (6,608,301)	\$ (585,758)	\$ (7,194,059)
2	Transmission Reserve	\$ (1,440,993)	\$ (722,765)	\$ (52,013)	(774,778)
3	Distribution Reserve	\$ (5,110,132)	\$ (3,785,538)	\$ (23,903)	(3,809,441)
4	General Reserve	\$ (459,397)	\$ (313,305)	\$ 22,954	(290,351)
5	Intangible Reserve	<u>(737,984)</u>	<u>(517,011)</u>	<u>\$ (55,690)</u>	<u>(572,701)</u>
6	Total	<u>\$ (17,621,458)</u>	<u>\$ (11,946,920)</u>	<u>\$ (694,410)</u>	<u>\$ (12,641,330)</u>
7	The annual composite rates based on the new depreciation study for computing depreciation (straight-line method) are shown below:				
8	Steam production plant	6.37%			
9	Nuclear production plant	2.21%			
10	Hydro production plant	2.31%			
11	Other production plant	3.42%			
12	Transmission plant	2.43%			
13	Distribution plant	2.45%			
14	General plant	Various			
15	Intangible plant	20.00%			

-- Some totals may not foot or compute due to rounding.

DUKE ENERGY CAROLINAS, LLC
MATERIALS AND SUPPLIES
FOR THE TEST PERIOD ENDED DECEMBER 31, 2021
(Thousands of Dollars)

SUPPLEMENTAL REVENUE REQUIREMENT STIPULATION Exhibit 2
Page 4.3 of 4.4

Line No.	Description	Total Company Per Books (Col. 1)	North Carolina Retail Operations		
			Per Books (Col. 2)	Accounting Adjustments (Col. 3)	As Adjusted (Col. 4)
	Fuel Stock:				
1	Coal	\$ 195,023	\$ 131,615	\$ (19,302) (a)	\$ 112,314
2	Gas	<u>42,456</u>	<u>28,652</u>	<u>\$ -</u>	<u>28,652</u>
3	Total fuel stock	237,480	160,268	(19,302)	140,966
4	Other electric materials and supplies and stores clearing	<u>862,469</u>	<u>598,351</u>	<u>\$ (69,985)</u>	<u>528,365</u>
5	Total Materials and Supplies	<u>\$ 1,099,948</u>	<u>\$ 758,618</u>	<u>\$ (89,287)</u>	<u>\$ 669,331</u>

-- Some totals may not foot or compute due to rounding.

Notes: (a) Adjusts coal inventory to reflect the targeted inventory level of 35 days at full load

DUKE ENERGY CAROLINAS, LLC
WORKING CAPITAL INVESTMENT
FOR THE TEST PERIOD ENDED DECEMBER 31, 2021
(Thousands of Dollars)

SUPPLEMENTAL REVENUE REQUIREMENT STIPULATION Exhibit 2
Page 4.4 of 4.4

Line No.	Description	Total Company Per Books (Col. 1)	North Carolina Retail Operations			Impact of Rev Incr (Col. 5)	With Rev Incr (Col. 6)
			Per Books (Col. 2)	Accounting Adjustments (Col. 3)	As Adjusted (Col. 4)		
1	Investor advanced funds: Cash Working Capital	179,942 (a)	122,878 (a)	20,785 (b)	143,663	31,097 (c)	174,760
2	Unamortized Debt	107,428	73,360	-	73,360		73,360
3	Required Bank Balance	300	205	-	205		205
4	SFAS-158	328,141	223,817	-	223,817		223,817
5	Prepayments	-	-	-	-		-
6	Average Taxes Accrual	-	-	-	-		-
7	ARO-related CCR regulatory assets and liabilities	325,093	325,093	(90,790)	234,303		234,303
8	Adjustments to EDIT	(2,242,484)	(1,282,526)	52,137	(1,230,389)		(1,230,389)
9	Injuries and Damages	604,045	404,523	-	404,523		404,523
10	Other	737,510	433,066	227,298	660,364		660,364
11	Total investor advanced funds	39,976	300,417	209,429	509,846	31,097	540,943
12	Less: customer deposits	(68,369)	(47,201)	-	(47,201)		(47,201)
13	Total working capital investment	<u>\$ (28,393)</u>	<u>\$ 253,217</u>	<u>\$ 209,429</u>	<u>\$ 462,646</u>	<u>\$ 31,097</u>	<u>\$ 493,743</u>

-- Some totals may not foot or compute due to rounding.

Notes: (a) From Speros Exhibit 2, Line 16 and Line 19
(b) Reflects a decrease in "operating funds per lead-lag study" for the adjusted total requirements in this rate case
(c) Reflects a decrease in "operating funds per lead-lag study" for the impact of the revenue increase

DUKE ENERGY CAROLINAS, LLC

RECONCILIATION OF PROPOSED REVENUE REQUIREMENT

SUPPLEMENTAL REVENUE REQUIREMENT STIPULATION Exhibit 2

DOCKET NO. Docket No. E-7 Sub 1276 FOR THE TEST PERIOD ENDED DECEMBER 31, 2021

Page 5

(Thousands of Dollars)

Line No.	Item	Amount
1	Revenue requirement increase per Company application	371,502
2	Impact of supplemental updates through April 2023	62,984
3	Impact of Second Supplemental through May 2023	5,814
4	Impact of Third Supplemental through June 2023	25,727
5	Impact of First Partial Settlement	(93,923)
6	Impact of Supplemental Partial Settlement	(2,742)
7		
8	Updated Proformas:	
9	NC2080 May/June Plant	(492)
10	NC2080 Extra Facilities Revenue	(313)
11	NC6020a Cash working Capital -Present*	4
12	NC6020b Cash working Capital -Proposed*	(6)
13	Rounding/other	(14)
14	Total Updates	<u>(822)</u>
15		
16	Adjusted Revenue Requirement	<u>368,540</u>
	Check Total	0



Transmission System Planning and Grid Transformation

Highlights

- Planning and constructing necessary transmission infrastructure is critical for implementing the Carolinas Resource Plan. This infrastructure is needed to ensure power supply reliability, to enable interconnection of new generating facilities and energy storage resource additions necessary to replace retiring resources, as well as to meet expected load growth.
- The Companies are working with other participating load-serving entities, with input from interested stakeholders, to evolve the Local Transmission Planning process to meet the changing energy landscape through increasing transparency and coordination and through process improvements that identify the best value transmission expansion projects for customers.
- Several of the Red Zone Transmission Expansion Plan projects were identified as needed in the 2022 Definitive Interconnection System Impact Study Phase 2 study for interconnecting Carolinas Resource Plan resources, and the Red Zone Transmission Expansion Plan projects will continue to provide benefits for customers and resource plan execution.
- To meet the challenge of interconnecting significant supply-side resources required by the Carolinas Resource Plan while ensuring adequacy and reliability of the existing grid is maintained or improved, Duke Energy will utilize the new annual Definitive Interconnection System Impact Study Cluster Study process and work through the Federal Energy Regulatory Commission jurisdictional transmission planning process to build out the transmission grid over time to meet Carolinas Resource Plan and reliability needs.

Transmission Planning in a Changing Energy Landscape

This Appendix discusses transmission system requirements and associated cost estimates related to the Carolinas Resource Plan for Duke Energy Carolinas, LLC (“DEC”) and Duke Energy Progress, LLC (“DEP”) and, together with DEC, “Duke Energy” or the “Companies”). Planning and constructing needed transmission infrastructure to ensure power supply reliability and provide for resource supply additions necessary to replace retiring resources, as well as to meet expected load growth, are critical path processes for implementing DEC and DEP’s resource plans.

This Appendix discusses transmission system adequacy and future 100 kilovolts (“kV”) and above transmission needs to accommodate resource supply additions necessary to replace retiring resources, improve resiliency and reliability, enable siting of new resources and support load growth and economic development. Current utility local and regional transmission planning processes and planned revisions to those processes will be discussed, as well as transmission system needs and projects identified in the most recent local transmission planning report.¹ These transmission planning processes are critical to plan for transmission needs, to determine lead times for construction, to ensure transmission projects meet in-service dates, to ensure reliability and to provide for resource supply additions necessary to replace retiring resources, as well as to meet load growth and economic development.

In 2021, DEC and DEP evaluated the need to proactively identify and construct transmission network upgrades that repeatedly impeded generation interconnection requests in the high solar viability “red zone” areas of DEC and DEP transmission systems. This evaluation led to the identification of 18 Red Zone Transmission Expansion Plan (“RZEP”) projects needed for reliability and resiliency during the energy transition, as well as integration of solar generation. 14 of the 18 RZEP projects were acknowledged as needed by the North Carolina Utilities Commission (“NCUC”) in the 2022 Carbon Plan Order² and were subsequently approved to be included as part of the 2022–2032 local transmission plan in accordance with the Federal Energy Regulatory Commission (“FERC”)-approved DEC and DEP Joint Open Access Transmission Tariff (“OATT”). Furthermore, in 2022, DEC and DEP developed strategic plans to seek FERC approval of a generation replacement process that would retain the interconnection rights of large generators being retired for the benefit of customers that had previously funded the transmission system upgrades to interconnect the retiring facilities. FERC accepted the generation replacement process in September 2022, and DEC and DEP are implementing it today. This Appendix will discuss how both achievements are now being leveraged in the execution of the Carolinas Resource Plan (the “Plan” or “the Resource Plan”) for the benefit of customers.

¹ North Carolina Transmission Planning Collaborative, Report on the NCTPC 2022–2032 Collaborative Transmission Plan, February 2023, available at http://www.nctpc.org/nctpc/document/REF/2023-02-21/2022%20NCTPC%20Report%2002_21_2023_FINAL.pdf.

² Order Adopting Initial Carbon Plan and Providing Direction for Future Planning, Docket No E-100, Sub 179 (Dec. 30, 2022) (“Carbon Plan Order”).

Transmission planning, expansion and planning process reform are also critical to the success of identifying transmission system needs and evaluating alternative solutions to arrive at transmission plans that have material benefit-to-cost ratios and that benefit load-serving entity and customer reliability, as well as economic development and support Resource Plan implementation. Foundational to this planning, expansion and process reform is the outcome that the Companies' transmission systems are designed and operated to ensure adequate and reliable service to DEC's and DEP's customers while meeting all regulatory requirements and standards.

Existing Transmission Systems of DEC and DEP

DEC and DEP are each Transmission Owners³ and Transmission Service Providers that independently own and operate transmission systems and provide transmission service under their OATT, which is filed with FERC.⁴ DEC has approximately 12,957 miles of transmission and sub-transmission lines⁵ in North Carolina and South Carolina at voltages ranging from 44 kV to 500 kV. DEP has approximately 6,306 miles of transmission lines in North Carolina and South Carolina at voltages ranging from 69 kV to 500 kV. Table L-1 below provides DEC's and DEP's installed transmission by voltage.

Table L-1: DEC and DEP Installed Transmission Circuit Lines by Voltage (in miles)

Circuit Voltage	44 kV	66–69 kV	100–199 kV	230 kV	500 kV
DEC	2,752	121	6,848	2,660	576
DEP	-	12	2,569	3,433	292

Table L-2 below identifies DEC's and DEP's transmission lines and associated facilities 100 kV and above that are under construction or for which DEC or DEP have approved specific plans for construction. In addition, Table L-2 reflects new transmission voltage class transformers planned or under construction. As discussed further below, DEC and DEP participate in FERC-regulated local, regional and interregional transmission planning processes and annually assess the reliability and adequacy of the interconnected transmission system to ensure the system is adequate to meet customers' electrical demands both in the near-term and long-term planning horizons. These transmission planning processes also encompass planning to satisfy generation resource additions and retirements, as well as increased load requirements. The Companies also identify the need for construction of new or upgraded transmission facilities through generator interconnection studies and transmission service requests in adherence to the FERC-approved joint OATT for DEC and DEP.

³ Capitalized terms not defined herein are defined in the Companies' OATT.

⁴ FERC, Joint Open Access Transmission Tariff of Duke Energy Carolinas, LLC Duke Energy Florida, LLC and Duke Energy Progress LLC, available at https://www.ferc.duke-energy.com/Tariffs/Joint_OATT.pdf.

⁵ Transmission voltage levels – 69 kV–500 kV; sub-transmission voltage levels 44 kV and below.

Table L-2: DEC and DEP Transmission Under Construction or Approved for Construction⁶

DEC/DEP	Year	From	To	Voltage (kV)	Capacity (MVA)	New/Upgrade
DEC	2024	Aquadale PV (50 MW)		100		New
DEC	2024	Blackburn PV (60.1 MW)		100		New
DEC	2024	Brookcliff PV (50 MW)		100		New
DEC	2024	Hornet PV (75 MW)		100		New
DEC	2024	IBM Tap	GE Aircraft Tap	100	200 ¹	Upgrade
DEC	2024	Mebane Tie	Piedmont EMC 10	100	143	New
DEC	2024	Newberry PV (74.5 MW)		100		New
DEC	2024	Oakboro PV (40 MW)		100		New
DEC	2024	West River PV (40 MW)		100		New
DEC	2024	Wilkes 230/100 kV Transformer		230/100	448	New
DEC	2024	Woodruff Tie	BMW	100		New
DEC	2025	Allen 230/100 kV Transformer (2)		230/100	448	Upgrade
DEC	2025	Cliffside	Peach Valley Tie	100		Upgrade
DEC	2025	Healing Springs PV (55 MW)		100		New
DEC	2025	Hodges Tie	Coronaca Tie	100	450	Upgrade
DEC	2025	Lee	Shady Grove (Lee Lines)	100	368 ¹	Upgrade
DEC	2025	Newberry Main	DESC Saluda	115	278 ¹	Upgrade
DEC	2025	North Greenville 230/100 kV Transformer		230/100	448	Upgrade
DEC	2026	Boyd Switching Station		230		New
DEC	2026	Bush River Tie	Laurens Tie	100	368 ¹	Upgrade
DEC	2026	Creto Tie	Coronaca Tie	100	404	New
DEC	2026	Hass Creek Switching Station		230		New
DEC	2026	Hilltop Tie	Shelby Tie	100		Upgrade
DEC	2026	Lee	Shady Grove (Piedmont Lines)	100	368 ¹	Upgrade
DEC	2026	Lyle Creek Switching Station		100		New
DEC	2026	North Greensboro Tie	Greensboro Main (Page)	100	368 ¹	Upgrade
DEC	2026	North Greensboro Tie	Greensboro Main (Guilford)	100	368 ¹	Upgrade
DEC	2026	Oakvale Tie	East Greenville	100		Upgrade
DEC	2026	Statesville Tie	Perth Road	100		New
DEC	2026	Wylie	Indianland Ret	100		New
DEC	2026	Wylie Hydro	Woodlawn Tie	100	240	Upgrade
DEC	2027	Lancaster Main	Monroe Main	100	242	Upgrade
DEC	2028	Dixon School Road	New Customer	230		New
DEC	2028	Harrisburg Tie	Amity	100		Upgrade
DEC	2028	Lakewood Tie	Woodlawn Tie	100		Upgrade
DEC	2028	Lee CC	Lee Steam	100	484	New
DEC	2028	Mebane Tie	Pleasant Garden Tie	100		Upgrade
DEC	2028	Oak Hollow Switching Station		100		New
DEC	2028	Shelby Tie 230/100 kV Transformer		230/100	448	Upgrade
DEC	2029	Concord Main	Winecoff Tie	100		Upgrade
DEC	2029	Concord Main	Harrisburg Tie	100		Upgrade
DEC	2029	Harrisburg Tie 230/100 kV Transformer		230/100	448	Upgrade
DEC	2029	Hodges 230/100 kV Transformer		230/100	448	Upgrade
DEC	2029	Newport Tie	Morning Star Tie	230	421	New

⁶ Table L-2 lists projects 100 kV and above pursuant to Rule R8-60(ii) that are under construction or approved by Duke Energy for construction.

Appendix L | Transmission System Planning and Grid Transformation

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DEC/DEP	Year	From	To	Voltage (kV)	Capacity (MVA)	New/Upgrade
DEC	2029	Tiger Tie 230/100 kV Transformer		230/100	448	Upgrade
DEC	2029	Wildcat Tie	Westfork	100		Upgrade
DEC	2030	Dan River	N Greensboro	100	242 ¹	Upgrade
DEC	2030	Lawsons Fork	W Spartanburg	100		Upgrade
DEC	2030	North Greenville	Marietta	100	484	Upgrade
DEC	2030	Research Triangle	Ellis Rd	100		Upgrade
DEC	2030	Shelby Tie	Cliffside	100		Upgrade
DEC	2031	Marshall Ret	Lookout Tie	100		New
DEC	2031	McGuire	Marshall	230		Upgrade
DEC	2032	Morning Star 230/100 kV Transformer (3)		230/100	448	Upgrade
DEC	2033	Dan River	Sadler (Wolf Creek)	100	242 ¹	Upgrade
DEC	2033	Dan River	Sadler (Reidsville)	100	242 ¹	Upgrade
DEC	2034	Winecoff Tie	Conley	100	484	Upgrade
DEP	2023	Havelock 230/115 kV Transformers		230/115	336	Upgrade
DEP	2023	Pig Basket Creek PV (80 MW)		230		New
DEP	2023	Porters Neck Tap	Porters Neck	230	442	New
DEP	2023	Wateree 115/100 kV Transformers (2)		115/100	336	Upgrade
DEP	2024	Camden	Camden Dupont	115	313	Upgrade
DEP	2024	Loftins Crossroads PV (75 MW)		230		New
DEP	2025	Arden Tap	Arden	115	280	New
DEP	2025	Carthage 230/115 kV Transformer Substation		230/115	336	New
DEP	2025	Craggy	Enka	230	644	New
DEP	2025	Weatherspoon	Marion	115	313	Upgrade
DEP	2026	Camden Junction	DPC Wateree	115	313	Upgrade
DEP	2026	Cape Fear	West End	230	1195	Upgrade
DEP	2026	Castle Hayne	Folkstone	115	296	Upgrade
DEP	2026	Erwin	Fayetteville East	230	1195	Upgrade
DEP	2026	Fayetteville	Fayetteville Dupont (4.9 miles)	115	313	Upgrade
DEP	2026	Holly Ridge North 115 kV Switching Station	JOEMC Folkstone POD	115	296	New
DEP	2026	Kingstree West PV (74.9 MW)		115		New
DEP	2026	Maxton	Pembroke	115	313	Upgrade
DEP	2026	Robinson	Rockingham	230	1195	Upgrade
DEP	2026	Sumter	DESC Eastover	115	270	Upgrade
DEP	2026	Weatherspoon	LREMC West Lumberton	115	313	Upgrade
DEP	2027	Robinson	Rockingham	115	310	Upgrade
DEP	2028	Delco	Leland Industrial	115	221	Upgrade
DEP	2028	Durham	Brier Creek	230	1195	Upgrade
DEP	2029	Cape Fear	Moncure	115	201	Upgrade

Note 1 : The MVA Capacity represents the capability for one circuit of the double circuit line.

Transmission System Planning to Ensure System Adequacy and Reliability

DEC and DEP manage the adequacy and reliability of their transmission systems and interconnections with neighboring entities through internal analysis and participation in regional reliability groups. The Companies' internal transmission planning team looks 10 years ahead at projected generating

resources and retirements, as well as projected load to identify needs and requirements for transmission system upgrades and transmission expansion. The Duke Energy team plans and implements corrective actions in advance to ensure continued cost-effective and reliable service. In addition to the internally developed 10-year transmission planning process, DEC and DEP coordinate transmission planning with local and regional groups, as well as with reliability working groups related to North American Electric Reliability Corporation (“NERC”) reliability standards.

DEC and DEP manage transmission system reliability through evaluating changes in load, generation, real and reactive capacity, transmission service needs, demand response resources and topography. A detailed annual screening ensures compliance with the Duke Energy Transmission Planning Summary for DEC⁷ and DEP⁸ for voltage and thermal loading. The annual screening uses methods that comply with SERC Reliability Corporation (“SERC”) policy and NERC Reliability Standards, and the screening results identify the need for future transmission system expansion and upgrades. The transmission system is planned to ensure there are no equipment overloads and adequate voltage is maintained to provide reliable service. Historically, the most stressful scenarios studied have been at projected summer and winter gross peak load and solar peak output. In addition to the base cases and in accordance with NERC Reliability Standard TPL-001-5.1 Requirement R2.1.4, sensitivity cases are utilized to demonstrate the impact of changes to the basic assumptions used in the base case models. To accomplish this, the sensitivity analysis varies one or more of the model conditions by an amount sufficient to stress the system within a range of credible conditions to evaluate their impact. Generation additions, retirements, or other dispatch scenarios are also considered in these NERC TPL-001 Standard transmission planning assessments. A thorough screening process is used to analyze the impact of potential equipment failures or other disturbances. As problems are identified, solutions are developed and evaluated. Transmission system evaluations will need to consider when additional load is placed on the system with the demand of energy from energy storage systems such as charging batteries or pumping water at pumped storage hydro facilities. The Companies developed a transmission planning business practice to provide guidance on storage considerations.⁹

Transmission planning and requests for transmission service and generator interconnection are interrelated with the resource planning process. DEC and DEP currently evaluate all transmission reservation requests for impact on transfer capability, as well as compliance with the Companies’ Transmission Planning Summary and the OATT. The Companies perform studies to ensure transfer

⁷ Transmission Planning Summary document, available at: <http://www.oatioasis.com/duk/index.html> (this document contains an overview of the fundamental guidelines followed by DEC’s Power Delivery employees to plan Duke Energy’s 500 kV, 230 kV, 161 kV, 100 kV, 66 kV and 44 kV transmission systems. FERC Order 890 requires that public utilities document and make available to stakeholders their basic methodology, criteria, and processes in order to ensure that transmission planning is performed on a consistent basis. The Transmission System Planning Summary contains general information on DEC transmission planning practices and provides links to other DEC documents that contain additional detail.)

⁸ Duke Energy Progress, Transmission System Planning Summary, May 2014, available at <https://www.oasis.oati.com/CPL/>.

⁹ Duke Energy, Duke Energy Business Practice: Studying Storage Interconnection Requests in DEC and DEP, October 2022, available at https://www.oasis.oati.com/woa/docs/CPL/CPLdocs/Storage_Studies_-_Duke_Energy_Business_Practice_2022-10-26.pdf.

capability is acceptable to meet reliability needs and customers' expected use of the transmission system. Generator interconnection requests are studied in accordance with the FERC Large and Small Generator Interconnection Procedures in the OATT and related North Carolina and South Carolina state procedures. It is important to note that location, megawatt ("MW") capacity of the interconnection requested, resource/load characteristics, and other clustered queued requests, both individually and in aggregate, are inputs that are determinative of the transmission network upgrades required to reliably accommodate the interconnection requests. While requests for transmission service and generator interconnection provide definitive details for these inputs, as some requests move forward and others do not, the aggregate impact of these modeling inputs changes, thus yielding a range of results — both in terms of cost and time to interconnection — for required transmission network upgrades. For this reason, transmission planning must be a continual and iterative process to calibrate transmission plans to objective and verifiable transmission needs.

DEC and DEP participate in several transmission-related planning group activities to ensure coordination of and collaboration for planning a reliable transmission system, as discussed further below.

Transmission System Planning Regulatory Requirements

The Companies' transmission systems are designed and operated to ensure adequate and reliable service to DEC's and DEP's customers while meeting all regulatory requirements and standards. The Companies are required to meet mandatory FERC, NERC and SERC reliability standards and planning requirements.

Pursuant to the Energy Policy Act of 2005 ("EPACT 2005"),¹⁰ FERC delegated the authority to NERC to develop reliability standards to ensure the safe and reliable operation of the Bulk Electric System ("BES") in the United States under a variety of operating conditions. The federally mandated NERC Reliability Standards constitute minimum criteria with which all public utilities must comply as components of the interstate electric transmission system. EPACT 2005 and FERC's implementing regulations and orders also mandate that electric utilities follow the NERC Reliability Standards and impose fines for noncompliance of approximately \$1.3 million per day per violation. The Reliability Standards are a federal requirement and are subject to oversight and enforcement by the SERC, NERC and FERC.

The NERC Reliability Standards include transmission planning ("TPL") Standards that specify the transmission system planning performance requirements to develop a bulk electric system that will operate reliably over a broad spectrum of system conditions. The TPL Standards also require study of a wide range of probable contingencies in both short-term (1–2 years) and long-term (10-year) scenarios to ensure system reliability. Together with any SERC regional planning criteria¹¹ and internal

¹⁰ 16 U.S.C. § 824o.

¹¹ SERC Reliability Corporation, Standards & Regional Criteria, available at <https://www.serc1.org/program-areas/standards-regional-criteria>.

DEC/DEP specific transmission planning criteria, the TPL Standards define the minimum transmission system planning requirements to safely and reliably serve customers.

In addition to the TPL Standards, as Transmission Service Providers,¹² the Companies must also comply with FERC Order No. 890, which was issued on February 16, 2007, and reformed the decade-old open access regulatory framework adopted in Order No. 888, and with the more recent Order No. 1000. Order No. 1000 establishes transmission planning reforms that: (1) require that each public utility transmission provider participate in a regional transmission planning process that produces a regional transmission plan; (2) require local and regional transmission planning processes to provide an opportunity to identify and evaluate transmission needs driven by public policy requirements established by state or federal laws or regulations; (3) improve coordination between neighboring transmission planning regions for new interregional transmission facilities; and (4) remove from commission-approved tariffs and agreements, a federal right of first refusal.¹³

Transmission Planning Processes

Local Transmission Planning Process

Attachment N-1 of the OATT reflects the Companies' Local Transmission Planning Process approved by the FERC for compliance with Order Nos. 890 and 1000. This Local Transmission Planning process for the Companies' interconnected transmission systems in North Carolina and South Carolina is effectuated through the North Carolina Transmission Planning Collaborative ("NCTPC").¹⁴ North Carolina's major electric load-serving entities ("LSEs"), including DEC, DEP, ElectriCities of North Carolina, Inc. ("ElectriCities," which is the umbrella organization of municipal electric power suppliers in the state) and the North Carolina Electric Membership Corporation ("NCEMC," which is the umbrella organization of cooperative electric power suppliers in the state), created the NCTPC in 2005 to enhance transmission planning by allowing all stakeholders to participate in shaping the future transmission network in the areas of North Carolina and South Carolina served by the LSEs. An independent administrator facilitates the NCTPC to ensure that the interests of all stakeholders are fairly and meaningfully represented. More details on the Transmission Advisory Group stakeholder membership are provided in this section. The NCTPC is intended to create an integrated long-term transmission expansion plan that will result in a reliable (i.e., meets all applicable reliability criteria) and cost-effective (i.e., provides meaningfully greater benefits than costs for consumers) transmission system. As discussed below, the NCTPC plans to file with FERC in the October/November 2023 timeframe to propose certain improvements, including changing its name to the Carolinas

¹² NERC, Glossary of Terms Used in NERC Reliability Standards, March 2023, available at https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf.

¹³ Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, available at <https://www.ferc.gov/sites/default/files/2020-06/OrderNo.1000-B.pdf>.

¹⁴ As part of the proposed revisions to Attachment N-1 of the Companies' OATT described below, which the Companies are currently vetting with stakeholders and intend to file for approval from FERC in October/November 2023, the Companies have proposed to change the name of the NCTPC to the Carolinas Transmission Planning Collaborative or CTPC to more accurately reflect the scope of local transmission planning in both South Carolina and North Carolina that the collaborative has historically done and will continue to do.

Transmission Planning Collaborative to reflect its dual-state applicability, as well as other changes to Attachment N-1 to the Companies' OATT.

Currently, Attachment N-1, the Local Planning Process, addresses transmission upgrades needed to maintain reliability and to integrate new generation resources and/or loads, as well as transmission upgrades needed for public policies and economic transfers analyzed. The Local Planning Process includes a base reliability study ("base case") that evaluates each transmission system's ability to meet projected load with a defined set of resources, as well as the needs of firm point-to-point transmission service customers, whose needs are reflected in their transmission contracts and reservations. A resource supply additions analysis is also conducted to evaluate transmission system impacts for other potential resource supply options to meet future load requirements.

The NCTPC annually develops a single, coordinated local transmission plan ("Local Transmission Plan") that appropriately balances costs, benefits and risks associated with the use of transmission, generation and demand-side resources to meet the needs of LSEs, as well as Transmission Customers under the OATT. This local transmission planning process enables solutions to public policy requirements to be considered for adoption into the Local Transmission Plan.¹⁵

The Local Transmission Plan may be adjusted over time to reflect changing system conditions, the iterative nature of transmission planning and coordination with regional and interregional processes. If regional transmission constraints or concerns are identified in local transmission planning studies, such constraints identified can be elevated to the Southeastern Regional Transmission Planning ("SERTP") group discussed further below.

The NCTPC comprises three main groups and an Administrator that carries out its roles and responsibilities under the FERC-approved Local Transmission Planning process.

Planning Working Group ("PWG"): Identifies potential solutions to the transmission problems identified (including public policy transmission needs) and tests the effectiveness of potential solutions through additional analysis as required to ensure that the solutions meet the study criteria previously developed. The PWG membership comprises representatives from the member LSEs and the independent administrator.

Transmission Advisory Group ("TAG"): Provides stakeholder input and recommendations to the LSEs for consideration for incorporation into the Local Transmission Plan, including with respect to public policy-driven transmission requirements. The TAG membership is open to the public and any individual may be a TAG participant. In addition, state regulators, including state-sanctioned entities representing the public, like other members of the public, may choose to be TAG participants. State public utility regulatory commissions also may seek to receive periodic status updates and the progress reports on the NCTPC Process. State public utility regulatory commissions may be TAG Sector Entities in the General Public Sector.

¹⁵ Section 5.7.1, page 801 of the Joint OATT.

Oversight/Steering Committee (“OSC”): Manages the NCTPC Participants' Transmission Planning Process and is currently chaired by a representative of ElectricCities. The OSC membership is composed of representatives from the member LSEs and the independent Administrator. The duties of the OSC, for the areas in the states of North Carolina and South Carolina served by the NCTPC Participants, include the following:

- Participate in the reliability planning process and oversee the development of the Local Economic Study Process.
- Review and approve transmission planning criteria and critical assumptions for the bulk transmission system and, where appropriate, develop and recommend such criteria and assumptions to be used by the PWG.
- Promote the application of such planning criteria and/or assumptions within the territories served by the NCTPC Participants.
- Direct the activities of and provide oversight for the PWG.
- Nominate and approve the PWG members.
- Keep the State Commissions, Regulatory Staff (Public Staff and Office of Regulatory Staff) and non-LSE stakeholders informed concerning the work undertaken by the Local Transmission Planning process.
- Forward the draft Local Transmission Plan Report to the TAG participants for their review and discussion.
- Evaluate results, PWG recommendations and TAG participants' input, and approve the final Local Transmission Plan. The final Plan is posted on the NCTPC website, posted on the Companies' Open Access Same-Time Information System (“OASIS”), and distributed to the TAG participants.¹⁵

NCTPC Administrator: The Administrator serves as a facilitator for the group by working to bring consensus within the group through transmission planning expertise and by providing an independent third-party view. The Administrator assists the Chair and Vice-Chair in the performance of their duties as requested and ensures that OSC meeting minutes are recorded and distributed. The Administrator maintains a record of all OSC proceedings, including responses, voting records and correspondence, and manages the timely posting of relevant materials to the NCTPC website. The Administrator also provides the leadership role in managing the Stakeholder Process, subject to the oversight of the OSC and normal regulatory oversight.

Results of 2022–2032 Local Transmission Plan and Development of 2023–2033 Plan

2022–2032 Local Transmission Plan

The NCTPC 2022-2032 Collaborative Transmission Plan dated February 21, 2023 (“2022–2032 Plan”) provides details on the development and evaluation of local transmission plan projects, including evaluation of the DEC and DEP supplemental studies that provided clear evidence of the need for strategic RZEP projects that would eliminate barriers to interconnecting resources in both South Carolina and North Carolina, and had stand-alone value based on the merits of replacing aging equipment and the associated reduction in the probability of customer service interruptions. The 2022–2032 Plan is the most recent annual local transmission plan prepared in accordance with FERC Order Nos. 890 and 1000 and includes the Reliability Planning and Local Economic Study Planning Processes, which are intended to be concurrent and iterative in nature.

The 2022–2032 Plan included 24 reliability projects and 14 RZEP projects. In addition, the OSC decided to examine the impacts of 14 different hypothetical transfers into, out of, and through the DEC and DEP systems under the Local Economic Planning Process. The results of the 14 hypothetical transfers under the Local Economic Planning Process are documented in the 2022–2032 Plan.

The study years and seasons for the 2022–2032 Plan were 2027 summer for evaluating near-term base reliability, 2027/28 winter for evaluating near-term base reliability, and 2032/33 winter for evaluating long-term base reliability. The results of the base reliability study, the resource supply option study and the local economic study were evaluated using established planning criteria. The planning criteria used to evaluate the results include: 1) NERC Reliability Standards; 2) SERC requirements; and 3) individual company criteria. The base case for the base reliability study was developed using the most current 2021 series NERC Multiregional Modeling Working Group (“MMWG”) model for the systems external to DEC and DEP.

The MMWG model of the external systems, in accordance with NERC MMWG criteria, included modeling known long-term firm transmission reservations. Detailed internal models of the DEC and DEP East/West systems were merged into the base case, including DEC and DEP transmission additions planned to be in service by the period under study. In the base cases, all confirmed long-term firm transmission reservations with roll-over rights were modeled. Contingency screenings on the base cases and scenarios were performed using Power System Simulator for Engineering power flow or equivalent. DEC and DEP each simulated its own transmission and generation down contingencies on its own transmission system.

The 2022 base reliability study verified that DEC and DEP have projects already planned to address reliability concerns for the near-term (5-year) and long-term (10-year) planning horizons. There were no unforeseen problems identified in the reliability studies performed on the base cases.

The 14 non-simultaneous economic transfer studies identified issues requiring solutions within the applicable planning window. Where issues were identified, alternative solutions were discussed and a

primary set of solutions was determined. All issues identified were either previously identified by the base reliability studies or can be mitigated with ancillary equipment upgrades.

The public policy study utilized the supplemental studies discussed in the 2022 Plan report. The OSC reviewed the supplemental study analysis and agreed with the study results and supported inclusion of the 14 RZEP projects in the 2022 Plan. The PWG did not identify, and the TAG stakeholder group did not recommend any alternative solutions to consider for the study.

2023–2033 Plan Development

During the June 21, 2023 Plan Mid-year Update Report to the TAG Stakeholder group,¹⁶ an update was provided on the status of the 2023–2033 Plan. This update included an overview of the base reliability study that will assess DEC and DEP transmission systems' reliability and develop a single Collaborative Transmission Plan and the study scope for evaluating the combined public policy requests received in the first quarter of 2023. The base reliability study will evaluate reliability of the DEC and DEP transmission system for 2028 and 2033 projected summer peak load and for 2028/29 and 2033/34 projected winter peak load scenarios. The study cases will be “All Firm Transmission” cases, which consider all confirmed long-term firm transmission reservations with rollover rights applicable to the study years and do not include generation without an executed Interconnection Agreement (“IA”). Generation is economically dispatched in the base cases and generation offline cases are created from common base cases.

Two public policy requests were submitted in 2023 and were combined under one study scope document that is currently being studied by the NCTPC with the final report expected by first quarter 2024. The first request focused on Resource Plan portfolio execution and resulting additional 230 kV and/or 500 kV transmission that may be needed long term. The second request focused on starting with resource plan Portfolio P1 from the Companies' initial 2022 proposed Carbon Plan and studying two different solar and solar paired with storage (“SPS”) volumes: 9.3 gigawatt (“GW”) and 12.5 GW by summer of 2033. As mentioned, these requests were combined into one study scope document.¹⁷ The results of the public policy study requests will provide further input into the RZEP 2.0 project needs, as well as address long-term transmission project needs such as greenfield 230 kV and 500 kV transmission lines.

As discussed in the next section, the local transmission planning process for addressing and identifying local transmission project needs will be further enhanced in the future to reflect multi-value benefits for local transmission expansion plan projects.

¹⁶ North Carolina Transmission Planning Collaborative, Transmission Advisory Group Meeting, June 2023, available at http://www.nctpc.org/nctpc/document/TAG/2023-06-21/M_Mat/TAG_Meeting_Presentation_for_06-21_2023_FINAL.pdf.

¹⁷ North Carolina Transmission Planning Collaborative, Study Process Scope, June 2023, available at http://www.nctpc.org/nctpc/document/REF/2023-06-12/2023_NCTPC_Study_Scope_06_12_2023%20_FINAL_DRAFT.pdf.

Revisions to the Local Transmission Planning Process

Through the development of the 2022 Local Transmission Plan and discussions with the TAG stakeholders, it was recognized that the Local Transmission Planning Process needed to be revised to increase transparency and coordination with stakeholders and improve processes to address the challenges of the ongoing generation transition. The NCUC also encouraged the Companies to engage with other NCTPC members to consider more strategic transmission planning opportunities to ensure reliability is maintained and to more robustly consider and develop strategic transmission planning requirements.¹⁸

Duke Energy, in coordination with the NCTPC OSC, established a plan for revising Attachment N-1 of the OATT, the Local Transmission Planning Process, to increase transparency and opportunities for engagement and coordination with stakeholders, as well as to create a new transmission planning process geared toward studying and developing strategic, multi-value transmission projects. In addition, a high-level presentation of the plans and timeline for revising the Local Transmission Planning Process was provided to the TAG stakeholder group in March 2023 with a more detailed presentation of the planned revisions and timeline provided to the TAG stakeholder group in June 2023.¹⁹ Duke Energy recently shared the proposed Attachment N-1 revisions with TAG stakeholders for review and to provide feedback in early August 2023. Duke Energy plans to file proposed revisions to the Local Transmission Planning Process with the FERC in the October/November 2023 time frame and will implement these changes upon FERC acceptance of the proposed revisions. The timeline for the Local Transmission Planning process changes and the FERC filing is provided below in Figure L-1.

Figure L-1: NCTPC Planning Study Process Changes Timeline



To facilitate a transparent and coordinated approach, the revisions to the Local Transmission Planning process will include: 1) an Assumptions Meeting with the TAG Stakeholders to review the criteria,

¹⁸ Carbon Plan Order at 121.

¹⁹ North Carolina Transmission Planning Collaborative, Transmission Advisory Group Meeting, March 2023, available at http://www.nctpc.org/nctpc/document/TAG/2023-03-15/M_Mat/TAG_Meeting_Presentation_for_03-15_2023_FINAL.pdf; North Carolina Transmission Planning Collaborative, Transmission Advisory Group Meeting, June 2023, available at <http://www.nctpc.org/nctpc/listDocument.do?catId=TAG&date=2023-06-21>.

assumptions and models NCTPC plans to use to study and identify local transmission system needs; 2) a Needs Meeting with TAG Stakeholders to review identified transmission system constraints and associated transmission system needs; and 3) a Solutions Meeting with TAG Stakeholders to review the identification of potential solutions to the transmission system constraints and system needs, as well as alternative solutions considered. These meetings will provide more opportunities for engagement and input from stakeholders on Local Economic Projects, Local Public Policy Projects and a newly proposed category of Strategic Multi-Value Projects, subject to the new planning processes.

For the new proposed category of Strategic Multi-Value Projects, a planning study would consider different scenarios for evaluation of new resource supply options, changing load dynamics, transmission solutions requiring longer lead times and/or economic development opportunities. TAG Stakeholders will also have the opportunity to propose scenarios to study as part of the multi-value strategic planning process. Potential solutions to the transmission system constraints identified by this scenario analysis would be developed and the benefits of each solution evaluated. Potential solutions will consider the use of Grid Enhancing Technologies (“GETs”) and non-wires alternatives as discussed further in the next section. Potential benefits to be evaluated and quantified for transmission solutions could include reliability, asset replacement, production cost and avoided transmission project benefits. In addition, the multi-value strategic transmission plan will evaluate transmission planning solutions with longer lead times.

While Duke Energy considers these planned revisions to the Local Transmission Planning process to be necessary for effective planning for future transmission needs and identifying the best solutions to meet those needs, there is a risk that FERC’s final rule associated with the NOPR²⁰ on Transmission Planning and Cost Allocation issued in April 2022 may specify materially different transmission planning process requirements. These different requirements may impact both the Local and Regional Transmission Planning processes. Duke Energy and the NCTPC are trying to adopt attributes from the FERC NOPR into the revised Local Transmission Planning process. Duke Energy and the NCTPC will keep this risk under consideration as the Companies move forward with planned revisions to the Local Transmission Planning process.

Use of Grid Enhancing Technologies and Consideration of Non-Wires Alternatives

Duke Energy has utilized GETs as alternative solutions to identified transmission needs in the past and will continue to evaluate and utilize these potential alternative solutions where evaluated to be a sustainable and reliable solution for addressing identified transmission needs. Duke Energy has utilized phase shifting transformers, switchable reactors and remedial action schemes as alternative solutions to reconductoring transmission lines or constructing new transmission lines. Duke Energy continues to consider different technologies for solutions to transmission needs as evidenced in the DEC and DEP 2022 Definitive Interconnection System Impact Study (“DISIS”) Phase 2 Study

²⁰ Notice of Proposed Rulemaking, available at <https://ferc.gov/media/rm21-17-000>.

Reports²¹ reflecting identified transmission network upgrade needs. These reports show that five transmission line loading issues are being resolved through application of switchable reactors and eight transmission lines requiring reconductoring are utilizing High Temperature Low Sag Aluminum Conductor Steel Supported/ Trapezoidal Wire conductor. An overall assessment methodology and summary of analytical results evaluating non-wires alternatives such as battery storage being considered to defer or avoid traditional transmission upgrades is provided in Appendix G (Integrated System and Operations Planning).

Duke Energy will continue to consider GETs as potential alternative solutions to transmission needs. However, alternative solutions must not create conditions that are so complex that system operators are no longer able to maintain local and wide area situational awareness. Over-reliance on GETs can lead to circumstances where operators cannot successfully assess potential risks, hazards, or system events that might occur. Duke Energy will continue to use due diligence when considering application of GETs and non-wires alternatives to ensure any operational complexity is minimized and operator situational awareness of system configuration is not lost.

Regional and Interregional Transmission Planning Process

On July 11, 2011, FERC issued Order No. 1000, which built on principles of transmission planning established in FERC Order No. 890. Order No. 1000 adopted regional transmission planning and cost allocation requirements, requiring that transmission-owning and -operating public utilities, among other things, participate in a regional transmission planning process that produces a regional transmission plan, amend their OATTs to describe procedures providing for consideration of transmission needs driven by public policy requirements in the local and regional transmission planning processes and improve coordination between neighboring transmission planning regions for interregional transmission facilities.

In compliance with these requirements, the Companies participate in the SERTP process. SERTP provides an open and transparent transmission planning forum for transmission providers to engage with stakeholders regarding transmission plans in the region. The SERTP was originally developed to comply with FERC Order No. 890 and was expanded in 2014 to implement Order No. 1000 directives.

The SERTP has expanded several times, both in scope and size of the region, since its initial formation. SERTP now includes the following Sponsors (Transmission Owners and Transmission Providers that participate in SERTP) in addition to DEC and DEP: Southern Company, Dalton Utilities, Georgia Transmission Corporation, Municipal Electric Authority of Georgia, PowerSouth, Louisville Gas & Electric Company and Kentucky Utilities Company, Associated Electric Cooperative Inc. and

²¹ Duke Energy Carolinas, LLC, 2022 Definitive Interconnection System Impact Study, March 2023, available at [https://www.oasis.oati.com/woa/docs/DUK/DUKdocs/2022_DEC_Definitive_Interconnection_System_Impact_Study_Cluster_\(Phase_2\)_Report.pdf](https://www.oasis.oati.com/woa/docs/DUK/DUKdocs/2022_DEC_Definitive_Interconnection_System_Impact_Study_Cluster_(Phase_2)_Report.pdf); Duke Energy Progress, LLC, 2022 Definitive Interconnection System Impact Study, March 2023, available at [https://www.oasis.oati.com/woa/docs/CPL/CPLdocs/2022_DEP_Definitive_Interconnection_System_Impact_Study_Cluster_\(Phase_2\)_Report.pdf](https://www.oasis.oati.com/woa/docs/CPL/CPLdocs/2022_DEP_Definitive_Interconnection_System_Impact_Study_Cluster_(Phase_2)_Report.pdf).

the Tennessee Valley Authority (“TVA”). As a result of this expanded size and scope, the SERTP region has become one of the largest regional transmission planning processes in the United States.

The Companies also participate in other local and regional planning and working groups as a primary participant or as requested, including:

1. Carolinas Transmission Coordination Arrangement between DEC, DEP, Dominion Energy South Carolina and the South Carolina Public Service Authority (“Santee Cooper”) – a forum for coordinating certain transmission planning assessment and operating activities among the participants.
2. South Carolina Regional Transmission Planning group – established by Dominion Energy South Carolina and Santee Cooper to meet the transmission planning requirements of FERC Orders 890 and 1000.
3. SERC Intra-Regional Long-Term Power Flow Working Group: Updates SERC Regional power flow base cases and conducts longer-term intra-regional reliability assessment studies to assist SERC in performing its delegated functions.
4. SERC Near-Term Power Flow Working Group: Conducts near-term intra-regional seasonal reliability studies to assist SERC in performing its delegated functions and builds Open Access OASIS study models.
5. Eastern Interconnection Planning Collaborative (“EIPC”): Provides coordinated interregional analysis for the entire Eastern Interconnection based on the regional expansion plans developed each year by regional stakeholders in collaboration with their respective NERC Planning Authorities.
6. Eastern Interconnection Reliability Assessment Group: Oversees NERC’s MMWG, which develops all Eastern Interconnection power flow and dynamic base case models, including seasonal updates to summer and winter power flow study cases.

The NCUC encouraged DEC and DEP to participate in a coordinated manner with SERTP and PJM Interconnection, L.L.C. (“PJM”) to ensure least cost paths for resource plan resources were identified.²² Several Public Policy Requests were submitted to SERTP for evaluation of regional impacts from the initial 2022 proposed Carbon Plan. The submitted requests identified the Carbon Plan Order as the basis for the requests. In the Order, the NCUC encouraged Duke Energy “to explore all possible efficiencies and to be vigilant in its participation in SERTP . . . to assure a least cost path to achieve the carbon dioxide emissions reduction requirements while maintaining and improving reliability.”²³

SERTP’s response to the Public Policy Requests indicated that in accordance with the NCUC Order, the Carbon Plan Order is currently being considered by Duke Energy and in its local planning activities

²² Carbon Plan Order at 121.

²³ Id.

with the NCTPC. Regarding SERTP's response, in addition to Local Transmission Planning process changes to address FERC Transmission Planning Notice of Proposed Rulemaking suggestions and incorporating a process for multi-value strategic transmission planning, as part of its 2023 plan, the NCTPC is studying a portfolio of resources suggested by the 2022 resource plan. Any resulting transmission plans will subsequently be made part of the SERTP process.

With respect to DEC and DEP participation in interregional transfer studies, SERTP is conducting an interregional transfer study to assess transfer capability with neighboring regions. EIPC is also developing a road map and schedule for conducting an interregional transfer capability study in 2024. Furthermore, Duke Energy has engaged with PJM through submission of a 1,000 MW transmission service request, which is pending study under PJM's revised queue reform process. The status of this request is discussed later in this Appendix.

Engagement with SERTP and other Regional Transmission Planning Groups such as SCRTP will continue to be important to assure power supply reliability for South Carolina and North Carolina customers.

Definitive Interconnection System Impact Studies and Generator Interconnection Impact on Transmission Upgrades

Generator interconnection requests are studied in accordance with the FERC Large and Small Generator Interconnection Procedures contained in the OATT and the South Carolina and North Carolina state generator interconnection procedures applicable to qualifying facilities selling their output to DEC or DEP under the Public Utility Regulatory Policies Act of 1978. In 2021, DEC and DEP obtained regulatory approvals from the NCUC, Public Service Commission of South Carolina and the FERC to transition from the serial "first-come, first-served" queuing process to a "first-ready, first-served" cluster study approach. In fall 2021, the Companies initiated the transition process for existing interconnection requests in the generator interconnection queue, providing an expedited window and study process for those projects to either proceed to interconnection or to withdraw with the option to reenter the new annual DISIS cluster study process. Projects that met transition process readiness requirements and completed study in the transitional serial or transitional cluster study process have now completed interconnection study and received IAs.

Definitive Interconnection System Impact Study Cluster Process

The first annual DISIS cluster commenced in August 2022 ("2022 DISIS") and is ongoing. Phase 1 and phase 2 studies for the 2022 DISIS cluster study are now complete and were an integral part of the joint systemwide 2022 Solar Procurement RFP process. The 2022 Solar Procurement RFP resulted in approximately 1 GW of new, controllable solar facilities selected on a highest-ranked, least-cost basis in DEC and DEP. In July 2023, the Companies determined that the 2022 DISIS requires restudy ("Phase 3 restudy") due to participants exiting the 2022 DISIS after 2022 DISIS phase 2 concluded. The Phase 3 restudy commenced on July 10, 2023. Table L-3 below summarizes the projects remaining in 2022 DISIS cluster.

Table L-3: Resources Remaining in 2022 DISIS Resources Phase 3 Cluster Study

Transmission Area	# of Projects	Total MW
DEC	15	2,607
DEP	23	1,514

Among the 15 DEC projects, five are FERC jurisdictional, six are state jurisdictional connected to transmission and four are state jurisdictional connected to distribution. Among the 23 DEP projects five are FERC jurisdictional, 16 are state jurisdictional connected to transmission and two are state jurisdictional connected to distribution. 12 of 15 projects in DEC and 19 of 23 projects in DEP are progressing as commercially ready projects, while three and four (or approximately 20% and 17%) in DEC and DEP, respectively, are progressing as non-ready projects that have provided increased financial security to remain in 2022 DISIS. As the Companies complete the Phase 3 restudies, the Companies will also monitor the risks of termination by the remaining projects and the potential need for further restudies.

The 2023 DISIS Cluster enrollment window closed on June 29, 2023, and the Phase 1 Study will commence on August 29, 2023. The Companies are also planning a resource solicitation cluster for studying proposals bid into the 2023 solar and SPS RFP to commence after 2023 DISIS. This Resource Solicitation Cluster will be designed to mitigate risks of restudy associated with the late-stage participant exits that the Companies recently witnessed in the 2022 DISIS.

Since undertaking the queue reform transition in 2021, all study phases in the Transitional and DISIS Cluster process have been completed in compliance with the required time frames of the FERC and state generator interconnection procedures. The average time to deliver an IA improved from more than four years under the serial process to two years under the cluster study if no restudy is required.

The cluster study process is superior to the serial study process, as the new study process has helped the goals of improving the study timelines for interconnection customers, incentivizing commercially ready projects in the queues, reducing the negative impact of speculative projects to other projects in the queue, as well as easing administrative burdens associated with processing significant volumes of Interconnection Requests in the prior serial study process. Interconnection customers benefit from a transparent and predictable process that is similar and aligned in each state and at the federal level.

On July 28, 2023, FERC issued its Final Rule on Improvements to Generator Interconnection Procedures and Agreements.²⁴ Order No. 2023 includes three broad categories of reforms to apply to all transmission providers: 1) transition to a “First Ready, First Served” cluster process; 2) reforms to increase the speed of generator interconnection queue processing; and 3) reforms to incorporate technological advancements into the interconnection process. DEC and DEP were early adopters of the First Ready, First Served Cluster Study process that FERC is now requiring each Transmission

²⁴ Improvements to Generator Interconnection Procedures and Agreements, Order No. 2023, 184 FERC ¶ 61,054 (2023) (“Order No. 2023”).

Service Provider to adopt in accordance with the Final Rule. With FERC changing the pro forma Large Generator Interconnection Procedure (“LGIP”), Large Generator Interconnection Agreement (“LGIA”) and Small Generator Interconnection Agreement (“SGIA”), DEC and DEP will need to review Order No. 2023 carefully to determine what, if any, revisions will be needed to the current DEC and DEP Joint OATT to comply with Order No. 2023’s directives. Currently, it is not yet clear whether or how the changes being imposed by the Final Rule could potentially impact the proceeding DISIS or Resource Solicitation Cluster schedules. The Companies will know and share more about the impacts of the Final Rule as they work to meet the schedule for implementation of the Final Rule. The Final Rule will be effective 60 days after publication in the Federal Register (likely early October), and DEC’s and DEP’s compliance filing is currently due 90 days after publication (likely early November).

Generator Replacement Request Process

In addition to queue reform associated with the Cluster Study process, DEC and DEP filed a request in June 2022 for FERC approval to revise the Large Generator Interconnection Procedure contained in their OATT to establish more efficient interconnection processes for certain replacement generation. This request was approved by FERC with an effective date of August 1, 2022, and the new generator replacement process was implemented for DEC and DEP. This new process will be critical to efficient, timely, and cost-effective replacement of retired coal-fired generation with new generation that interconnects at the same switchyard where the retiring generation is located. Utilization of the same switchyard for interconnection will save the cost of potentially expensive interconnection facilities that would be required if the same replacement generation was constructed at a greenfield site. DEC and DEP are already leveraging this new process for the benefit of DEC and DEP customers for replacing retiring coal generation at the DEC Marshall Plant and the DEP Roxboro Plant. More discussion on how this generation replacement process is being used for facilitating coal generation retirements is provided later in this Appendix.

Impacts for Solar and Solar Paired with Storage Interconnections and Allowable Capacity

The pace at which Duke Energy can interconnect renewables to the transmission grid is a result of a number of different factors, including the location of new generating facilities, size of facility (MW), interconnection requested, resource/load characteristics and prior queued requests, both individually and in aggregate. One such factor is reliability of the transmission grid and the ability to maintain single contingency operations with outage coordination as discussed further below. Another factor is the availability of solar and SPS projects that will be discussed further in the interconnection risk section. Finally, the number of annual interconnections to the system is dependent on the following additional key factors:

- **Expected Project Size** - One of the major evolving factors that will influence the achievable amount of MW of interconnections is the size of the solar projects procured under future competitive solar RFPs. Looking forward, the Companies will primarily procure substantially larger, transmission-connected projects. Third-party-owned projects are expected to be 50 to 80 MW and utility-owned projects could be substantially larger.

- **Need for Transmission Upgrades** - The influx of solar into the Carolinas has created a continued need for significant transmission system upgrades to allow for additional resource interconnections. These areas have been communicated through guidance documents and maps showing constrained transmission areas and are posted on the DEC and DEP OASIS sites for developers. These constrained transmission areas are associated with large, flat land parcels, ideal for solar development. These areas will become more attractive for solar development as Resource Plan implementation moves forward. Based on the timeline to complete these projects, the Companies project interconnected solar increases over time as network upgrades are completed.
- **Increasingly Complex Interconnections** - Not only will more complex system upgrades be required to interconnect solar, but the average cost for direct interconnection facilities will also increase in the future. This cost increase results from the fact that most prime real estate close to existing transmission infrastructure has been or is already being developed. New solar facilities seeking to interconnect will, on average, be built further from existing infrastructure than historical developments. Building farther from existing infrastructure requires larger direct interconnection facilities, which will further consume available resources and limit the maximum achievable annual interconnections.

Transmission Outage Coordination Impacts

The 2022 DISIS Phase 2 study results, shown below in Table L-4, revealed the average sizes for solar facilities requesting interconnection in DEC and DEP.

Table L-4: 2022 DISIS Phase 2 Solar Resources Requesting Interconnection

DEC/DEP	Avg Solar MW	Jurisdiction	# of Facilities	Total MW
DEP	73	State	19	1,393
DEP	78	FERC	2	155
DEC	85	FERC	2	171
DEC	52	State	11	570
Total			34	2,289

Deriving an “average” project from the solar facilities requesting interconnection in DISIS as reflected in Table L-4 above would imply the number of annual interconnections shown below in Table L-5 at a given aggregate level of solar and solar paired with storage.

Table L-5: Number of Interconnections Needed to Meet Solar and Solar Paired with Storage Targets

		Resource Plan Annual Solar Target (MW)				
		750	1000	1350	1500	1800
DEP Interconnections	UOT	4	5	7	7	9
	PPA	3	4	6	6	8
DEC Interconnections	UOT	1	2	3	3	3
	PPA	2	3	4	4	5
Total Interconnections		10	14	19	21	25

Note : Assume 70%/30% DEP/DEC split, UOT – Utility-owned track, PPA – Power Purchase Agreement

Annually, Transmission Outages, shown below in Table L-6, are needed for a variety of reasons including maintenance, NERC preventive maintenance requirements, asset management programs, NERC TPL-001 Standard Upgrade projects, new retail and wholesale delivery points, outage restoration, resource interconnections and associated Network Upgrades. Outage coordination groups currently accommodate about as many outages as can be accommodated and maintain reliable, single contingency operations in accordance with NERC Reliability Standards and prudent outage planning. Outages to accommodate interconnections of resources are additive to the line outages needed in a given year, which are scheduled to occur primarily in the spring and fall.

Table L-6: Transmission Outages (37-42% Annually are Line Outages)

	2019	2020	2021	2022	2023
DEC Outages	895	1,352	1,214	1,204	276
DEP Outages	786	1,308	1,086	1,168	132
Data Available	May 1 - Dec 31	Full Year	Full Year	Full Year	Jan 1 - Mar 15

Note : Each Interconnection can add up to four line outages per year with two additional outages for each associated network upgrade, e.g., eight interconnections could add 48 line outages per year assuming one network upgrade per interconnection.

From information provided above in Tables L-4, L-5 and L-6, ten interconnections for 750 MW could add an estimated 60 line outages (~+6%) per year and for 25 interconnections for 1,800 MW, an additional 150 line outages (~+15%) per year could be expected. This increase in line outages needed to meet higher levels of annual solar and SPS resource interconnections significantly increases execution risks and requires a fine balance between outages for interconnection and those required to preserve system operational reliability. One possible solution to decrease the number of annual interconnections required to meet Carolinas Resource Plan specified volumes would be to increase the size of the PPA (closer to the 80-MW limit) and Duke Energy-owned solar facilities (greater than 120 MW on average) as compared to the average sizes of solar facilities reflected in Table L-4.

As further addressed below, the Companies are designing process improvements to achieve increased resource interconnections; however, the Companies are doing so prudently with the objective of ensuring interconnecting new resources does not in any way negatively impact the

adequacy or reliability of the existing grid across the Carolinas in accordance with NERC Reliability Guidelines and Institute of Electrical and Electronics Engineers (“IEEE”) Standards.

Interconnection Process Improvements – From Fully Executed Generator Interconnection Agreement to Permission to Operate

DEC and DEP continue to develop new practices to advance interconnection timelines. Accordingly, a team was formed in 2022 to review options and actions to accelerate the interconnection timeline with an objective to complete interconnection activity in as few as 20 months from a fully executed IA for resources that can connect with a standard design and for which developers can partner to meet carefully aligned construction and commissioning milestones. The team consists of multi-function subject matter experts, stakeholders and process element owners for the interconnection queue, customer interface, interconnection study work, project planning and management, engineering, construction and facility commissioning. To date, those efforts have identified the following enhancements:

- Development of standard interconnection engineering designs
- Options for early ordering of equipment with long lead times
- Ability to parallel certain engineering design activities when developers can provide timely facility information
- Steps to accelerate timing for certain construction activities
- Definition of more visible program level performance measurement and tracking
- Identification of critical commissioning steps to ensure facility operational reliability

These efforts and initiatives will continue to improve interconnection timeline efficiencies, thereby enabling interconnection of solar and SPS resources on the timeline necessary to meet Resource Plan objectives for resource supply additions and coal retirements.

Improvements include increased developer coordination, industry learnings and application, improved commissioning coordination from industry best practices, DEC and DEP construction phase process improvements and visible interconnection and project financial performance metrics.

Working with Inverter Based Resources (“IBR”) developers from the transitional cluster, DEC and DEP piloted a commissioning process and used learnings of the pilot to implement the new transmission IBR Technical Requirements and commissioning process released in March 2023. DEC and DEP have incorporated additional developer meetings at key points in the construction process to ensure both parties understand the timing of upcoming requirements and align new interconnection milestones. Obtaining cooperation and coordination with solar developers for commissioning of IBRs will be imperative to preserving the reliability of the transmission grid now and in the future as highlighted by several NERC Event Reports and associated Reliability Guidelines addressing IBR reliability during grid disturbances.

As evidenced by the Companies' past interconnection performance of the process improvements, Duke Energy is an industry leader in IBR interconnections and this initiative reflects the Companies' continued constructive efforts to achieve increased annual generator interconnections while ensuring transmission system reliability is not adversely impacted. Through the generation transition, the Companies will continue to check and adjust the interconnection process to ensure timely interconnection of all generators, as well as to maintain the reliability of the transmission grid.

With respect to industry learnings and application, Duke Energy is working with NERC, IEEE and other industry regulatory agencies, as well as coordinating with peer utilities to ensure interconnection/commissioning processes are effective at promoting grid resilience while not being overly burdensome to developers or the utilities.

Internally, Duke Energy is focused on efficient procurement of materials and resources for the interconnection process given the increased time in obtaining key transmission interconnection materials from vendors. Duke Energy holds monthly internal meetings to ensure interconnection milestones are being met and to review the status of developer milestones. In addition, Duke Energy has aligned IA milestones and project management tools for increased visibility, coordination and focus on Duke Energy and developer milestones. Also, Duke Energy has developed a standard engineering design for single-breaker interconnections to make the design and construction phase more efficient where this standard design can be applied.

Interconnection Risks – Customer Delays and Transmission Upgrades

Duke Energy continues to see risks to meeting interconnection milestones as developer in-service dates are being pushed out and not pulled in to the 20-month timeline from signed generator IA to construction completion due to permitting issues, the ability to obtain materials in a timely manner due to global supply chain disruptions and other unforeseen developer realizations such as material and labor cost inflation occurring between bid acceptance and construction phases. This trend introduces the risk of solar and SPS resources not interconnecting at the pace needed to meet Resource Plan objectives. Another risk is being able to coordinate transmission system outages needed to accommodate the construction of network upgrades and interconnection facilities to meet Resource Plan objectives. As highlighted by Table L-4 and Table L-5, larger-sized solar and SPS facilities would result in a lower number of interconnections for a given amount of MW being interconnected and thus, could result in fewer outages needed per interconnected MW. Furthermore, addressing transmission network upgrades in a proactive manner would help to lower the risk and accelerate the path from executed IA to commercial operations.

Transmission Network Upgrades Keeping Pace with Solar and Solar Paired with Storage Interconnections

Multi-value strategic transmission planning that includes studying scenarios of different grid conditions results in identifying transmission needs and solutions that have multiple benefits for transmission customers and are cost-effective and sustainable solutions. This type of transmission planning avoids the piecemeal practice of identifying transmission needs and solving transmission constraints in an

isolated manner. In accordance with FERC Orders on transmission planning, these planning methods have to address local and regional transmission planning for reliability, economic studies and public policy requirements; however, FERC does not require that these studies be conducted in an isolated manner. As mentioned earlier in this Appendix, Duke Energy is working to expand local transmission planning processes to adopt this type of planning method. Duke Energy's first step with proactive transmission planning and determination of multiple benefits associated with local transmission projects was introduced with the RZEP projects in the NCTPC 2022–2032 Local Transmission Plan.

In the summer of 2022, DEC and DEP conducted cluster-type studies and presented these studies to the NCTPC TAG stakeholders for input and feedback. The studies were performed in a cluster study manner modeling the transmission system impacts of interconnecting 5.4 GW of historical solar generator interconnection requests. It revealed that even under changing assumptions about location, MW size, resource characteristics and queue order, a common set of transmission upgrades was needed in order to unlock a transmission-constrained area that has high viability for solar and SPS facilities known as a red zone region. These studies validated a set of identified recurrent transmission upgrades that were impeding solar facilities in the high solar viability areas of the DEC and DEP systems from moving forward to IAs.

From the results of the cluster-type studies, 14 transmission upgrade projects were identified. The NCUC acknowledged in the Carbon Plan Order that the results of the studies showed that the 14 RZEP projects were needed to execute the Companies' Resource Plan. The NCTPC OSC reviewed the cluster-type study analysis, agreed with the study results and supported inclusion of the RZEP projects in the 2022 Plan.²⁵ As noted in the Report on the NCTPC 2022–2032 Collaborative Transmission Plan,²⁶ the aforementioned cluster-type studies show that completion of the 2022 RZEP projects should enable the interconnection of approximately 3,759 MW of solar-generating facilities in Duke Energy's territory – 2,778 MW in DEP and 981 MW in DEC. Furthermore, the Interruption Cost Estimate tool considering asset replacement value revealed each of the 14 projects had a benefit-to-cost ratio of at least 5.1. This cost-benefit analysis excludes any benefit associated with carbon reduction.

Since the inclusion of the 14 RZEP projects into the 2022-2032 Plan, new 2022 DISIS Phase 1 and Phase 2 studies were completed for DEC and DEP. For DEC, the Phase 1 study identified multiple upgrades needed for the 5.1 GW of differing resource types (solar, battery storage, pumped storage hydro and gas generation) proposing to interconnect in those studies. In evaluating the 2022 DISIS in a similar manner to the prior supplemental study assessment of solar resources, it was identified that transmission upgrades that are complementary with the initial four DEC RZEP projects are needed for interconnecting additional solar and SPS facilities in DEC's South Carolina area (red circle on Figure L-2). For DEP, the Phase 1 study identified multiple upgrades needed primarily for the 4.6 GW of solar

²⁵ North Carolina Transmission Planning Collaborative, Report on the NCTPC 2022-2032 Collaborative Transmission Plan, February 2023, available at http://www.nctpc.org/nctpc/document/REF/2023-02-21/2022%20NCTPC%20Report%2002_21_2023_FINAL.pdf p. 27.

²⁶ North Carolina Transmission Planning Collaborative, Report on the NCTPC 2022-2032 Collaborative Transmission Plan, February 2023, available at http://www.nctpc.org/nctpc/document/REF/2023-02-21/2022%20NCTPC%20Report%2002_21_2023_FINAL.pdf p. 26-28.

facilities requesting interconnection. With the 4.8 GW of all resource types requesting interconnection, the DEP Phase 1 study revealed that more transfer capability is needed between the eastern and western areas of the DEC and DEP systems as more of the Resource Plan-identified resources are integrated into the systems. This additional transfer capability should enable reliable and efficient economic dispatch of these resources. In addition, new transmission-constrained areas on the DEP transmission system were identified, primarily with solar facilities requesting interconnection along the Jacksonville to New Bern to Goldsboro corridor (red ellipse on Figure L-2). Evaluating the results of the 2022 DISIS Phase 1 Studies, a second phase of RZEP projects, shown below in Table L-7, has been identified that are longer duration and start to address these constraints. It should be noted that some of the proposed RZEP 2.0 projects are still being reflected in the 2022 DISIS Phase 2 study results. Ultimately, the results of the 2022 DISIS studies, as well as the results of the 2023 NCTPC study will determine the network transmission upgrade projects that need to be proactively pursued and the projects that will be approved in the 2024-2034 NCTPC Plan.

Figure L-2: 2022 DISIS Phase 1 Interconnection Requests

DISIS 2022 - Red Zone Map

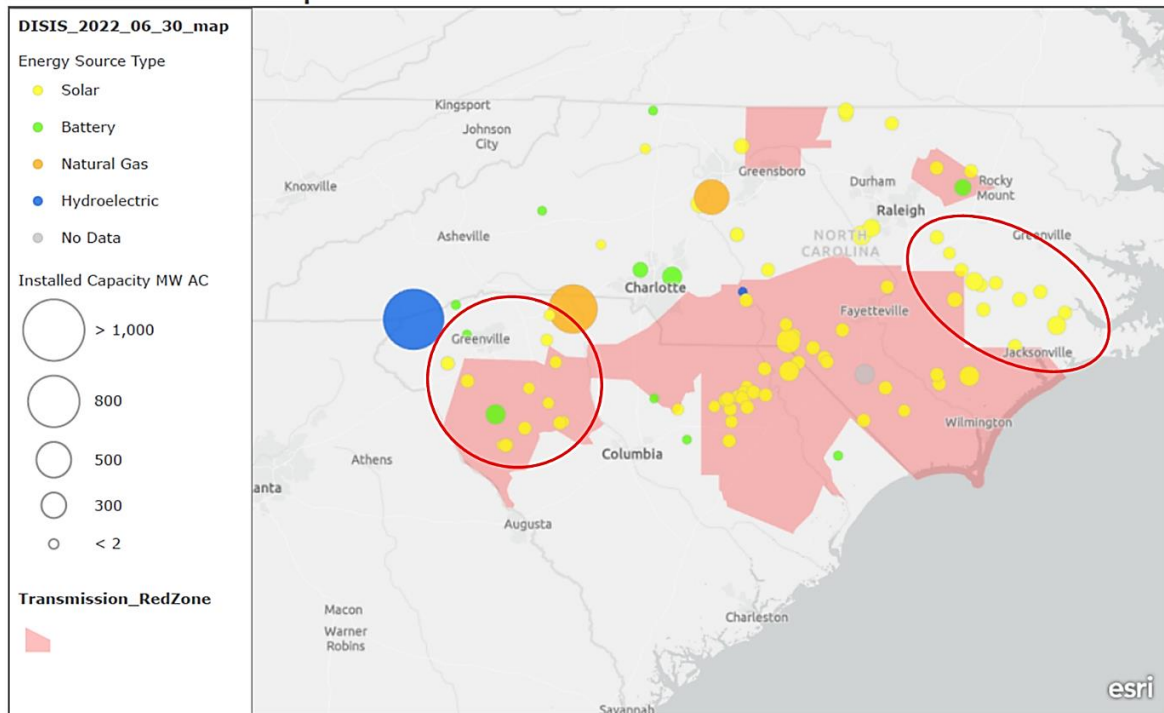


Table L-7: Proposed Red Zone Expansion Plan (RZEP 2.0) Upgrades

Project	Owner	Project Description	Cost Estimate ^{1,2}	Potential In-Service Date
Broadway B/W 100 kV (Belton Tie-W.S. Lee Combined Cycle)	DEC	Rebuild	\$19,749,000	May 2028
Bush River 115/100 kV Transformers	DEC	Upgrade	\$8,523,000	May 2028
Champion B/W 100 kV (Bush River-New Berry PV)	DEC	Rebuild	\$29,114,000	May 2028
Clayton Industrial - Selma 115 kV	DEP	Rebuild	\$27,741,000	Sep 2028
Lilesville-Oakboro 230 kV Black³	DEP	Rebuild	\$54,470,000	Dec 2029
Lilesville-Oakboro 230 kV White³	DEP	Rebuild	\$54,470,000	Dec 2029

Note 1 : Class 5 Cost Estimate from the DEC 2022 DISIS Phase 2 Study Report.²⁷

Note 2 : Class 5 Cost Estimate from the DEP 2022 DISIS Phase 1 Study Report.²⁸

Note 3 : Cost Estimate includes upgrading the entire tie-line but excludes any upgrades to be identified as needed in the DEC Oakboro 230 kV substation.

Status Update on Transmission Expansion Plan Projects and Benefits from These Upgrades

Table L-8 below reflects the 14 RZEP projects approved through the Local Transmission Planning process as outlined in the DEC and DEP Joint OATT, Attachment N-1. For the 2022 DISIS, there were 11 solar facilities representing over 760 MW in the Phase 1 study that identified dependencies on one or more of the four DEC RZEP projects. There were nine solar facilities representing over 530 MW in the Phase 2 study that identified dependencies on one or more of the four RZEP projects. For the 2022 DISIS, there were 30 solar facilities representing over 2.4 GW in the Phase 1 study that identified dependencies on four of the 10 DEP RZEP projects. There were 12 solar facilities representing over 830 MW in the Phase 2 study that identified dependencies on four of the 10 DEP RZEP projects. Included in Table L-8 is the July 2023 status of all 14 RZEP projects including an updated cost estimate reflecting a fully burdened cost with contingency included. It should be noted that all 14 RZEP projects are on or ahead of the original planned in-service date schedule. The aggregated cost estimates for the projects, inclusive of burdens and contingency, have increased from \$554 million to \$576 million. Additionally, the Camden-Camden Dupont 115 kV upgrade, one of the original 18 recommended RZEP upgrades and supported by the summer 2022 DEP cluster-type study results, is included in Table L-8 as being proposed for inclusion in the 2023 Local Transmission Plan as presented in the 2022 Plan Mid-Year Update Report. All of the project status updates were provided in the Semi-Annual

²⁷ Duke Energy Carolinas, LLC 2022 Definitive Interconnection System Impact Study Phase 2 Report – Rev. 1 July 7, 2023, available at

[https://www.oasis.oati.com/woa/docs/DUK/DUKdocs/DRAFT_2022_DEC_Definitive_Interconnection_System_Impact_Study_Cluster_\(Phase_2\)_Report_rev1.pdf](https://www.oasis.oati.com/woa/docs/DUK/DUKdocs/DRAFT_2022_DEC_Definitive_Interconnection_System_Impact_Study_Cluster_(Phase_2)_Report_rev1.pdf).

²⁸ Duke Energy Progress, LLC 2022 Definitive Interconnection System Impact Study Phase 1 Report November 23, 2022, available at https://www.oasis.oati.com/woa/docs/CPL/CPLdocs/2022_DEP_DISIS_Phase_1_study_report_11-23.pdf.

Report on Status of Transmission Upgrades and Status Report on NCTPC Process under NCUC
Docket No. E-100, Sub 190T.

Table L-8: Proposed Red Zone Expansion Plan (RZEP 1.0) Project Status

Project	Owner	Project Description	Cost Estimate ¹	Planned In-Service Date
Lee 100 kV (Lee-Shady Grove)	DEC	Rebuild	\$39,660,000	Aug 2025
Piedmont 100 kV (Lee-Shady Grove)	DEC	Rebuild	\$40,080,000	Aug 2026
Newberry 115 kV (Bush River-DESC)	DEC	Rebuild	\$34,583,000	Apr 2025
Clinton 100 kV (Bush River-Laurens)	DEC	Rebuild	\$86,091,000	Oct 2026
Cape Fear Plant-West End 230 kV Line	DEP	Rebuild	\$83,033,000	Jun 2026
Erwin-Fayetteville East 230 kV Line	DEP	Rebuild	\$95,826,000	Jun 2026
Erwin-Fayetteville 115 kV Line	DEP	Rebuild	\$24,083,000	Jun 2025
Fayetteville-Fayetteville Dupont 115 kV Line – 3.2-mile section	DEP	Rebuild	\$15,574,000	Dec 2024
Milburnie 230 kV Substation	DEP	Redundant Bus Protection	\$5,205,000	Apr 2026
Weatherspoon-Marion 115 kV Line	DEP	Rebuild	\$21,167,000	Dec 2025
Camden Junction-DPC Wateree 115 kV Line	DEP	Rebuild	\$15,909,000	Dec 2026
Robinson Plant-Rockingham 115 kV Line	DEP	Rebuild	\$42,293,000	Jun 2027
Robinson Plant-Rockingham 230 kV Line	DEP	Rebuild	\$49,020,000	Jun 2026
Fayetteville-Fayetteville Dupont 115 kV Line – 4.9-mile section	DEP	Rebuild	\$15,574,000	Apr 2026
Camden-Camden Dupont 115 kV Line ²	DEP	Rebuild	\$9,372,000	Nov 2024

Note 1 : Cost Estimate is fully burdened with contingency and can change over the project life cycle due to labor and materials costs.

Note 2 : Upgrade proposed to be included in NCTPC 2023 Local Transmission Plan.

Impacts for Standalone Storage Interconnections

Large scale standalone storage will continue to migrate to proactively selected sites such as retired coal sites that should minimize network upgrades relative to early projects and potentially garner the additional 10% Inflation Reduction Act of 2022²⁹ (“IRA”) energy community tax credit. Additionally, locating standalone battery storage at transmission substations near load centers where the land availability for solar is not required should reduce the need for transmission network upgrades as well. In addition, the existing communications infrastructure can be leveraged at these locations.

²⁹ Inflation Reduction Act, S. Con. Res., 117th Cong. (2022).

Transmission Planning for Enabling an Orderly Transition with Coal Plant Retirements

The Companies must plan the transmission system to enable and execute an orderly utility system transition and achieve the Plan's target schedule for retiring the Companies' coal-fired generating units in North Carolina. The schedule for coal unit retirements is further addressed in Appendix F (Coal Retirement Analysis) and Chapter 4 (Execution Plan). The transmission planning team works closely with the Companies' Generation and Transmission Strategy team to ensure coordinated and executable planning for coal unit retirements and potential replacement generation. DEC and DEP transmission planning groups perform coal unit retirement assessments based on assumptions for replacement generation in order to analyze potential impacts to the DEC and DEP transmission systems. Critical to the results of the assessments are: 1) location and size of the coal-fired generation being retired; 2) the year of retirement or sequence with other generators retiring; and 3) the size and location of replacement generation. If the replacement generation can be located at the site of the retiring coal generation and utilize the existing interconnection to the same electrical point of interconnection, there will likely be minimal to no network upgrades required for the replacement generation and the schedule for interconnecting the replacement generation will be more certain. Enabling this efficient, timely, and cost-effective replacement of retired coal units is the objective of the aforementioned Generation Replacement queue process that DEC and DEP designed and FERC approved for implementation in 2022. If replacement generation cannot be interconnected to the same electrical point of interconnection as the retiring generation, network upgrades, due to thermal overload issues or voltage support issues, may be required.

DEC

- Allen Station Units 1 and 5: Transmission upgrades will be completed to enable retirement of the remaining Allen Station Units 1 and 5 are planned to be retired by the end of 2024.
- Cliffside Unit 5 (earliest planned retirement date December 2030): Planning analysis does not identify any major transmission upgrades to be required from Cliffside Unit 5 retirement.
- Marshall Station Units 1-4 (earliest planned retirement date Marshall 1-2 December 2028; Marshall 3-4 December 2031): Retirement of any Marshall coal units, if by the end of 2028, will require replacement generation on site coincident with retirement. If any Marshall coal units are retired and not replaced with new generation on-site, then significant transmission projects will be needed (i.e., upgrade McGuire to Marshall 230 kV lines currently shown in Table L-2 to be in-service in 2031 coincident with retirement of Marshall 3-4) and in service by December 2028. The project will also allow removal of Marshall generation from reliability must run status if performed earlier than the planned retirement date. A Generation Replacement Request for Marshall Plant Units 1 and 2 replacement generation (780 MW of advanced CT generation) has been submitted to the Generation Replacement Coordinator for study in accordance with the Generation Replacement queue process approved by FERC and provided in the OATT. Also, in accordance with the OATT, the 140 incremental MW above the 780 MW replacement

generation necessary to achieve Network Resource Interconnection Service for the full 920 MW capacity³⁰ of the 2 advanced CTs has been submitted as an interconnection request into the 2023 DISIS.

- Belews Creek Units 1-2 (earliest planned retirement date December 2035): Belews Creek units will continue to operate into the 2030s and DEC plans to evaluate transmission upgrades to enable retirements as the planned retirement date approaches. However, preliminary analysis does suggest that transmission upgrades will be required to retire the 2,220 MW of capacity at Belews Creek if not replaced with new generation on-site and coincident with the retirements.

DEP

- Roxboro Station Units 1-4 and Mayo Unit 1 (earliest planned retirement dates Roxboro 3-4 December 2033; Roxboro 1-2 December 2028; Mayo 1 December 2030) will cause the need for additional transmission projects if the generation is not replaced sufficiently at the Roxboro and/or Mayo sites coincident with the retirements. If the Roxboro/Mayo generation is not replaced by new generation at the same location, but within DEP, then some transmission projects will be required. It is likely that a static var compensator would be needed in the DEP northern region along with some other moderately small transmission upgrades with an estimated cost of less than \$100 million. A Generation Replacement Request for Roxboro Plant Units 1 and 2 replacement generation (1,053 MW of gas fired CC generation) has been submitted to the Generation Replacement Coordinator for study in accordance with the Generation Replacement queue process approved by FERC and provided in the OATT. Also, in accordance with the OATT, the 313 incremental MW above the 1,053 MW replacement generation necessary to achieve Network Resource Interconnection Service for the full 1,366 MW capacity³¹ of the gas-fired CC has been submitted as an interconnection request into the 2023 DISIS.
- Currently, there is no available long-term firm import capability from DEC to DEP. Thus, if the Roxboro/Mayo replacement generation is located in DEC and requires import into DEP, then additional upgrades would be required. Conceptual transmission projects that would likely be needed would be a Durham-Parkwood Tie 500 kV interconnection, a Bynum 500/230 kV Switching Station interconnection along with associated line upgrades, and potentially a Roxboro Plant-Sadler Tie 230 kV interconnection.

Actual retirement dates may extend beyond the planned retirement dates identified in the Plan to avoid power system reliability issues. Generation retirement reliability assessments will continue to be updated with results provided in future iterations of the Carolinas Resource Plan.

³⁰ 920 MW capacity represents the maximum winter output capacity for coldest ambient temperatures.

³¹ 1,366 MW capacity represents the maximum winter output capacity for coldest ambient temperatures.

Transmission Needed to Enable Additional Pumped Storage Hydro Capacity at Bad Creek

As described in Appendix I (Renewables and Energy Storage), the planned Bad Creek II project will increase the capacity of the Bad Creek pumped storage hydro facility from 1,640 MW to approximately 3,320 MW with an 80-year asset life resource. To determine the transmission needs for injecting an additional 1,680 MW of energy into the transmission system at the Bad Creek point of interconnection, a generator interconnection request was submitted into the 2022 DISIS. The recent 2022 Phase 2 DISIS study report³² identifies that approximately \$455 million of network upgrades are assigned to the Bad Creek II project, which is a significant portion of the total upgrades in the DEC 2022 Cluster. Approximately \$153 million of the \$455 million of network upgrades are identified solely for the Bad Creek II project. However, several solar and battery projects in 2022 DISIS are also contributing to certain of the same network upgrades identified as needed to interconnect the Bad Creek II project. Specifically, approximately 645 MW of standalone solar and 534 MW of standalone battery resources are dependent on several of the same network upgrades as the Bad Creek II project. It is also notable that the \$455 million of network upgrades identified as needed in 2022 DISIS Phase 2 is less than the \$627 million assumed to develop the network upgrade cost proxy for this resource utilized for capacity expansion modeling.

Near-Term Transmission Needed to Enable Onshore and Potential Offshore Wind Resources

Appendix I addresses feasibility, technology and other considerations associated with planning, siting and installing onshore and offshore wind resources in the Carolinas. This section addresses the transmission required to support onshore and offshore wind as a resource in the Carolinas. The transmission needed to interconnect offshore wind was evaluated through a 2020 NCTPC planning study, dated June 7, 2021, which Duke Energy has used along with its own internal analysis to inform the Companies' strategy around installing offshore wind as a resource plan resource. In addition, for onshore wind, the results of a siting feasibility study are key inputs to assessing potential transmission upgrade needs for this resource type.

Onshore Wind

From Appendix I, the Companies do not currently have onshore wind generation installed in the Carolinas, but the U.S. onshore wind market continues to grow with approximately 146 GW operational nationwide and approximately 40 GW coming online in the last three years. The Companies are expecting to develop onshore wind capacity, with 1,200 MW identified in Chapter 4 as needed to come

³² Duke Energy Carolinas, LLC 2022 Definitive Interconnection System Impact Study Phase 2 Report – Rev. 1 July 7, 2023, available at [https://www.oasis.oati.com/woa/docs/DUK/DUKdocs/DRAFT_2022_DEC_Definitive_Interconnection_System_Impact_Study_Cluster_\(Phase_2\)_Report_rev1.pdf](https://www.oasis.oati.com/woa/docs/DUK/DUKdocs/DRAFT_2022_DEC_Definitive_Interconnection_System_Impact_Study_Cluster_(Phase_2)_Report_rev1.pdf).

online by 2033 to transition to a diverse and reliable clean energy portfolio. Additionally, the Companies have initiated a siting feasibility study to understand areas suitable for onshore wind development within the Carolinas.

Interconnection of onshore wind facilities will be another variable the Companies will continue to monitor. Once an appropriate site is identified and site control established for the development of an onshore wind facility, the next critical risk is interconnection of that generator. Similar to other generation resources needed to execute the capacity additions identified in the Resource Plan, interconnection is also a critical path item for the execution of onshore wind. In addition to the fact that there are a limited number of interconnection projects that can be constructed and interconnected in a given year, onshore wind resources could be located farther from population centers than other generation resources, resulting in more complex and expensive interconnection projects, which further exacerbates this constraint.

As stated in Appendix I, proximity to existing transmission infrastructure was used in the siting feasibility study. However, actual transmission impacts associated with developing onshore wind projects will need to be evaluated in future DISIS clusters and may be impacted by other generator interconnection requests in an earlier cluster or the same cluster.

Offshore Wind

For offshore wind, the first step to address the transmission infrastructure challenge was to determine the best point of interconnection of the offshore wind generation to the DEP transmission network. Based on the 2020 NCTPC study and Duke Energy's own internal analysis, the Companies determined that the New Bern 230 kV substation would be the most appropriate point of interconnection for both the Kitty Hawk and the Carolina Long Bay Wind Energy Areas, due to having higher MW capability at relatively lower cost. However, Duke Energy continues to assess alternate points of interconnection for offshore wind to consider IRA benefits and cost of infrastructure changes for interconnection and bulk power transfer of appreciable offshore wind energy into the Carolinas and impacts to transmission system power flows.

The 2020 NCTPC study screened 32 potential injection sites and based on the injection capability and cost results of that screening analysis, further analyzed the feasibility and costs of injecting up to 5,000 MW of offshore wind power at the three most promising sites based on those criteria in eastern DEP. The power from the offshore wind plants was delivered 40% to DEP and 60% to DEC. Rather than studying pre-determined MW levels, it was requested that NCTPC find the MW breakpoints at which transmission upgrades would be needed. As reflected in the 2020 NCTPC Offshore Wind Study Report,³³ the New Bern 230 kV substation would be one of the three most promising sites to inject up to 3.2 GW of offshore wind based on cost and feasibility. No other site stood out for both high MW capability and relatively lower cost, but two additional sites were selected to provide geographic diversity — the Greenville 230 kV (selected for high initial MW screening levels, though with higher

³³ North Carolina Transmission Planning Collaborative, Report on the NCTPC 2020 Offshore Wind Study, June 2021, available at http://www.nctpc.org/nctpc/document/REF/2021-06-07/W_Doc/2020_NCTPC_Offshore_Wind_Report_06_07_2021-FINAL%20Rev%202.pdf.

cost per watt) and the Sutton North 230 kV switching station (relatively low cost per watt but only up to 2,500 MW). After the power flow screening of 32 potential injection sites, the site that stood out for high MW injection capability at relatively lower cost was DEP's New Bern 230 kV substation. The New Bern 230 kV substation benefits from already having five 230 kV lines, two of which head in the direction of the DEP Raleigh load center. In addition, DEP has a partial 500 kV right-of-way ("ROW") available from New Bern 230 kV to Wommack 230 kV and a full 500 kV ROW from Wommack 230 kV to Wake 500 kV, which is located just east of Raleigh. These unused ROWs were used in the study to add new 500 kV lines to maximize the injection capability at New Bern 230 kV. The study indicated that no new network transmission was required in DEC to import a share of the offshore wind output.

Additional internal analysis estimated the full transmission cost for a landing area commensurate with sourcing offshore wind from Kitty Hawk or Carolina Long Bay (see Figure L-3 below³⁴) and injecting from 800 MW up to 1.6 GW of offshore wind into a New Bern 230 kV point of interconnection.³⁵ These estimates reflect the cost of radial transmission interconnection facilities from the offshore wind source to the New Bern point of interconnection and then transmission network upgrades from New Bern to the Wake 500 kV substation of \$1.3 billion to \$2.7 billion for injection of 800 MW up to 1.6 GW of offshore wind into New Bern, respectively. Under the existing generator interconnection cost allocation rules, the cost of the radial transmission interconnection facilities from the offshore wind source to the New Bern substation would be assigned to the wind generation developer. The schedule associated with siting, permitting and constructing this transmission is dependent on public engagement, routing, scoping and acquisition of new ROW for new 500 kV DC and 500 kV AC transmission lines that will be required to import up to 1.6 GW of wind. Delays in these schedule dependencies are key risks in meeting any timeline for importing offshore wind energy. Seeking to mitigate this risk, as well as lowering cost for customers for this resource, DEP has collaborated with the NC Department of Environmental Quality ("NCDEQ") State Energy Office to submit an application for \$250 million of Department of Energy ("DOE") funding for a 500 kV line from New Bern to Raleigh needed to support the import of offshore wind energy into the Carolinas. This networked transmission line will also support new interconnections of solar, solar paired with storage and potential onshore wind sites. The 2023 NCTPC study scope includes 800 MW of offshore wind, in addition to 12.5GW of solar and solar paired with storage, which will provide a clearer picture of what network upgrades may be needed to accommodate these resources injecting power into the eastern DEP transmission system.

³⁴ Carolina Long Bay formerly known as Wilmington East.

³⁵ Kitty Hawk offshore wind will be viable prior to Carolina Long Bay offshore wind due to being further along in the process of having leased OSW area as well as its Construction and Operations Plan with BOEM.

Figure L-3: BOEM – North Carolina Designated Wind Energy Areas



Figure source: Bureau of Ocean Energy Management

Transmission Needed to Support Importing Capacity and/or Energy from Neighboring Systems (Southern Co, TVA, PJM)

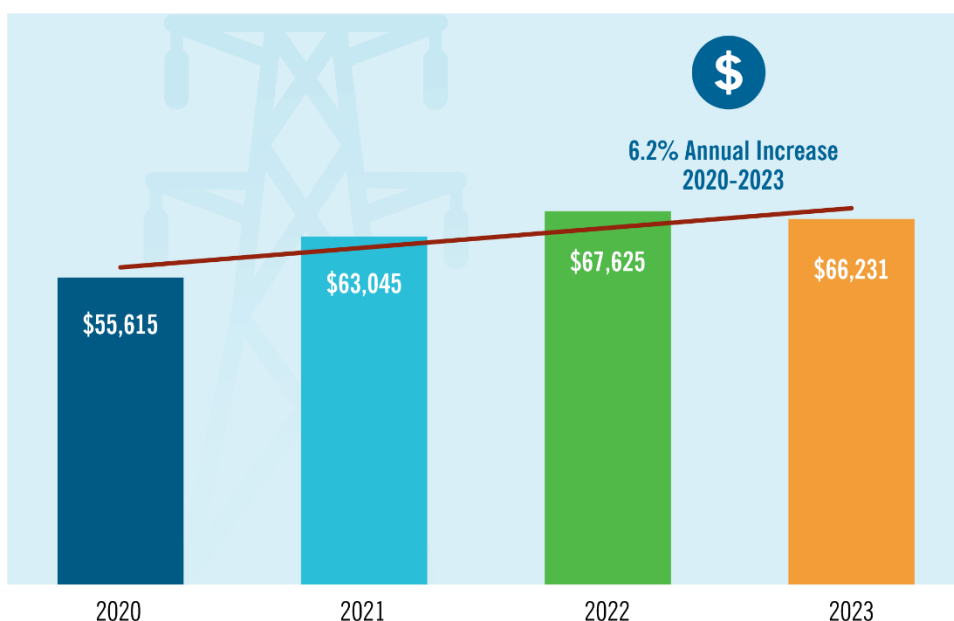
DEC and DEP continue to explore import capabilities for alternative capacity resources to consider in the Carolinas Resource Plan. In the 2022 resource plans, Duke Energy performed import capability studies specifically for a capacity purchase from PJM and to continue to assess costs, risks and reliability aspects of potential off-system purchases. Duke Energy conducted the analysis in a manner that would ensure reliability of the bulk electric system, both through the execution of the proposed transmission upgrades, as well as the coordinated timing of an off-system purchase with proposed generation retirements.

Import Capability from PJM

The process to study a capacity purchase from PJM to DEP involves submitting the applicable Transmission Service Reservation or Network Integrated Transmission Service request on the PJM and DEP OASIS sites, respectively. The request must be for firm transmission service to ensure the continued reliable operation and deliverability of energy from PJM to DEP. PJM's current Border Rate is \$66,231/MW-year to purchase Long-Term Firm Point-to-Point transmission service. At the current

rate, a 1,000 MW service request would cost approximately \$66 million/year to reserve the transmission service. This cost excludes the cost of the capacity resource(s) and energy cost utilizing the transmission service and any identified upgrades on the Duke Energy transmission system needed to enable the imported capacity and energy. The PJM Border Rate has increased 6.2% annually on average since 2020, as illustrated in Figure L-4 below. The PJM Border Rate is based on transmission investment in PJM. As the entire country is focused on the transmission buildout necessary to support the ongoing energy transition resulting in significant coal retirements and distributed resource additions, the level of transmission investment in PJM and thus, the PJM Border Rate, is likely to continue to increase in future years.

Figure L-4: PJM Border Charge, 2020–2023



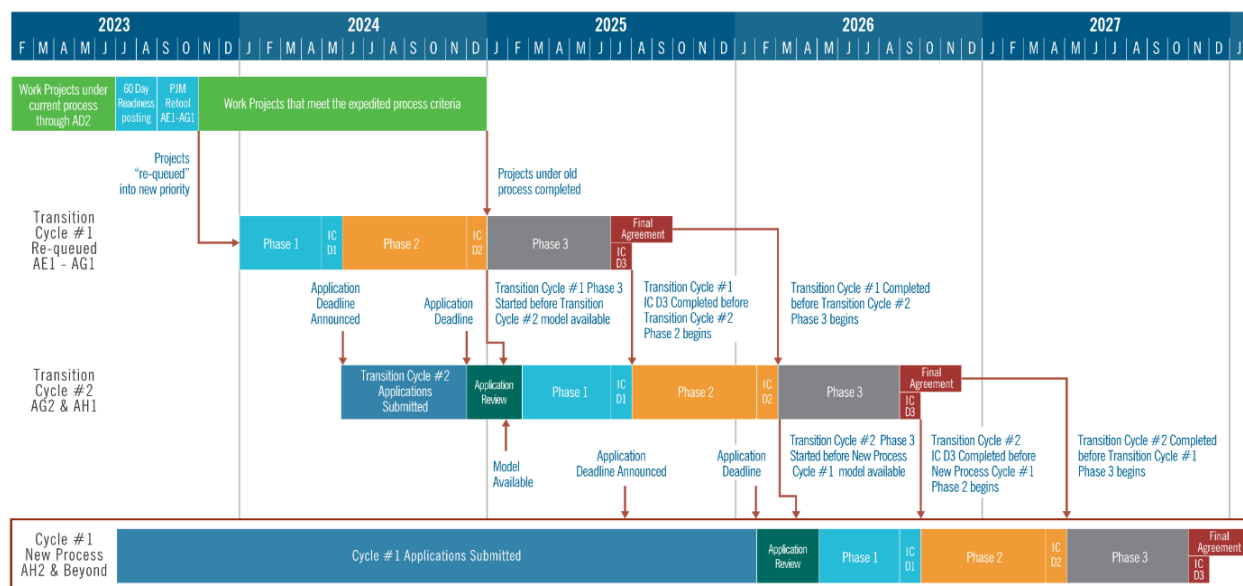
As Transmission Service Providers, PJM and DEP each study transmission service requests consistent with their respective OATT provisions and approve the requests accordingly, subject to the completion of transmission facility upgrades or modifications. Presently, there is no Long-Term Firm Point-to-Point Transmission Service available from PJM to DEP unless several costly transmission network upgrades are implemented. In the initial 2022 proposed Carbon Plan, it was estimated that significant system reinforcement projects are needed on both the PJM and DEP transmission systems to enable such import capacity with initial cost estimates starting at approximately \$700 million. This is consistent with previous transmission service requests submitted to PJM³⁶ by DEP, as well as DEP's own Affected System studies and supported by DEP's own analysis of PJM system limits utilizing the PJM Generator Deliverability tool developed by Power-GEM. The PJM Generator Deliverability tool is

³⁶ PJM Feasibility Study Report – Long-Term Firm Transmission Service/OASIS Assignment Reference 4966477, 4966479, and 4966484 Queue Project AE1-110/AE1-111/AE1-112 — to be provided upon request.

utilized by PJM in the analysis of the PJM Generator Interconnection Queue, including the analysis of Long-Term Firm Transmission Service requests.

Upon evaluation of previous PJM and DEP feasibility studies and Affected System Studies, as well as utilizing the same study tools and PJM queue data, a 1,500 MW transfer was studied from PJM to DEP. The results of this study indicate the need to upgrade transmission facilities in both PJM and DEP, both requiring significant time and expense. The PJM queue reform process presents additional uncertainty with predicting the timing of implementing a new Transmission Service Request. DEP has submitted a request for 1,000 MW for Firm Point-to-Point Transmission Service from PJM to DEP. This request was submitted into the queue window AH2 and is expected to be processed in accordance with the dark red outlined transition process shown in the revised process flow diagram Figure L-5 below. The expected milestone dates for the Firm Transmission Feasibility Study based upon the below timeline for DEP's transmission service request ("TSR") submittal into queue window AH2 is for the Transmission Service Request to be studied sometime within 2026 with Final Agreements made in late 2027. The revised queue reform transition process flow diagram is found in PJM's redlined Manual 14H – New Service Requests Cycle Process.³⁷

Figure L-5: PJM Revised Queue Process Flow Diagram



³⁷ PJM Manual 14H: New Service Requests Cycle Process, available at <https://www.pjm.com/-/media/committees-groups/subcommittees/ips/2023/20230525/20230525-item-06c---m14h-redlined.ashx>.

Import Capability from Southern Company

The 2021 SERTP Regional Transmission Planning Analysis³⁸ performed Regional Analysis of Potential Transmission Project Alternatives between the Southern Company and DEC areas, shown below in Figure L-6. A transmission project was evaluated as a 140-mile, 500 kV transmission line with one termination point at the Thomson Primary 500 kV substation in Georgia within the Southern Balancing Authority Area and the other termination point at the Newport 500 kV substation in South Carolina within the DEC Balancing Authority Area.

Although the project alternative did not reveal any local projects that it would displace, the project would add single contingency transfer capability between Southern Company and DEC since the main contingency between the two areas, currently the Oconee-South Hall 500 kV line, would no longer be the sole 500 kV path between the two areas.

Figure L-6: SERTP Regional Analysis of Potential Transmission Project Alternatives



The planning level estimate for the Thomson Primary-Newport 500 kV transmission line is approximately \$792.5 million. Additional underlying 500 kV, 230 kV and 100 kV upgrades could be necessary and would be identified in a TSR study if submitted on each Company's OASIS site. Other potential options would be to study a Thomson Primary-Richmond 500 kV transmission line possibly looping through a new substation in the Dominion Energy South Carolina VC Summer Plant area.

Import Capability from TVA

Current import capability into DEC and DEP from TVA is subject to contract path limitations. The contract path limit for DEC is 692 MW and for DEP is 276 MW. The primary concern with the DEP

³⁸ Southeastern Regional Transmission Planning, Regional Transmission Planning Analysis, November 2021, available at <http://www.southeastertrtp.com/docs/general/2021/2021-SERTP-Regional-Transmission-Planning-Analyses-Summary-Final.pdf>.

path is there is only one tie-line between DEP and TVA. Another risk with a purchase from TVA is that TVA's system experiences a high level of transmission congestion and curtailments as referenced in the 2022–2023 SERC Regional Risk Report.³⁹ Furthermore, as indicated in Winter Storm Elliott, TVA most likely does not have any surplus winter capacity.⁴⁰

Risks Associated with Off-System Capacity Purchases

The system risks associated with relying on significant incremental off-system capacity purchases for resource plan needs include, but are not limited to:

- Delay in resource availability: If required transmission network upgrades on the DEC/DEP transmission systems or neighboring transmission systems are delayed due to siting, permitting or construction issues, these delays can jeopardize the scheduled in-service date of the transmission upgrades necessary for importing the capacity resource.
- Loss of local ancillary benefits that are inherent with an on-system resource (e.g., Voltage/Reactive Support, Inertia/Frequency Response, Automatic Generation Control/Regulation for balancing renewable output) may require more on-system transmission upgrades such as adding static var compensators for voltage support.
- Curtailment due to transmission constraints and/or capacity emergencies in neighboring areas such as occurred on December 24, 2022.
- Transmission system stability issues under certain scenarios due to added distance between the capacity resource and load.
- Other systems have aging coal generators and are retiring units at the same time as Duke Energy. For example, TVA plans to retire its 865 MW Bull Run plant at the end of 2023, its 2,470 MW Cumberland coal-fired plant by 2028 and all remaining coal-fired generation will be retired by 2035.⁴¹

Southeast Energy Exchange Market

The Southeast Energy Exchange Market ("SEEM") is a unique regionally coordinated approach to enhancing sharing of economic energy through automation of the bilateral market. The SEEM platform facilitates sub-hourly, bilateral trading, allowing participants to buy and sell power close to the time the energy is consumed, utilizing available unreserved transmission. Participation in SEEM is open to any

³⁹ SERC Reliability Corporation, 2022-2023 Regional Risk Report, available at https://www.serc1.org/docs/default-source/committee/ec-reliability-risk-working-group/2022-23-serc_regional_risk_report_final.pdf page 40.

⁴⁰ Tennessee Valley Authority, After Action Report / Winter Storm Elliott, available at <https://bloximages.newyork1.vip.townnews.com/local3news.com/content/tncms/assets/v3/editorial/4/3e/43e4b436-eb67-11ed-a87a-530b1c4c2bd9/645537f5cd9d7.pdf>.

⁴¹ Tennessee Valley Authority, Power System (Coal), available at <https://www.tva.com/energy/our-power-system/coal/>.

entity that meets the criteria. DEC and DEP customers will see cost and environmental benefits because of the platform.

The current SEEM Members are Associated Electric Cooperative Inc., Dalton Utilities, Dominion Energy South Carolina, DEC, Duke Energy Florida, DEP, Georgia System Operations Corporation, Georgia Transmission Corporation, JEA, Louisville Gas & Electric Company and Kentucky Utilities Energy, Municipal Electric Authority of Georgia Power, N.C. Municipal Power Agency No. 1, NCEMC, Oglethorpe Power Corp., PowerSouth, Santee Cooper, Seminole Electric Cooperative, Southern Company, Tampa Electric Company and TVA. These SEEM members represent 23 entities in parts of 12 states with more than 180,000 MW (summer capacity; winter capacity is nearly 200,000 MW) across two time zones. These companies serve the energy needs of more than 36 million retail customers (nearly 60 million people).

DEC and DEP started executing purchase and sales of economic energy matched through the SEEM platform on November 9, 2022. SEEM facilitates as-available economic energy exchanges that optimize benefits and rely on available non-firm transmission capability provided by all SEEM Members. This available non-firm transmission capability is transmission capability utilized on a 15-minute period basis that would otherwise not be utilized. From inception through May 2023, DEC and DEP have entered into over 16,000 SEEM trades with an estimated benefit of over \$1 million. These benefits are expected to grow as the market matures and as new SEEM members and participants — Duke Energy Florida, Tampa Electric, JEA and Gainesville Regional Utilities — are integrated into the SEEM platform with the ability to participate in SEEM transactions.

On July 14, 2023, the D.C. Circuit Court of Appeals issued its opinion on appeals of the FERC's orders accepting the SEEM Agreement and certain Member's related OATT revisions. The 2-1 majority opinion granted certain aspects of the appeals, denied others and ordered that the case be remanded back to the FERC for further explanation. Parties have the opportunity to seek rehearing of the Court's opinion until August 28, 2023. If there are no rehearing requests filed, the Court is expected to issue an order remanding the case back to the FERC. During the rehearing period, SEEM remains operational and the SEEM Members are continuing to evaluate next steps to support SEEM's operation and preserve the customer benefits that SEEM generates.

New Greenfield Transmission Needed to Achieve Long-Term Transmission System Transformation

The 2023 NCTPC Public Policy Request Study will study retirement of 6,200 MW of coal generation by 2033, as well as the transmission system needs to reliably interconnect and deliver to load almost 24,000 nameplate MW of additional resources by summer 2033. The 2023 NCTPC Public Policy Request Study Scope Document⁴² states that the study is intended to identify the future year(s) that it is projected that greenfield 230 kV and/or 500 kV transmission lines would be needed. The study

⁴² North Carolina Transmission Planning Collaborative, 2023 NCTPC Public Policy Request Study Scope Document, June 2023, available at http://www.nctpc.org/nctpc/document/REF/2023-06-12/2023_NCTPC_Study_Scope_06_12_2023%20_FINAL_DRAFT.pdf.

would also utilize the 2033 Summer case and 2033/2034 Winter case with resource additions and generation retirements to be aligned with the initial 2022 proposed Carbon Plan P1 Portfolio for DEC and DEP. The study results and any identified greenfield 230 kV and/or 500 kV transmission line needs will be discussed and included in the NCTPC study report and will be included in future Carolinas Resource Plans along with recommendations for potential transmission expansion projects.

Assessment of Transmission System Upgrade Cost Impacts of Carolinas Resource Plan Portfolios

In this section, the estimated transmission network upgrade cost for the Carolinas Resource Plan Portfolio P3 Base is provided. These network upgrade costs are determined using representative proxy costs for network upgrades with the capacity expansion plan modeling selection of resources. These proxy costs for network upgrades are representative of the upgrades that would be required for interconnecting solar, SPS, standalone storage, combustion turbine generators, combined cycle generators, wind generation and small modular reactors to each of the DEC and DEP transmission systems. The proxy costs are derived from the results of the 2022 DISIS Phase 1 Study or assessments of transmission upgrades needed to enable interconnection of the particular resource type.

The identification of required transmission network upgrades is highly dependent upon assumptions of location, MW capacity of the interconnection requested, resource/load characteristics and other queued requests evaluated in the cluster. Also, consistent with current requirements of the OATT, actual network upgrades and transmission projects necessary to support the various resource plan portfolios will need to be planned and developed either in response to specific generator interconnection requests or through the other FERC-approved transmission planning processes such as the local transmission planning process discussed in this Appendix.

Applying the transmission network upgrade proxy costs to transmission network upgrades needed to enable the interconnection of new resources for Portfolio P3 Base resulted in the cumulative transmission network upgrade cost estimates reflected in Table L-9 below.

Table L-9: Portfolio P3 Base Transmission Upgrade Cost Estimate (\$M)

Transmission Area	2030	2035
DEC	\$1,489	\$5,397
DEP	\$1,323	\$3,378

Execution and Risk Management

Integrated transmission planning and timely construction of the significant transmission projects that will be needed to retire coal generation and interconnect new resources selected in the Carolinas Resource Plan present a key interdependency and timing risk.

Iterative interconnection study process: Location, MW of the interconnection requested, resource/load characteristics and other clustered queued requests, both individually and in aggregate, are inputs that are determinative of the transmission network upgrades required to reliably accommodate interconnection requests. While requests for transmission service and generator interconnection provide definitive details for these inputs, as some requests move forward while others do not, the aggregate impact of these modeling inputs change, thus yielding a range of results — both in terms of cost and time to interconnection — for required transmission network upgrades. For this reason, transmission planning must be a continual and iterative process to calibrate transmission plans to objective and verifiable transmission needs.

Red zone constraints: Several common transmission upgrades on the DEC and DEP transmission systems were repeatedly shown to be needed for the interconnection of new solar resources identified in the resource plans through past interconnection studies such as the Transitional Cluster Study, as well as the aforementioned supplemental studies identifying the need for the RZEP 1.0 projects. The Local Transmission Planning Process was utilized in assessing and including these common transmission upgrades in the 2022–2032 NCTPC Plan. Utilization of the Local Transmission Planning process will continue to be needed to identify transmission needs and solutions to those needs to relieve these high solar viability region transmission constraints.

Strategic transmission planning: If the pathway for planning, development and construction of all transmission projects is limited to the traditionally reactive generator interconnection process, the timeline for interconnecting resource plan-identified resources is likely to be adversely impacted. The proposed revisions to the NCTPC local transmission planning process that are under development will offer a more strategic route to transmission planning needed to interconnect resource plan-identified resources in a timely manner. The first group of strategic transmission planning projects to resolve red-zone constraints was supported through past generator interconnection studies, such as the Transitional Cluster Study and the validating supplemental studies. Likewise, the second phase of RZEP projects has been identified through the 2022 Phase 1 DISIS studies. Future transmission expansion plans and resulting projects will most likely be identified or validated through a revised local transmission planning process framework based on scenario analysis and identification of projects with multiple benefit streams. The Companies are planning to participate with the NCTPC in a more comprehensive 2023 study of the long-term transmission needs to meet the needs of the resource plans. Furthermore, upon FERC approval of the revisions planned for the local transmission planning process, a more robust, transparent and coordinated strategic planning process will be available for identification and validation of future transmission projects.

Long-term greenfield needs: Upgrades of existing transmission lines, although very successful with enabling interconnections of near-term identified resource plan resources, will not be sufficient to interconnect later phases of incremental resources associated with resource plan implementation. New transmission infrastructure with new rights-of-way will likely be required toward 2030 and through

the 2030s to enable resource interconnections and economic energy transfers. The 2023 NCTPC Study⁴³ should assist the Companies with identifying potential future greenfield needs.

Coal retirement replacement: Potentially significant transmission upgrades could be required to facilitate the retirement of coal units if replacement generation is not developed commensurate with the retirement of the coal units and interconnected at the retiring generation brownfield site. In 2022, FERC accepted DEC and DEP's filing for a revised interconnection process for replacement generation. This new generation replacement queue process will be critical to efficient, timely and cost-effective replacement of retired coal-fired generation with new generation that interconnects at the same electrical point of interconnection where the retiring generation is located, thereby saving the cost of potentially expensive interconnection facilities that would be required if the same replacement generation was constructed at a greenfield site. DEC and DEP are already leveraging this new process with requests to replace retiring coal generation at the DEC Marshall Plant and at the DEP Roxboro Plant.

Pumped Storage Hydro: Completing the significant number of transmission projects to support interconnection of Bad Creek II, a 1,680 MW expansion of the current Bad Creek capacity and staying on schedule with the year the resource has been selected in the Resource Plan will require starting these transmission projects in 2024. As noted previously in this Appendix, several solar and battery projects in 2022 DISIS are also dependent on certain of the same network upgrades identified as needed to interconnect the Bad Creek II project.

Offshore wind: Completing transmission projects to support interconnection of offshore wind as a diverse resource in the resource plan portfolio will be challenging from a timing and scheduling standpoint. To enable offshore wind interconnection to the DEP system, new ROW and major transmission construction will be required, involving supply chain, siting, permitting and construction risks, as well as risks associated with acquiring the new ROW. Delays in these schedule dependencies are key risks in meeting any timeline for importing offshore wind energy. Seeking to mitigate some of the scheduling risk, as well as lowering cost for customers for this resource, DEP has collaborated with the NCDEQ to submit an application for \$250 million of DOE funding for a 500 kV line from New Bern to Raleigh needed to support the import of offshore wind energy into the Carolinas. This new 500 kV line would also support solar and SPS, as well as potential onshore wind resources.

Off-system purchases: System risks associated with relying on significant incremental off-system capacity purchases for resource plan needs include, but are not limited to, delay in resource availability, loss of local ancillary benefits that are inherent with an on-system resource, thus requiring more on-system transmission upgrades, curtailment due to transmission constraints and/or capacity emergencies in neighboring areas and transmission system stability issues.

⁴³ North Carolina Transmission Planning Collaborative, 2023 NCTPC Public Policy Request Study Scope Document, June 2023, available at http://www.nctpc.org/nctpc/document/REF/2023-06-12/2023_NCTPC_Study_Scope_06_12_2023%20_FINAL_DRAFT.pdf.

Illustration of Nuclear PTC Rider ("Rider") proposed in the Amended Agreement and Stipulation of Partial Settlement ("Stipulation")

Note: This exhibit is for illustrative purposes only and is not intended to modify the terms as agreed to in the Stipulation.

	<u>Proposed Rider Stipulation Framework</u>												
	<u>2025</u>	<u>2026</u>	<u>2027</u>	<u>2028</u>	<u>2029</u>	<u>2030</u>	<u>2031</u>	<u>2032</u>	<u>2033</u>	<u>2034</u>	<u>2035</u>	<u>2036</u>	<u>2037</u>
2025 Tranche	\$50M												
2026 Tranche		\$100M											
2027 Tranche			Generated in 2024 & 2025, monetized by Oct. 2026, net of amounts previously returned										
2028 Tranche				Generated in 2026, monetized by Oct. 2027									
2029 Tranche					Generated in 2027, monetized by Oct. 2028								
2030 Tranche						Generated in 2028, monetized by Oct. 2029							
2031 Tranche							Generated in 2029, monetized by Oct. 2030						
2032 Tranche								Generated in 2030, monetized by Oct. 2031					
2033 Tranche									Generated in 2031, monetized by Oct. 2032				
2034 Tranche										Generated in 2032, monetized by Oct. 2033			

The Rider is based on projections for 2025/2026, and thereafter will credit nuclear PTCs (earned and monetized/used) on an annual basis. All amounts in the Rider will be NC retail amounts. Variance to actual amounts monetized/used will be deferred to a regulatory asset/liability account and accrue a return at the Company's last authorized weighted average cost of capital ("WACC") until reflected in the Rider. Rider will reflect credits generated in the years above and any prior years not yet included in the Rider and will include a levelized WACC return during the amortization period. Amounts to be flowed back included in the Rider in 2025 and 2026 may be adjusted under certain conditions, subject to Commission approval, if the Company is not able to monetize/use nuclear PTCs in amounts equal to the assumed amounts. The Rider will be subject to a true-up. Customers will receive all of the NC retail benefit of nuclear PTCs, net of costs.

Duke Energy Carolinas, LLC
Late-Filed Exhibit 3
Docket No. E-7, Sub 1276

Request:

On September 1, 2023, during the expert witness hearing held by the Commission in Docket No. E-7, Sub 1276 involving the Performance-Based Ratemaking Application of Duke Energy Carolinas, LLC (DEC), Commissioner Duffley requested a late- filed exhibit showing the amount of the estimated Inflation Reduction Act (IRA) tax credits -- investment tax credits (ITC) and production tax credits (PTC) -- by type in the revenue requirement for each MYRP year for NC retail as shown on Abernathy Supplemental Settlement Exhibit 2, page 68 of 68.

Response:

DEC included estimates of IRA tax credits within the MYRP revenue requirement for the energy storage and solar projects included within the MYRP. Estimates for ITC were calculated for the energy storage projects and estimates for PTC were calculated for the solar projects. The specific estimates, calculations, assumptions and amounts can be found within the workpapers supporting the Abernathy exhibits; specifically, tabs Ex 4 WP 12 ITC and Ex 4 WP 13 PTC within the “Abernathy Supplemental Settlement Exhibits and WPs.xlsx” file that was provided at the time of filing Ms. Abernathy’s supplemental settlement testimony. The calculations within those workpapers roll up to Abernathy Supplemental Settlement Exhibit 4. The operating income impact over the MYRP is shown within Lines 5 & 6 of Abernathy Supplemental Settlement Exhibit 4 for each rate year. The rate base impacts are shown on Lines 12 and 13 of Abernathy Supplemental Settlement Exhibit 4. Since these credits impact income tax expense, the amounts are not included within the project estimates shown in Abernathy Supplemental Settlement Exhibit 2.

The following tables show the NC retail tax credit amounts that were calculated within the ITC and PTC workpapers referenced above.

ITC Amounts by Project			
Project	NC Retail Credit Amount	In-Service Date	Within the revenue requirement calculation, ITCs amortize over the life of the asset (15 years) starting with the in-service date.
Allen Battery	\$33,817,425	12/2025	
Frieden Battery	\$1,805,982	12/2024	
Monroe Battery	\$6,875,030	12/2024	
Nebo Battery	\$2,563,588	9/2025	
Longtown Battery	\$1,325,488	9/2025	
Farr’s Bridge Battery	\$2,226,525	12/2025	

<u>PTC Amounts by Project</u>			
Project	NC Retail Credit Amount	In-Service Date	Within the revenue requirement calculation, the PTC is earned when power is generated from the solar facility. DEC has estimated the solar generation for June 2026-December 2026 to include in the MYRP revenue requirement.
2026 Solar Investment	\$1,469,951	06/2026	
2026 Solar Investment – Selected Solar	\$1,991,211	06/2026	

As part of the Company's deferral request related to IRA impacts, DEC will track actual amounts received, net of costs incurred, related to these credits and will defer the impact to the revenue requirement of any differences from what has been assumed within the revenue requirement calculation shown in Abernathy Supplemental Settlement Exhibit 4.

**Duke Energy Carolinas, LLC
Late-Filed Exhibit 4
Docket No. E-7, Sub 1276**

Request:

On September 1, 2023, during the expert witness hearing held by the Commission in Docket No. E-7, Sub 1276 involving the Performance-Based Ratemaking Application of Duke Energy Carolinas, LLC (DEC), Commissioner Duffley requested a late- filed exhibit showing a list of only the specific agreed upon projects and the corresponding amounts for which the Infrastructure Investment and Jobs Act ("IIJA") funding has been reflected in the revenue requirement.

Response:

In the Amended Agreement and Stipulation of Partial Settlement filed with the Commission on August 28, 2023, the Stipulating Parties agreed that in the case of certain IIJA applications previously submitted by the Company in connection with certain hydroelectric projects identified in Public Staff's testimony, Public Staff's recommendation to incorporate assumed receipt of such IIJA grants, net of costs incurred, should be accepted for purposes of establishing the base period and MYRP revenue requirement for such projects, with deferral of any variance to the revenue requirement once actual IIJA funding amounts are known, including the impact should the Company not receive the funding.

The attached file Late Filed Exhibit IIJA Funding.xlsx contains a listing of all agreed upon projects and the corresponding amounts for which the IIJA funding has been reflected in the revenue requirement.

DUKE ENERGY CAROLINAS, LLC
Docket No. E-7 Sub 1276
Late Filed Exhibit No. 4. IIJA Funding

Project Funding (Dollars in thousands)

The following amounts relate to capital projects, and as such the amounts below were offset against the capital costs included in the base case or in the MYRP. For the base case, the amounts were adjusted in Proforma NC2080(S4) and for MYRP the amount was included as an offset to the project cost shown on Line No. 265 of Abernathy Supplemental Settlement Exhibit 1, page 16 of 21.

Rate Year	Project ID	Project Name	Potential IIJA Funding	Costs Incurred to apply for funding	Potential Funding reflected in revenue requirement, net of costs
Base Case	CBA03MGEN	Bad Creek 3 Hydroelectric	\$ 5,000	\$ 50	\$ 4,950
Base Case	CDE001203	Dearborn Dam Hydroelectric	\$ 5,000	\$ 30	\$ 4,970
MYRP RY1	CE000012	FERC Cedar Cliff Dam IDF Spillway&Gate House	\$ 5,000	\$ 30	\$ 4,970

In addition, DEC has applied for Section 40331 (Hydroelectric Production Incentives) for uprates for Bad Creek Units 1 and 2, in which potential funding of \$1.0 million has also been reflected as a reduction to O&M in the base case within Proforma NC2080(S4).

Note: All amounts presented are at a system level

Duke Energy Carolinas, LLC
Late-Filed Exhibit 5
Docket No. E-7, Sub 1276

OFFICIAL COPY

Nov 02 2023

Request:

On September 5, 2023, during the expert witness hearing held by the Commission in Docket No. E-7, Sub 1276 involving the Performance-Based Ratemaking Application of Duke Energy Carolinas, LLC (DEC), Commissioner Duffley requested a late- filed exhibit showing a reconciliation between the Abernathy Supplemental Settlement Exhibit 2 projected in-service costs of \$4,637,911,471 (NC Retail) and the Abernathy Supplemental Settlement Exhibit 4 column 3 line 10 Electric Plant-in-Service costs of \$3,738,375 (NC Retail).

Response:

Abernathy Supplemental Settlement Exhibit 2 shows the total projected costs of all the MYRP projects to be placed in service over the three-year period. Abernathy Supplemental Settlement Exhibit 4 provides the calculation of the revenue requirement for the projects shown on Exhibit 2 for each rate year. For the return on rate base calculation, a 13-month average rate base is used for the calculation for each rate year. As such, the \$3,738,375 amount shown on Exhibit 4, Line 10 for Electric Plant In-Service for Rate Year 3 is the 13-month average balance of gross plant in-service for Rate Year 3 shown in thousands of dollars for NC retail.

The calculation of rate base for the MYRP rate years is performed within the workpapers supporting the Abernathy exhibits; specifically, workpapers 1, 2, and 3 (tab names: Ex4 WP1 RB-OM Summary, Ex 4 WP 2 Monthly Detail, and Ex 4 WP 3 Plant Summary) within the "Abernathy Supplemental Settlement Exhibits and WPs.xlsx" file that was provided at the time of filing Ms. Abernathy's supplemental settlement testimony. The workpapers and associated plant in-service amounts are described below:

- Workpaper 3 shows the MYRP additions by month as well as associated depreciation expense by month over the MYRP period. The total of the additions shown on Line 14 is \$4,637,911,471 which agrees to Abernathy Supplemental Settlement Exhibit 2.
- Workpaper 2, Lines 1 through 12 show the cumulative plant in-service for the MYRP projects by FERC function by month. The last column of Line 12 totals to \$4,637,911,471 which agrees to the total shown at the bottom of Abernathy Supplemental Settlement Exhibit 2.
- Workpaper 1, Supplemental Settlement column, Lines 20 through 27 (on each of the three pages) includes a formula that calculates the 13-month average plant in-service balance for the MYRP projects using the monthly balances within Workpaper 2 for each rate year (i.e. rate year 3 is the 13-month average of

December 2025-December 2026 balances). The amounts calculated in Workpaper 1 are used within the calculation of return on rate base for Abernathy Supplemental Settlement Exhibit 4. For reference, the 13-month average balance calculated on Line 27 of Workpaper 1, Page 3 of 3, agrees to the \$3,738,375 amount shown on Abernathy Supplemental Settlement Exhibit 4 for Rate Year 3.

Duke Energy Carolinas, LLC
Late-Filed Exhibit 6
Docket No. E-7, Sub 1276

OFFICIAL COPY

Nov 22 2023

Request:

On September 1, 2023, during the expert witness hearing held by the Commission in Docket No. E-7, Sub 1276 involving the Performance-Based Ratemaking Application of Duke Energy Carolinas, LLC (DEC), Commissioner Clotfelter requested a late-filed exhibit showing the effect on depreciation expense as a result of changing the retirement date for Cliffside 5 and the impact of the change to the proposed amount to be securitized when Cliffside 5 is finally retired.

Response:

The Q. Bowman Settlement exhibits show the total change in depreciation expense resulting from the settlement but do not isolate the change in depreciation expense for Cliffside 5 that results from changing the retirement date. This late-filed exhibit isolates the impact of changing the retirement date for Cliffside 5 from December 31, 2025 to December 31, 2030.

Line No.	Impact of Change in Accelerated Retirement Date	12/31/2025		12/31/2030	
		Retirement Date		Retirement Date	Change
1	Proposed Accelerated Depreciation CLIFFSIDE UNIT 5 - DEC System	75,138,030	[2]	46,488,111	[3] (28,649,919)
2	Non-Accelerated Depreciation CLIFFSIDE UNIT 5 - DEC System	39,987,105	[2]	39,987,105	[3] -
3	Incremental depreciation expense due to accelerated retirement date	\$ 35,150,925		\$ 6,501,006	\$ (28,649,919)
4	NC Retail Allocation %	66.97%	[2]	66.97%	[3]
5		\$ 23,540,207		\$ 4,353,656	\$ (19,186,551)
6	Eligible for Securitization %	50.00%		50.00%	
7	Annual Incremental Depreciation Expense Deferred (NC Retail) [1]	\$ 11,770,103		\$ 2,176,828	\$ (9,593,275)
8					
9					
10	Change in Accelerated Depreciation Expense	Retirement Date		Retirement Date	Change
11	Proposed Accelerated Depreciation CLIFFSIDE UNIT 5 - DEC System	\$ 75,138,030		\$ 46,488,111	\$ (28,649,919)
12	NC Retail Allocation %	66.97%		66.97%	
13		50,319,152		31,132,601	(19,186,551)
14	Less: Reg Asset due to Annual Accelerated Depreciation Expense (NC Retail)	\$ (11,770,103)		\$ (2,176,828)	\$ 9,593,275
15	Net Annual DEC-NC Retail Depreciation Expense	38,549,049		28,955,774	(9,593,275)
	[1] This amount does not include the impact of additional 25% deferral per the settlement that is not eligible for securitization.				
	[2] Source: Q. Bowman Third Supplemental Exhibit 4 Page 179 of 308				
	[3] Source: Q. Bowman Supplemental Partial Settlement Exhibit 4 page 178 of 308				

As shown in the chart above, the net annual depreciation expense (for NC Retail) for Cliffside 5 will decrease by \$9.6M as a result of changing the retirement date in the depreciation study (Line 15). This amount includes the impact of deferring 50% of incremental accelerated depreciation expense as originally proposed by the Company and agreed to as part of settlement with Public Staff. Increasing the deferral from 50% to 75% also decreases the net annual depreciation expense.

Note, however, the change in retirement date in the depreciation study should not impact the amount eligible for securitization when Cliffside 5 is finally retired. The intent of the proposed deferral of 50% of the incremental accelerated depreciation expense is to preserve the net book value eligible for securitization (50%) at the same level that it would have been had the expected retirement dates not been updated in the depreciation study. The \$9.6M decrease in depreciation expense referenced above solely relates to the 50% portion of the plant not eligible for securitization.

<u>Line No.</u>	<u>Impact of Accelerated Retirement Date</u>	<u>12/31/2025</u> <u>Retirement Date</u>	<u>12/31/2030</u> <u>Retirement Date</u>	<u>Change</u>
1	Proposed Accelerated Depreciation CLIFFSIDE UNIT 5 - DEC System	75,138,030 [2]	46,488,111 [3]	(28,649,919)
2	Non-Accelerated Depreciation CLIFFSIDE UNIT 5 - DEC System	39,987,105 [2]	39,987,105 [3]	-
3	Incremental depreciation expense due to accelerated retirement date	\$ 35,150,925	\$ 6,501,006	\$ (28,649,919)
4	NC Retail Allocation %	66.97% [2]	66.97% [3]	
5		\$ 23,540,207	\$ 4,353,656	\$ (19,186,551)
6	Eligible for Securitization %	50.00%	50.00%	
7	Annual Incremental Depreciation Expense Deferred (NC Retail) [1]	\$ 11,770,103	\$ 2,176,828	\$ (9,593,275)
8				
9				
10	<u>Change in Accelerated Depreciation Expense</u>	<u>12/31/2025</u> <u>Retirement Date</u>	<u>12/31/2030</u> <u>Retirement Date</u>	<u>Change</u>
11	Proposed Accelerated Depreciation CLIFFSIDE UNIT 5 - DEC System	\$ 75,138,030	\$ 46,488,111	\$ (28,649,919)
12	NC Retail Allocation %	66.97%	66.97%	
13		50,319,152	31,132,601	(19,186,551)
14	Less: Reg Asset due to Annual Accelerated Depreciation Expense (NC Retail)	\$ (11,770,103)	\$ (2,176,828)	\$ 9,593,275
15	Net Annual DEC-NC Retail Depreciation Expense	38,549,049	28,955,774	(9,593,275)

[1] This amount does not include the impact of additional 25% deferral per the settlement that is not eligible for securitization.

[2] Source: Q. Bowman Third Supplemental Exhibit 4 Page 179 of 308

[3] Source: Q. Bowman Supplemental Partial Settlement Exhibit 4 page 178 of 308

DUKE ENERGY CAROLINAS, LLC
Docket No. E-7, Sub 1276
North Carolina Retail Operations
REVENUE IMPACT OF PUBLIC STAFF ADJUSTMENTS
For the Test Year Ended December 31, 2021
(in Thousands)

**Public Staff
Supplemental and Settlement Accounting Exhibit 1
Schedule 1**

Line No.		Public Staff Excluding CCR Amount	Public Staff CCR Amount	Total Public Staff Amount
1	Revenue requirement increase per Company application, base rates	\$304,806 ^{1/}	\$66,696 ^{1/}	\$371,502 ^{1/}
2	Revenue impact of Company updates	66,226	(3,242)	62,984
3	Revenue impact of settlement	(61,102)	(4,021)	(65,123)
4	Revenue requirement increase per Company	\$309,930	\$59,433	\$369,363
	<u>Revenue impact of Public Staff adjustments:</u>			
	Unsettled Issues:			
5	Change in equity ratio from 53.00% to 52.00% equity	(\$17,519)	\$0	(\$17,519)
6	Change in return on equity from 10.40% to 9.35%	(138,523)	(1,289)	(139,812)
7	Adjust for COVID expense & deferral	(62,508)		(62,508)
8	Total revenue impact of unsettled issues	(\$218,550)	(\$1,289)	(\$219,839)
	Settled Issues:			
9	Change in debt cost rate from 4.50% to 4.56%	\$0	\$0	\$0
10	Update plant and accumulated depreciation to June 30, 2023	(448)		(448)
11	Adjust depreciation rates	0		0
12	Adjust cash working capital under present rates	1,063		1,063
13	Adjust cash working capital under proposed rates	(1,308)		(1,308)
14	Adjust materials and supplies	0		0
15	Adjust coal inventory	0		0
16	Update revenues, customer growth, and weather to June 30, 2023	0		0
17	Adjust GIP deferral	0		0
18	Adjust Allen Unit 4 deferral	0		0
19	Adjust lighting audit deferral	0		0
20	Adjust nonresidential credit card fees	0		0
21	Adjust aviation expenses	0		0
22	Adjust executive compensation	0		0
23	Adjust salaries & wage expense	0		0
24	Adjust rent expense	0		0
25	Adjust Test Year EFC Revenue, Nuclear Outage Amortization, Reliability Assurance, Bad Creek, & Marshall O&M, EFC-Apex Solar	(313)		(313)
26	Adjust rate case expense	(2,015)		(2,015)
27	Adjust EOL nuclear materials & supplies reserve amortization expense	0		0
28	Adjust to normalize storm costs	0		0
29	Adjust test year expenses	0		0
30	Adjust for vegetation management	0		0
31	Adjust incentives	0		0
32	Adjust uncollectibles	0		0
33	Adjust steam deferral	0		0
34	Adjust charitable contributions, corporate sponsorships, and corporate donations	0		0
35	Adjust lobbying expense	0		0
36	Adjust Board of Directors expense	0		0
37	Adjust inflation	0		0
38	Adjust over amortization - Sub 1146 rate case expense	0		0
39	Adjust over amortization - CCR deferral	0	0	0
40	Regulatory Asset/Liability - E&Y Contract	0		0
41	Rounding	(1)	0	(1)
42	Total revenue impact of settled issues	(\$3,022)	\$0	(\$3,022)
43	Total revenue impact of Public Staff adjustments	(\$221,572)	(\$1,289)	(\$222,861)
44	Public Staff recommended increase (decrease) in base rate revenue requirement	\$88,358	\$58,144	\$146,502
45	Public Staff recommended increase (decrease) in base rate revenue requirement (L44)	\$88,358	\$58,144	\$146,502
46	Public Staff recommended overamortizations one year rider	(\$485)		(\$485)
47	Annual Federal unprotected EDIT Rider recommended (for first 2 years)	(\$10,394) ^{3/}		(\$10,394) ^{3/}
48	Public Staff recommended change in revenue requirement including rider (Sum of L45 through L 47)	\$77,479	\$58,144	\$135,623

^{1/} Bowman Exhibit 2, Page 1.

^{2/} Calculated based on Accounting Exhibit 1, Schedules 2, 3, 4, 5, and backup schedules.

^{3/} Supplemental Accounting Exhibit 2, Schedule 1.

DUKE ENERGY CAROLINAS, LLC

Docket No. E-7, Sub 1276
North Carolina Retail Operations
SUPPORT FOR RECONCILIATION SCHEDULE
For the Test Year Ended December 31, 2021
(in Thousands)

Public Staff
Supplemental and Settlement Accounting Exhibit 1
Schedule 1-1

Line No.	Item	Rate Base Impact (a)	Income Statement Impact (b)	Total Revenue Impact (c)
1	Update plant and accumulated depreciation to April 30, 2023	(\$344)	(\$104)	(\$448)
2	Adjust rate case expense	-	(2,015)	(2,015)
3	Adjust depreciation rates	-	-	-
4	Adjust GIP deferral	-	-	-
5	Adjust COVID deferral	(8,033)	(54,475)	(62,508)
6	Remove Lighting audit deferral	-	-	-
7	Adjust steam deferral	-	-	-
8	Adjust Allen Unit 4 deferral	-	-	-
CCR:				
9	Adjust over amortization - CCR	\$0	\$0	\$0

1/ Supplemental and Settlement Accounting Exhibit 1, Schedule 2-1, Line 16.

2/ Supplemental and Settlement Accounting Exhibit 1, Schedule 3-1, Line 18.

3/ Column (a) plus Column (b).

DUKE ENERGY CAROLINAS, LLC
Docket No. E-7, Sub 1276
North Carolina Retail Operations
CALCULATION OF GROSS REVENUE EFFECT FACTORS
For the Test Year Ended December 31, 2021
(in Thousands)

Public Staff
Supplemental and Settlement Accounting Exhibit 1
Schedule 1-2

Line No.	Item	Capital Structure (a)	Cost Rates (b)	Retention Factor (c)	Gross Revenue Effect (d)
1	<u>Rate Base Factor</u>				
2	Long-term debt	48.000% ^{1/}	4.560% ^{1/}	0.9926862 ^{2/}	0.0220493 ^{4/}
3	Common equity	52.000% ^{1/}	9.35% ^{1/}	0.7608915 ^{3/}	0.0638987 ^{4/}
4	Total (Sum of Lines 2 and 3)	<u>100.000%</u>			<u>0.0859480</u>
					<u>Amount</u>
5	<u>Net Income Factor</u>				
6	Total revenue				1.0000000
7	Uncollectibles				0.0058474 ^{5/}
8	Balance (L6 - L7)				0.9941526
9	Regulatory fee (L8 x 0.1475%)	6/			0.0014664
10	Balance (L8 - L9)				0.9926862
11	State income tax (L10 x 2.9750%)	7/			0.0295324
12	Balance (L10 - L11)				0.9631538
13	Federal income tax (L12 x 21%)	8/			0.2022623
14	Retention factor (L12 - L13)				<u>0.7608915</u>

1/ Per Public Staff witness Walters.

2/ Line 10.

3/ Line 14.

4/ Column (a) times Column (b) divided by Column (c).

5/ NC1010-5.

6/ Current regulatory fee rate.

7/ Supplemental and Settlement Accounting Exhibit 1, Schedule 1-3, Line 4, Column (a).

8/ Statutory rate.

DUKE ENERGY CAROLINAS, LLC
Docket No. E-7, Sub 1276
North Carolina Retail Operations
CALCULATION OF GROSS REVENUE EFFECT FACTORS
For the Test Year Ended December 31, 2021
(in Thousands)

Public Staff
Supplemental and Settlement Accounting Exhibit 1
Schedule 1-2 CCR

Line No.	Item	Capital Structure	Cost Rates	Retention Factor	Gross Revenue Effect
		(a)	(b)	(c)	(d)
1	<u>Rate Base Factor</u>				
2	Long-term debt	48.000% ^{1/}	4.560% ^{1/}	0.9926862 ^{2/}	0.0220493 ^{4/}
3	Common equity	52.000% ^{1/}	7.85% ^{1/}	0.7608915 ^{3/}	0.0536476 ^{4/}
4	Total (Sum of Lines 2 and 3)	<u>100.000%</u>			<u>0.0756969</u>
					<u>Amount</u>
5	<u>Net Income Factor</u>				
6	Total revenue				1.0000000
7	Uncollectibles				<u>0.0058474</u> ^{5/}
8	Balance (L6 - L7)				0.9941526
9	Regulatory fee (L8 x .01475%)	6/			<u>0.0014664</u>
10	Balance (L8 - L9)				0.9926862
11	State income tax (L10 x 2.9750%)	7/			<u>0.0295324</u>
12	Balance (L10 - L11)				0.9631538
13	Federal income tax (L12 x 21%)	8/			<u>0.2022623</u>
14	Retention factor (L12 - L13)				<u>0.7608915</u>

1/ Per Public Staff witness Walters.

2/ Line 10.

3/ Line 14.

4/ Column (a) times Column (b) divided by Column (c).

5/ NC1010-5.

6/ Current regulatory fee rate.

7/ Supplemental and Settlement Accounting Exhibit 1, Schedule 1-3, Line 4, Column (a).

8/ Statutory rate.

DUKE ENERGY CAROLINAS, LLC

Docket No. E-7, Sub 1276
North Carolina Retail Operations
CALCULATION OF COMPOSITE INCOME
TAX RATE
For the Test Year Ended December 31, 2021
(in Thousands)

Public Staff
Supplemental and Settlement Accounting Exhibit 1
Schedule 1-3

Line No.	Item	Total System (a)	North Carolina (b)	South Carolina (c)
1	<u>Weighted state income tax rate</u>			
2	Apportionment factor		67.0000% ^{2/}	26.0000% ^{2/}
3	State income tax rate		2.50% ^{3/}	5.00% ^{3/}
4	Weighted state income tax rate	<u>2.9750% ^{1/}</u>	<u>1.67500% ^{4/}</u>	<u>1.30000% ^{4/}</u>
5	<u>Composite income tax rate</u>			
6	Weighted state income tax rate (L4)	2.9750%		
7	Federal income tax rate	21% ^{5/}		
8	Composite income tax rate	23.3503% ^{6/}		

- 1/ Sum of Columns (b) and (c).
 2/ Per NC1010-4 Tax Rate, Column (b).
 3/ Per NC1010-4 Tax Rate, Column (a).
 4/ Line 2 times Line 3.
 5/ Statutory rate.
 6/ 1 minus ((1 minus Line 6) times (1 minus Line 7)).

DUKE ENERGY CAROLINAS, LLC
Docket No. E-7, Sub 1276
North Carolina Retail Operations
ORIGINAL COST RATE BASE
For the Test Year Ended December 31, 2021
(in Thousands)

Public Staff
Supplemental and Settlement Accounting Exhibit 1
Schedule 2

Line No.	Item	Under Present Rates			After Public Staff Recommended Decrease	
		NC Retail Adjusted Per Company ^{1/}	Public Staff Adjustments ^{2/}	After Public Staff Adjustments ^{3/}	Rate Decrease ^{4/}	After Rate Decrease ^{5/}
		(a)	(b)	(c)	(d)	(e)
1	Electric plant in service	\$33,956,908	(\$4,231)	\$33,952,677	\$0	\$33,952,677
2	Accumulated depreciation and amortization	(12,641,563)	232	(12,641,331)	-	(12,641,331)
3	Net electric plant in service (L1 + L2)	21,315,345	(3,999)	21,311,346	-	21,311,346
4	Materials and supplies	669,331	(0)	669,331	-	669,331
	Other Working Capital					
5	Operating funds per lead-lag study	143,622	12,373	155,995	18,883 ^{4/}	174,878
6	Unamortized debt	73,360	-	73,360	-	73,360
7	Regulatory assets and liabilities, excluding ARO-related CCR	58,520	(121,934)	(63,414)	-	(63,414)
8	Total other working capital	275,502	(109,561)	165,941	18,883	184,824
9	ARO-related CCR regulatory assets and liabilities	-	-	-	-	-
10	Customer deposits	(47,201)	-	(47,201)	-	(47,201)
11	Accumulated deferred income taxes	(2,758,489)	28,472	(2,730,016)	-	(2,730,016)
12	Operating reserves	(150,195)	-	(150,195)	-	(150,195)
13	Adjustments to federal excess deferred income taxes	-	-	-	-	-
14	Construction work in progress	-	-	-	-	-
15	Total original cost rate base (L3 + L4 + L8 + sum of L9 thru L14)	<u>19,304,293</u>	<u>(\$85,088)</u>	<u>19,219,205</u>	<u>\$18,883</u>	<u>\$19,238,088</u>

1/ Per Bowman Supplemental Partial Settlement Exhibit 2, Page 4.

2/ Supplemental and Settlement Accounting Exhibit 1, Schedule 2-1, Column (I).

3/ Column (a) plus Column (b).

4/ Supplemental and Settlement Accounting Exhibit 1, Schedule 2-1(g), Line 82, Column (k).

5/ Column (c) plus Column (d).

DUKE ENERGY CAROLINAS, LLC
Docket No. E-7, Sub 1276
North Carolina Retail Operations
CCR DEFERRAL RATE BASE
For the Test Year Ended December 31, 2021
(in Thousands)

Public Staff
Supplemental and Settlement Accounting Exhibit 1
Schedule 2 CCR

Line No.	Item	Under Present Rates			After Public Staff Recommended Increase	
		NC Retail as Adjusted Per Company	Public Staff Adjustments	After Public Staff Adjustments	Rate Increase	After Rate Increase
		(a)	(b)	(c)	(d)	(e)
1	ARO-related CCR regulatory assets and liabilities	\$234,303 ^{1/}	\$0 ^{3/}	\$234,303	-	\$234,303
2	Accumulated deferred income taxes (L2 x 23.3503%)	(54,710) ^{1/}	\$0 ^{3/}	(54,710)	-	(54,710)
3	Total original cost rate base (L1 + L2)	<u>\$179,593</u>	<u>-</u>	<u>\$179,593</u>	<u>-</u>	<u>\$179,593</u>
4	Retention factor	0.075697 ^{2/}		0.075697		0.075697
5	Rate base revenue requirement (L3 x L4)	<u>\$13,595</u>		<u>\$13,595</u>		<u>\$13,595</u>

1/ Bowman Supplemental Partial Settlement Exhibit 2, Page 4.

2/ Supplemental and Settlement Accounting Exhibit 1, Schedule 1-2 CCR, Line 4, Column (d).

3/ Supplemental and Settlement Accounting Exhibit 1, Schedule 2-1, Column (m).

DUKE ENERGY CAROLINAS, LLC
Docket No. E-7, Sub 1276
North Carolina Retail Operations

Public Staff
Supplemental and Settlement Accounting Exhibit 1
Schedule 2-1
Page 1 of 3

SUMMARY OF PUBLIC STAFF RATE BASE ADJUSTMENTS

For the Test Year Ended December 31, 2021
(in Thousands)

Line No.	Item	Update Plant and Accumulated Depreciation to 6/30/23 ^{1/} (a)	Adjust Allen Unit 4 Deferral ^{2/} (b)	Adjust Steam Deferral ^{3/} (c)	Adjust GIP Deferral ^{4/} (d)	Adjust Coal Inventory ^{5/} (e)
1	Electric plant in service	(\$4,231)				
2	Accumulated depreciation and amortization	\$232				
3	Net electric plant in service (L1 + L2)	(\$3,999)	-	-	-	-
4	Materials and supplies	-				(0)
	Other Working Capital					
5	Operating funds per lead-lag study	-				
6	Unamortized debt	-				
7	Regulatory assets and liabilities, excluding ARO-related CCR	-	\$0	(\$0)	(\$0)	
8	Total Working Capital	-	-	(0)	(0)	-
9	CCR regulatory assets and liabilities					
10	Customer deposits					
11	Accumulated deferred income taxes		\$0	(\$0)	\$0	
12	Operating reserves					
13	Adjustments to federal excess deferred income taxes					
14	Construction work in progress					
15	Total original cost rate base (L3 + L4 + L8 + sum of L9 thru L14)	(\$3,999)	0	(0)	(0)	(0)
16	Revenue requirement impact	^{14/} (\$344)	\$0	\$0	\$0	\$0

- 1/ Supplemental and Settlement Accounting Exhibit 1, Schedule 2-1(a), Line 3.
2/ Supplemental and Settlement Accounting Exhibit 1, Schedule 2-1(b), Lines 13 and 17.
3/ Supplemental and Settlement Accounting Exhibit 1, Schedule 2-1(c), Lines 6 and 9.
4/ Supplemental and Settlement Accounting Exhibit 1, Schedule 2-1(d), Lines 12 and 16.
5/ Supplemental and Settlement Accounting Exhibit 1, Schedule 2-1(e), Line 10.
14/ Line 15 x rate base retention factor from Schedule 1-2.

DUKE ENERGY CAROLINAS, LLC
Docket No. E-7, Sub 1276
North Carolina Retail Operations

Public Staff
Supplemental and Settlement Accounting Exhibit 1
Schedule 2-1
Page 2 of 3

SUMMARY OF PUBLIC STAFF RATE BASE ADJUSTMENTS

For the Test Year Ended December 31, 2021
(in Thousands)

Line No.	Item	Adjust Depreciation Rates (f) 6/	Adjust Materials and Supplies (g) 7/	Adjust COVID Deferral (h) 8/	Adjust Lighting Audit Deferral (i) 9/
1	Electric plant in service				
2	Accumulated depreciation and amortization	\$0			
3	Net electric plant in service (L1 + L2)	-	-	-	-
4	Materials and supplies	-	0		
	Other Working Capital				
5	Operating funds per lead-lag study	-			\$0
6	Unamortized debt	-			
7	Regulatory assets and liabilities, excluding ARO-related CCR	-		(121,934)	
8	Total Working Capital	-	-	(121,934)	-
9	CCR regulatory assets and liabilities				
10	Customer deposits				
11	Accumulated deferred income taxes			\$28,472	\$0
12	Operating reserves				
13	Adjustments to federal excess deferred income taxes				
14	Construction work in progress				
15	Total original cost rate base (L3 + L4 + L8 + sum of L9 thru L14)	-	-	(93,462)	-
16	Revenue requirement impact	14/ \$0	\$0	(\$8,033)	\$0

6/ Supplemental and Settlement Accounting Exhibit 1, Schedule 3-1(b), Line 10.

7/ Supplemental and Settlement Accounting Exhibit 1, Schedule 3-1(f), Line 8.

8/ Supplemental and Settlement Accounting Exhibit 1, Schedule 3-1(g), Lines 20 and 21.

9/ Supplemental and Settlement Accounting Exhibit 1, Schedule 3-1(r), Lines 7 and 10.

14/ Line 15 x rate base retention factor from Suppl. Acctg Exhibit 1, Sch 1-2.

DUKE ENERGY CAROLINAS, LLC
Docket No. E-7, Sub 1276
North Carolina Retail Operations

Public Staff
Supplemental and Settlement Accounting Exhibit 1
Schedule 2-1
Page 3 of 3

SUMMARY OF PUBLIC STAFF RATE BASE ADJUSTMENTS

For the Test Year Ended December 31, 2021
(in Thousands)

(in Thousands)							CCR	
Line No.	Item	Remove Rate Case Expense from rate base 10/ (j)	Adjust Cash Working Capital 11/ (k)	Total Rate Base Adjustments 12/ (l)	Adjust Over Amortization CCR 13/ (m)			
1	Electric plant in service			(\$4,231)				
2	Accumulated depreciation and amortization			\$232				
3	Net electric plant in service (L1 + L2)	-	-	(\$3,999)				
4	Materials and supplies			(0)				
	Other Working Capital							
5	Operating funds per lead-lag study	\$0	\$12,373	12,373				
6	Unamortized debt			-				
7	Regulatory assets and liabilities, excluding ARO-related CCR			(121,934)				
8	Total Working Capital	-	12,373	(109,561)		-		
9	CCR regulatory assets and liabilities			-		\$0		
10	Customer deposits			-				
11	Accumulated deferred income taxes	\$0		28,472		\$0		
12	Operating reserves			-				
13	Adjustments to federal excess deferred income taxes			-				
14	Construction work in progress			-				
15	Total original cost rate base (L3 + L4 + L8 + sum of L9 thru L14)	-	12,373	(\$85,088)		-		
16	Revenue requirement impact	14/ \$0	\$1,063	(\$7,313)		\$0		

10/ Supplemental and Settlement Accounting Exhibit 1, Schedule 3-1(s), Lines 19 and 22.

11/ Supplemental and Settlement Accounting Exhibit 1, Schedule 2-1(f), Line 87.

12/ Sum of Column (a) through Column (k).

13/ Supplemental Settlement Accounting Exhibit 1, Schedule 3-1(v)(1), Lines 7 and 9.

14/ Line 15 x rate base retention factor from Sch 1-2.

DUKE ENERGY CAROLINAS, LLC

Docket No. E-7, Sub 1276
North Carolina Retail Operations
ADJUSTMENT TO UPDATE PLANT AND ACCUMULATED
DEPRECIATION
For the Test Year Ended December 31, 2021
(in Thousands)

Public Staff
Supplemental and Settlement
Accounting Exhibit 1
Schedule 2-1(a)

Line No.	Item	Plant in Service (a)	Accumulated Depreciation (b)
1	Adjustment to update balances to June 30, 2023	(\$4,231) ^{1/}	\$232 ^{2/}
2	Adjustment for annualization of depreciation expense	<u>0</u>	<u>(0) ^{3/}</u>
3	Total adjustment to update plant and accumulated depreciation (L1 + L2)	<u><u>(\$4,231)</u></u>	<u><u>\$232</u></u>

1/ Supplemental and Settlement Accounting Exhibit 1, Schedule 2-1(a)(1), Line 16, Column (e).

2/ Supplemental and Settlement Accounting Exhibit 1, Schedule 2-1(a)(2), Line 12, Column (e).

3/ Supplemental and Settlement Accounting Exhibit 1, Schedule 2-1(a)(3), Line 17.

DUKE ENERGY CAROLINAS, LLC

Docket No. E-7, Sub 1276
North Carolina Retail Operations
ADJUSTMENT TO UPDATE PLANT IN
SERVICE TO JUNE 30, 2023
For the Test Year Ended December 31, 2021
(in Thousands)

Public Staff
Supplemental and Settlement
Accounting Exhibit 1
Schedule 2-1(a)(1)

Line No.	Item	Total System			NC Retail Percentage ^{4/}	NC Retail Amount ^{5/}
		Amount As Of 6/30/2023 ^{1/}	Amount As Of 12/31/2021 ^{2/}	Change in Plant in Service ^{3/}		
		(a)	(b)	(c)	(d)	(e)
1	Steam plant	\$8,825,289	\$8,876,973	(\$51,684)		
2	Hydro plant	2,940,482	2,561,084	379,398		
3	Other production plant	3,579,496	3,446,850	132,646		
4	Nuclear plant	9,368,346	9,133,654	234,692		
5	Total production plant (Sum of L1 to L4)	24,713,613	24,018,561	695,052	66.9690%	\$465,469 ^{5/}
6	Transmission plant	5,624,144	4,963,954	660,190	48.1470%	317,861 ^{5/}
7	Distribution plant	16,401,384	14,480,906	1,920,478	74.0820%	1,422,728 ^{5/}
8	General plant	2,003,513	1,424,450	579,063	68.1625%	394,703 ^{5/}
9	Intangible plant	1,285,829	1,206,177	79,652	69.5124%	55,368 ^{5/}
10	Total plant in service (Sum of L5 to L9)	<u>\$50,028,483</u>	<u>\$46,094,048</u>	<u>\$3,934,435</u>		<u>\$2,656,129</u>
11	Update to plant (L10)					\$2,656,129
12	Less: additional plant related to REPS & CPRE					1,508 ^{6/}
13	Update to plant through 6/30/2023 per Public Staff (L11 - L12)					2,654,622
14	Company adjustment for plant additions since last rate case					\$2,654,622 ^{7/}
15	Public Staff engineer adjustments to plant					(4,230) ^{8/}
16	Public Staff adjustment to update plant (L13 - L14 + L15)					<u>(\$4,231)</u>

- 1/ Per NC3030(S3)-6.
2/ Per NC3030-6.
3/ Column (a) minus Column (b).
4/ Per E-1, Item 45a, 12 CP.
5/ Column (c) times Column (d).
6/ Per NC3030(S3) with actuals through June 30, 2023.
7/ Per NC3030(S3)-1, Line 22.
8/ Per Accounting Supplemental and Settlement Exhibit 1, Schedule 2-1(a)(1)(a), Line 23, Column (d).

DUKE ENERGY CAROLINAS, LLC

Docket No. E-7, Sub 1276
North Carolina Retail Operations
ADJUSTMENT TO PLANT IN SERVICE
For the Test Year Ended December 31, 2021
(in Thousands)

Public Staff
Supplemental and Settlement
Accounting Exhibit 1
Schedule 2-1(a)(1)(a)

Line No.	Item	Total System		NC Retail Percentage ^{2/}	NC Retail Amount ^{3/}
		Plant Type	Public Staff Adjustment Amount ^{1/}		
		(a)	(b)	(c)	(d)
Adjustment to Test Year Plant In Service:					
1	Mount Holly Project	Intangible Plant	\$0	69.5124%	\$0
2	Mount Holly Project	General Plant	0	68.1625%	0
3	526 S. Church Reno - Switchgear and Generator Replacement	General Plant	0	68.1625%	0
4	Remove EV charging infrastructure costs - 2021	General Plant	0	68.1625%	0
5	Lincoln Ct Unit 17 - Combustion Turbine Pipeline	Other Production Plant	0	66.9690%	0
6	Total Public Staff adjustmnet to TY plant in service (Sum of L1 to L5)		<u>\$0</u>		<u>\$0</u>
Adjustment to Post Test Year Plant In Service Update:					
7	Mount Holly Project	Intangible Plant	0	69.5124%	0
8	Pleasant Garden 550kV Breaker Replacements	Distribution Plant	0	74.0820%	0
9	Pleasant Garden 550kV Breaker Replacements	Transmission Plant	0	48.1470%	0
10	Bad Creek 3 Hydroelectric	Hydro Plant	0	66.9690%	0
11	Dearborn Dam Hydroelectric	Hydro Plant	0	66.9690%	0
12	Remove EV charging infrastructure costs - 2022	General Plant	0	68.1625%	0
13	Workstation Project	General Plant	0	68.1625%	0
14	Duke Plaza	General Plant	0	68.1625%	0
15	Duke Plaza - Land	General Plant	0	68.1625%	0
16	Lincoln Ct Unit 17 removal	Other Production Plant	0	66.9690%	0
17	Allen 230KV Transformer Project	Transmission Plant	(5,024)	48.1470%	(2,419)
18	Reclassification - Durham Mn SPCC	Distribution Plant	(2,834)	74.0820%	(2,100)
19	Reclassification - Durham Mn SPCC	Transmission Plant	2,834	48.1470%	1,365
20	Durham Mn SPCC cost removal	Distribution Plant	(752)	74.0820%	(557)
21	Reclassification - PWRUP Fairplains	Distribution Plant	(419)	74.0820%	(310)
22	Reclassification - PWRUP Fairplains	Transmission Plant	419	48.1470%	202
23	Misenhiemer Solar cost removal	Transmission Plant	(853)	48.1470%	(411)
24	Total Public Staff adjustmnet to Post TY plant additions (Sum of L7 to L23)		<u>(\$6,629)</u>		<u>(\$4,230)</u>
25	Total Public Staff adjustmnet to plant in service (L6 + L24)		<u>(\$6,629)</u>		<u>(\$4,230)</u>

1/ Supplemental and Settlement Accounting Exhibit 1, Schedule 2-1(a)(1)(a)(1).

2/ E-1, Item No. 45a, 12CP.

3/ Column (b) times Column (c).

DUKE ENERGY CAROLINAS, LLC
Docket No. E-7, Sub 1276
North Carolina Retail Operations
ADJUSTMENT DETAILS FOR PLANT IN SERVICE, ACCUM.
DEPRECIATION AND DEPRECIATION EXPENSE
For the Test Year Ended December 31, 2021
(in Thousands)

Public Staff
Supplemental and Settlement Accounting Exhibit 1
Schedule 2-1(a)(1)(a)(1)

Line No.	Item	Plant Type (a)	Total System			Total System	
			Public Staff Adjustment Amount ^{1/} (b)	Closed to Plant ^{2/} (c)	Depreciation Rates ^{1/} (d)	Depreciation Amount ^{4/} (e)	Accumulated Depr. Adjustment Amount as of 6/30/2023 ^{5/} (f)
	Adjustment to Test Year & Post TY Plant In Service						
1	Pleasant Garden 550kV Breaker Replacements	Distribution Plant	\$0	12/15/2022	2.45%	\$0	\$0
2	Pleasant Garden 550kV Breaker Replacements	Transmission Plant	0	12/15/2022	2.43%	0	0
3	Bad Creek 3 Hydroelectric	Hydro Plant	0	3/1/2023	1.81%	0	15
4	Dearborn Dam Hydroelectric	Hydro Plant	0	12/1/2022	1.55%	0	13
5	Remove EV charging infrastructure costs - 2021	General Plant	0	1/1/2021	5.00%	0	0
6	Remove EV charging infrastructure costs - 2022	General Plant	0	3/1/2023	5.00%	0	0
7	Mt Holly Traning Facility Renovatio - 2020	General Plant	0	12/1/2020	3.06%	0	0
8	Mt Holly Traning Facility Renovatio - 2021	General Plant	0	12/1/2020	3.06%	0	0
9	Mt Holly ETO Renovation - 2020	General Plant	0	11/1/2020	3.06%	0	0
10	Mt Holly ETO Renovation - 2021	General Plant	0	11/1/2020	3.06%	0	0
11	Mount Holly microgrid control sys	General Plant	0	9/1/2020	10.00%	0	13
12	Open Field Message Bus (OpenFMB)	Intangible Plant	0	8/1/2020	20.00%	0	22
13	Feeder Operational Controls	Intangible Plant	0	10/1/2021	20.00%	0	17
14	(OpenFMB) Microservices Development	Intangible Plant	0	9/1/2020	20.00%	0	15
15	MT Holly Simulation an Testing - 2021	Intangible Plant	0	10/1/2021	20.00%	0	11
16	Mount Holly Simulation and Testing - 2020	Intangible Plant	0	10/1/2020	12.50%	0	5
17	Mt. Holly Simulation & Testing -2022	Intangible Plant	0	4/1/2022	20.00%	0	22
18	Workstation Refresh 2023-2024	General Plant	0	3/1/2023	12.50%	0	55
19	526 S. Church Reno - Switchgear and Generator Replacement - 2020	General Plant	0	11/1/2020	3.06%	0	0
20	526 S. Church Reno - Switchgear and Generator Replacement - 2021	General Plant	0	11/1/2020	3.06%	0	0
21	Duke Plaza	General Plant	0	6/30/2023	1.85%	0	0
22	Duke Plaza - Land	General Plant	0	n/a	n/a	n/a	n/a
23	Lincoln Ct Unit 17 - Combustion Turbine Pipeline	Other Production Plant	0	5/1/2020	6.59%	0	0
24	Lincoln Ct Unit 17 removal	Other Production Plant	0	5/1/2020	6.59%	0	0
	May and June 2023 Updates						
25	Allen 230KV Transformer Project	Transmission Plant	(5,024) ^{3/}	5/1/2023	2.43%	(122)	122
26	Reclassification - Durham Mn SPCC	Distribution Plant	(2,834) ^{3/}	6/1/2023	2.45%	(69)	69
27	Reclassification - Durham Mn SPCC	Transmission Plant	2,834 ^{3/}	6/1/2023	2.43%	69	(69)
28	Durham Mn SPCC cost removal	Distribution Plant	(752) ^{3/}	6/1/2023	2.45%	(18)	18
29	Reclassification - PWRUP Fairplains	Distribution Plant	(419) ^{3/}	5/1/2023	2.45%	(10)	10
30	Reclassification - PWRUP Fairplains	Transmission Plant	419 ^{3/}	5/1/2023	2.43%	10	(10)
31	Misenhiemer Solar cost removal	Transmission Plant	(853) ^{3/}	6/1/2023	2.43%	(21)	21
32	Total Public Staff adjustment (Sum of L1 to L24)		<u>(\$6 629)</u>			<u>(\$162)</u>	<u>\$350</u>

1/ Per Settlement.

2/ Per Company.

3/ Per Public Staff engineers Metz, Thomas, and T. Williamson.

4/ Column (b) times Column (d).

5/ Per Public Staff.

DUKE ENERGY CAROLINAS, LLC
Docket No. E-7, Sub 1276
North Carolina Retail Operations
ADJUSTMENT TO UPDATE ACCUMULATED
DEPRECIATION TO JUNE 30, 2023
For the Test Year Ended December 31, 2021
(in Thousands)

Public Staff
Supplemental and Settlement Accounting Exhibit 1
Schedule 2-1(a)(2)

Line No.	Item	Total Carolinas			NC Retail Percentage ^{3/}	NC Retail Amount
		Amount As Of	Amount As Of	Change in Accumulated Depreciation		
		6/30/2023 ^{1/}	12/31/2021 ^{1/}	Depreciation ^{2/}		
		(a)	(b)	(c)	(d)	(e)
1	Production plant	(\$10,591,617)	(\$9,872,951)	(\$718,666)	66.9690%	(\$481,283) ^{4/}
2	Transmission plant	(1,533,034)	(1,440,993)	(92,041)	48.1470%	(44,315) ^{4/}
3	Distribution plant	(5,084,430)	(5,110,132)	25,702	74.0820%	19,041 ^{4/}
4	General plant	(413,986)	(459,397)	45,411	68.1625%	30,953 ^{4/}
5	Intangible plant	(819,239)	(737,984)	(81,255)	69.5124%	(56,482) ^{4/}
6	Total accumulated depreciation (Sum of L1 to L5)	<u>(\$18,442,306)</u>	<u>(\$17,621,457)</u>	<u>(\$820,849)</u>		<u>(\$532,086)</u>
7	Change in accumulated depreciation (L6)					(\$532,086)
8	Less: Non-fuel rider activity					(5,098) ^{5/}
9	Public Staff adjustment to update to 4/30/2023 (L7 - L8)					(526,987)
10	Company adjustment to update					(526,987) ^{6/}
11	Public Staff engineer adjustments					233 ^{7/}
12	Public Staff adjustment (L9 - L10 + L11)					<u>\$232</u>

- 1/ Per NC3030(S3)-7.
2/ Column (a) minus Column (b).
3/ Per E-1, Item 45a, 12 CP.
4/ Column (c) times Column (d).
5/ Per NC3030(S3) with actuals through June 30, 2023.
6/ Per NC3030(S3)-1, Line 30.
7/ Supplemental and Settlement Accounting Exhibit 1, Schedule 2-1(a)(2)(a).

DUKE ENERGY CAROLINAS, LLC
Docket No. E-7, Sub 1276
North Carolina Retail Operations
ADJUSTMENT TO ACCUMULATED DEPRECIATION FOR
PUBLIC STAFF PLANT ADJUSTMENTS
For the Test Year Ended December 31, 2021
(in Thousands)

Public Staff
Supplemental and Settlement Accounting Exhibit 1
Schedule 2-1(a)(2)(a)

Line No.	Item	Total System		NC Retail	
		Plant Type	Public Staff Accum. Depr. Adj. Amount ^{1/}	NC Retail Percentage ^{2/}	Accum. Depr. Adjustment ^{3/}
		(a)	(b)	(c)	(d)
Adjustment to Test Year Accumulated Depreciation:					
1	Mount Holly Project	Intangible Plant	\$71	69.5124%	\$49
2	Mount Holly Project	General Plant	13	68.1625%	9
3	526 S. Church Reno - Switchgear and Generator Replacement	General Plant	0	68.1625%	0
4	Remove EV charging infrastructure costs - 2021	General Plant	0	68.1625%	0
5	Lincoln Ct Unit 17 - Combustion Turbine Pipeline	Other Production Plant	0	66.9690%	0
6	Total Test Year adjustments (sum of L1 to L5)		<u>\$84</u>		<u>\$58</u>
Adjustment to Post Test Year Accumulated Depreciation:					
7	Mount Holly Project	Intangible Plant	22	69.5124%	15
8	Pleasant Garden 550kV Breaker Replacements	Distribution Plant	0	74.0820%	0
9	Pleasant Garden 550kV Breaker Replacements	Transmission Plant	0	48.1470%	0
10	Bad Creek 3 Hydroelectric	Hydro Plant	15	66.9690%	10
11	Dearborn Dam Hydroelectric	Hydro Plant	13	66.9690%	9
12	Remove EV charging infrastructure costs - 2022	General Plant	0	68.1625%	0
13	Workstation Project	General Plant	55	68.1625%	38
14	Duke Plaza	General Plant	0	68.1625%	0
15	Lincoln Ct Unit 17 removal	Other Production Plant	0	66.9690%	0
16	Allen 230KV Transformer Project	Transmission Plant	122	48.1470%	59
17	Reclassification - Durham Mn SPCC	Distribution Plant	69	74.0820%	51
18	Reclassification - Durham Mn SPCC	Transmission Plant	(69)	48.1470%	(33)
19	Durham Mn SPCC cost removal	Distribution Plant	18	74.0820%	14
20	Reclassification - PWRUP Fairplains	Distribution Plant	10	74.0820%	8
21	Reclassification - PWRUP Fairplains	Transmission Plant	(10)	48.1470%	(5)
22	Misenheimer Solar cost removal	Transmission Plant	21	48.1470%	10
23	Total Post Test Year adjustments (sum of L7 to L22)		<u>\$267</u>		<u>\$175</u>
24	Total adjustment impact (L6 + L23)		<u>\$350</u>		<u>\$233</u>

1/ Supplemental and Settlement Accounting Exhibit 1, Schedule 2-1(a)(1)(a)(1).

2/ E-1, Item No. 45a, 12CP.

3/ Column (b) times Column (c).

DUKE ENERGY CAROLINAS, LLC
Docket No. E-7, Sub 1276
North Carolina Retail Operations
ADJUSTMENT TO ACCUMULATED
DEPRECIATION FOR ANNUALIZATION OF
DEPRECIATION EXPENSE
For the Test Year Ended December 31, 2021
(in Thousands)

Public Staff
Supplemental and Settlement Accounting Exhibit 1
Schedule 2-1(a)(3)

Line No.	Item	Annualized Depreciation Expense at 6/30/2023 ^{1/} (a)	Per Books Depreciation Expense for Twelve Months 6/30/2023 ^{1/} (b)	Difference ^{2/} (c)	NC Retail Percentage ^{3/} (d)	NC Retail Amount ^{4/} (e)
1	Production plant	\$708,048	\$696,779	\$11,269	66.9690%	\$7,547
2	Production Direct assigned to NC	(4,654)	(3,602)	(1,052)	100.0000%	(1,052)
3	Production Direct assigned to SC	(3,531)	(3,464)	(67)	0.0000%	-
4	Transmission plant	122,362	114,382	7,980	48.1470%	3,842
5	Transmission Direct assigned to NC			\$0	100.0000%	-
6	Transmission Direct assigned to SC			\$0	0.0000%	-
7	NC Distribution plant	268,219	252,657	15,562	99.6277%	15,504
8	Distr bution Direct assigned to NC			-	100.0000%	-
9	SC Distr bution plant	88,505	87,743	762	0.0000%	-
10	General plant	102,843	91,184	11,659	68.1625%	7,947
11	General Direct assigned to SC			-	0.0000%	-
12	Intangible plant	75,066	75,066	-	69.5124%	-
13	Adjustment to depreciation Sum of L1 to L12)	<u>\$1,356,858</u>	<u>\$1,310,745</u>	<u>\$46,113</u>		<u>\$33,788</u>
14	Adjustment to depreciation recovered through in riders					<u>60</u> ^{5/}
15	Total adjustment to accumulated depreciation					(\$33,848)
16	Company adjustment					<u>(33,848)</u> ^{6/}
17	Public Staff adjustment to accumulated depreciation					<u>(\$0)</u>

1/ NC3030(S3)-5, Columns (c) and (d), Lines 26-28, 35, 41-45, 63, and 69.

2/ Column (a) minus Column (b).

3/ E-1, Item 45a, 12CP.

4/ Column (c) times Column (d).

5/ Per Company.

6/ NC3030(S3)-4, Line 15.

DUKE ENERGY CAROLINAS, LLC

Docket No. E-7, Sub 1276

North Carolina Retail Operations

ADJUSTMENT TO ALLEN NET BOOK VALUE AND AMORTIZATION

For the Test Year Ended December 31, 2021

(in Thousands)

Public Staff
 Supplemental and Settlement
 Accounting Exhibit 1
 Schedule 2-1(b)

Line No.	Item	Amount (a)
<u>Income Statement Impact</u>		
1	Allen Unit 4 deferred costs per Company at December 31, 2023	\$28,184 1/
2	Costs removed by Public Staff	- 2/
3	Add back Buck over amortization per Company	- 2/
4	Public Staff Allen Unit 4 deferred costs (L1 - L2 + L3)	\$28,184
5	Amortization period	6 1/
6	Public Staff annual amortization (L4/L5)	\$4,697
7	Company annual amortization	4,697 3/
8	Public Staff adjustment to annual amortization (L6 - L7)	\$0
<u>Rate Base Impact</u>		
9	Allen regulatory asset in COS	\$47,285 4/
10	Allen regulatory asset as of 6/30/2023	31,558 4/
11	Impact to working capital investment (L9 - L10)	(15,727)
12	Working capital impact per Company	(15,727) 4/
13	Adjustment to rate base (L11 - L12)	\$0
14	Composite income tax rate	23.3503% 5/
15	Public Staff impact to ADIT (-L11 x L14)	3,672
16	Company impact to ADIT	3,672 6/
17	Public Staff Adjustment to ADIT (L15 - L16)	\$0

1/ Per NC5060(S3)-2, Lines 34 - 35.

2/ Per Settlement.

3/ Per NC5060(S3)-1, Line 2.

4/ Per NC5060(S3)-1, Lines 11 to 13.

5/ Composite tax rate.

6/ Per NC5060(S3)-1, Line 16.

DUKE ENERGY CAROLINAS, LLC

Docket No. E-7, Sub 1276
North Carolina Retail Operations
ADJUSTMENT TO STEAM DEFERRAL
For the Test Year Ended December 31, 2021
(in Thousands)

Public Staff
Supplemental and Settlement
Accounting Exhibit 1
Schedule 2-1(c)

Line No.	Item	Amount
Income Statement Impact		
1	Adjustment to depreciation & amortization for steam deferral per Company	(\$34,161) ^{1/}
2	Adjustment to depreciation & amortization for steam deferral per Public Staff	(34,161) ^{2/}
3	Public Staff adjustment to steam deferral	<u>0</u>
Rate Base Impact		
4	Adjustment to working capital investment per Company	\$34,161 ^{1/}
5	Adjustment to working capital investment per Public Staff	<u>34,161</u> ^{2/}
6	Adjustment to working capital (L5 - L4)	<u>(\$0)</u>
7	Adjustment to ADIT per Company	\$7,977 ^{1/}
8	Adjustment to ADIT per Public Staff	<u>7,977</u> ^{2/}
9	Adjustment to ADIT (L8 - L7)	<u>(\$0)</u>

1/ NC3040(S3)-1

2/ Per Settlement.

DUKE ENERGY CAROLINAS, LLC

Docket No. E-7, Sub 1276

North Carolina Retail Operations

ADJUSTMENT TO GIP DEFERRAL

For the Test Year Ended December 31, 2021

(in Thousands)

Public Staff

Supplemental and Settlement

Accounting Exhibit 1

Schedule 2-1(d)

Line No.	Item	Amount (a)
<u>Income Statement Impact</u>		
1	GIP deferred costs per Company	\$71,121 ^{1/}
2	Costs removed by Public Staff	- ^{1/}
3	Public Staff GIP deferred costs (L1 + L2)	\$71,121
4	Public Staff amortization period	18 ¹
5	Public Staff annual amortization (L3/L4)	\$3,951
6	Company annual amortization	3,951 ^{1/}
7	Public Staff adjustment to annual amortization (L5 - L6)	\$0
<u>Rate Base Impact</u>		
8	Adjusted regulatory assets and liabilities (L3)	\$71,121
9	Less first year amortization (L5)	3,951
10	Impact to working capital investment (L8 - L9)	\$67,170
11	Working capital impact per Company	\$67,170 ^{1/}
12	Adjustment to rate base (L10 - L11)	(\$0)
13	Composite income tax rate	23.3503% ^{2/}
14	Impact to accumulated deferred income taxes (-L10 x L13)	(15,684)
15	ADIT per Company	(15,684) ^{1/}
16	Adjustment to ADIT (L14 - L15)	\$0

1/ Per Supplemental Settlement.

2/ Per Company.

DUKE ENERGY CAROLINAS, LLC

Docket No. E-7, Sub 1276
North Carolina Retail Operations
ADJUSTMENT TO COAL INVENTORY
For the Test Year Ended December 31, 2021
(in Thousands)

Public Staff
Supplemental and Settlement Accounting
Exhibit 1
Schedule 2-1(e)

Line No.	Item	Total System (a)	NC Retail Allocation (b)	Total NC Retail (c)
Rate Base impact				
1	Estimated full load burn - excluding retirements, in tons	51,746 ^{1/}		
2	Target number of days inventory per Public Staff	35 ^{2/}		
3	Target coal inventory balance at December 31, 2023 in tons (L1 x L2)	1,811,110 ^{Tons}		
4	Projected average delivered coal cost per ton	91.89 ^{3/}		
5	Projected coal inventory balance at target (L3 x L4/1,000)	166,423	67.4869% ^{4/}	\$112,314
6	Total coal inventory balance at target	166,423		112,314
7	Actual coal inventory balance per Company	195,023 ^{5/}	67.4869% ^{4/}	131,615
8	Impact to materials and supplies (L7 - L8)	(28,601)		(19,302)
9	Company adjustment			(19,302) ^{6/}
10	Public Staff adjustment to coal inventory (L8 - L9)			(\$0)

1/ Per NC6010(S3)-1.

2/ Per Public Staff witness Michna, the number of days in coal inventory.

3/ NC6010-2 - Docket No. E-2, Sub 1263, Direct Testimony of John Verderame page 8, line 24.

4/ NC Retail Allocation Factor - All MWHs at Generation - Jur.

5/ E-1 Item 2, Working Trial Balance - Accounts 0151130, 0151131 and 0151132.

6/ Per NC6010(S3)-1, Line 12.

DUKE ENERGY CAROLINAS, LLC
Docket No. E-7, Sub 1276
North Carolina Retail Operations
CALCULATION OF WORKING CAPITAL FROM
LEAD / LAG STUDY UNDER PRESENT RATES
For the Test Year Ended December 31, 2021
(in Thousands)

Public Staff
Supplemental and Settlement Accounting Exhibit 1
Schedule 2-1(f)

Line No.	Item	Per Books Amounts ^{1/}	Company Ratemaking Adjustments ^{2/}	After Company Adjustments ^{3/}	Public Staff Adjustments ^{4/}	After Public Staff Adjustments ^{5/}	(Lead) / Lag Days ^{6/}	Working Capital From Lead/Lag Study ^{7/}
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Electric operating revenues:							
2	Rate revenues	\$4,745,958	\$349,039	\$5,094,997	\$256,361	\$5,351,358	39 58	\$580,292
3	Sales for resale revenues	46,066		46,066	-	46,066	35.44	4,473
4	Forfeited discounts	3,355		3,355	-	3,355	70 00	643
5	Miscellaneous service revenues	3,422		3,422	-	3,422	76 00	713
6	Total miscellaneous rider revenue	(65,229)		(65,229)	-	(65,229)		-
7	Rent revenues - extra facilities - other	23,937		23,937	-	23,937	30.13	1,976
8	Rent revenues - pole & line attachments	27,824		27,824	-	27,824	143 39	10,931
9	Tower lease revenues	13,295		13,295	-	13,295	(93 97)	(3,423)
10	Other electric rents	4,199		4,199	-	4,199	45 21	520
11	454 Rent - labor- REL	10,091		10,091	-	10,091	(15 21)	(421)
12	Other misc revenues - CIAC & comp for svc	1,061		1,061	-	1,061	(15 21)	(44)
13	Other misc revenues - profit/loss on sale of M&S	15		15	-	15	-	-
14	Lincoln Siemens billing	167		167	-	167	(15 21)	(7)
15	Deferred DSM costs - NC	(657)		(657)	-	(657)	-	-
16	Steam sales revenues (Clemson CHP)	1,109		1,109	-	1,109	25 50	77
17	Revenues from transm of electricity to others	6,343		6,343	-	6,343	40.41	702
18	Other electric revenues	1,468		1,468	(1,757)	(289)	36 03	(29)
19	Other transmission revenues	1,535		1,535		1,535		-
20	Electric operating revenues	4 823 959	349 039	5 172 998	\$254 604	\$5 427 602	40.11	596 403
21	Fuel used in electric generation	1,023,187	120,669	1,143,856	256,361	1,400,217	(25 50)	(97,823)
22	Account 555 - Purchased Power	279,049	(44,928)	234,121	-	234,121	(39 00)	(25,016)
23	Retail Deferred Fuel Exp - NCR	(220,117)		(220,117)		(220,117)	(25 50)	15,378
24	Transmission reallocation		19,749	19,749	-	19,749	(39 00)	(2,110)
25	NRC inspection fees in Acct 524			-	-	-		-
26	Labor expense	465,451	(883)	464,568	0	464,568	(36 37)	(46,291)
27	Benefits expense	54,175	(641)	53,534	-	53,534	(12 21)	(1,791)
28	Uncollectibles expense	18,913		18,913	-	18,913		-
29	Regulatory commission expense	8,889		8,889	-	8,889	(89 82)	(2,187)
30	Property insurance	(3,412)		(3,412)	-	(3,412)	474 55	(4,436)
31	Injuries and damages for corp	6,091		6,091	-	6,091	145 50	2,428
32	Other O&M expense	642,759		642,759	(\$1,680)	641,079	(36.49)	(64,090)
33	Remove non-fuel rider costs and update fuel		(99,407)	(99,407)	-	(99,407)	(35 69)	9,720
34	Adjust for executive comp		(4,463)	(4,463)	0	(4,463)	(36 37)	445
35	Adjust for inflation		52,823	52,823	-	52,823	(32 50)	(4,703)
36	Adjust for approved reg assets and liabilities			-	-	-		-
37	Adjust for O&M reliability assurance		4,500	4,500	-	4,500	(36.49)	(450)
38	Adjust vegetation management, storm, & DE plaza		4,414	4,414	(0)	4,414	(36.49)	(441)
39	Adjust for credit card fees		-	-	\$0	-	(36.49)	-
40	Adjust for nuclear refueling outage costs			-		-	(36.49)	-

DUKE ENERGY CAROLINAS, LLC
Docket No. E-7, Sub 1276
North Carolina Retail Operations
CALCULATION OF WORKING CAPITAL FROM
LEAD / LAG STUDY UNDER PRESENT RATES
For the Test Year Ended December 31, 2021
(in Thousands)

Public Staff
Supplemental and Settlement Accounting Exhibit 1
Schedule 2-1(f)

Line No.	Item	Per Books Amounts ^{1/} (a)	Company Ratemaking Adjustments ^{2/} (b)	After Company Adjustments ^{3/} (c)	Public Staff Adjustments ^{4/} (d)	After Public Staff Adjustments ^{5/} (e)	(Lead) / Lag Days ^{6/} (f)	Working Capital From Lead/Lag Study ^{7/} (g)
41	Adjust for COVID & storm normalization & Nuc Outage		1,883	1,883	(\$1,680)	203	(35 69)	(20)
42	Annualize retail revenues for current rates			-	-	-	(33 90)	-
43	Normalize for weather		110	110		110	(35 69)	(11)
44	Annualize revenues for customer growth		2,767	2,767		2,767	(35 69)	(271)
45	Amortize rate case costs & expiring amortizations		(15,657)	(15,657)	(2,001)	(17,658)	-	-
46	Adjust aviation expense and test year		(5,880)	(5,880)	(0)	(5,880)	(35 69)	575
47	Adjust NC regulatory fee		857	857	-	857	(89 82)	(211)
48	Adjust other revenues		1,584	1,584	-	1,584	(35 69)	(155)
49	Other adjustments to reg fees and uncoll.							
50	Total O&M expenses	2 274 985	37 497	2 312 482	251 000	2 563 482		(221 460)
51	Depreciation expense	1,033,226	186,997	1,220,223	(54,257)	1,165,966	-	-
52	REPS rider NC amortization expense			-	-	-	-	-
53	Annual NOx proceeds			-	-	-	-	-
54	Other amortization expense		-	-	-	-	-	-
55	Remove non-fuel rider costs			-	-	-	-	-
56	Rounding							-
57	Depreciation and amortization expense	1,033,226	186,997	1,220,223	(54,257)	1,165,966		-
58	Other taxes - NC property tax	97,922		97,922	-	97,922	(186 50)	(50,034)
59	Other taxes - NC franchise & deferred prop. tax			-	-	-	-	-
60	Other taxes - NC state unemployment tax			-	-	-	-	-
61	Other taxes - NC industrial comm - electric			-	-	-	-	-
62	Other taxes - SC property tax	96,571		96,571	-	96,571	(196 50)	(51,990)
63	Other taxes - SC property tax - license fee			-	-	-	-	-
64	Other taxes - NC franchise tax			-	-	-	-	-
65	Other taxes - SC state unemployment tax			-	-	-	-	-
66	Other taxes - federal payroll taxes	26,503	1,519	28,022	-	28,022	(51.17)	(3,928)
67	Other taxes - federal unemployment tax			-	-	-	-	-
68	Adjust propoerty taxes		(1,623)	(1,623)	-	(1,623)	(186 50)	829
69	Other taxes	(8,506)		(8,506)	-	(8,506)	(21 04)	490
70	Adjust payroll taxes		(940)	(940)	-	(940)	(180.79)	466
71	Total taxes other than income	212,490	(1,044)	211,446	-	211,446		(104,167)
72	Interest on customer deposits	5 652	-	5 652	-	5 652	(218.40)	(3 382)
73	Current state and federal income tax	184,634	-	184,634	-	184,634	(44.75)	(22,637)
74	Deferred income taxes	35,671		35,671	-	35,671	-	-
	Adjust Incme tax and Interest Synch		17,692	17,692		17,692	37 50	1,818
	EDIT amortization	(204,469)	180,377	(24,092)		(24,092)	-	-
75	Adjust income taxes			-		-		-
76	Total income taxes	15,836	198,069	213,905	-	213,905		(20,819)
77	Amortization of ITC	(2,830)	1,026	(1,804)	-	(1,804)	-	-
78	Total electric operating expenses	3,539,359	422,545	3,961,904	196,743	4,158,647		(349,828)

DUKE ENERGY CAROLINAS, LLC
Docket No. E-7, Sub 1276
North Carolina Retail Operations
CALCULATION OF WORKING CAPITAL FROM
LEAD / LAG STUDY UNDER PRESENT RATES
For the Test Year Ended December 31, 2021
(in Thousands)

Public Staff
Supplemental and Settlement Accounting Exhibit 1
Schedule 2-1(f)

Line No.	Item	Per Books Amounts ^{1/}	Company Ratemaking Adjustments ^{2/}	After Company Adjustments ^{3/}	Public Staff Adjustments ^{4/}	After Public Staff Adjustments ^{5/}	(Lead) / Lag Days ^{6/}	Working Capital From Lead/Lag Study ^{7/}
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
79	Interest expense	358,096	58,986	417,082	695	417,777	(85 20)	(97,519)
80	Income available for common equity	926,504	(132,492)	794,012	(533)	793,479		-
81	Net operating income for return	1,284,600	(73,506)	1,211,094	162	1,211,256		(97,519)
82	Total requirement	<u>\$4,823,959</u>	<u>\$349,039</u>	<u>\$5,172,998</u>	<u>\$196,905</u>	<u>\$5,369,903</u>		<u>(447,347)</u>
83	Cash working capital before sales tax requirement							\$149,056
84	Working capital related to sales tax							6 939
85	Cash working capital per Public Staff							155,995
86	Amount per Company application							143,622 ^{2/}
87	Adjustment to cash working capital							<u>\$12,373</u>

1/ E-1, tem No. 14, Appendix A, Lead Lag Details, NC Retail Jurisdictional Amount.

2/ Bowman Supplemental Exhibit 1.

3/ Column (a) plus Column (b).

4/ Supplemental and Settlement Accounting Exhibit 1, Schedule 2-1(f)(1), Column (z).

5/ Column (c) plus Column (d).

6/ E-1, tem No. 14, Appendix A, Lead Lag Details, Lead Lag Days, corrected per responses to Company data request responses.

7/ Column (e) divided by 365 days times Column (f).

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DUKE ENERGY CAROLINAS, LLC

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North Carolina Retail Operations
PUBLIC STAFF ADJUSTMENTS TO BE
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Line No.	Item	Adjust Weather Normalization 1/ (a)	Update Plant to 4/30/2023 1/ (b)	Adjust GIP Deferral 1/ (c)	Adjust Distribution Vegetation Management 1/ (d)	Adjust Salaries and Wages 1/ (e)
1	Electric operating revenues:					
2	Rate revenues	\$0	\$0	\$0	\$0	\$0
3	Sales for resale revenues	-	-	-	-	-
4	Forfeited discounts	-	-	-	-	-
5	Miscellaneous service revenues	-	-	-	-	-
6	Total miscellaneous rider revenue	-	-	-	-	-
7	Rent revenues - extra facilities - other	-	-	-	-	-
8	Rent revenues - pole & line attachments	-	-	-	-	-
9	Tower lease revenues	-	-	-	-	-
10	Other electric rents	-	-	-	-	-
11	454 Rent - labor- REL	-	-	-	-	-
12	Other misc revenues - CIAC & comp for svc	-	-	-	-	-
13	Other misc revenues - profit/loss on sale of M&S	-	-	-	-	-
14	Lincoln Siemens billing	-	-	-	-	-
15	Deferred DSM costs - NC	-	-	-	-	-
16	Steam sales revenues (Clemson CHP)	-	-	-	-	-
17	Revenues from transm of electricity to others	-	-	-	-	-
18	Other electric revenues	-	-	-	-	-
19	Electric operating revenues	-	-	-	-	-
20	Fuel used in electric generation	\$0	-	\$0	-	-
21	Account 555 - Purchased Power	-	-	-	-	-
22	Transmission reallocation	-	-	-	-	-
23	NRC inspection fees in Acct 524	-	-	-	-	-
24	Labor expense	-	-	-	-	-
25	Benefits expense	-	-	-	-	-
26	Uncollectibles expense	-	-	-	-	-
27	Regulatory commission expense	-	-	-	-	-
28	Property insurance	-	-	-	-	-
29	Injuries and damages for corp	-	-	-	-	-
30	Other O&M expense	-	-	-	-	-
31	Remove non-fuel rider costs and update fuel	-	-	-	-	-
32	Adjust for executive comp	-	-	-	-	-
33	Adjust for inflation	-	-	-	-	-
34	Adjust for approved reg assets and liabilities	-	-	-	-	-
35	Adjust for O&M reliability assurance	-	-	-	-	-
36	Adjust vegetation management, storm, & DE plaza	-	-	-	(0)	-
37	Adjust NC regulatory fee	-	-	-	-	-
	Adjust rate case expense & expiring amortizations	-	-	-	-	-
38	Adjust other revenues	-	-	-	-	-
39	Total O&M expenses	-	-	-	(0)	-
40	Depreciation expense	-	(104)	\$0	-	-
41	REPS rider NC amortization expense	-	-	-	-	-
42	Annual NOx proceeds	-	-	-	-	-
43	Other amortization expense	-	-	-	-	-
44	Remove non-fuel rider costs	-	-	-	-	-
45	Depreciation and amortization expense	-	(104)	0	-	-
46	Other taxes - NC property tax	-	-	-	-	-
47	Other taxes - NC franchise & deferred prop. tax	-	-	-	-	-
48	Other taxes - NC state unemployment tax	-	-	-	-	-
49	Other taxes - NC industrial comm - electric	-	-	-	-	-
50	Other taxes - SC property tax	-	-	-	-	-
51	Other taxes - SC property tax - license fee	-	-	-	-	-
52	Other taxes - NC franchise tax	-	-	-	-	-
53	Other taxes - SC state unemployment tax	-	-	-	-	-
54	Other taxes - federal payroll taxes	-	-	-	-	-
55	Other taxes - federal unemployment tax	-	-	-	-	-
56	Adjust propoerty taxes	-	-	-	-	-
57	Other taxes	-	-	-	-	-
58	Adjust payroll taxes	-	-	-	-	-
59	Total taxes other than income	-	-	-	-	-
60	Interest on customer deposits	-	-	-	-	-
61	Current state and federal income tax	-	-	-	-	-
62	Deferred income taxes	-	-	-	-	-
63	Adjust income taxes	-	24	(0)	-	-
64	Total income taxes	-	24	(0)	-	-
65	Amortization of ITC	-	-	-	-	-
66	Total electric operating expenses	-	(79)	0	(0)	-
67	Interest expense	-	-	-	-	-
68	Income available for common equity (L39 -L66 - L67)	-	79	(0)	0	-
69	Net operating income for return	-	79	(0)	0	-
70	Total requirement	\$0	\$0	\$0	\$0	\$0

DUKE ENERGY CAROLINAS, LLC

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Line No.	Item	Adjust COVID Deferral 1/	Adjust Fuel Rates 1/	Adjust Depreciation Rates 1/	Adjust Incentives 1/	Adjust Executive Compensation 1/
		(f)	(g)	(h)	(i)	(j)
1	Electric operating revenues:					
2	Rate revenues	\$0	\$256,361	\$0	\$0	\$0
3	Sales for resale revenues	-	-	-	-	-
4	Forfeited discounts	-	-	-	-	-
5	Miscellaneous service revenues	-	-	-	-	-
6	Total miscellaneous rider revenue	-	-	-	-	-
7	Rent revenues - extra facilities - other	-	-	-	-	-
8	Rent revenues - pole & line attachments	-	-	-	-	-
9	Tower lease revenues	-	-	-	-	-
10	Other electric rents	-	-	-	-	-
11	454 Rent - labor- REL	-	-	-	-	-
12	Other misc revenues - CIAC & comp for svc	-	-	-	-	-
13	Other misc revenues - profit/loss on sale of M&S	-	-	-	-	-
14	Lincoln Siemens billing	-	-	-	-	-
15	Deferred DSM costs - NC	-	-	-	-	-
16	Steam sales revenues (Clemson CHP)	-	-	-	-	-
17	Revenues from trans of electricity to others	-	-	-	-	-
18	Other electric revenues	(1,757)	-	-	-	-
19	Electric operating revenues	(1,757)	256,361	-	-	-
20	Fuel used in electric generation	-	256,361	-	-	-
21	Account 555 - Purchased Power	-	-	-	-	-
22	Transmission reallocation	-	-	-	-	-
23	NRC inspection fees in Acct 524	-	-	-	-	-
24	Labor expense	-	-	-	0	0
25	Benefits expense	-	-	-	-	-
26	Uncollectibles expense	-	-	-	-	-
27	Regulatory commission expense	-	-	-	-	-
28	Property insurance	-	-	-	-	-
29	Injuries and damages for corp	-	-	-	-	-
30	Other O&M expense	(\$1,680)	-	-	-	-
31	Remove non-fuel rider costs and update fuel	-	-	-	-	-
32	Adjust for executive comp	-	-	-	-	-
33	Adjust for inflation	-	-	-	-	-
34	Adjust for approved reg assets and liabilities	-	-	-	-	-
35	Adjust for O&M reliability assurance	-	-	-	-	-
36	Adjust vegetation management, storm, & DE plaza	-	-	-	-	-
37	Adjust NC regulatory fee	-	-	-	-	-
	Adjust rate case expense & expiring amortizations	-	-	-	-	-
38	Adjust other revenues	-	-	-	-	-
39	Total O&M expenses	(1,680)	256,361	-	0	0
40	Depreciation expense	(54,154)	-	-	-	-
41	REPS rider NC amortization expense	-	-	-	-	-
42	Annual NOx proceeds	-	-	-	-	-
43	Other amortization expense	-	-	-	-	-
44	Remove non-fuel rider costs	-	-	-	-	-
45	Depreciation and amortization expense	(54,154)	-	-	-	-
46	Other taxes - NC property tax	-	-	-	-	-
47	Other taxes - NC franchise & deferred prop. tax	-	-	-	-	-
48	Other taxes - NC state unemployment tax	-	-	-	-	-
49	Other taxes - NC industrial comm - electric	-	-	-	-	-
50	Other taxes - SC property tax	-	-	-	-	-
51	Other taxes - SC property tax - license fee	-	-	-	-	-
52	Other taxes - NC franchise tax	-	-	-	-	-
53	Other taxes - SC state unemployment tax	-	-	-	-	-
54	Other taxes - federal payroll taxes	-	-	-	-	-
55	Other taxes - federal unemployment tax	-	-	-	-	-
56	Adjust propoerty taxes	-	-	-	-	-
57	Other taxes	-	-	-	-	-
58	Adjust payroll taxes	-	-	-	-	-
59	Total taxes other than income	-	-	-	-	-
60	Interest on customer deposits	-	-	-	-	-
61	Current state and federal income tax	-	-	-	-	-
62	Deferred income taxes	-	-	-	-	-
63	Adjust income taxes	12,627	-	-	(0)	(0)
64	Total income taxes	12,627	-	-	(0)	(0)
65	Amortization of ITC	-	-	-	-	-
66	Total electric operating expenses	(43,207)	256,361	-	0	0
67	Interest expense	-	-	-	-	-
68	Income available for common equity (L39 -L66 - L67)	41,450	-	-	(0)	(0)
69	Net operating income for return	41,450	-	-	(0)	(0)
70	Total requirement	(\$1,757)	\$256,361	\$0	\$0	\$0

1/ Supplemental Accounting Exhibit 1, Schedule 3-1.

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DUKE ENERGY CAROLINAS, LLC

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**PUBLIC STAFF ADJUSTMENTS TO BE
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Line No.	Item	Adjust Aviation Expenses (k)	1/	Adjust Credit Card Fees (l)	1/	Adjust Advertising Expense (m)	1/	Adjust Lighting Audit Deferral (n)	1/
1	Electric operating revenues:								
2	Rate revenues	\$0		\$0		\$0		\$0	
3	Sales for resale revenues	-		-		-		-	
4	Forfeited discounts	-		-		-		-	
5	Miscellaneous service revenues	-		-		-		-	
6	Total miscellaneous rider revenue	-		-		-		-	
7	Rent revenues - extra facilities - other	-		-		-		-	
8	Rent revenues - pole & line attachments	-		-		-		-	
9	Tower lease revenues	-		-		-		-	
10	Other electric rents	-		-		-		-	
11	454 Rent - labor- REL	-		-		-		-	
12	Other misc revenues - CIAC & comp for svc	-		-		-		-	
13	Other misc revenues - profit/loss on sale of M&S	-		-		-		-	
14	Lincoln Siemens billing	-		-		-		-	
15	Deferred DSM costs - NC	-		-		-		-	
16	Steam sales revenues (Clemson CHP)	-		-		-		-	
17	Revenues from transm of electricity to others	-		-		-		-	
18	Other electric revenues	-		-		-		-	
19	Electric operating revenues	-		-		-		-	
20	Fuel used in electric generation	-		-		-		-	
21	Account 555 - Purchased Power	-		-		-		-	
22	Transmission reallocation	-		-		-		-	
23	NRC inspection fees in Acct 524	-		-		-		-	
24	Labor expense	-		-		-		-	
25	Benefits expense	-		-		-		-	
26	Uncollectibles expense	-		-		-		-	
27	Regulatory commission expense	-		-		-		-	
28	Property insurance	-		-		-		-	
29	Injuries and damages for corp	-		-		-		-	
30	Other O&M expense	(0)		\$0		\$0		-	
31	Remove non-fuel rider costs and update fuel	-		-		-		-	
32	Adjust for executive comp	-		-		-		-	
33	Adjust for inflation	-		-		-		-	
34	Adjust for approved reg assets and liabilities	-		-		-		-	
35	Adjust for O&M reliability assurance	-		-		-		-	
36	Adjust vegetation management, storm, & DE plaza	-		-		-		-	
37	Adjust NC regulatory fee	-		-		-		-	
	Adjust rate case expense & expiring amortizations	-		-		-		-	
38	Adjust other revenues	-		-		-		-	
39	Total O&M expenses	(0)		-		-		-	
40	Depreciation expense	-		-		-		\$0	
41	REPS rider NC amortization expense	-		-		-		-	
42	Annual NOx proceeds	-		-		-		-	
43	Other amortization expense	-		-		-		-	
44	Remove non-fuel rider costs	-		-		-		-	
45	Depreciation and amortization expense	-		-		-		-	
46	Other taxes - NC property tax	-		-		-		-	
47	Other taxes - NC franchise & deferred prop. tax	-		-		-		-	
48	Other taxes - NC state unemployment tax	-		-		-		-	
49	Other taxes - NC industrial comm - electric	-		-		-		-	
50	Other taxes - SC property tax	-		-		-		-	
51	Other taxes - SC property tax - license fee	-		-		-		-	
52	Other taxes - NC franchise tax	-		-		-		-	
53	Other taxes - SC state unemployment tax	-		-		-		-	
54	Other taxes - federal payroll taxes	-		-		-		-	
55	Other taxes - federal unemployment tax	-		-		-		-	
56	Adjust propoerty taxes	-		-		-		-	
57	Other taxes	-		-		-		-	
58	Adjust payroll taxes	-		-		-		-	
59	Total taxes other than income	-		-		-		-	
60	Interest on customer deposits	-		-		-		-	
61	Current state and federal income tax	-		-		-		-	
62	Deferred income taxes	-		-		-		-	
63	Adjust income taxes	0		-		-		-	
64	Total income taxes	0		-		-		-	
65	Amortization of ITC	-		-		-		-	
66	Total electric operating expenses	(0)		-		-		-	
67	Interest expense	-		-		-		-	
68	Income available for common equity (L39 -L66 - L67)	0		-		-		-	
69	Net operating income for return	0		-		-		-	
70	Total requirement	\$0		\$0		\$0		\$0	

DUKE ENERGY CAROLINAS, LLC

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Line No.	Item	Adjust Lobbying Expense (o)	1/ 1/	Adjust Board of Directors Expense (p)	1/ 1/	Adjust Allen Unit 4 (q)	1/ 1/	Adjust Rent Expense (r)	1/ 1/	Adjust Sponsorships and Donations (s)	1/ 1/
1	Electric operating revenues:										
2	Rate revenues	\$0		\$0		\$0		\$0		\$0	
3	Sales for resale revenues	-		-		-		-		-	
4	Forfeited discounts	-		-		-		-		-	
5	Miscellaneous service revenues	-		-		-		-		-	
6	Total miscellaneous rider revenue	-		-		-		-		-	
7	Rent revenues - extra facilities - other	-		-		-		-		-	
8	Rent revenues - pole & line attachments	-		-		-		-		-	
9	Tower lease revenues	-		-		-		-		-	
10	Other electric rents	-		-		-		-		-	
11	454 Rent - labor- REL	-		-		-		-		-	
12	Other misc revenues - CIAC & comp for svc	-		-		-		-		-	
13	Other misc revenues - profit/loss on sale of M&S	-		-		-		-		-	
14	Lincoln Siemens billing	-		-		-		-		-	
15	Deferred DSM costs - NC	-		-		-		-		-	
16	Steam sales revenues (Clemson CHP)	-		-		-		-		-	
17	Revenues from transm of electricity to others	-		-		-		-		-	
18	Other electric revenues	-		-		-		-		-	
19	Electric operating revenues	-		-		-		-		-	
20	Fuel used in electric generation	-		-		-		-		-	
21	Account 555 - Purchased Power	-		-		-		-		-	
22	Transmission reallocation	-		-		-		-		-	
23	NRC inspection fees in Acct 524	-		-		-		-		-	
24	Labor expense	-		-		-		-		-	
25	Benefits expense	-		-		-		-		-	
26	Uncollectibles expense	-		-		-		-		-	
27	Regulatory commission expense	-		-		-		-		-	
28	Property insurance	-		-		-		-		-	
29	Injuries and damages for corp	-		-		-		-		-	
30	Other O&M expense	-		-		-		-		-	
31	Remove non-fuel rider costs and update fuel	-		-		-		-		-	
32	Adjust for executive comp	-		-		-		-		-	
33	Adjust for inflation	-		-		-		-		-	
34	Adjust for approved reg assets and liabilities	-		-		-		-		-	
35	Adjust for O&M reliability assurance	-		-		-		-		-	
36	Adjust vegetation management, storm, & DE plaza	-		-		-		-		-	
37	Adjust NC regulatory fee	-		-		-		-		-	
	Adjust rate case expense & expiring amortizations	-		-		-		-		-	
38	Adjust other revenues	-		-		-		-		-	
39	Total O&M expenses	-		-		-		-		-	
40	Depreciation expense	-		-		-		-		-	
41	REPS rider NC amortization expense	-		-		-		-		-	
42	Annual NOx proceeds	-		-		-		-		-	
43	Other amortization expense	-		-		-		-		-	
44	Remove non-fuel rider costs	-		-		-		-		-	
45	Depreciation and amortization expense	-		-		-		-		-	
46	Other taxes - NC property tax	-		-		-		-		-	
47	Other taxes - NC franchise & deferred prop. tax	-		-		-		-		-	
48	Other taxes - NC state unemployment tax	-		-		-		-		-	
49	Other taxes - NC industrial comm - electric	-		-		-		-		-	
50	Other taxes - SC property tax	-		-		-		-		-	
51	Other taxes - SC property tax - license fee	-		-		-		-		-	
52	Other taxes - NC franchise tax	-		-		-		-		-	
53	Other taxes - SC state unemployment tax	-		-		-		-		-	
54	Other taxes - federal payroll taxes	-		-		-		-		-	
55	Other taxes - federal unemployment tax	-		-		-		-		-	
56	Adjust propoerty taxes	-		-		-		-		-	
57	Other taxes	-		-		-		-		-	
58	Adjust payroll taxes	-		-		-		-		-	
59	Total taxes other than income	-		-		-		-		-	
60	Interest on customer deposits	-		-		-		-		-	
61	Current state and federal income tax	-		-		-		-		-	
62	Deferred income taxes	-		-		-		-		-	
63	Adjust income taxes	-		-		-		-		-	
64	Total income taxes	-		-		-		-		-	
65	Amortization of ITC	-		-		-		-		-	
66	Total electric operating expenses	-		-		-		-		-	
67	Interest expense	-		-		-		-		-	
68	Income available for common equity (L39 -L66 - L67)	-		-		-		-		-	
69	Net operating income for return	-		-		-		-		-	
70	Total requirement	\$0		\$0		\$0		\$0		\$0	

DUKE ENERGY CAROLINAS, LLC

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**PUBLIC STAFF ADJUSTMENTS TO BE
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Accounting Exhibit 1
Schedule 2-1(f)(1)
Page 5 of 6

Line No.	Item	Adjust Storm Normalization 1/ (t)	Adjust Test Year Revenue & Expenses (u) 1/	Adjust Rate Case Expense (v) 1/	Adjust Steam Deferral (w) 1/
1	Electric operating revenues:				
2	Rate revenues	\$0	\$ -	\$0	\$0
3	Sales for resale revenues	-			
4	Forfeited discounts	-			
5	Miscellaneous service revenues	-			
6	Total miscellaneous rider revenue	-			
7	Rent revenues - extra facilities - other	-			
8	Rent revenues - pole & line attachments	-			
9	Tower lease revenues	-			
10	Other electric rents	-			
11	454 Rent - labor- REL	-			
12	Other misc revenues - CIAC & comp for svc	-			
13	Other misc revenues - profit/loss on sale of M&S	-			
14	Lincoln Siemens billing	-			
15	Deferred DSM costs - NC	-			
16	Steam sales revenues (Clemson CHP)	-			
17	Revenues from trans of electricity to others	-			
18	Other electric revenues	-			-
19	Electric operating revenues	-	-	-	-
20	Fuel used in electric generation	-			
21	Account 555 - Purchased Power	-			
22	Transmission reallocation	-			
23	NRC inspection fees in Acct 524	-			
24	Labor expense	-			
25	Benefits expense	-			
26	Uncollectibles expense	-			
27	Regulatory commission expense	-			
28	Property insurance	-			
29	Injuries and damages for corp	-			
30	Other O&M expense	-	0		0
31	Remove non-fuel rider costs and update fuel	-			
32	Adjust for executive comp	-			
33	Adjust for inflation	-			
34	Adjust for approved reg assets and liabilities	-			
35	Adjust for O&M reliability assurance	-			
36	Adjust vegetation management, storm, & DE plaza	-			
37	Adjust NC regulatory fee	-			
	Adjust rate case expense & expiring amortizations	-		(2,001)	
38	Adjust other revenues	-			
39	Total O&M expenses	-	-	(2,001)	-
40	Depreciation expense	-			0
41	REPS rider NC amortization expense	-			
42	Annual NOx proceeds	-			
43	Other amortization expense	-			
44	Remove non-fuel rider costs	-			
45	Depreciation and amortization expense	-	-	-	0
46	Other taxes - NC property tax	-			
47	Other taxes - NC franchise & deferred prop. tax	-			
48	Other taxes - NC state unemployment tax	-			
49	Other taxes - NC industrial comm - electric	-			
50	Other taxes - SC property tax	-			
51	Other taxes - SC property tax - license fee	-			
52	Other taxes - NC franchise tax	-			
53	Other taxes - SC state unemployment tax	-			
54	Other taxes - federal payroll taxes	-			
55	Other taxes - federal unemployment tax	-			
56	Adjust propoerty taxes	-			
57	Other taxes	-			
58	Adjust payroll taxes	-			
59	Total taxes other than income	-	-	-	-
60	Interest on customer deposits	-	-	-	-
61	Current state and federal income tax	-			
62	Deferred income taxes	-			
63	Adjust income taxes	-	73	467	-
64	Total income taxes	-	73	467	-
65	Amortization of ITC	-	-		-
66	Total electric operating expenses	-	73	(1,533)	0
67	Interest expense	-	-	-	-
68	Income available for common equity (L39 -L66 - L67)	-	(73)	1,533	(0)
69	Net operating income for return	-	(73)	1,533	(0)
70	Total requirement	\$0	\$0	\$0	\$0

Supplemental and Settlement Accounting Exhibit 1,
1/ Schedule 3-1.

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Nov 02 2023

DUKE ENERGY CAROLINAS, LLC

Docket No. E-7, Sub 1276
North Carolina Retail Operations
PUBLIC STAFF ADJUSTMENTS TO BE
REFLECTED IN LEAD / LAG CALCULATION
For the Test Year Ended December 31, 2021
(in Thousands)

Public Staff
Supplemental and Settlement
Accounting Exhibit 1
Schedule 2-1(f)(1)
Page 6 of 6

Line No.	Item	Adjustment to Inflation Adjustment (x)	Adjust EOL Nuclear Reserve Amortization (y)	Adjust Aover Rate Case Expense (z)	Interest Synchronization (aa)	Total Public Staff Adjustments (bb)
1	Electric operating revenues:					
2	Rate revenues	\$0	\$0	\$0	\$0	\$256,361
3	Sales for resale revenues	-	-	-	-	0
4	Forfeited discounts	-	-	-	-	0
5	Miscellaneous service revenues	-	-	-	-	0
6	Total miscellaneous rider revenue	-	-	-	-	0
7	Rent revenues - extra facilities - other	-	-	-	-	0
8	Rent revenues - pole & line attachments	-	-	-	-	0
9	Tower lease revenues	-	-	-	-	0
10	Other electric rents	-	-	-	-	0
11	454 Rent - labor- REL	-	-	-	-	0
12	Other misc revenues - CIAC & comp for svc	-	-	-	-	0
13	Other misc revenues - profit/loss on sale of M&S	-	-	-	-	0
14	Lincoln Siemens billing	-	-	-	-	0
15	Deferred DSM costs - NC	-	-	-	-	0
16	Steam sales revenues (Clemson CHP)	-	-	-	-	0
17	Revenues from trans of electricity to others	-	-	-	-	0
18	Other electric revenues	-	-	-	-	(1,757)
19	Electric operating revenues	-	-	-	-	254,604
20	Fuel used in electric generation	-	-	-	-	\$256,361
21	Account 555 - Purchased Power	-	-	-	-	-
22	Transmission reallocation	-	-	-	-	-
23	NRC inspection fees in Acct 524	-	-	-	-	-
24	Labor expense	-	-	-	-	0
25	Benefits expense	-	-	-	-	-
26	Uncollectibles expense	-	-	-	-	-
27	Regulatory commission expense	-	-	-	-	-
28	Property insurance	-	-	-	-	-
29	Injuries and damages for corp	-	-	-	-	-
30	Other O&M expense	-	-	-	-	(1,680)
31	Remove non-fuel rider costs and update fuel	-	-	-	-	-
32	Adjust for executive comp	-	-	-	-	-
33	Adjust for inflation	-	-	-	-	-
34	Adjust for approved reg assets and liabilities	-	-	-	-	-
35	Adjust for O&M reliability assurance	-	-	-	-	-
36	Adjust vegetation management, storm, & DE plaza	-	-	-	-	(0)
37	Adjust NC regulatory fee	-	-	-	-	-
38	Adjust rate case expense & expiring amortizations	-	-	-	-	(2,001)
39	Adjust other revenues	-	-	-	-	-
39	Total O&M expenses	-	-	-	-	252,680
40	Depreciation expense	-	-	\$0	-	(54,257)
41	REPS rider NC amortization expense	-	-	-	-	-
42	Annual NOx proceeds	-	-	-	-	-
43	Other amortization expense	-	-	-	-	-
44	Remove non-fuel rider costs	-	-	-	-	-
45	Depreciation and amortization expense	-	-	-	-	(54,257)
46	Other taxes - NC property tax	-	-	-	-	-
47	Other taxes - NC franchise & deferred prop. tax	-	-	-	-	-
48	Other taxes - NC state unemployment tax	-	-	-	-	-
49	Other taxes - NC industrial comm - electric	-	-	-	-	-
50	Other taxes - SC property tax	-	-	-	-	-
51	Other taxes - SC property tax - license fee	-	-	-	-	-
52	Other taxes - NC franchise tax	-	-	-	-	-
53	Other taxes - SC state unemployment tax	-	-	-	-	-
54	Other taxes - federal payroll taxes	-	-	-	-	-
55	Other taxes - federal unemployment tax	-	-	-	-	-
56	Adjust propoerty taxes	-	-	-	-	-
57	Other taxes	-	-	-	-	-
58	Adjust payroll taxes	-	-	-	-	-
59	Total taxes other than income	-	-	-	-	-
60	Interest on customer deposits	-	-	-	-	-
61	Current state and federal income tax	-	-	-	-	-
62	Deferred income taxes	-	-	-	-	-
63	Adjust income taxes	-	-	-	(775)	12,416
64	Total income taxes	-	-	-	(775)	12,416
65	Amortization of ITC	-	-	-	-	-
66	Total electric operating expenses	-	-	-	(775)	210,839
67	Interest expense	-	-	-	3,317	3,317
68	Income available for common equity (L39 -L66 - L67)	-	-	-	(2,543)	40,447
69	Net operating income for return	-	-	-	775	43,765
70	Total requirement	\$0	\$0	\$0	\$0	\$254,604

Supplemental and Settlement Accounting Exhibit 1,
1/ Schedule 3-1.
2/ Sum of Column (a) to Column (aa).

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Nov 02 2023

DUKE ENERGY CAROLINAS, LLC
Docket No. E 7, Sub 1276
North Carolina Retail Operations
CALCULATION OF WORKING CAPITAL FROM
LEAD / LAG STUDY AFTER RATE DECREASE
For the Test Year Ended December 31, 2021
(in Thousands)

Public Staff
Supplemental and Settlement Accounting Exhibit 1
Schedule 2 1(g)
Page 1 of 2

Line No.	Item	Under Present Rates After Adjustments	(Lead) Lag Days	Iteration 1		
		(a)	(b)	Increase (c)	With Increase (d)	CWC Change (e)
1	Electric operating revenues					
2	Rate revenues	\$5,351,358	39.58	\$196,731 ^{5/}	\$5,548,089	\$21,333
3	Sales for resale revenues	46,066	35.44	-	46,066	-
4	Forfeited discounts	3,355	70.00	-	3,355	-
5	Miscellaneous service revenues	3,422	76.00	- ^{6/}	3,422	-
6	Total miscellaneous rider revenue	(65,229)	-	-	(65,229)	-
7	Rent revenues - extra facilities - other	23,937	30.13	-	23,937	-
8	Rent revenues - pole & line attachments	27,824	143.39	-	27,824	-
9	Tower lease revenues	13,295	(93.97)	-	13,295	-
10	Other electric rents	4,199	45.21	-	4,199	-
11	454 Rent - labor- REL	10,091	(15.21)	-	10,091	-
12	Other misc revenues - CIAC & comp for svc	1,061	(15.21)	-	1,061	-
13	Other misc revenues - prof t/loss on sale of M&S	15	-	-	15	-
14	Lincoln Siemens billing	167	(15.21)	-	167	-
15	Deferred DSM costs - NC	(657)	-	-	(657)	-
16	Steam sales revenues (Clemson CHP)	1,109	25.50	-	1,109	-
17	Revenues from transm of electricity to others	6,343	40.41	-	6,343	-
18	Other electric revenues	(289)	36.03	-	(289)	-
19	Other transmission revenues	1,535	-	-	1,535	-
		<u>5,427,602</u>		<u>196,731 ^{7/}</u>	<u>5,624,333</u>	<u>\$21,333</u>
20	Fuel used in electric generation	1,400,217	(25.50)	-	1,400,217	-
21	Account 555 - Purchased Power	234,121	(39.00)	-	234,121	-
22	Retail Deferred Fuel Exp - NCR	(220,117)	(25.50)	-	(220,117)	-
23	Transmission reallocation	19,749	(39.00)	-	19,749	-
24	NRC inspection fees in Acct 524	-	-	-	-	-
25	Labor expense	464,568	(36.37)	-	464,568	-
26	Benefits expense	53,534	(12.21)	-	53,534	-
27	Uncollectibles expense	18,913	-	-	18,913	-
28	Regulatory commission expense	8,889	(89.82)	-	8,889	-
29	Property insurance	(3,412)	474.55	-	(3,412)	-
30	Injuries and damages for corp	6,091	145.50	-	6,091	-
31	Other O&M expense	641,079	(36.49)	-	641,079	-
32	Remove non-fuel rider costs and update fuel	(99,407)	(35.69)	-	(99,407)	-
33	Adjust for executive comp	(4,463)	(36.37)	-	(4,463)	-
34	Adjust for inflation	52,823	(32.50)	-	52,823	-
35	Adjust for approved reg assets and liabilities	-	-	-	-	-
36	Adjust for O&M reliability assurance	4,500	(36.49)	-	4,500	-
37	Adjust vegetation management, storm, & DE plaza	4,414	(36.49)	-	4,414	-
38	Adjust for credit card fees	-	(36.49)	-	-	-
39	Adjust for nuclear refueling outage costs	-	(36.49)	-	-	-
40	Adjust for merger related costs	203	(35.69)	-	203	-
41	Annualize retail revenues for current rates	-	(33.90)	-	-	-
42	Normalize for weather	110	(35.69)	-	110	-
43	Annualize revenues for customer growth	2,767	(35.69)	-	2,767	-
44	Amortize rate case costs	(17,658)	-	-	(17,658)	-
45	Adjust aviation expense	(5,880)	(35.69)	-	(5,880)	-
46	Adjust NC regulatory fee	857	(89.82)	-	857	-
47	Adjust other revenues	1,584	(35.69)	-	1,584	-
48	Other adjustments to reg fees and uncoll.	-	(36.49)	-	-	(144)
49	Total O&M expenses	<u>2,563,482</u>		<u>1,439 ^{8/}</u>	<u>2,564,921</u>	<u>-</u>
50						
51	Depreciation expense	1,165,966	-	-	1,165,966	-
52	REPS rider NC amortization expense	-	-	-	-	-
53	Annual NOx proceeds	-	-	-	-	-
54	Other amortization expense	-	-	-	-	-
55	Remove non-fuel rider costs	-	-	-	-	-
56	Depreciation and amortization expense	<u>1,165,966</u>		<u>-</u>	<u>1,165,966</u>	<u>-</u>
57	Other taxes - NC property tax	97,922	(186.50)	-	97,922	-
58	Other taxes - NC franchise & deferred prop. tax	-	-	-	-	-
59	Other taxes - NC state unemployment tax	-	-	-	-	-
60	Other taxes - NC industrial comm - electric	-	-	-	-	-
61	Other taxes - SC property tax	96,571	(196.50)	-	96,571	-
62	Other taxes - SC property tax - license fee	-	-	-	-	-
63	Other taxes - NC franchise tax	-	-	-	-	-
64	Other taxes - SC state unemployment tax	-	-	-	-	-
65	Other taxes - federal payroll taxes	28,022	(51.17)	-	28,022	-
66	Other taxes - federal unemployment tax	-	-	-	-	-
67	Adjust property taxes	(1,623)	(186.50)	-	(1,623)	-
68	Other taxes	(8,506)	(21.04)	-	(8,506)	-
69	Adjust payroll taxes	(940)	(180.79)	-	(940)	-
70	Current state and federal income tax	<u>211,446</u>		<u>-</u>	<u>211,446</u>	<u>-</u>
71	Interest on customer deposits	<u>5,652</u>	(218.40)	<u>-</u>	<u>5,652</u>	<u>-</u>
72	Current state and federal income tax	184,634	(44.75)	-	184,634	-
73	Deferred income taxes	35,671	-	-	35,671	-
	Adjust income tax and Interest Synch	17,692	37.50	-	17,692	-
	EDIT amortization	(24,092)	-	-	(24,092)	-
74	Adjust income taxes	-	37.50	<u>45,601 ^{9/}</u>	<u>45,601</u>	<u>4,685</u>
75	Total income taxes	<u>213,905</u>		<u>45,601</u>	<u>259,506</u>	<u>4,685</u>
76	Amortization of ITC	<u>(1,804)</u>	-	<u>-</u>	<u>(1,804)</u>	<u>-</u>
77	Total electric operating expenses	<u>4,158,647</u>		<u>47,040</u>	<u>4,205,687</u>	<u>4,685</u>
78	Interest expense	417,777	(85.20)	-	417,777	-
79	Income available for common equity	<u>793,479</u>	-	<u>149,691 ^{10/}</u>	<u>943,170 ^{12/}</u>	<u>-</u>
80	Net operating income for return	<u>1,211,256</u>		<u>149,691</u>	<u>1,360,947</u>	<u>-</u>
81	Total requirement	<u>\$5,369,903</u>		<u>\$196,731</u>	<u>\$5,566,634</u>	<u>\$4,685</u>
82	Cumulative change in working capital					\$26,018
83	Rate base under present rates					<u>19,398,798</u>
84	Rate base after rate increase	<u>\$19,398,798 ^{2/}</u>				<u>\$19,424,816</u>
85	Overall rate of return	6.24%				7.01%
86	Target rate of return	7.05% ^{3/}				7.05% ^{3/}

1/ Supplemental and Settlement Accounting Exhibit 1, Schedule 2-1(f), Column (e) 8/ Line 19 times (uncollectibles rate of 0.58474% plus regulatory fee rate, net of uncollectibles, of 0.14664%).
2/ Sum of Suppl Acctg. Exh 1, Sch 2, L15, Col (c) & Sch 2 CCR L3, Col (a).
3/ Supplemental and Settlement Accounting Exhibit 1, Schedule 4, Line 3, Column 9/ (Line 79 divided by (1 minus 23.3503%)) minus Line 79.
4/ Supplemental and Settlement Accounting Exhibit 1, Schedule 2-1(f), Column (f) 10/ Column (d) minus Column (a).
5/ Line 19 minus (Sum of Line 3 thru Line 18). 11/ Column (a) plus Column (c), unless footnoted otherwise.
6/ Supplemental and Settlement Accounting Exhibit 1, Schedule 3, Line 3, Column 12/ Line 84, Column (a) times 52.000% times 9.350%.
7/ Line 79 divided by retention factor of 0.7608915. 13/ Column (c) divided by 365 days times Column (b).

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Nov 02 2023

DUKE ENERGY CAROLINAS, LLC
Docket No. E 7, Sub 1276
North Carolina Retail Operations
CALCULATION OF WORKING CAPITAL
FROM LEAD / LAG STUDY AFTER RATE
INCREASE
For the Test Year Ended December 31, 2021
(in Thousands)

Public Staff
Supplemental and Settlement Accounting Exhibit 1
Schedule 2 1(g)
Page 2 of 2

Line No.	Item	Iteration 2			Iteration 3			After Increase	
		Increase	With Increase	CWC Change	Increase	With Increase	CWC Change	Cumulative Increase	After Increase
		(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	Electric operating revenues								
2	Rate revenues	(\$50,094) 5/	\$5,497,995	(\$5,432)	(\$608) 5/	\$5,497,387	(\$66)	\$146,029	\$5,497,387
3	Sales for resale revenues	-	46,066	-	-	46,066	-	-	46,066
4	Forfeited discounts	-	3,355	-	-	3,355	-	-	3,355
5	Miscellaneous service revenues	-	3,422	-	-	3,422	-	-	3,422
6	Total miscellaneous rider revenue	-	(65,229)	-	-	(65,229)	-	-	(65,229)
7	Rent revenues - extra facilities - other	-	23,937	-	-	23,937	-	-	23,937
8	Rent revenues - pole & line attachments	-	27,824	-	-	27,824	-	-	27,824
9	Tower lease revenues	-	13,295	-	-	13,295	-	-	13,295
10	Other electric rents	-	4,199	-	-	4,199	-	-	4,199
11	454 Rent - labor- REL	-	10,091	-	-	10,091	-	-	10,091
12	Other misc revenues - CIAC & comp for svc	-	1,061	-	-	1,061	-	-	1,061
13	Other misc revenues - profit/loss on sale of M&S	-	15	-	-	15	-	-	15
14	Lincoln Siemens billing	-	167	-	-	167	-	-	167
15	Deferred DSM costs - NC	-	(657)	-	-	(657)	-	-	(657)
16	Steam sales revenues (Clemson CHP)	-	1,109	-	-	1,109	-	-	1,109
17	Revenues from transm of electricity to others	-	6,343	-	-	6,343	-	-	6,343
18	Other electric revenues	-	(289)	-	-	(289)	-	-	(289)
19	Electric operating revenues	(50,094) 1 /	5,574,239 16/	(5,432)	(608) 20/	5,573,631 16/	(66)	146,029	5,573,631
20	Fuel used in electric generation	-	1,400,217	-	-	1,400,217	-	-	1,400,217
21	Account 555 - Purchased Power	-	234,121	-	-	234,121	-	-	234,121
22	Retail Deferred Fuel Exp - NCR	-	(220,117)	-	-	(220,117)	-	-	(220,117)
23	Transmission reallocation	-	19,749	-	-	19,749	-	-	19,749
24	NRC inspection fees in Acct 524	-	-	-	-	-	-	-	-
25	Labor expense	-	464,568	-	-	464,568	-	-	464,568
26	Benefits expense	-	53,534	-	-	53,534	-	-	53,534
27	Uncollectibles expense	-	18,913	-	-	18,913	-	-	18,913
28	Regulatory commission expense	-	8,889	-	-	8,889	-	-	8,889
29	Property insurance	-	(3,412)	-	-	(3,412)	-	-	(3,412)
30	Injuries and damages for corp	-	6,091	-	-	6,091	-	-	6,091
31	Other O&M expense	-	641,079	-	-	641,079	-	-	641,079
32	Remove non-fuel rider costs and update fuel	-	(99,407)	-	-	(99,407)	-	-	(99,407)
33	Adjust for executive comp	-	(4,463)	-	-	(4,463)	-	-	(4,463)
34	Adjust for inflation	-	52,823	-	-	52,823	-	-	52,823
35	Adjust for approved reg assets and liabilities	-	-	-	-	-	-	-	-
36	Adjust for O&M reliability assurance	-	4,500	-	-	4,500	-	-	4,500
37	Adjust vegetation management, storm, & DE plaza	-	4,414	-	-	4,414	-	-	4,414
38	Adjust for credit card fees	-	-	-	-	-	-	-	-
39	Adjust for nuclear refueling outage costs	-	-	-	-	-	-	-	-
40	Adjust for merger related costs	-	203	-	-	203	-	-	203
41	Annualize retail revenues for current rates	-	-	-	-	-	-	-	-
42	Normalize for weather	-	110	-	-	110	-	-	110
43	Annualize revenues for customer growth	-	2,767	-	-	2,767	-	-	2,767
44	Amortize rate case costs	-	(17,658)	-	-	(17,658)	-	-	(17,658)
45	Adjust aviation expense	-	(5,880)	-	-	(5,880)	-	-	(5,880)
46	Adjust NC regulatory fee	-	857	-	-	857	-	-	857
47	Adjust other revenues	-	1,584	-	-	1,584	-	-	1,584
48	Other adjustments to reg fees and uncoll.	67 8/	1,506	(7)	(4) 8/	1,502	-	1,502	1,502
49	Total O&M expenses	67	2,563,482	-	(4)	2,563,482	-	-	2,563,482
50									
51	Depreciation expense	-	1,165,966	-	-	1,165,966	-	-	1,165,966
52	REPS rider NC amortization expense	-	-	-	-	-	-	-	-
53	Annual NOx proceeds	-	-	-	-	-	-	-	-
54	Other amortization expense	-	-	-	-	-	-	-	-
55	Remove non-fuel rider costs	-	-	-	-	-	-	-	-
56	Depreciation and amortization expense	-	1,165,966	-	-	1,165,966	-	-	1,165,966
57	Other taxes - NC property tax	-	97,922	-	-	97,922	-	-	97,922
58	Other taxes - NC franchise & deferred prop. tax	-	-	-	-	-	-	-	-
59	Other taxes - NC state unemployment tax	-	-	-	-	-	-	-	-
60	Other taxes - NC industrial comm - electric	-	-	-	-	-	-	-	-
61	Other taxes - SC property tax	-	96,571	-	-	96,571	-	-	96,571
62	Other taxes - SC property tax - license fee	-	-	-	-	-	-	-	-
63	Other taxes - NC franchise tax	-	-	-	-	-	-	-	-
64	Other taxes - SC state unemployment tax	-	-	-	-	-	-	-	-
65	Other taxes - federal payroll taxes	-	28,022	-	-	28,022	-	-	28,022
66	Other taxes - federal unemployment tax	-	-	-	-	-	-	-	-
67	Adjust property taxes	-	(1,623)	-	-	(1,623)	-	-	(1,623)
68	Other taxes	-	(8,506)	-	-	(8,506)	-	-	(8,506)
69	Adjust payroll taxes	-	(940)	-	-	(940)	-	-	(940)
70	Current state and federal income tax	-	211,446	-	-	211,446	-	-	211,446
71	Interest on customer deposits	-	5,652	-	-	5,652	-	-	5,652
72	Current state and federal income tax	-	184,634	-	-	184,634	-	-	184,634
73	Deferred income taxes	-	35,671	-	-	35,671	-	-	35,671
		-	17,692	-	-	17,692	-	-	17,692
		-	(24,092)	-	-	(24,092)	-	-	(24,092)
74	Adjust income taxes	385 9/	45,987	40	(106) 9/	45,881	13	45,881	45,881
75	Total income taxes	385	259,892	40	(106)	259,786	13	45,881	259,786
76	Amortization of ITC	-	(1,804)	-	-	(1,804)	-	-	(1,804)
77	Total electric operating expenses	452	4,204,634	40	(110)	4,204,528	13	45,881	4,204,528
78	Interest expense	7,393 1 /	425,170 17/	(1,726)	(155) 20/	425,015 22/	36	7,238	425,015
79	Income available for common equity	1,265 1 /	944,435 18/	-	(347) 20/	944,088 23/	-	150,609	944,088
80	Net operating income for return	8,658	1,369,605	(1,726)	(502)	1,369,103	36	157,847	1,369,103
81	Total requirement	\$9,110	\$5,574,239	(\$1,686)	(\$612)	\$5,573,631	\$49	\$203,728	\$5,573,631
82	Cumulative change in working capital			\$18,900			18,883		\$18,883
83	Rate base under present rates			19,398,798			19,398,798		19,398,798
84	Rate base after rate increase			\$19,417,698			\$19,417,681		\$19,417,681
85	Overall rate of return			7.05%			7.05%		7.05%
86	Target rate of return			7.05% 3/			7.05% 3/		7.05%

14/ Column (g) minus Column (d).
15/ Column (d) plus Column (f), unless footnoted otherwise.
16/ Sum of Line 77 and Line 80.
17/ Line 84, Column (e) times 48.000% times 4.560%.
18/ Line 84, Column (e) times 52.000% times 9.350%.
19/ Column (f) divided by 365 days times Column (b).
20/ Column (j) minus Column (g).

21/ Column (g) plus Column (i), unless footnoted otherwise.
22/ Line 84, Column (h) times 48.000% times 4.560%.
23/ Line 84, Column (h) times 52.000% times 9.350%.
24/ Column (i) divided by 365 days times Column (b).

DUKE ENERGY CAROLINAS, LLC
Docket No. E-7, Sub 1276
North Carolina Retail Operations
NET OPERATING INCOME FOR RETURN
For the Test Year Ended December 31, 2021
(in Thousands)

Public Staff
Supplemental and Settlement Accounting Exhibit 1
Schedule 3

Line No.	Item	Under Present Rates			After Public Staff Recommended Decrease	
		NC Retail Adjusted Per Company ^{1/}	Public Staff Adjustments ^{2/}	After Public Staff Adjustments ^{3/}	Rate Decrease ^{4/}	After Rate Decrease ^{8/}
		(a)	(b)	(c)	(d)	(e)
1	Electric operating revenues:					
2	Sales of electricity	\$5,148,172	\$256,361	\$5,404,533	\$88,358 ^{4/}	\$5,492,891
3	Other revenues	0	(1,446)	(1,446)	0	(1,446)
4	Electric operating revenues (L2 + L3)	5,148,172	254,915	5,403,087	88,358 ^{5/}	5,491,445
5	Electric operating expenses:					
6	Operations and maintenance:					
7	Fuel used in electric generation	1,143,856	256,361	1,400,217	0	1,400,217
8	Purchased power	33,754	0	33,754	0	33,754
9	Other operations and maintenance expenses	1,134,778	(3,681)	1,131,097	646 ^{6/}	1,131,743
10	Depreciation and amortization	1,152,465	(54,257)	1,098,208	0	1,098,208
11	General taxes	211,446	0	211,446	0	211,446
12	Interest on customer deposits	5,652	0	5,652	0	5,652
13	Net income taxes	247,927	11,570	259,497	20,384 ^{7/}	279,881
14	Amortization of protected EDIT, net of tax	(24,092)	0	(24,092)	0	(24,092)
15	Amortization of investment tax credit	(1,804)	0	(1,804)	0	(1,804)
16	Total electric operating expenses (Sum of L7 thru L15)	3,903,982	209,993	4,113,975	21,030	4,135,005
17	Net operating income for return (L4 minus L16)	\$1,244,190	\$44,922	\$1,289,112	\$67,328	\$1,356,440

1/ Per Bowman Supplemental Partial Settlement Exhibit 2, Page 1.1

2/ Supplemental and Settlement Accounting Exhibit 1, Schedule 3-1, Column (z).

3/ Column (a) plus Column (b).

4/ Line 4 minus Line 3.

5/ Supplemental and Settlement Accounting Exhibit 1, Schedule 5, Line 5, Column (c).

6/ Line 4 times (1 minus retention factor after uncollectibles and regulatory fee of 0.9926862 from Supplemental and Settlement Accounting Exhibit 1, Schedule 1-2, Line 10.)

7/ Line 4 minus Line 9 minus change in interest expense from Supplemental and Settlement Accounting Exhibit 1, Schedule 5, Line 3, Column (a), times composite income tax rate of

8/ Column (c) plus Column (d).

DUKE ENERGY CAROLINAS, LLC
Docket No. E-7, Sub 1276
North Carolina Retail Operations
NET OPERATING INCOME FOR RETURN - CCR DEFERRAL
For the Test Year Ended December 31, 2021
(Dollar Amounts Expressed in Thousands)

Public Staff
Supplemental and Settlement Accounting Exhibit 1
Schedule 3 CCR
Page 1 of 1

Line No.		Under Present Rates			After Public Staff Recommended Increase	
		NC Retail Adjusted Per Company ^{1/}	Public Staff Adjustments ^{2/}	After Public Staff Adjustments ^{3/}	Rate Increase ^{4/}	After Rate Increase ^{7/}
		(a)	(b)	(c)	(d)	(e)
1	Electric operating revenues:					
2	Sales of electricity	\$24,826		\$24,826	\$58,144 ^{4/}	\$82,970
3	Other revenues	0		0	0	0
4	Electric operating revenues (L2 + L3)	<u>24,826</u>	<u>0</u>	<u>24,826</u>	<u>58,144</u>	<u>82,970</u>
5	Electric operating expenses:					
6	Operations and maintenance:					
7	Fuel used in electric generation			0	0	0
8	Purchased power			0		0
9	Other operations and maintenance expenses	94		94	\$425 ^{5/}	519
10	Depreciation and amortization	67,758	0	67,758		67,758
11	General taxes			0		0
12	Interest on customer deposits			0		0
13	Net income taxes	(10,047)	0	(10,047)	\$13,478 ^{6/}	3,431
14	Amortization of protected EDIT, net of tax			0		0
15	Amortization of investment tax credit			0		0
16	Total electric operating expenses (Sum of L6 through L15)	<u>57,805</u>	<u>0</u>	<u>57,805</u>	<u>13,903</u>	<u>71,708</u>
17	Net operating income for return (L4 minus L16)	<u>(\$32,979)</u>	<u>\$0</u>	<u>(\$32,979)</u>	<u>\$44,241</u>	<u>\$11,262</u>

1/ Bowman Supplemental Partial Settlement Exhibit 2, Page 1.2

2/ Supplemental Accounting Exhibit 1, Schedule 3-1, Line 10, Column (aa).

3/ Column (a) plus Column (b).

4/ Supplemental and Settlement Accounting Exhibit 1, Schedule 5 CCR, Line 5, Column (c).

5/ Line 4 times (1 minus retention factor after uncollectibles and regulatory fee of 0.9926862 from Exhibit 1, Schedule 1-2 CCR, Line 10).

6/ (Line 4 minus Line 9) minus (increase in debt expense from Accounting Exhibit 1, Schedule 5, Line 5, Column (a) multiplied by composite income tax rate of 23.133%).

7/ Column (c) plus Column (d).

DUKE ENERGY CAROLINAS, LLC

Docket No. E-7, Sub 1276
North Carolina Retail Operations
SUMMARY OF PUBLIC STAFF NET
OPERATING INCOME ADJUSTMENTS
For the Test Year Ended December 31, 2021
(in Thousands)

Public Staff
Supplemental and Settlement Accounting Exhibit 1
Schedule 3-1
Page 1 of 6

Line No.	Item	Update Plant to 4/30/2023 1/	Adjust Depreciation Rates 2/	Adjust EOL Nuclear M&S Reserve Amortization 3/	Adjust Distribution Vegetation Management 4/	Adjust Fuel rates 5/
		(a)	(b)	(c)	(d)	(e)
1	Electric operating revenues:					
2	Sales of electricity		\$0		\$0	\$256,361
3	Other revenues	-	-	-	-	-
4	Electric operating revenues (L2 + L3)	-	-	-	-	256,361
5	Electric operating expenses:					
6	Operations and maintenance:					
7	Fuel used in electric generation					256,361
8	Purchased power					
9	Other operations and maintenance expenses				(0)	
10	Depreciation and amortization	(104)	-	-		
11	General taxes	-				
12	Interest on customer deposits					
13	Net income taxes	28/ 24	-	-	0	-
14	Amortization of protected EDIT, net of tax					
15	Amortization of investment tax credit	-	-	-	-	
16	Total electric operating expenses (Sum of L7 thru L15)	(79)	-	-	(0)	256,361
17	Net operating income for return (L4 minus L16)	79	-	-	0	-
18	Calculated revenue requirement impact	29/ (\$104)	\$0	\$0	\$0	\$0

1/ Supplemental and Settlement Accounting Exhibit 1, Schedule 3-1(a), Lines 4 and 12.

2/ Supplemental and Settlement Accounting Exhibit 1, Schedule 3-1(b), Line 9.

3/ Supplemental and Settlement Accounting Exhibit 1, Schedule 3-1(c), Line 14.

4/ Supplemental and Settlement Accounting Exhibit 1, Schedule 3-1(d), Line 26.

5/ Supplemental and Settlement Accounting Exhibit 1, Schedule 3-1(e), Lines 6 and 7.

28/ Line 4 minus Sum of Line 7 through 12 times composite income tax rate of 23.3503%.

29/ Negative Line 17 divided by Schedule 1-2, Line 14.

DUKE ENERGY CAROLINAS, LLC

Docket No. E-7, Sub 1276
North Carolina Retail Operations
SUMMARY OF PUBLIC STAFF NET
OPERATING INCOME ADJUSTMENTS
For the Test Year Ended December 31, 2021
(in Thousands)

Exhibit 1

Public Staff
Supplemental and Settlement Accounting Exhibit 1
Schedule 3-1
Page 2 of 6

Line No.	Item	Adjust Test Year Revenue and Expenses (f) 6/	Adjust COVID Deferral (g) 7/	Adjust Aviation Expenses (h) 8/	Adjust Incentives (i) 9/
1	Electric operating revenues:				
2	Sales of electricity		\$0	\$0	\$0
3	Other revenues	311	(1,757)	-	-
4	Electric operating revenues (L2 + L3)	311	(1,757)	-	-
5	Electric operating expenses:				
6	Operations and maintenance:				
7	Fuel used in electric generation				
8	Purchased power				
9	Other operations and maintenance expenses	-	(1,680)	(0)	0
10	Depreciation and amortization		(54,154)		
11	General taxes			-	
12	Interest on customer deposits				
13	Net income taxes	28/ 73	12,627	0	(0)
14	Amortization of protected EDIT, net of tax				
15	Amortization of investment tax credit		-	-	-
16	Total electric operating expenses (Sum of L7 thru L15)	73	(43,207)	(0)	0
17	Net operating income for return (L4 minus L16)	238	41,450	0	(0)
18	Calculated revenue requirement impact	29/ (\$313)	(\$54,475)	\$0	\$0

6/ Supplemental and Settlement Accounting Exhibit 1, Schedule 3-1(f), Lines 3 and 7.

7/ Supplemental and Settlement Accounting Exhibit 1, Schedule 3-1(g), Lines 3, 6, and 19.

8/ Supplemental and Settlement Accounting Exhibit 1, Schedule 3-1(h), Lines 9, 16, and 21.

9/ Supplemental and Settlement Accounting Exhibit 1, Schedule 3-1(i), Line 19.

28/ Line 4 minus Sum of Line 7 through 12 times composite income tax rate of 23.3503%.

29/ Negative Line 17 divided by Schedule 1-2, Line 14.

DUKE ENERGY CAROLINAS, LLC
Docket No. E-7, Sub 276
North Carolina Retail Operations
SUMMARY OF PUBLIC STAFF NET
OPERATING INCOME ADJUSTMENTS
For the Test Year Ended December 31, 2021
(in Thousands)

Exhibit 1

Public Staff
Supplemental and Settlement Accounting Exhibit 1
Schedule 3-1
Page 3 of 6

Line No.	Item	Adjust Executive Compensation 10/ (j)	Adjust Rent Expense 11/ (k)	Adjust Credit Card Fees 12/ (l)	Adjust Lobbying Expense 13/ (m)	Adjust Sponsorships & Donations 14/ (n)
1	Electric operating revenues:					
2	Sales of electricity	\$0		\$0	\$0	\$0
3	Other revenues	-	0	-	-	-
4	Electric operating revenues (L2 + L3)	-	-	-	-	-
5	Electric operating expenses:					
6	Operations and maintenance:					
7	Fuel used in electric generation					
8	Purchased power					
9	Other operations and maintenance expenses	0	-	0	-	-
10	Depreciation and amortization					
11	General taxes					
12	Interest on customer deposits					
13	Net income taxes	28/ (0)	-	0	-	-
14	Amortization of protected EDIT, net of tax					
15	Amortization of investment tax credit	-	-	-	-	-
16	Total electric operating expenses (Sum of L7 thru L15)	0	-	-	-	-
17	Net operating income for return (L4 minus L16)	(0)	-	-	-	-
18	Calculated revenue requirement impact	29/ \$0	\$0	\$0	\$0	\$0

10/ Supplemental and Settlement Accounting Exhibit 1, Schedule 3-1(j), Line 13.

11/ Supplemental and Settlement Accounting Exhibit 1, Schedule 3-1(k), Lines 3 and 20.

12/ Supplemental and Settlement Accounting Exhibit 1, Schedule 3-1(l) Line 3.

13/ Supplemental and Settlement Accounting Exhibit 1, Schedule 3-1(m), Line 9.

14/ Supplemental and Settlement Accounting Exhibit 1, Schedule 3-1(n), Line 7.

28/ Line 4 minus Sum of Line 7 through 12 times composite income tax rate of 23.3503%.

29/ Negative Line 17 divided by Schedule 1-2, Line 14.

DUKE ENERGY CAROLINAS, LLC
Docket No. E-7, Sub 1276
North Carolina Retail Operations
SUMMARY OF PUBLIC STAFF NET
OPERATING INCOME ADJUSTMENTS
For the Test Year Ended December 31, 2021
(in Thousands)

ibit 1

Public Staff
Supplemental and Settlement Accounting Exhibit 1
Schedule 3-1
Page 4 of 6

Line No.	Item	Adjust Board of Directors Expense 15/ (o)	Adjust Salaries & Wages 16/ (p)	Adjust Storm Normalization 17/ (q)	Adjust Lighting Audit Deferral 18/ (r)	Adjust Rate Case Expense 19/ (s)
1	Electric operating revenues:					
2	Sales of electricity	\$0			\$0	
3	Other revenues	-	-	-	-	-
4	Electric operating revenues (L2 + L3)	-	-	-	-	-
5	Electric operating expenses:					
6	Operations and maintenance:					
7	Fuel used in electric generation					
8	Purchased power					
9	Other operations and maintenance expenses	0	-	-		(2,001)
10	Depreciation and amortization				0	
11	General taxes					
12	Interest on customer deposits					
13	Net income taxes 28/	0	-	-	0	467
14	Amortization of protected EDIT, net of tax					
15	Amortization of investment tax credit	-	-	-	-	
16	Total electric operating expenses (Sum of L7 thru L15)	-	-	-	-	(1,533)
17	Net operating income for return (L4 minus L16)	-	-	-	-	1,533
18	Calculated revenue requirement impact 29/	\$0	\$0	\$0	\$0	(\$2,015)

15/ Supplemental and Settlement Accounting Exhibit 1, Schedule 3-1(o), Line 17.

16/ Supplemental and Settlement Accounting Exhibit 1, Schedule 3-1(p), Lines 16, and 21.

17/ Supplemental and Settlement Accounting Exhibit 1, Schedule 3-1(q), Line 13.

18/ Supplemental and Settlement Accounting Exhibit 1, Schedule 3-1(r), Line 4.

19/ Supplemental and Settlement Accounting Exhibit 1, Schedule 3-1(s), Line 16.

28/ Line 4 minus Sum of Line 7 through 12 times composite income tax rate of 23.3503%.

29/ Negative Line 17 divided by Schedule 1-2, Line 14.

DUKE ENERGY CAROLINAS, LLC

Docket No. E-7, Sub 1276
North Carolina Retail Operations
SUMMARY OF PUBLIC STAFF NET
OPERATING INCOME ADJUSTMENTS
For the Test Year Ended December 31, 2021
(in Thousands)

Public Staff
Supplemental and Settlement Accounting Exhibit 1
Schedule 3-1
Page 5 of 6

Line No.	Item	Adjustment to Inflation Adjustment (t)	Adjust Steam Deferral (u)	Adjust GIP Deferral (v)	Adjust Allen Unit 4 Deferral (w)
1	Electric operating revenues:				
2	Sales of electricity				4/ \$0
3	Other revenues	-		-	-
4	Electric operating revenues (L2 + L3)	-	-	-	-
5	Electric operating expenses:				
6	Operations and maintenance:				
7	Fuel used in electric generation				
8	Purchased power				
9	Other operations and maintenance expenses	0			
10	Depreciation and amortization		0	0	0
11	General taxes				
12	Interest on customer deposits				
13	Net income taxes	28/ -	(0)	(0)	-
14	Amortization of protected EDIT, net of tax				
15	Amortization of investment tax credit	-		-	-
16	Total electric operating expenses (Sum of L7 thru L15)	-	0	0	-
17	Net operating income for return (L4 minus L16)	-	(0)	(0)	-
18	Calculated revenue requirement impact	29/ \$0	\$0	\$0	\$0

20/ Supplemental and Settlement Accounting Exhibit 1, Schedule 3-1(t), Line 15.
21/ Supplemental and Settlement Accounting Exhibit 1, Schedule 2-1(c), Line 3.
22/ Supplemental and Settlement Accounting Exhibit 1, Schedule 2-1(d), Line 7.
23/ Supplemental and Settlement Accounting Exhibit 1, Schedule 2-1(b), Line 8.
28/ Line 4 minus Sum of Line 7 through 12 times composite income tax rate of 23.3503%.
29/ Negative Line 17 divided by Schedule 1-2 CCR, Line 14.

DUKE ENERGY CAROLINAS, LLC

Docket No. E-7, Sub 1276
North Carolina Retail Operations
SUMMARY OF PUBLIC STAFF NET
OPERATING INCOME ADJUSTMENTS
For the Test Year Ended December 31, 2021
(in Thousands)

Public Staff
Supplemental and Settlement Accounting Exhibit 1
Schedule 3-1
Page 6 of 6

Line No.	Item	Adjust Over Amortization Rate Case Expense ^{24/}	Interest Synchronization Adjustment ^{25/}	Total NOI Adjustments ^{26/}	Adjust Over Amortization CCR ^{27/}
		(x)	(y)	(z)	(aa)
1	Electric operating revenues:				
2	Sales of electricity			\$256,361	
3	Other revenues		-	(1,446)	
4	Electric operating revenues (L2 + L3)	-	-	254,915	-
5	Electric operating expenses:				
6	Operations and maintenance:				
7	Fuel used in electric generation		-	256,361	
8	Purchased power		-	-	
9	Other operations and maintenance expenses		-	(3,681)	
10	Depreciation and amortization	-	-	(54,257)	-
11	General taxes		-	-	
12	Interest on customer deposits		-	-	
13	Net income taxes ^{28/}	-	(1,621)	11,570	-
14	Amortization of protected EDIT, net of tax		-	-	
15	Amortization of investment tax credit		-	-	
16	Total electric operating expenses (Sum of L7 thru L15)	-	(1,621)	209,993	-
17	Net operating income for return (L4 minus L16)	-	1,621	44,922	-
18	Calculated revenue requirement impact ^{29/}	^{29/} \$0	(\$2,130)	(\$59,039)	\$0 ^{31/}

24/ Supplemental and Settlement Accounting Exhibit 1, Schedule 3-1(u)(2), Line 2.

25/ Supplemental and Settlement Accounting Exhibit 1, Schedule 3-1(v), Line 8.

26/ Sum of Columns (a) to (y).

27/ Supplemental and Settlement Accounting Exhibit 1, Schedule 3-1(u)(1), Line 4.

28/ Line 4 minus Sum of Line 7 through 12 times composite income tax rate of 23.3503%.

29/ Negative Line 17 divided by Schedule 1-2 CCR, Line 14.

DUKE ENERGY CAROLINAS, LLC

Public Staff

Supplemental and Settlement Accounting Exhibit 1

Schedule 3-1(a)

Docket No. E-7, Sub 1276

North Carolina Retail Operations

ADJUSTMENT TO DEPRECIATION EXPENSE AND
PROPERTY TAXES FOR PLANT UPDATE

For the Test Year Ended December 31, 2021

(in Thousands)

Line No.	Item	Amount
1	<u>Depreciation expense</u>	
2	Depreciation expense on increase in plant per Public Staff	\$75,256 ^{1/}
3	Company adjustment	<u>75,360</u> ^{2/}
4	Public Staff adjustment to depreciation expense for update of plant (L2 - L3)	<u>(\$104)</u>
5	<u>General taxes</u>	
6	Update to plant per Public Staff	2,654,622 ^{3/}
7	Less: adjustment to intangible plant	<u>55,368</u> ^{4/}
8	Adjustment to plant excluding intangible plant (L6 - L7)	2,599,254
9	Property tax rate per \$1000	0.52227% ^{5/}
10	Impact to property taxes of Public Staff plant update (L8 x L9)	13,575
11	Company adjustment	<u>13,575</u> ^{6/}
12	Public Staff adjustment to property taxes (L10 - L11)	<u>\$0</u>

1/ Supplemental and Settlement Accounting Exhibit 1, Schedule 3-1(a)(1), Line 15, Column (e).

2/ Per NC3030(S3)-1, Line 56.

3/ Supplemental and Settlement Accounting Exhibit 1, Schedule 2-1(a)(1), Line 13, Column (e).

4/ Supplemental and Settlement Accounting Exhibit 1, Schedule 2-1(a)(1), Line 9, Column (e).

5/ Per NC3030(S3)-1.

6/ Per NC3030(S3)-1, Line 67.

DUKE ENERGY CAROLINAS, LLC
Docket No. E-7, Sub 1276
North Carolina Retail Operations
CALCULATION OF DEPRECIATION
EXPENSE ON PLANT UPDATE
For the Test Year Ended December 31, 2021
(in Thousands)

Public Staff
Supplemental and Settlement Accounting Exhibit 1
Schedule 3-1(a)(1)

Line No.	Item	Increase in Plant in Service ^{1/} (a)	Depreciation Rate ^{2/} (b)	Increase in Depreciation ^{3/} (c)	NC Retail Percentage ^{5/} (d)	NC Retail Amount ^{6/} (e)
1	Steam plant	\$39,851	5.66%	\$2,256		
2	Steam plant - Lee unit 3 retirement	(91,535)	0.00%	-		
3	Hydro plant	379,398	2.27%	8,612		
4	Other production plant	132,646	3.39%	4,497		
5	Nuclear plant	234,692	2.21%	5,187		
6	Total production plant	695,052		20,552	66.9690%	\$13,763
7	Transmission plant	660,190	2.43%	16,043	48.1470%	7,724
8	Distribution plant	1,920,478	2.45%	47,052	74.0820%	34,857
9	General plant	12,027	5.31%	639	68.1625%	436
10	General plant - Duke Plaza	567,036	1.85%	10,490	68.1625%	7,150
11	Intangible plant	79,652	n/a	16,542 ^{4/}	69.5124%	11,499
12	Total	<u>\$ 3,934,435</u>		<u>\$ 111,318</u>		75,429
13	Less: depreciation on REPS & CPRE additions					69 ^{7/}
14	Depreciation expense on Public Staff plant adjustment					(103) ^{8/}
15	Depreciation expense per Public Staff (L12-L13+L14)					<u>\$ 75,256</u>

1/ Supplemental and Settlement Accounting Exhibit 1, Schedule 2-1(a)(1), Column (c).

2/ Per Settlement.

3/ Column (a) times Column (b).

4/ Per NC3030(S3)-1, Line 11.

5/ E-1, Item 45a, 12CP.

6/ Column (c) times Column (d).

7/ Per Company.

8/ Supplemental and Settlement Accounting Exhibit 1, Schedule 3-1(a)(1)(a), Column (d), Line 17.

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1300
North Carolina Retail Operations
ADJUSTMENT TO DEPRECIATION FOR PUBLIC STAFF PLANT
ADJUSTMENTS
For the Test Year Ended December 31, 2021
(in Thousands)

Public Staff
Supplemental and Settlement Accounting Exhibit 1
Schedule 3-1(a)(1)(a)

Line No.	Item	Total System		NC Retail	
		Plant Type	Public Staff Depreciation Adj. Amount ^{1/}	NC Retail Percentage ^{2/}	Depreciation Adjustment ^{3/}
		(a)	(b)	(c)	(d)
Adjustment to Test Year Depreciation Expense:					
1	Mount Holly Project	Intangible Plant	\$ -	69.5124%	\$ -
2	Mount Holly Project	General Plant	-	68.1625%	-
3	526 S. Church Reno - Switchgear and Generator Replacement	General Plant	-	68.1625%	-
4	Remove EV charging infrastructure costs - 2021	General Plant	-	68.1625%	-
5	Lincoln Ct Unit 17 - Combustion Turbine Pipeline	Other Production Plant	-	66.9690%	-
6	Total Test Year adjustments (Sum of L1 to L5)		<u>\$ -</u>		<u>\$ -</u>
Adjustment to Post Test Year Depreciation Expense:					
7	Mount Holly Project	Intangible Plant	-	69.5124%	-
8	Pleasant Garden 550kV Breaker Replacements	Distribution Plant	-	74.0820%	-
9	Pleasant Garden 550kV Breaker Replacements	Transmission Plant	-	48.1470%	-
10	Bad Creek 3 Hydroelectric	Hydro Plant	-	66.9690%	-
11	Dearborn Dam Hydroelectric	Hydro Plant	-	66.9690%	-
12	Remove EV charging infrastructure costs - 2022	General Plant	-	68.1625%	-
13	Workstation Project	General Plant	-	68.1625%	-
14	Duke Plaza	General Plant	-	68.1625%	-
15	Lincoln Ct Unit 17 removal	Other Production Plant	-	66.9690%	-
16	Allen 230KV Transformer Project	Transmission Plant	(122)	48.1470%	(59)
17	Reclassification - Durham Mn SPCC	Distribution Plant	(69)	74.0820%	(51)
18	Reclassification - Durham Mn SPCC	Transmission Plant	69	48.1470%	33
19	Durham Mn SPCC cost removal	Distribution Plant	(18)	74.0820%	(14)
20	Reclassification - PWRUP Fairplains	Distribution Plant	(10)	74.0820%	(8)
21	Reclassification - PWRUP Fairplains	Transmission Plant	10	48.1470%	5
22	Misenheimer Solar cost removal	Transmission Plant	(21)	48.1470%	(10)
23	Total Post Test Year adjustments Sum of L7 to L22)		<u>\$ (162)</u>		<u>\$ (103)</u>
24	Total adjustment impact (L6 + L23)		<u>\$ (162)</u>		<u>\$ (103)</u>

1/ Supplemental and Settlement Accounting Exhibit 1, Schedule 2-1(a)(1)(a)(1).

2/ E-1, Item No. 45a, 12CP.

3/ Column (b) times Column (c).

DUKE ENERGY CAROLINAS, LLC

Docket No. E-7, Sub 1276
North Carolina Retail Operations
ADJUSTMENT FOR CHANGE IN DEPRECIATION RATES
For the Test Year Ended December 31, 2021
(in Thousands)

Public Staff
Supplemental and Settlement Accounting Exhibit 1
Schedule 3-1(b)

Line No.	Item	Total System (a)	NC Retail Percentage (b)	NC Retail Amount (c)
	<u>Change in depreciation and amortization per Public Staff</u>			
1	Production	\$168,535	66.9690%	\$112,866 ^{3/}
2	Transmission	9,531	48.1470%	4,589 ^{3/}
3	Distribution	37,386	74.0820%	27,696 ^{3/}
4	General	376	68.1625%	256 ^{3/}
5	General amortization	-	68.1625%	- ^{3/}
6	Adjust to depr and amort for costs recovered through riders		66.9690%	- ^{3/}
7	Public Staff adjustment to depreciation and amortization expense (Sum of L1 to L6)	<u>\$215,828</u>		<u>145,407</u>
8	Adjustment per Company			<u>145,407 ^{4/}</u>
9	Adjustment to depreciation and amortization expense (L7 - L8)			<u>\$0</u>
10	Adjustment to accumulated depreciation (-L9)			<u>\$0</u>

1/ Per Settlement.

2/ Per E-1, Item 45a, 12 CP.

3/ Column (a) times Column (b).

4/ Per NC3040(S3)-1, Line 7.

DUKE ENERGY CAROLINAS, LLC
Docket No. E-7, Sub 1276
North Carolina Retail Operations
ADJUSTMENT TO END OF LIFE RESERVE FOR NUCLEAR MATERIALS AND
SUPPLIES AMORTIZATION EXPENSE
For the Test Year Ended December 31, 2021
(in Thousands)

Public Staff
Supplemental and Settlement Accounting Exhibit 1
Schedule 3-1(c)

Line No.	Item	McGuire (a)	Oconee (b)	Catawba (c)	Total (d) ^{8/}
1	Inventory as of December 31, 2021	\$ 141,072 ^{1/}	\$ 182,903 ^{1/}	\$ 30,173 ^{1/}	\$ 354,148
2	Percentage of M&S with salvage value or transferrable per Public Staff	5% ^{2/}	5% ^{2/}	5% ^{2/}	
3	Public Staff adjustment for salvage value (L1 x L2)	<u>(7,054)</u>	<u>(9,145)</u>	<u>(1,509)</u>	<u>(17,708)</u>
4	Nuclear M&S inventory base for amortization per Public Staff(L1 + L3)	134,018	173,758	28,664	<u>\$ 336,440</u>
5	NC Retail Allocation Factor	66.969% ^{3/}	66.969% ^{3/}	66.969% ^{3/}	
6	NC retail nuclear M&S base for amortization (L4 x L5)	<u>89,751</u>	<u>116,364</u>	<u>19,196</u>	225,311
7	<u>Less:</u> Projected inventory reserve at 12/31/2023	<u>31,302</u> ^{4/}	<u>57,866</u> ^{4/}	<u>5,771</u> ^{4/}	<u>94,939</u>
8	NC nuclear reserve required at rates effective date (L6 - L7)	58,449	58,498	13,425	130,372
9	Years of remaining plant life	<u>39</u> ^{5/}	<u>31</u> ^{5/}	<u>40</u> ^{5/}	
10	NC retail annual expense for reserve per Public Staff (L8 / L9)	1,492	1,915	336	3,743
11	Current NC Retail annual expense for reserve per Company	<u>3,474</u> ^{6/}	<u>6,228</u> ^{6/}	<u>612</u> ^{6/}	<u>10,314</u>
12	Public Staff adjustment to annual expense for end of life reserve for nuclear M&S (L10 - L11)	<u>(1,982)</u>	<u>(4,313)</u>	<u>(276)</u>	<u>(6,571)</u>
13	Adjustment per Company	<u>(1,982)</u> ^{7/}	<u>(4,313)</u> ^{7/}	<u>(276)</u> ^{7/}	<u>(6,571)</u>
14	Public Staff adjustment to nuclear M&S reserve amortization expense (L12 - L13)	<u>\$ -</u>	<u>\$ -</u>	<u>\$ -</u>	<u>\$ -</u>

1/ NC2120(S3)-3, Lines 2 and 3.

2/ Per Public Staff witness Metz.

3/ NC Retail Allocation Factor - All - Production Demand

4/ NC2120(S3)-3, Line 13.

5/ NC2120(S3)-3, Line 19.

6/ NC2120(S3)-3, Line 23.

7/ NC2120(S3)-3, Line 24.

8/ Sum of Columns (a) through (c).

DUKE ENERGY CAROLINAS, LLC
Docket No. E-7, Sub 1276
North Carolina Retail Operations
ADJUSTMENT TO DISTRIBUTION AND TRANSMISSION
VEGETATION MANAGEMENT
For the Test Year Ended December 31, 2021
(in Thousands)

Public Staff
Supplemental and Settlement Accounting Exhibit
1 Schedule 3-1(d)

Line No.	Item	Total Miles (a)	Target Cycle (In Years) (b)	Test Year Amount (c)	Adjusted Amount (d)
	<u>Vegetation Management Adjustment - Distribution</u>				
1	Number of trim miles per year:				
2	Urban Miles	2,097	5		419 ^{2/}
3	Mountain Miles	4,295	7		614 ^{2/}
4	Other Miles (includes Nantahala Mountain Miles)	45,200	9		5,022 ^{2/}
5	Total number of trim miles (L2 + L3 + L4)	51,592		6,168	6,055
6	Cost per Mile in dollars			9,884	10,393 ^{3/}
7	Production \$ (Sum L5 x L6)			\$ 60,961,236	\$62,930,084
8	Demand \$			3,073,167	3,144,679 ^{1/}
9	Herbicide \$			3,245,598	3,310,510 ^{1/}
10	Contract Inspectors \$			762,418	785,290 ^{1/}
11	Program Target \$ (Sum L7 through L10)			\$ 68,042,419	\$70,170,538
12	Adjusted VM program costs (Line 11, Col (d) less Col (c))				\$2,128,119
13	NC Retail allocation				74.1732% ^{4/}
14	Total distribution vegetation management per Public Staff (L12 x L13)				1,578
	<u>Vegetation Management Adjustment - Transmission</u>				
15	Transmission Routine Maintenance \$			\$ 3,177,323	\$4,796,449 ^{3/}
16	Transmission Reactive Maintenance \$			2,405,781	2,477,954
17	Transmission Herbicide \$			4,835,092	4,980,145
18	Transmission Inspections \$			317,330 ^{3/}	1,307,609 ^{3/}
19	Transmission Substation Maintenance \$			1,481,083	1,629,191
20	Targeted Program Costs \$ (Sum L15 through L19)			\$ 12,216,609	\$ 15,191,348
21	Adjusted VM program costs (Line 20, Col (d) less Col (c))				\$ 2,974,739
22	NC Retail allocation				48.1470% ^{5/}
23	Total transmission vegetation management adjustment per Public Staff (L21 x L22)				1,432
24	Total Adjusted VM per Public Staff				3,011 ^{7/}
25	Adjusted VM per Company				3,011 ^{6/}
26	Public Staff adjustment to VM (L24 - L25)				(\$0)

- 1/ Per NC2070(c)-2, unless otherwise noted.
2/ Column (a) divided by Column (b).
3/ Per Public Staff Witness Tommy Williamson.
4/ Per E-1, Item 45a, 12CP, All - Dist PIt OH allocation factor.
5/ Per E-1, Item 45a, 12CP, All - Transmission Demand - Jur allocation factor.
6/ Per NC2070(c), Line 9.
7/ Per Settlement.

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DUKE ENERGY CAROLINAS, LLC

Docket No. E-7, Sub 1276
North Carolina Retail Operations
ADJUSTMENT TO FUEL RATES
For the Test Year Ended December 31, 2021
(in Thousands)

Public Staff
Supplemental and Settlement Accounting Exhibit 1
Schedule 3-1(e)

Line No.	Item	Test Year kWh by Class ^{1/} (a)	Fuel Costs in Cents per KWH ^{2/} (b)	Amount ^{3/} (c)
<u>Fuel Cost Update:</u>				
1	Residential	22,379,004,323	2.3345	\$ 522,438
2	General Service and Lighting	23,421,233,214	2.3387	547,752
3	Industrial	12,268,184,505	2.3326	286,168
4	Public Staff calculated fuel costs update (Sum of L1 through L3)	<u>58,068,422,042</u>		\$ 1,356,358
5	Company's fuel cost update			\$ 1,099,997 ^{1/}
6	Public Staff adjustment to fuel cost update (L4 - L5)			<u>\$ 256,361</u>
7	Fuel Revenue Impact			<u>\$ 256,361</u>

1/ NC2010(B)-1, Lines 11-12.

2/ Per Public Staff Engineer Lucas.

3/ Column (a) x Column (c) divided by (100 x 1000).

DUKE ENERGY CAROLINAS, LLC
Docket No. E-7, Sub 1276
North Carolina Retail Operations
ADJUSTMENT TO REVENUE AND TEST YEAR EXPENSES
For the Test Year Ended December 31, 2021
(in Thousands)

Public Staff
Supplemental and Settlement Accounting Exhibit 1
Schedule 3-1(f)

Line No.	Item	Amount per Company (a)	Amount per Public Staff (b)	NC Retail Allocation Factors (c) ^{1/}	Adjustment Amount (d) ^{2/}
Revenue Impact:					
1	NC Retail Extra Facility Charge	\$ 3,681 ^{7/}	\$ 3,681 ^{4/}	100.0000%	\$ -
2	NC Retail Extra Facility Charge - Apex Solar	-	311 ^{4/}	100.0000%	311
3	Total Revenue adjustment (L1 + L2)	<u>\$ 3,681</u>	<u>\$ 3,992</u>		<u>\$ 311</u>
Income Statement Impact:					
4	NC Retail annual amortization on Outage Costs	56,402 ^{3/}	56,402 ^{4/}	100.0000%	-
5	System O&M for Reliability Assurance	6,719 ^{5/}	6,719 ^{4/}	66.9690%	-
6	O&M cost reduction related to Bad Creek - Sec. 40331 Hydro Production Incentives	(1,000) ^{6/}	(1,000) ^{4/}	66.9690%	-
7	Non-fuel O&M cost reduction for Marshall	-	- ^{4/}		-
8	Total Public Staff O&M adjustment (Sum of L4 to L7)	<u>\$ 62,121</u>	<u>\$ 62,121</u>		<u>\$ -</u>
Rate Base Impact:					
9	Material and supplies for Lee Unit 3 plant retirement	(739) ^{8/}	(739) ^{4/}	66.9690%	-
10	Total rate base adjustment	<u>\$ (739)</u>	<u>\$ (739)</u>		<u>\$ -</u>

1/ E1, Item 45a, 12CP.

2/ [Column (b) - Column (a)] x Column (c).

3/ Per NC2100(D)-1, Line 20.

4/ Per settlement.

5/ Per settlement, in NC2160(S3)-1.

6/ Per settlement, in NC2080(S4)-2.

7/ Per settlement, in NC2080(S4)-5.

8/ Per settlement, in NC2080(S4)-3.

DOCKET NO. E-7, Sub 1276

**PUBLIC STAFF SUPPLEMENTAL AND SETTLEMENT
ACCOUNTING EXHIBIT 1**

CONFIDENTIAL SCHEDULE 3-1(G)

DUKE ENERGY CAROLINAS, LLC

Docket No. E-7, Sub 1276
North Carolina Retail Operations
ADJUSTMENT TO AVIATION EXPENSES
For the Test Year Ended December 31, 2021
(in Thousands)

Public Staff
Supplemental and Settlement Accounting Exhibit 1
Schedule 3-1(h)

Line No.	Item	Amount
	Wages, benefits, materials, etc.	
1	Corporate aviation O&M and depreciation expense	\$5,467 ^{1/}
2	Percentage to be excluded per Public Staff	50.00% ^{2/}
3	Corporate aviation expenses to be excluded per Public Staff (L1 x L2)	2,734
4	Specific charter flights to be excluded	- ^{2/}
5	Total corporate aviation expenses to be excluded per Public Staff (L3 + L4)	2,734
6	Corporate aviation expenses to be excluded per Company	2,734 ^{3/}
7	Additional aviation O&M expenses to be excluded (L5 - L6)	-
8	NC retail percentage	68.2076% ^{4/}
9	Public Staff adjustment to aviation O&M expenses (-L7 x L8)	\$0
	General taxes	
10	Corporate aviation general taxes	\$100 ^{5/}
11	Percentage to be excluded per Public Staff	50.00% ^{2/}
12	Corporate aviation general taxes to be excluded per Public Staff (L10 x L11)	50
13	Corporate aviation general taxes to be excluded per Company	50 ^{6/}
14	Additional aviation general taxes to be excluded (L12 - L13)	-
15	NC retail percentage	68.2076% ^{4/}
16	Public Staff adjustment to aviation general taxes (-L14 x L15)	\$0
	Commercial flights	
17	International flight expense	\$1 ^{2/}
18	Allocation percentage from DEBS to DEC	33.90% ^{7/}
19	International flight expense allocated to DEC (L17 x L18)	0
20	NC retail percentage	68.2076% ^{4/}
21	Public Staff adjustment to O&M for commercial flights (-L19 x L20)	(\$0)

1/ NC2090-2, Line 29.

2/ Per Settlement.

3/ NC2090-2, Line 31.

4/ NC2090-1, Line 5.

5/ NC2090-2, Line 1.

6/ NC2090-2, Line 3.

7/ NC2090-5.

DUKE ENERGY CAROLINAS, LLC
Docket No. E-7, Sub 1276
North Carolina Retail Operations
ADJUSTMENT TO INCENTIVES
For the Test Year Ended December 31, 2021
(in Thousands)

Public Staff
Supplemental and Settlement Accounting Exhibit 1
Schedule 3-1(i)

Line No.	Item	Amount
	Short Term Incentive Plan (STIP)	
1	Total Company STIP pay accrued expense associated with earnings per share (EPS)	\$155,325 ^{1/}
2	Total Company STIP accrual	353,012 ^{1/}
3	Percentage of STIP related to EPS (L1 / L2)	44.00%
4	STIP at target level associated with O&M expense per Company, net of Joint Owners	18,330 ^{5/}
5	Adjustment to remove STIP related to EPS outcomes - total system (-L3 x L4)	(8,065)
6	NC retail percentage	68.2076% ^{2/}
7	Adjustment to remove STIP related to EPS outcomes - NC retail (L5 x L6)	(5,501)
8	Executive STIP already removed in executive compensation adjustment	630 ^{3/}
9	Company adjustment to STIP	(4,871) ^{2/}
10	Adjustment to STIP (L7 + L8 - L9)	\$0
	Long Term Incentive Plan (LTIP)	
11	LTIP Performance Shares at target, net Joint Owners	\$12,160 ^{4/}
12	Percentage associated with EPS and TSR	75.00%
13	Adjustment to remove LTIP associated with EPS and TSR - total system (-L11 x L12)	(9,120)
14	NC retail percentage	68.2076% ^{2/}
15	Adjustment to remove LTIP associated with EPS and TSR - NC retail (L13 x L14)	(6,221)
16	Executive LTIP already removed in executive compensation adjustment	2,400 ^{3/}
17	Company adjustment to LTIP	(3,820)
18	Adjustment to LTIP (L15 + L16 - L17)	\$0
19	Total adjustment to incentive pay (L10 + L18)	\$0

1/ Company response to PS DR 94-24.

2/ NC2050-1(S3).

3/ Per Settlement.

4/ NC2050(B)-10(c) net of Catawba Joint Owners.

5/ Per Settlement.

DUKE ENERGY CAROLINAS, LLC
Docket No. E-7, Sub 1276
North Carolina Retail Operations
ADJUSTMENT TO EXECUTIVE COMPENSATION
For the Test Year Ended December 31, 2021
(in Thousands)

Public Staff
Supplemental and Settlement Accounting Exhibit 1
Schedule 3-1(j)

Line No.	Item	Amount
1	Executive compensation for top 5 executives per Company	\$13,405 ^{1/}
2	Inclusion of executive benefits in adjustment	1,080 ^{2/}
3	Executive compensation subject to exclusion adjustment per Public Staff (L1 + L2)	14,485
4	Catawba reimbursement allocation rate	11.956% ^{1/}
5	Non-ownership percentage in Catawba plant	80.754% ^{1/}
6	Costs reimbursed by Catawba Joint Owners (L3 x L4 x L5)	1,399
7	Compensation subject to exclusion after Joint Owners' Share (L3 - L6)	13,086
8	NC retail Allocation Factor	68.2076% ^{1/}
9	NC retail portion of executive compensation subject to exclusion adjustment (L7 x L8)	8,926
10	Exclusion percentage	50.00% ^{1/}
11	Public Staff adjustment to exclude executive compensation (L9 x L10)	(4,463)
12	Adjustment per Company	(4,463) ^{1/}
13	Adjustment to remove additional executive compensation (L11 - L12)	\$0

^{1/} NC2040(S3)-1.

^{2/} From Company response to PSDR 44-2.

DUKE ENERGY CAROLINAS, LLC
Docket No. E-7, Sub 1276
North Carolina Retail Operations
ADJUSTMENT TO RENT EXPENSE
For the Test Year Ended December 31, 2021
(in Thousands)

Public Staff
Supplemental and Settlement Accounting Exhibit 1
Schedule 3-1(k)

Line No.	Item	Amount
1	Inter-Company rent revenue per Company	\$22,513 ^{1/}
2	Inter-Company rent revenue per Public Staff	22,513 ^{2/}
3	Adjustment to the rent revenue Public Staff (L2-L1)	<u>\$0</u>
4	Adjustment to removed impact of retirement on depr expense per Company	\$0 ^{1/}
5	Adjustment to removed impact of retirement on depreciation expense per Public Staff	0 ^{2/}
6	Public Staff adjustment to removed impact of retirement on depr expense (L5 - L4)	<u>\$0</u>
7	Adjustment to removed impact of retirement on property tax	\$0 ^{1/}
8	Adjustment to removed impact of retirement on property tax per Public Staff	0 ^{2/}
9	Public Staff adjustment to removed impact of retirement on property tax (L8 - L7)	<u>\$0</u>
10	Inter-Company rent expense increase per Company	\$4,385 ^{1/}
11	DEBS allocated depreciation expense per Company	(2,975) ^{1/}
12	Increased property insurance	7 ^{1/}
13	Remove test year DEBS allocated expenses related to artwork	<u>(14) ^{1/}</u>
14	Total Company adjustment to rent expense (sum of Lines 10 through 13)	<u>1,403</u>
15	Inter-Company rent expense per Public Staff	\$4,385 ^{2/}
16	DEBS allocated depreciation expense per Company	(2,975) ^{2/}
17	Increased property insurance	7 ^{2/}
18	Remove test year DEBS allocated expenses related to artwork	<u>(14) ^{2/}</u>
19	Impact to operations and maintenance expense per Public Staff (sum of Lines 15 through 18)	<u>1,403</u>
20	Adjustment to the rent expense per Public Staff (L19 - L14)	<u>\$0</u>

^{1/} Per NC2150(S3)-1, Lines 1, 4, 6, 8-11.

^{2/} Per Settlement.

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DUKE ENERGY CAROLINAS, LLC
Docket No. E-7, Sub 1276
North Carolina Retail Operations
ADJUSTMENT TO CREDIT CARD FEES
For the Test Year Ended December 31, 2021
(in Thousands)

Public Staff
Supplemental and Settlement Accounting Exhibit 1
Schedule 3-1(I)

Line No.	Item	Amount
1	Non-residential credit card transaction fees per Company	0 ^{1/}
2	O&M transaction costs included in cost of service adjusted per Company	- ^{1/}
3	Public Staff adjustment to remove non-residential credit card fee $-(L1 + L2)$	-

^{1/} Per settlement.

DUKE ENERGY CAROLINAS, LLC

Docket No. E-7, Sub 1276
North Carolina Retail Operations
ADJUSTMENT TO LOBBYING
For the Test Year Ended December 31, 2021
(in Thousands)

Public Staff
Supplemental and Settlement Accounting Exhibit 1
Schedule 3-1(m)

Line No.	Item	Amount
1	Remove Federal Governmental Affair charges related to lobbying	(\$157) ^{1/}
2	Remove Government Affairs & External Relation charges related to lobbying	(100) ^{1/}
3	Remove Natural Engagement charges related to lobbying	(13) ^{1/}
4	Remove Edison Electric Institute (EEI) O&M charges related to lobbying	(525) ^{1/}
5	Total lobbying costs to be removed from O&M expense (sum L1 through L4)	(795)
6	NC Retail Allocation Factor	68.2076% ^{2/}
7	Public Staff adjustment to remove lobbying costs before settlement (L5 x L6)	(542)
8	Company adjustment to remove lobbying costs	(542) ^{3/}
9	Public Staff adjustment to remove lobbying costs (L7 - L8)	<u>\$0</u>

1/ Per Company responses to PSDR-63-2.

2/ Per Company.

3/ Per settlement.

DUKE ENERGY CAROLINAS, LLC
Docket No. E-7, Sub 1276
North Carolina Retail Operations
ADJUSTMENT TO SPONSORSHIPS AND DONATIONS
For the Test Year Ended December 31, 2021
(in Thousands)

Public Staff
Supplemental and Settlement Accounting Exhibit 1
Schedule 3-1(n)

Line No.	Item	Amount
1	Remove contributions included by the Company in error	(\$32) ^{1/}
2	Remove corporate donations & membership dues related to unregulated products	(2) ^{2/}
3	Total sponsorships and donations to be removed per Public Staff (L1 + L2)	(34)
4	NC Retail percentage	68.2076% ^{3/}
5	Public Staff adjustment to remove sponsorships and donations - NC retail before settlement (L3 x L4)	(23)
6	Company adjustment to remove sponsorships and donations - NC retail	(23) ^{4/}
7	Public Staff adjustment to remove sponsorships and donations - NC retail (L5 - L6)	<u>\$0</u>

- 1/ From Company response to Public Staff Data Request No. 62-3
2/ From Company response to Public Staff Data Request No. 62-4.
3/ Per Company.
4/ Per settlement.

DUKE ENERGY CAROLINAS, LLC

Docket No. E-7, Sub 1276
North Carolina Retail Operations
ADJUSTMENT TO BOARD OF DIRECTORS EXPENSE
For the Test Year Ended December 31, 2021
(in Thousands)

Public Staff
Supplemental and Settlement Accounting Exhibit 1
Schedule 3-1(o)

Line No.	Item	Amount
1	Total Board of Directors (BOD) cash compensation	\$587 ^{1/}
2	Percentage of exclusion per Public Staff	50% ^{2/}
3	Public Staff adjustment to BOD compensation (-L1 x L2)	(293)
4	BOD expenses	133 ^{3/}
5	Percentage of exclusion per Public Staff	50% ^{2/}
6	Public Staff adjustment to BOD expenses (-L4 x L5)	(66)
7	BOD insurance charged to DEC	4,727 ^{4/}
8	Percentage of exclusion per Public Staff	50% ^{2/}
9	Public Staff adjustment to BOD insurance (-L7 x L8)	(2,364)
10	BOD and executive members expenses allocated to DEC	36 ^{3/}
11	Percentage of exclusion per Public Staff	50% ^{2/}
12	Public Staff adjustment to BOD and executive members expenses (-L10 x L11)	(18)
13	Total Public Staff adjustment to BOD compensation and expenses (L3 + L6 + L9 + L12)	(2,741)
14	NC retail percentage	68.2076% ^{5/}
15	Public Staff adjustment to BOD expenses - NC retail before settlement (L13 x L14)	(1,870)
16	Public Staff adjustment to BOD expenses - NC retail	(1,870) ^{6/}
17	Public Staff adjustment to BOD expenses - NC retail (L15 - L16)	-

1/ Amount from 2021 Proxy Statement, allocated to DEC.

2/ Recommended by Public Staff.

3/ Company Response to PS DR 161-2 and 161-4.

4/ Company Response to PS DR 161-1.

5/ NC retail allocation factor.

6/ Per settlement.

DUKE ENERGY CAROLINAS, LLC
Docket No. E-7, Sub 1276
North Carolina Retail Operations
ADJUSTMENT TO SALARIES AND WAGES
For the Test Year Ended December 31, 2021
(in Thousands)

Public Staff
Supplemental and Settlement Accounting Exhibit 1
Schedule 3-1(p)

Line No.	Item	Duke Energy Carolinas (a)	Duke Energy Progress (b)	Service Company (c)	Total (d)
1	Labor per payroll company at April 30, 2023	\$874,874 ^{1/}	\$452,692 ^{1/}	\$812,635 ^{1/}	
2	April 2023 allocation percentages	81.48% ^{1/}	7.47% ^{1/}	24.48% ^{1/}	
3	Annual salaries as of April 30, 2023 per Public Staff (L1 x L2)	712,823	33,837	198,893	
4	Per books salaries	664,741 ^{2/}	32,987 ^{2/}	193,129 ^{2/}	
5	Adjustment to salaries and wages for employees per Public Staff (L3 - L4)	48,082	850	5,764	\$54,696 ^{3/}
6	Company adjustment to salaries and wages for employees	48,082 ^{2/}	850 ^{2/}	5,764 ^{2/}	54,696 ^{3/}
7	Adjustment to salaries and wages (L5 - L6)	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>	<u>0</u>
8	Public Staff adjustment to total salaries and wages (L7)				0
9	Percent charged to electric expense				58.29% ^{4/}
10	Adjustment to net electric O&M salaries and wages (L7 x L8)				<u>0</u>
11	Adjustment to net electric O&M salaries and wages (L10)				0
12	Fringe benefits contribution rate				10.01% ^{5/}
13	Adjustment to fringe benefits (L11 x L12)				<u>0</u>
14	Total adjustment to O&M expense - total system (L10 + L13)				0
15	NC retail percentage				68.2076% ^{7/}
16	Total adjustment to O&M expense - NC retail (L14 x L15)				<u>\$0</u>
17	Impact on payroll taxes before Medicare				\$0 ^{6/}
18	Impact on Medicare payroll taxes				0 ^{6/}
19	Adjustment to payroll taxes - total system (L17 + L18)				<u>0</u>
20	NC retail percentage				68.2076% ^{7/}
21	Adjustment to payroll taxes - NC retail (L19 x L20)				<u>\$0</u>

1/ NC2050(S3)-4, Lines 2, 10, and 6.

2/ NC2050(S3)-1, Lines 3-5.

3/ Sum of Columns (a) to (c).

4/ NC2050-1(B), Line 18.

5/ NC2050-1(B), Line 37.

6/ Per Public Staff.

7/ E-1, Item 45a, NC Retail Allocation Factor - All - Labor - Jur.

DUKE ENERGY CAROLINAS, LLC
Docket No. E-7, Sub 1276
North Carolina Retail Operations
ADJUSTMENT TO NORMALIZE STORM COSTS
For the Test Year Ended December 31, 2021
(in Thousands)

Public Staff
Supplemental and Settlement Accounting Exhibit 1
Schedule 3-1(q)

Line No.	Item	Amount	
		(a)	1/
	<u>Normalized storm expense</u>		
1	NC retail amount of storm costs considered normal for 2022	\$48,652	
2	NC retail percentage	100%	
3	2022 storm costs to be included in calculation of normalized level (L1 x L2)	48,652	
4	2013 through 2022 costs adjusted for inflation, excluding 2022	385,810	
5	Total storm costs for ten years adjusted for inflation (L3 + L4)	434,462	
6	Number of years	10	
7	Normalized level of storm costs - total system (L5 / L6)	43,446	
8	NC retail percentage	74.1732%	
9	Normalized level of storm costs per Public Staff (L7 x L8)	32,225	
10	2021 storm costs to be included in calculation of normalized level	37,035	
11	Public Staff adjustment to normalized level of storm costs (L9 - L10)	(4,810)	
12	Company adjustment to normalized level of storm costs	(4,810)	
13	Adjustment to normalize level of storm costs (L11 - L12)	\$0	

1/ NC7010-1(D), assuming deferrals sought for Hurricane Zeta, Izzy, and Ian are approved by the Commission.

DUKE ENERGY CAROLINAS, LLC
Docket No. E-7, Sub 1276
North Carolina Retail Operations
ADJUSTMENT TO LIGHTING AUDIT DEFERRAL
For the Test Year Ended December 31, 2021
(in Thousands)

Public Staff
Supplemental and Settlement Accounting Exhibit 1
Schedule 3-1(r)

Line No.	Item	Amount
	<u>Income Statement:</u>	
1	Annual amortization of lighting audit per Company	\$0 ^{1/}
2	Annual amortization of lighting audit per Public Staff	0 ^{2/}
4	Adjustment to depreciation and amortization for storm deferral (L2 - L1)	<u>\$0</u>
	<u>Rate Base Impact:</u>	
5	Adjusted lighting audit in rate base per Company	\$0 ^{1/}
6	Adjusted lighting audit in rate base per Public Staff	- ^{2/}
7	Adjustment to working capital for storm deferral (L6 - L5)	<u>\$0</u>
8	Impact to ADIT for storm deferral per Company	\$0 ^{3/}
9	Impact to ADIT for storm deferral per Public Staff	- ^{2/}
10	Adjustment to ADIT for storm deferral (L9 - L8)	<u>\$0</u>
1/	NC5130(S4)-1.	
2/	Per Public Staff.	
3/	Line 5 times composite income tax rate.	

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DUKE ENERGY CAROLINAS, LLC

Public Staff
Supplemental and Settlement Accounting Exhibit 1
Schedule 3-1(s)

Docket No. E-7, Sub 1276

North Carolina Retail Operations

ADJUSTMENT TO RATE CASE EXPENSE AND AMORTIZATION

For the Test Year Ended December 31, 2021

(in Thousands)

Line No.	Item	Amount
<u>Income Statement Impact</u>		
1	Actual rate case expense incurred through June 2023	\$7,618 ^{1/}
2	Additional rate case expense incurred Sub 1214 per Company	6,990 ^{3/}
3	Amortization period in years	3 ^{2/}
4	Annual normalized level of rate case expense per Public Staff ((L1 + L2) / L3))	<u>\$4,869</u>
5	Additional rate case expense incurred Sub 1214 per Company	6,990 ^{3/}
6	NC Retail actual expenses incurred Sub 1276 per Company	5,371 ^{3/}
7	NC projection remaining through rates effective date per Company	<u>8,248 ^{3/}</u>
8	Total NC Retail rate case expenses per Company (L5 + L6 + L7)	20,609
9	Amortization period in years	<u>3 ^{3/}</u>
10	Adjustment to annual normalized rate case expense (L8/L9)	<u>\$6,870</u>
11	Adjustment to annual normalized rate case expense (L4 - L10)	<u><u>(\$2,001)</u></u>
12	Over amortization amounts per Company	\$1,155 ^{3/}
13	Amortization period in years	3 ^{3/}
14	Annual amortization of over amortized amounts per Company(L12/L13)	<u>\$385</u>
15	Annual over amortization per the Public Staff	<u>385 ^{2/}</u>
16	Removal of amortization (L15 - L14)	<u><u>\$0</u></u>
17	Total Adjustment to O&M (L11 + L16)	<u><u>(\$2,001)</u></u>
<u>Rate Base Impact</u>		
18	Projected working capital after first year of amortization per Company	\$0 ^{3/}
19	Public Staff recommended regulatory asset amount for rate case expense	<u>0 ^{2/}</u>
20	Adjustment to rate base for rate case expense (L19 - L18)	<u><u>\$0</u></u>
21	Impact to ADIT for rate case expense per Company	\$0 ^{3/}
22	Impact to ADIT for rate case expense per Public Staff	<u>0 ^{2/}</u>
23	Adjustment to ADIT for rate case expense (L22 - L21)	<u><u>\$0</u></u>

1/ Per PS DR 273-2 Response.

2/ Per settlement.

3/ NC5020(S4)-1.

DUKE ENERGY CAROLINAS, LLC

Docket No. E-7, Sub 1276
North Carolina Retail Operations

Public Staff

Supplemental and Settlement Accounting Exhibit 1
Schedule 3-1(t)

ADJUSTMENT TO COMPANY'S INFLATION ADJUSTMENT

For the Test Year Ended December 31, 2021
(in Thousands)

Line No.	Item	Amount
1	Total non-labor O&M expense to be adjusted per Company	\$414,104 ^{1/}
2		
3	Public Staff adjustment to variable O&M expenses for changes in customer growth	0
4	Public Staff adjustment to aviation expense	(0) ^{2/}
5	Public Staff adjustment to rent expense	0 ^{3/}
6	Public Staff adjustment to sponsorships and donations	0 ^{4/}
7	Public Staff adjustment to advertising	0
8	Public Staff adjustment to uncollectibles	0
9	Public Staff adjustment to lobbying	0 ^{5/}
10	Public Staff adjustment to Board of Directors expenses	0 ^{6/}
11	Total adjusted O&M subject to inflation (Sum of L1 thru L10)	414,104
12	Inflation percentage per Public Staff	12.76% ^{7/}
13	Public Staff inflation adjustment (L11 x L12)	52,823
14	Inflation adjustment per Company	52,823 ^{1/}
15	Public Staff adjustment to inflation adjustment (L13- L14)	\$0

1/ NC2110-1(S4).

2/ Supplemental and Settlement Accounting Exhibit 1, Schedule 3-1(h), Line 9 plus Line 21.

3/ Supplemental and Settlement Accounting Exhibit 1, Schedule 3-1(k), Line 6.

4/ Supplemental and Settlement Accounting Exhibit 1, Schedule 3-1(n), Line 7.

5/ Supplemental and Settlement Accounting Exhibit 1, Schedule 3-1(m).

6/ Supplemental and Settlement Accounting Exhibit 1, Schedule 3-1(o).

7/ Supplemental and Settlement Accounting Exhibit 1, Schedule 3-1(t)(1).

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DUKE ENERGY CAROLINAS, LLC
Docket No. E-7, Sub 1276
North Carolina Retail Operations
CALCULATION OF INFLATION RATE
For the Test Year Ended December 31, 2021
(in Thousands)

Public Staff
Supplemental and Settlement Accounting Exhibit 1
Schedule 3-1(t)(1)

Line No.	Item	CPI (a)	PPI Finished Goods Less Food & Energy (b)	PPI Processed Materials Less Food & Energy (c)	PPI Average (d)	Inflation Rate (e)
1	June 2023	305.1 1/	247.1 1/	257.9 1/		
2	Thirteen month average for test year	270.2 2/	217.9 2/	230.8 2/		
3	Increase from average to April 2023 (L1 - L2)	34.9	29.2	27.1		
4	Percentage increase	12.94% 3/	13.39% 3/	11.76% 3/	12.58% 4/	<u>12.76% 5/</u>
5	Five year average inflation per Public Staff	12.94% 1/	13.39% 1/	11.76% 1/	12.58% 4/	<u>12.76% 5/</u>

1/ Per Settlement.

2/ NC2110(S4)-2, Line 15.

3/ Line 3 divided by Line 2.

4/ Average of percentage increases in Columns (b) and (c).

5/ Average of CPI percentage increase and PPI average percentage increase in Columns (a) and (d).

DUKE ENERGY CAROLINAS, LLC

Docket No. E-7, Sub 1276

North Carolina Retail Operations

ONE YEAR RIDER - SEVERANCE OVER AMORTIZATION

For the Test Year Ended December 31, 2021

(in Thousands)

Public Staff
Supplemental and Settlement Accounting Exhibit 1
Schedule 3-1(u)

Line No.	Item	Amount (a)
1	Total NC retail regulatory liability to be amortized	(\$466) ^{1/}
2	Annuity factor	0.9693 ^{2/}
3	Levelized rider EDIT regulatory liability (L1 / L2)	(481) ^{2/}
4	One minus composite income tax rate	76.6497% ^{3/}
5	Net operating income effect (L3 x L4)	(369)
6	Retention factor	76.0892% ^{4/}
7	Levelized rider EDIT credit (L5 / L6)	(\$485)

1/ Per NC5010(B) workpapers through August 31, 2023.

2/ Supplemental and Settlement Accounting Exhibit 1,

3/ One minus composite income tax rate of 23.3503%.

4/ Supplemental and Settlement Accounting Exhibit 1, Schedule 1-2, Line 14, Column (d).

DUKE ENERGY CAROLINAS, LLC

Public Staff
Supplemental and Settlement Accounting Exhibit 1
Schedule 3-1(u)(1)Docket No. E-7, Sub 1276
North Carolina Retail Operations
CALCULATION OF ANNUITY FACTOR FOR
OVERAMORTIZATION RIDER
For the Test Year Ended December 31, 2021
(in Thousands)

Line No.	Item	Amount
	<u>Annuity Factor</u>	
1	Number of years	1 ^{1/}
2	Payment per period	1
3	After tax rate of return (L9)	6.540%
4	Present value of 1 dollar over number of years with with 1 payment per year	0.9386
5	1 plus (interest rate divided by two)	1.0327
6	Annuity factor (L4 x L5)	<u>0.9693</u>

	Capital Structure (a)	Cost Rates (b)	Overall Rate of Return ^{6/} (c)	Net of Tax Rate (d)
	<u>After Tax Rate of Return</u>			
7	Long-term debt	48.00% ^{2/}	4.560% ^{4/}	2.189%
8	Common equity	52.00% ^{3/}	9.350% ^{5/}	4.862% ^{8/}
9	Total	<u>100.00%</u>	<u>7.051%</u>	<u>6.540%</u>

- 1/ Rider period recommended by Public Staff.
2/ Supplemental and Settlement Accounting Exhibit 1, Schedule 4, Line 1, Column (a).
3/ Supplemental and Settlement Accounting Exhibit 1, Schedule 4, Line 2, Column (a).
4/ Supplemental and Settlement Accounting Exhibit 1, Schedule 4, Line 1, Column (g).
5/ Supplemental and Settlement Accounting Exhibit 1, Schedule 4, Line 2, Column (g).
6/ Column (a) times Column (b).
7/ Column (c) times (1 minus combined income tax rate of 23.3503%).
8/ Amount from Column (c).

DUKE ENERGY CAROLINAS, LLC

Docket No. E-7, Sub 1276
North Carolina Retail Operations
OVER AMORTIZATION - CCR DEFERRAL
For the Test Year Ended December 31, 2021
(in Thousands)

Public Staff
Supplemental and Settlement Accounting Exhibit 1
Schedule 3-1(u)(1)

Line No.	Item	Amount
	Income Statement Impact	
1	Correct the balance by removing Company's over amortization and return	\$ - ^{1/}
2	Total increase to deferred balance (L1)	-
3	Year to amortize	5 ^{2/}
4	Public Staff annual amortization increase (L2/L3)	\$ -
	Rate Base Impact	
5	Public Staff adjustment to CCR deferral - to interim rates	- ^{1/}
6	Less first year amortization decrease (L4)	-
7	Adjustment to rate base (L5 - L6)	-
8	Composite income tax rate	23.3503% ^{3/}
9	Adjustment to accumulated deferred income taxes (-L7 x L8)	\$ -

1/ Per settlement.

2/ Per NC4010(B)-1, Line 6.

3/ Accounting Exhibit 1, Schedule 1-3.

DUKE ENERGY CAROLINAS, LLC
Docket No. E-7, Sub 1276
North Carolina Retail Operations
EXPIRING AMORTIZATION
For the Test Year Ended December 31, 2021
(in Thousands)

Public Staff
Supplemental and Settlement Accounting Exhibit 1
Schedule 3-1(u)(2)

Line No.	Item	Amount
Income Statement Impact		
1	Remove the Sub 1146 rate case expense expiring amortization	\$ - ^{1/}
2	Public Staff annual amortization increase (L2/L3)	\$ -

1/ Per settlement.

DUKE ENERGY CAROLINAS, LLC

Docket No. E-7, Sub 1276
North Carolina Retail Operations
INTEREST SYNCHRONIZATION ADJUSTMENT
For the Test Year Ended December 31, 2021
(in Thousands)

Public Staff
Supplemental and Settlement Accounting Exhibit 1
Schedule 3-1(v)

Line No.	Item	Amount
1	Public Staff original cost rate base	\$19,219,205 ^{1/}
2	Public Staff long term debt ratio	48.000% ^{2/}
3	Public Staff embedded cost of debt	<u>4.560% ^{3/}</u>
4	Public Staff interest expense income tax deduction (L1 x L2 x L3)	420,670
5	Company interest expense income tax deduction	<u>413,730 ^{4/}</u>
6	Adjustment to interest expense (L4 - L5)	6,940
7	Composite tax rate	<u>23.3503% ^{5/}</u>
8	Adjustment to income taxes (-L6 x L7)	<u><u>(\$1,621)</u></u>

1/ Supplemental and Settlement Accounting Exhibit 1, Schedule 2, Line 15, Column (c).

2/ Supplemental and Settlement Accounting Exhibit 1, Schedule 4, Line 1, Column (a).

3/ Supplemental and Settlement Accounting Exhibit 1, Schedule 4, Line 1, Column (c).

4/ Supplemental and Settlement Accounting Exhibit 1, Schedule 3-1(v)(1), Line 4.

5/ Supplemental and Settlement Accounting Exhibit 1, Schedule 1-3, Line 8.

DUKE ENERGY CAROLINAS, LLC
Docket No. E-7, Sub 1276
North Carolina Retail Operations
CALCULATION OF COMPANY'S INTEREST
SYNCHRONIZATION ADJUSTMENT
For the Test Year Ended December 31, 2021
(in Thousands)

Public Staff
Supplemental and Settlement Accounting Exhibit 1
Schedule 3-1(v)(1)

Line No.	Item	Amount
1	NC retail rate base per Company	\$19,304,293 ^{1/}
2	Long term debt ratio per Company	47.000% ^{2/}
3	Long term debt cost rate per Company	<u>4.560% ^{2/}</u>
4	Interest tax deduction per Company (L1 x L2 x L3)	<u><u>\$413,730</u></u>

1/ Supplemental and Settlement Accounting Exhibit 1, Schedule 2, Line 15, Column (a).

2/ Per NC6030(B).

DUKE ENERGY CAROLINAS, LLC
Docket No. E-7, Sub 1276
North Carolina Retail Operations
RETURN ON EQUITY AND ORIGINAL COST RATE BASE BEFORE AND
AFTER PUBLIC STAFF PROPOSED DECREASE
For the Test Year Ended December 31, 2021
(in Thousands)

Public Staff
Supplemental and Settlement Accounting Exhibit 1
Schedule 4

Line No.	Item	Capitalization Ratio (a)	Before Public Staff Proposed Decrease				After Public Staff Proposed Decrease			
			NC Retail Rate Base (b)	Embedded Cost or Return (c)	Weighted Cost or Return (d)	Net Operating Income (e)	NC Retail Rate Base (f)	Embedded Cost or Return (g)	Weighted Cost or Return (h)	Net Operating Income (i)
1	Long-term debt	48.000% ^{1/}	\$9,225,219 ^{2/}	4.560% ^{1/}	2.19% ^{5/}	\$420,670 ^{6/}	\$9,234,282 ^{9/}	4.560% ^{1/}	2.19% ^{11/}	\$421,083 ^{12/}
2	Common equity	52.000% ^{1/}	9,993,987 ^{2/}	8.69% ^{4/}	4.52% ^{5/}	868,442 ^{7/}	10,003,806 ^{9/}	9.35% ^{1/}	4.86% ^{11/}	935,356 ^{12/}
3	Total (L1 + L2)	100.000%	\$19,219,205 ^{3/}		6.71%	\$1,289,112 ^{8/}	\$19,238,088 ^{10/}		7.05%	\$1,356,439

1/ Per Public Staff witness Walters.

2/ Column (b), Line 3 times Column (a)

3/ Supplemental and Settlement Accounting Exhibit 1, Schedule 2, Line 15, Column (c).

4/ Column (e) divided by Column (b).

5/ Column (a) times Column (c).

6/ Column (b) times Column (c).

7/ Line 3, Column (e) minus Line 1, Column (e).

8/ Supplemental and Settlement Accounting Exhibit 1, Schedule 3, Line 16, Column (c).

9/ Column (f), Line 3 times Column (a)

10/ Supplemental and Settlement Accounting Exhibit 1, Schedule 2, Line 15, Column (e).

11/ Column (a) times Column (g).

12/ Column (f) times Column (g).

DUKE ENERGY CAROLINAS, LLC
Docket No. E-7, Sub 1276
North Carolina Retail Operations
RETURN ON EQUITY AND ORIGINAL COST RATE BASE BEFORE
AND AFTER PUBLIC STAFF PROPOSED INCREASE
For the Test Year Ended December 31, 2021
(in Thousands)

Public Staff
Supplemental and Settlement Accounting Exhibit 1
Schedule 4

			Before Public Staff Proposed Increase				After Public Staff Proposed Increase			
Line		Capitalization		Embedded	Weighted	Net		Embedded	Weighted	Net
No.	Item	Ratio	NC Retail	Cost or	Cost or	Operating	NC Retail	Cost or	Cost or	Operating
		(a)	Rate Base	Return	Return	Income	Rate Base	Return	Return	Income
		(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	
	CCR:									
1	Long-term debt	48.000% ^{1/}	\$86,204 ^{2/}	4.56% ^{1/}	2.19% ^{5/}	\$3,931 ^{6/}	\$86,204 ^{9/}	4.56% ^{1/}	2.19% ^{11/}	\$3,931 ^{12/}
2	Common equity	52.000% ^{1/}	93,388 ^{2/}	-39.52% ^{4/}	-20.55% ^{5/}	(\$36,910) ^{7/}	93,388 ^{9/}	7.85% ^{1/}	4.08% ^{11/}	7,331 ^{12/}
3	Total (L1 + L2)	100.000%	\$179,593 ^{3/}		-18.36%	(\$32,979) ^{8/}	\$179,593 ^{10/}		6.2708%	\$11,262

1/ Per Public Staff witness Walters, reduced by 1.5% per Commission Order.

2/ Column (b), Line 3 times Column (a)

3/ Supplemental and Settlement Accounting Exhibit 1, Schedule 2 CCR, Line 3, Column (a).

4/ Column (e) divided by Column (b).

5/ Column (a) times Column (c).

6/ Column (b) times Column (c).

7/ Line 3, Column (e) minus Line 1, Column (e).

8/ Supplemental and Settlement Accounting Exhibit 1, Schedule 3, Line 16, Column (c).

9/ Column (f), Line 3 times Column (a)

10/ Supplemental and Settlement Accounting Exhibit 1, Schedule 2, Line 12, Column (e).

11/ Column (a) times Column (g).

12/ Column (f) times Column (g).

DUKE ENERGY CAROLINAS, LLC

Docket No. E-7, Sub 1276

North Carolina Retail Operations

**CALCULATION OF PUBLIC STAFF'S ADDITIONAL GROSS
REVENUE REQUIREMENT**

**For the Test Year Ended December 31, 2021
(in Thousands)**

Public Staff

Supplemental and Settlement Accounting Exhibit 1
Schedule 5

Line No.	Item	Debt (a)	Equity (b)	Total (c) ^{7/}
	<u>Calculation of additional gross revenue requirement</u>			
1	Required net operating income	\$421,083 ^{1/}	\$935,356 ^{4/}	\$1,356,439
2	Net operating income before proposed increase	<u>\$420,670 ^{2/}</u>	<u>868,442 ^{5/}</u>	<u>1,289,112</u>
3	Additional net operating income requirement (L1 - L2)	413	66,914	67,327
4	Retention factor	<u>0.9926862 ^{3/}</u>	<u>0.7608915 ^{6/}</u>	
5	Additional revenue requirement (L3 / L4)	<u><u>\$416</u></u>	<u><u>\$87,942</u></u>	<u><u>\$88,358</u></u>

1/ Supplemental and Settlement Accounting Exhibit 1, Schedule 4, Line 1, Column (i).

2/ Supplemental and Settlement Accounting Exhibit 1, Schedule 4, Line 1, Column (e).

3/ Supplemental and Settlement Accounting Exhibit 1, Schedule 1-2, Line 10.

4/ Supplemental and Settlement Accounting Exhibit 1, Schedule 4, Line 2, Column (i).

5/ Supplemental and Settlement Accounting Exhibit 1, Schedule 4, Line 2, Column (e).

6/ Supplemental and Settlement Accounting Exhibit 1, Schedule 1-2, Line 14.

7/ Column (a) plus Column (b).

DUKE ENERGY CAROLINAS, LLC

Docket No. E-7, Sub 1276

North Carolina Retail Operations

**CALCULATION OF PUBLIC STAFF'S ADDITIONAL GROSS
REVENUE REQUIREMENT - CCR DEFERRAL**

For the Test Year Ended December 31, 2021

(in Thousands)

Public Staff

Supplemental and Settlement Accounting Exhibit 1

Schedule 5 CCR

Line No.	Item	Debt (a)	Equity (b)	Total (c) ^{7/}
	<u>Calculation of additional gross revenue requirement</u>			
1	Required net operating income	\$3,931 ^{1/}	7,331 ^{4/}	\$11,262
2	Net operating income before proposed increase	<u>\$3,931 ^{2/}</u>	<u>(\$36,910) ^{5/}</u>	<u>(32,979)</u>
3	Additional net operating income requirement (L1 - L2)	\$0	\$44,241	\$44,241
4	Retention factor	<u>0.9926862 ^{3/}</u>	<u>0.7608915 ^{6/}</u>	
5	Additional revenue requirement (L3 ÷ L4)	<u>\$0</u>	<u>\$58,144</u>	<u>\$58,144</u>

1/ Supplemental and Settlement Accounting Exhibit 1, Schedule 4 CCR.

2/ Supplemental and Settlement Accounting Exhibit 1, Schedule 4 CCR.

3/ Supplemental and Settlement Accounting Exhibit 1, Schedule 1-2 CCR.

4/ Supplemental and Settlement Accounting Exhibit 1, Schedule 4 CCR.

5/ Supplemental and Settlement Accounting Exhibit 1, Schedule 4 CCR.

6/ Supplemental and Settlement Accounting Exhibit 1, Schedule 1-2 CCR.

7/ Column (a) plus Column (b).

DUKE ENERGY CAROLINAS, LLC
Docket No. E-7, Sub 1276
North Carolina Retail Operations
CALCULATION OF LEVELIZED FEDERAL UNPROTECTED
EDIT RIDER CREDIT
For the Test Year Ended December 31, 2021
(in Thousands)

Public Staff
Supplemental and Settlement Accounting Exhibit 2
Schedule 1

Line No.	Item	Year 1 Revenue Requirement (a)	Year 2 Revenue Requirement (b)	Year 3 Revenue Requirement (c)	Total Revenue Requirement (d)
1	Total NC retail regulatory liability to be amortized	(\$22,981) ^{1/}	(\$22,981) ^{1/}	(\$22,981) ^{1/}	
2	Annuity factor	2.2272 ^{2/}	2.2272 ^{2/}	2.2272 ^{2/}	
3	Levelized rider EDIT regulatory liability (L1 / L2)	(10,318)	(10,318)	(4,299)	(\$24,935) ^{5/}
4	One minus composite income tax rate	76.6497% ^{3/}	76.6497% ^{3/}	76.6497% ^{3/}	76.6497%
5	Net operating income effect (L3 x L4)	(7,909)	(7,909)	(3,295)	(19,113)
6	Retention factor	0.7608915 ^{4/}	0.7608915 ^{4/}	0.7608915 ^{4/}	0.7608915
7	Levelized rider EDIT credit (L5 / L6)	(\$10,394)	(\$10,394)	(\$4,330)	(\$25,119)

1/ Bowman Exhibit 3(S4).

2/ Supplemental and Settlement Accounting Exhibit 2, Schedule 1-1, Line 6.

3/ One minus composite income tax rate of 23.3503%.

4/ Supplemental and Settlement Accounting Exhibit 1, Schedule 1-2, Line 14, Column (d).

5/ Sum of Columns(a) through (e).

Public Staff
Supplemental and Settlement Accounting Exhibit 2
Schedule 1-1

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	Capital Structure	Cost Rates	Overall Rate of Return	Net of Tax Rate
	(a)	(b)	(c)	(d)
<u>After Tax Rate of Return</u>				
7 Long-term debt	48.00% ^{2/}	4.560% ^{4/}	2.189%	1.678% ^{7/}
8 Common equity	52.00% ^{3/}	9.350% ^{5/}	4.862%	4.862% ^{8/}
9 Total	100.00%		7.051%	6.540%

- 1/ Rider period recommended by Public Staff.
- 2/ Supplemental and Settlement Accounting Exhibit 1, Schedule 4, Line 1, Column (a).
- 3/ Supplemental and Settlement Accounting Exhibit 1, Schedule 4, Line 2, Column (a).
- 4/ Supplemental and Settlement Accounting Exhibit 1, Schedule 4, Line 1, Column (g).
- 5/ Supplemental and Settlement Accounting Exhibit 1, Schedule 4, Line 2, Column (g).
- 6/ Column (a) times Column (b).
- 7/ Column (c) times (1 minus combined income tax rate of 23.3503%).
- 8/ Amount from Column (c).

DUKE ENERGY CAROLINAS, LLC
Docket No. E-7, Sub 1276
North Carolina Retail Operations
MYRP REVENUE REQUIREMENT CALCULATION
For the Rate Year 1 Ended December 31, 2024
(in Thousands)

Public Staff
Supplemental and Settlement Accounting Exhibit 3
Schedule RY1

		NC Retail,	Public Staff	
Line No.	Item	1st Supplemental	PS	Amount
		Per Company ^{1/}	Adjustment ^{2/}	after Adjustment
		(a)	(b)	(c)
OPERATING INCOME				
1	Depreciation Expense	\$ 42,099	\$ (8,216)	\$ 33,883 ^{3/}
2	Incremental O&M Expense	16,780	(13,591)	3,189 ^{3/}
3	Property Taxes	629	(107)	522 ^{3/}
4	Income taxes impact on deductible expenses	(13,895)	5,117	(8,778) ^{4/}
5	Amortization of Investment Tax Credit (ITC)	(52)	4	(48) ^{7/}
6	Amortization of Production Tax Credit (PTC)	-	-	- ^{7/}
7	Nuclear PTC @ NC Retail			- ^{7/}
8	Operating Income (Sum of L1 to L7)	45,560	(16,793)	28,767
9	Retention Factor	76.09%	76.09%	76.09% ^{8/}
10	Operating Income Revenue Requirement (L8/L9)	\$ 59,873	\$ (22,070)	\$ 37,808
RETURN ON RATE BASE				
11	Electric Plant In-Service	\$ 1,150,670	\$ (211,055)	\$ 939,615 ^{5/}
12	Accumulated Depreciation	(20,825)	4,072	(16,753) ^{6/}
13	ITC Net Rate Base Impact	4	0	4 ^{7/}
14	PTC Rate Base Impact	-	-	- ^{7/}
15	Total Rate Base (Sum of L11 to L14)	<u>\$ 1,129,850</u>	<u>\$ (206,983)</u>	<u>\$ 922,866</u>
16	Return on Rate Base	9.37%	-	8.59% ^{9/}
17	Rate Base Revenue Requirement (L15 x L16)	\$ 105,912	\$ (26,594)	\$ 79,319
18	Cumulative MYRP Revenue Requirement (L10+L17)	<u>\$ 165,785</u>	<u>\$ (48,664)</u>	<u>\$ 117,126</u>
19	Incremental MYRP Rate Year Revenue Requirement	<u>\$ 165,785</u>	<u>\$ (48,664)</u>	<u>\$ 117,126</u>
20	NC Retail Operations Base Case Revenue Requirement	<u>\$ 5,615,798 ^{11/}</u>	<u>\$ (41,383)</u>	<u>5,574,415 ^{10/}</u>
21	4% Annual Increase Test for Rate Years 2 & 3			
22	Total Base Rate Revenue Requirement (L18+L20)	<u>\$ 5,781,583</u>	<u>\$ (90,047)</u>	<u>\$ 5,691,541</u>

1/ Per Company Abernathy Supplemental Exhibit 4.

2/ Column (c) minus column (a).

3/ Per Supplemental and Settlement Accounting Exhibit 3, Schedule RY1 - Depr & Prop Tax, Lines 1 to 3, Column (c).

4/ Column (c), (L1 + L2 + L3) x 0.233503 x (-1).

5/ Per Supplemental and Settlement Accounting Exhibit 3, Schedule RY1 - Plants, Line 7, Column (c).

6/ Per Supplemental and Settlement Accounting Exhibit 3, Schedule RY1 - AD, Line 6, Column (c).

7/ Per Supplemental and Settlement Accounting Exhibit 3, Schedule RY1 - ITC & PTC, Lines 5 and 6, Column (c).

8/ Per Supplemental and Settlement Accounting Exhibit 1, Schedule 1-2, Line 14, Column (d).

9/ Per Supplemental and Settlement Accounting Exhibit 1, Schedule 1-2, Line 4, Column (d).

10/ Per Supplemental and Settlement Accounting Exhibit 1, Schedules 3 & 3 CCR, Line 4, Column (e).

11/ Company Revenue included in Column (a), Line 20 includes rider revenue.

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DUKE ENERGY CAROLINAS, LLC
Docket No. E-7, Sub 1276
North Carolina Retail Operations
SUMMARY OF OPERATING INCOME IMPACTS FOR
MYRP ADJUSTMENTS
For the Rate Year 1 Ended December 31, 2024
(in Thousands)

Public Staff
Supplemental and Settlement Accounting Exhibit 3
Schedule RY1-NOI

Line No.	Item	Operating Income Impacts from MYRP Projects ^{1/}	Revenue and Expenses from Proposed Increase ^{3/}	After Proposed Increase ^{6/}
		(a)	(b)	(c)
1	Electric operating revenue		\$ 117,126	\$ 117,126
	Electric operating expenses:			
	Operation and maintenance:			
2	Fuel used in electric generation			-
3	Purchased power			-
4	Other operation and maintenance expense	3,189	\$857 ^{4/}	4,046
5	Depreciation and amortization	33,883		33,883
6	General taxes	522		522
7	Interest on customer deposits			-
8	EDIT Amortization (net of tax)			-
9	Net income taxes	(13,495) ^{2/}	27,149 ^{5/}	13,654
10	Amortization of investment tax credit	(48)		(48)
11	Amortization of production tax credit	-		-
12	Total electric operating expenses (Sum of L2 to L11)	24,051	28,006	52,057
13	Operating income (L1-L12)	<u>\$ (24,051)</u>	<u>\$ 89,120</u>	<u>\$ 65,069</u>
14	Rate Base	<u>\$ 922,866</u>		<u>\$ 922,866</u>
15	Rate of return on North Carolina retail rate base (L13/L14)	-2.61%		7.05%

1/ Per Supplemental and Settlement Accounting Exhibit 3, Schedule RY1, Lines 1 to 3, and 5 to 6.

2/ $-1 \times [(\text{Sum of Col. (a), Lns 4 to 6}) + \text{Col. (a), Ln 14} \times 48\% \text{ Debt Ratio} \times 4.56\% \text{ Cost of Debt}] \times 23.3503\% \text{ Composite Tax Rate}$.

3/ Per Supplemental and Settlement Accounting Exhibit 3, Schedule RY1, Line 18.

4/ Column (b), Line 1 grossed up for 0.1475% regulatory fee and 0.58474% uncollectibles.

5/ Column (b), Line 1 minus Line 4, then times 23.3503% Composite Tax Rate.

6/ Column (a) + Column (b).

DUKE ENERGY CAROLINAS, LLC
Docket No. E-7, Sub 1276
North Carolina Retail Operations
ADJUSTMENT TO MYRP INCREMENTAL CAPITAL
PROJECTS
For the Rate Year 1 Ended December 31, 2024
(in Thousands)

Public Staff
Supplemental and Settlement Accounting Exhibit 3
Schedule RY1 - Plants

Line No.	Item	NC Retail		
		Total per Application ^{1/}	Total Public Staff Adjustments ^{2/}	Total Public Staff Recommended ^{3/}
		(a)	(b)	(c)
1	Total production plant	\$ 346,116	\$ (104,061)	\$242,055
2	Transmission Plant	149,931	(42,824)	107,107
3	Distribution Plant	465,621	(22,383)	443,238
4	General Plant	138,600	(41,775)	96,825
5	Intangible Plant	50,403	(13)	50,390
6	Nuclear Fuel (Net)	-	-	-
7	Total plant in service (Sum of L1 to L6)	<u>\$ 1,150,670</u>	<u>\$ (211,055)</u>	<u>\$ 939,615</u>

1/ Per Company Abernathy Supplemental Exhibit 4 WP 1 RB-OM Summary.

2/ Column (c) minus column (a).

3/ Per Settlement.

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Nov 02 2023

DUKE ENERGY CAROLINAS, LLC
Docket No. E-7, Sub 1276
North Carolina Retail Operations
ADJUSTMENT TO ACCUMULATED DEPRECIATION
For the Rate Year 1 Ended December 31, 2024
(in Thousands)

Public Staff
Supplemental and Settlement Accounting Exhibit 3
Schedule RY1 - AD

Line No.	Item	NC Retail		
		Total per Application ^{1/}	Total Public Staff Adjustments ^{2/}	Total Public Staff Recommended ^{3/}
		(a)	(b)	(c)
1	Production Reserve	(5,976)	\$ 2,525	\$ (3,451)
2	Transmission Reserve	(2,125)	117	(2,008)
3	Distribution Reserve	(5,053)	227	(4,826)
4	General Reserve	(4,773)	1,203	(3,570)
5	Intangible Reserve	(2,898)	0	(2,898)
6	Total accumulated depreciation (Sum of L1 to L5)	<u>\$ (20,825)</u>	<u>\$ 4,072</u>	<u>\$ (16,753)</u>

1/ Per Company Abernathy Supplemental Exhibit 4 WP 1 RB-OM Summary.

2/ Column (c) minus column (a).

3/ Per Settlement.

DUKE ENERGY CAROLINAS, LLC
Docket No. E-7, Sub 1276
North Carolina Retail Operations
ADJUSTMENT TO INVESTMENT TAX CREDIT AND
PRODUCTION TAX CREDIT
For the Rate Year 1 Ended December 31, 2024
(in Thousands)

Public Staff
Supplemental and Settlement Accounting Exhibit 3
Schedule RY1 - ITC & PTC

Line No.	Item	NC Retail		
		Total per Application ^{1/}	Total Public Staff Adjustments ^{2/}	Total Public Staff Recommended ^{3/}
		(a)	(b)	(c)
	<u>Operating Income</u>			
1	Amortization of Investment Tax Credit (ITC)	\$ (52)	4	(48)
2	Amortization of Production Tax Credit (PTC)	-	-	-
3	Nuclear PTC @ NC Retail			
4	Total Operating Income Impact (L1 + L2)	<u>\$ (52)</u>	<u>\$ 4</u>	<u>\$ (48)</u>
	<u>Return on Rate Base</u>			
5	ITC Net Rate Base Impact	\$ 4	\$ 0	\$ 4
6	PTC Rate Base Impact	-	-	0
7	Total Rate Base Impact (L5 + L6)	<u>\$ 4</u>	<u>\$ 0</u>	<u>\$ 4</u>

1/ Per Company Abernathy Supplemental Exhibit 4 WP 1 RB-OM Summary.

2/ Column (c) minus column (a).

3/ Per Settlement.

DUKE ENERGY CAROLINAS, LLC
Docket No. E-7, Sub 1276
North Carolina Retail Operations
ADJUSTMENT TO OPERATING EXPENSE,
DEPRECIATION AND PROPERTY TAX
For the Rate Year 1 Ended December 31, 2024
(in Thousands)

Public Staff
Supplemental and Settlement Accounting Exhibit 3
Schedule RY1 - Depr & Prop Tax

Line No.	Item	NC Retail		
		Total per Application ^{1/}	Total Public Staff Adjustments ^{2/}	Total Public Staff Recommended ^{3/}
		(a)	(b)	(c)
	<u>Operating Income</u>			
1	Depreciation Expense	\$ 42,099	\$ (8,216)	33,883
2	Other O&M	16,780	(13,591)	3,189
3	Property Tax	629	(107)	522
4	Total Operating Income Impact (L1 + L2 + L3)	<u>\$ 59,508</u>	<u>\$ (21,914)</u>	<u>\$ 37,594</u>

1/ Per Company Abernathy Supplemental Exhibit 4 WP 1 RB-OM Summary.

2/ Column (c) minus column (a).

3/ Per Settlement.

DUKE ENERGY CAROLINAS, LLC
Docket No. E-7, Sub 1276
North Carolina Retail Operations
MYRP REVENUE REQUIREMENT CALCULATION
For the Rate Year 2 Ended December 31, 2025
(in Thousands)

Public Staff
Supplemental and Settlement Accounting Exhibit 3
Schedule RY2

Line No.	Item	Public Staff Recommended		
		NC Retail, 1st Supplemental Per Company ^{1/}	PS Adjustment ^{2/}	Amount after Adjustment
		(a)	(b)	(c)
<u>OPERATING INCOME</u>				
1	Depreciation Expense	\$ 87,697	\$ (11,528)	\$ 76,169 ^{3/}
2	Incremental O&M Expense	8,638	(7,164)	1,474 ^{3/}
3	Property Taxes	4,093	(536)	3,557 ^{3/}
4	Income taxes impact on deductible expenses	(23,450)	4,490	(18,960) ^{4/}
5	Amortization of Investment Tax Credit (ITC)	(927)	62	(865) ^{7/}
6	Amortization of Production Tax Credit (PTC)	-	-	- ^{7/}
7	Nuclear PTC @ NC Retail	-	-	-
8	Operating Income (Sum of L1 to L7)	76,051	(14,677)	61,375
9	Retention Factor	76.09%	76.09%	76.09% ^{8/}
10	Operating Income Revenue Requirement (L8/L9)	\$ 99,943	\$ (19,289)	\$ 80,661
<u>RETURN ON RATE BASE</u>				
11	Electric Plant In-Service	\$ 2,718,457	\$ (307,368)	\$ 2,411,089 ^{5/}
12	Accumulated Depreciation	(85,303)	13,800	(71,503) ^{6/}
13	ITC Net Rate Base Impact	397	(27)	370 ^{7/}
14	PTC Rate Base Impact	-	-	- ^{7/}
15	Total Rate Base (Sum of L11 to L14)	\$ 2,633,552	\$ (293,596)	\$ 2,339,956
16	Return on Rate Base	9.37%	-	8.59% ^{9/}
17	Rate Base Revenue Requirement (L15 x L16)	\$ 246,869	\$ (45,755)	\$ 201,115
18	<u>Cumulative MYRP Revenue Requirement (L10+L17)</u>	<u>\$ 346,812</u>	<u>\$ (65,044)</u>	<u>\$ 281,776</u>
19	Incremental MYRP Rate Year Revenue Requirement	\$ 181,027	\$ (49,000) ^{8/}	\$ 164,650
20	<u>NC Retail Operations Base Case Revenue Requirement</u>	<u>\$ 5,615,798</u> ^{11/}	<u>\$ (41,383)</u>	<u>5,574,415</u> ^{10/}
21	Annual Increase % Test for Rate Years 2 & 3 (L19/L20)	3.2%		3.0%
22	4% statutory cap at PS Base Case Revenue for Rate Years 2 & 3 (L20 x 4%)			222,977
23	PS adjustment to 4% statutory cap			\$ -
24	Incremental MYRP Rate Year Revenue Requirement allowed by statute (L19+L23)			\$ 164,650
25	<u>Total Base Rate Revenue Requirement (L18+L20+L23)</u>	<u>\$5,962,610</u>	<u>(\$106,427)</u>	<u>\$5,856,191</u>

1/ Per Company Abernathy Supplemental Exhibit 4.

2/ Column (c) minus column (a).

3/ Per Supplemental and Settlement Accounting Exhibit 3, Schedule RY2 - Depr & Prop Tax, Lines 1 to 3, Column (c).

4/ Column (c), (L1 + L2 + L3) x 0.233503 x (-1).

5/ Per Supplemental and Settlement Accounting Exhibit 3, Schedule RY2 - Plants, Line 7, Column (c).

6/ Per Supplemental and Settlement Accounting Exhibit 3, Schedule RY2 - AD, Line 6, Column (c).

7/ Per Supplemental and Settlement Accounting Exhibit 3, Schedule RY2 - ITC & PTC, Lines 1, 2, and 3, Column (c).

8/ Per Supplemental and Settlement Accounting Exhibit 1, Schedule 1-2, Line 14, Column (d).

9/ Per Supplemental and Settlement Accounting Exhibit 1, Schedule 1-2, Line 4, Column (d).

10/ Per Supplemental and Settlement Accounting Exhibit 1, Schedules 3 & 3 CCR, Line 4, Column (e).

11/ Company Revenue included in Column (a), Line 20 includes rider revenue.

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DUKE ENERGY CAROLINAS, LLC
Docket No. E-7, Sub 1276
North Carolina Retail Operations
SUMMARY OF OPERATING INCOME IMPACTS FOR
MYRP ADJUSTMENTS
For the Rate Year 2 Ended December 31, 2025
(in Thousands)

Public Staff
Supplemental and Settlement Accounting Exhibit 3
Schedule RY2-NOI

Line No.	Item	Operating Income Impacts from MYRP Projects ^{1/}	Revenue and Expenses from Proposed Increase	After Proposed Increase ^{6/}
		(a)	(b)	(c)
1	Electric operating revenue		\$ 281,776 ^{3/}	\$ 281,776
	Electric operating expenses:			
	Operation and maintenance:			
2	Fuel used in electric generation			-
3	Purchased power			-
4	Other operation and maintenance expense	1,474	\$2,061 ^{4/}	3,535
5	Depreciation and amortization	\$76,169		76,169
6	General taxes	3,557		3,557
7	Interest on customer deposits			-
8	EDIT Amortization (net of tax)			-
9	Net income taxes	(30,920) ^{2/}	65,314 ^{5/}	34,394
10	Amortization of investment tax credit	(865)		(865)
11	Amortization of production tax credit	-		-
12	Total electric operating expenses (Sum of L2 to L11)	49,415	67,375	116,790
13	Operating income (L1-L12)	<u>\$ (49,415)</u>	<u>\$ 214,401</u>	<u>\$ 164,986</u>
14	Rate Base	<u>\$ 2,339,956</u>		<u>\$ 2,339,956</u>
15	Rate of return on North Carolina retail rate base (L13/L14)	-2.11%		7.05%

1/ Per Supplemental and Settlement Accounting Exhibit 3, Schedule RY2, Lines 1 to 3, and 5 to 6.

2/ $-1 \times [(\text{Sum of Col. (a), Lns 4 to 6}) + \text{Col. (a), Ln 14} \times 48\% \text{ Debt Ratio} \times 4.56\% \text{ Cost of Debt}] \times 23.3503\% \text{ Composite Tax Rate}$.

3/ Per Supplemental and Settlement Accounting Exhibit 3, Schedule RY2, Line 18.

4/ Column (b), Line 1 grossed up for 0.1475% regulatory fee and 0.58474% uncollectibles.

5/ Column (b), Line 1 minus Line 4, then times 23.3503% Composite Tax Rate.

6/ Column (a) + Column (b).

DUKE ENERGY CAROLINAS, LLC
Docket No. E-7, Sub 1276
North Carolina Retail Operations
ADJUSTMENT TO MYRP INCREMENTAL CAPITAL
PROJECTS
For the Rate Year 2 Ended December 31, 2025
(in Thousands)

Public Staff
Supplemental and Settlement Accounting Exhibit 3
Schedule RY2 - Plants

Line No.	Item	NC Retail		
		Total per Application ^{1/}	Total Public Staff Adjustments ^{2/}	Total Public Staff Recommended ^{3/}
		(a)	(b)	(c)
1	Total production plant	\$ 579,011	\$ (76,692)	\$502,319
2	Transmission Plant	361,486	(64,433)	297,053
3	Distribution Plant	1,467,522	(80,905)	1,386,617
4	General Plant	249,038	(84,959)	164,079
5	Intangible Plant	61,400	(379)	61,021
6	Nuclear Fuel (Net)	-	-	-
7	Total plant in service (Sum of L1 to L6)	<u>\$ 2,718,457</u>	<u>\$ (307,368)</u>	<u>\$ 2,411,089</u>

1/ Per Company Abernathy Supplemental Exhibit 4 WP 1 RB-OM Summary.

2/ Column (c) minus column (a).

3/ Per Settlement.

DUKE ENERGY CAROLINAS, LLC
Docket No. E-7, Sub 1276
North Carolina Retail Operations
ADJUSTMENT TO ACCUMULATED DEPRECIATION
For the Rate Year 2 Ended December 31, 2025
(in Thousands)

Public Staff
Supplemental and Settlement Accounting Exhibit 3
Schedule RY2 - AD

Line No.	Item	NC Retail		
		Total per Application ^{1/}	Total Public Staff Adjustments ^{2/}	Total Public Staff Recommended ^{3/}
		(a)	(b)	(c)
1	Production Reserve	\$ (22,297)	\$ 6,015	\$ (16,282)
2	Transmission Reserve	(8,203)	665	(7,538)
3	Distribution Reserve	(27,445)	1,414	(26,031)
4	General Reserve	(18,096)	5,682	(12,414)
5	Intangible Reserve	(9,262)	24	(9,238)
6	Total accumulated depreciation (Sum of L1 to L5)	<u>\$ (85,303)</u>	<u>\$ 13,800</u>	<u>\$ (71,503)</u>

1/ Per Company Abernathy Supplemental Exhibit 4 WP 1 RB-OM Summary.

2/ Column (c) minus column (a).

3/ Per Settlement.

DUKE ENERGY CAROLINAS, LLC
Docket No. E-7, Sub 1276
North Carolina Retail Operations
ADJUSTMENT TO INVESTMENT TAX CREDIT AND
PRODUCTION TAX CREDIT
For the Rate Year 2 Ended December 31, 2025
(in Thousands)

Public Staff
Supplemental and Settlement Accounting Exhibit 3
Schedule RY2 - ITC & PTC

Line No.	Item	NC Retail		
		Total per Application ^{1/}	Total Public Staff Adjustments ^{2/}	Total Public Staff Recommended ^{3/}
		(a)	(b)	(c)
	<u>Operating Income</u>			
1	Amortization of Investment Tax Credit (ITC)	\$ (927)	\$ 62	\$ (865)
2	Amortization of Production Tax Credit (PTC)	-	-	-
3	Nuclear PTC @ NC Retail	-	-	-
4	Total Operating Income Impact (L1 + L2)	<u>\$ (927)</u>	<u>\$ 62</u>	<u>\$ (865)</u>
	<u>Return on Rate Base</u>			
5	ITC Net Rate Base Impact	\$ 397	\$ (27)	\$ 370
6	PTC Rate Base Impact	-	-	-
7	Total Rate Base Impact (L5 + L6)	<u>\$ 397</u>	<u>\$ (27)</u>	<u>\$ 370</u>

1/ Per Company Abernathy Supplemental Exhibit 4 WP 1 RB-OM Summary.

2/ Column (c) minus column (a).

3/ Per Settlement.

DUKE ENERGY CAROLINAS, LLC
Docket No. E-7, Sub 1276
North Carolina Retail Operations
ADJUSTMENT TO OPERATING EXPENSE,
DEPRECIATION AND PROPERTY TAX
For the Rate Year 2 Ended December 31, 2025
(in Thousands)

Public Staff
Supplemental and Settlement Accounting Exhibit 3
Schedule RY2 - Depr & Prop Tax

Line No.	Item	NC Retail		
		Total per Application ^{1/}	Total Public Staff Adjustments ^{2/}	Total Public Staff Recommended ^{3/}
		(a)	(b)	(c)
	<u>Operating Income</u>			
1	Depreciation Expense	\$ 87,697	\$ (11,528)	\$76,169
2	Other O&M	8,638	(7,164)	1,474
3	Property Tax	4,093	(536)	3,557
4	Total Operating Income Impact (L1 + L2 + L3)	<u>\$ 100,428</u>	<u>\$ (19,228)</u>	<u>\$ 81,200</u>

1/ Per Company Abernathy Supplemental Exhibit 4 WP 1 RB-OM Summary.

2/ Column (c) minus column (a).

3/ Per Settlement.

DUKE ENERGY CAROLINAS, LLC
Docket No. E-7, Sub 1276
North Carolina Retail Operations
MYRP REVENUE REQUIREMENT CALCULATION
For the Rate Year 3 Ended December 31, 2026
(in Thousands)

Public Staff
Supplemental and Settlement Accounting Exhibit 3
Schedule RY3

Line No.	Item	NC Retail,	Public Staff	
		1st Supplemental Per Company ^{1/}	PS Adjustment ^{2/}	Amount after Adjustment
		(a)	(d)	(c)
	<u>OPERATING INCOME</u>			
1	Depreciation Expense	\$ 142,367	\$ (20,606)	\$ 121,761 ^{3/}
2	Incremental O&M Expense	7,133	(3,568)	3,565 ^{3/}
3	Property Taxes	7,566	(857)	6,709 ^{3/}
4	Income taxes impact on deductible expenses	(36,675)	5,845	(30,831) ^{4/}
5	Amortization of Investment Tax Credit (ITC)	(3,547)	306	(3,241) ^{7/}
6	Amortization of Production Tax Credit (PTC)	(4,734)	2,715	(2,019) ^{7/}
7	<u>Nuclear PTC @ NC Retail</u>			-
7	Operating Income (Sum of L1 to L6)	112,109	(16,165)	95,944
8	<u>Retention Factor</u>	76.09%	76.09%	76.09% ^{8/}
9	Operating Income Revenue Requirement (L7/L8)	\$ 147,328	\$ (21,244)	\$ 126,095
	<u>RETURN ON RATE BASE</u>			
11	Electric Plant In-Service	\$ 4,298,064	\$ (559,689)	\$ 3,738,375 ^{5/}
12	Accumulated Depreciation	(199,885)	29,302	(170,583) ^{6/}
13	ITC Net Rate Base Impact	\$2,733	(199)	\$2,534 ^{7/}
14	<u>PTC Rate Base Impact</u>	\$1,457	(836)	\$621 ^{7/}
15	Total Rate Base (Sum of L11 to L14)	<u>\$ 4,102,369</u>	<u>\$ (531,422)</u>	<u>\$ 3,570,947</u>
16	Return on Rate Base	9.37%	-	8.59% ^{9/}
17	<u>Rate Base Revenue Requirement (L15 x L16)</u>	\$ 384,557	\$ (77,641)	\$ 306,916
18	<u>Cumulative MYRP Revenue Requirement (L9+L17)</u>	<u>\$ 531,884</u>	<u>\$ (98,885)</u>	<u>\$ 433,011</u>
19	Incremental MYRP Rate Year Revenue Requirement	\$ 185,072	\$ (33,841)	\$ 151,235
20	<u>NC Retail Operations Base Case Revenue Requirement</u>	<u>\$ 5,615,798 ^{11/}</u>	<u>(\$41,383)</u>	<u>5,574,415 ^{10/}</u>
21	Annual Increase % Test for Rate Years 2 & 3 (L19/L20)	3.3%		2.7%
22	4% statutory cap at PS Base Case Revenue for Rate Years 2 & 3 (L20 x 4%)			222,977
23	PS adjustment to 4% statutory cap			\$ -
24	Incremental MYRP Rate Year Revenue Requirement allowed by statute (L19+L23)			\$ 151,235
25	<u>Total Base Rate Revenue Requirement (L18+L20+L23)</u>	<u>\$6,147,682</u>	<u>(\$140,257)</u>	<u>\$6,007,425</u>

1/ Per Company Abernathy Supplemental Exhibit 4.

2/ Column (c) minus column (a).

3/ Per Supplemental and Settlement Accounting Exhibit 3, Schedule RY3 - Depr & Prop Tax, Lines 1 to 3, Column (c).

4/ Column (c), (L1 + L2 + L3) x 0.233503 x (-1).

5/ Per Supplemental and Settlement Accounting Exhibit 3, Schedule RY3 - Plants, Line 7, Column (c).

6/ Per Supplemental and Settlement Accounting Exhibit 3, Schedule RY3 - AD, Line 6, Column (c).

7/ Per Supplemental and Settlement Accounting Exhibit 3, Schedule RY3 - ITC & PTC, Lines 1 and 2, Column (c).

8/ Per Supplemental and Settlement Accounting Exhibit 1, Schedule 1-2, Line 14, Column (d).

9/ Per Supplemental and Settlement Accounting Exhibit 1, Schedule 1-2, Line 4, Column (d).

10/ Per Supplemental and Settlement Accounting Exhibit 1, Schedules 3 & 3 CCR, Line 4, Column (e).

11/ Company Revenue included in Column (a), Line 20 includes rider revenue.

DUKE ENERGY CAROLINAS, LLC
Docket No. E-7, Sub 1276
North Carolina Retail Operations
SUMMARY OF OPERATING INCOME IMPACTS FOR
MYRP ADJUSTMENTS
For the Rate Year 3 Ended December 31, 2026
(in Thousands)

Public Staff
Supplemental and Settlement Accounting Exhibit 3
Schedule RY3-NOI

Line No.	Item	Operating Income Impacts from MYRP Projects ^{1/}	Revenue and Expenses from Proposed Increase	After Proposed Increase ^{6/}
		(a)	(b)	(c)
1	Electric operating revenue		\$ 433,011 ^{3/}	\$ 433,011
	Electric operating expenses:			
	Operation and maintenance:			
2	Fuel used in electric generation			-
3	Purchased power			-
4	Other operation and maintenance expense	3,565	\$3,167 ^{4/}	6,732
5	Depreciation and amortization	121,761		121,761
6	General taxes	6,709		6,709
7	Interest on customer deposits			-
8	EDIT Amortization (net of tax)			-
9	Net income taxes	(49,081) ^{2/}	100,370 ^{5/}	51,289
10	Amortization of investment tax credit	(3,241)		(3,241)
11	Amortization of production tax credit	(2,019)		(2,019)
12	Total electric operating expenses (Sum of L2 to L11)	77,694	103,537	181,231
13	Operating income (L1-L12)	<u>\$ (77,694)</u>	<u>\$ 329,474</u>	<u>\$ 251,780</u>
14	Rate Base	<u>\$ 3,570,947</u>		<u>\$ 3,570,947</u>
15	Rate of return on North Carolina retail rate base (L13/L14)	-2.18%		7.05%

1/ Per Supplemental and Settlement Accounting Exhibit 3, Schedule RY3, Lines 1 to 3, and 5 to 6.

2/ $-1 \times [(\text{Sum of Col. (a), Lns 4 to 6}) + \text{Col. (a), Ln 14} \times 48\% \text{ Debt Ratio} \times 4.56\% \text{ Cost of Debt}] \times 23.3503\% \text{ Composite Tax Rate}$.

3/ Per Supplemental and Settlement Accounting Exhibit 3, Schedule RY3, Line 18.

4/ Column (b), Line 1 grossed up for 0.1475% regulatory fee and 0.58474% uncollectibles.

5/ Column (b), Line 1 minus Line 4, then times 23.3503% Composite Tax Rate.

6/ Column (a) + Column (b).

DUKE ENERGY CAROLINAS, LLC
Docket No. E-7, Sub 1276
North Carolina Retail Operations
ADJUSTMENT TO MYRP INCREMENTAL CAPITAL
PROJECTS
For the Rate Year 3 Ended December 31, 2026
(in Thousands)

Public Staff
Supplemental and Settlement Accounting Exhibit 3
Schedule RY3 - Plants

Line No.	Item	NC Retail		
		Total per Application ^{1/}	Total Public Staff Adjustments ^{2/}	Total Public Staff Recommended ^{3/}
		(a)	(b)	(c)
1	Total production plant	\$ 1,024,319	\$ (237,298)	\$787,021
2	Transmission Plant	555,693	(81,736)	473,957
3	Distribution Plant	2,275,977	(135,259)	2,140,718
4	General Plant	348,694	(102,426)	246,268
5	Intangible Plant	93,382	(2,971)	90,411
6	Nuclear Fuel (Net)	-	-	-
7	Total plant in service (Sum of L1 to L6)	<u>\$ 4,298,064</u>	<u>\$ (559,689)</u>	<u>\$ 3,738,375</u>

1/ Per Company Abernathy Supplemental Exhibit 4 WP 1 RB-OM Summary.

2/ Column (c) minus column (a).

3/ Per Settlement.

DUKE ENERGY CAROLINAS, LLC
Docket No. E-7, Sub 1276
North Carolina Retail Operations
ADJUSTMENT TO ACCUMULATED DEPRECIATION
For the Rate Year 3 Ended December 31, 2026
(in Thousands)

Public Staff
Supplemental and Settlement Accounting Exhibit 3
Schedule RY3 - AD

Line No.	Item	NC Retail		
		Total per Application ^{1/} (a)	Total Public Staff Adjustments ^{2/} (b)	Total Public Staff Recommended ^{3/} (c)
1	Production Reserve	\$ (52,232)	\$ 11,252	\$ (40,980)
2	Transmission Reserve	(19,120)	2,120	(17,000)
3	Distribution Reserve	(71,177)	3,961	(67,216)
4	General Reserve	(37,559)	11,605	(25,954)
5	Intangible Reserve	(19,798)	365	(19,433)
6	Total accumulated depreciation (Sum of L1 to L5)	<u>\$ (199,885)</u>	<u>\$ 29,302</u>	<u>\$ (170,583)</u>

1/ Per Company Abernathy Supplemental Exhibit 4 WP 1 RB-OM Summary.

2/ Column (c) minus column (a).

3/ Per Settlement.

DUKE ENERGY CAROLINAS, LLC
Docket No. E-7, Sub 1276
North Carolina Retail Operations
ADJUSTMENT TO INVESTMENT TAX CREDIT AND
PRODUCTION TAX CREDIT
For the Rate Year 3 Ended December 31, 2026
(in Thousands)

Public Staff
Supplemental and Settlement Accounting Exhibit 3
Schedule RY3 - ITC & PTC

Line No.	Item	NC Retail		
		Total per Application ^{1/}	Total Public Staff Adjustments ^{2/}	Total Public Staff Recommended ^{3/}
		(a)	(b)	(c)
	<u>Operating Income</u>			
1	Amortization of Investment Tax Credit (ITC)	\$ (3,547)	\$ 306	\$ (3,241)
2	Amortization of Production Tax Credit (PTC)	(4,734)	2,715	(2,019)
3	Nuclear PTC @ NC Retail	-	-	
4	Total Operating Income Impact (L1 + L2)	<u>\$ (8,282)</u>	<u>\$ 3,022</u>	<u>\$ (5,260)</u>
	<u>Return on Rate Base</u>			
5	ITC Net Rate Base Impact	\$ 2,733	\$ (199)	\$ 2,534
6	PTC Rate Base Impact	1,457	(836)	621
7	Total Rate Base Impact (L5 + L6)	<u>\$ 4,190</u>	<u>\$ (1,035)</u>	<u>\$ 3,155</u>

1/ Per Company Abernathy Supplemental Exhibit 4 WP 1 RB-OM Summary.

2/ Column (c) minus column (a).

3/ Per Settlement.

DUKE ENERGY CAROLINAS, LLC
Docket No. E-7, Sub 1276
North Carolina Retail Operations
ADJUSTMENT TO OPERATING EXPENSE,
DEPRECIATION AND PROPERTY TAX
For the Rate Year 3 Ended December 31, 2026
(in Thousands)

Public Staff
Supplemental and Settlement Accounting Exhibit 3
Schedule RY3 - Depr & Prop Tax

Line No.	Item	NC Retail		
		Total per Application ^{1/}	Total Public Staff Adjustments ^{2/}	Total Public Staff Recommended ^{3/}
		(a)	(b)	(c)
	<u>Operating Income</u>			
1	Depreciation Expense	\$ 142,367	\$ (20,606)	\$ 121,761
2	Other O&M	7,133	(3,568)	3,565
3	Property Tax	7,566	(857)	6,709
4	Total Operating Income Impact (L1 + L2 + L3)	<u>\$ 157,066</u>	<u>\$ (25,031)</u>	<u>\$ 132,035</u>

1/ Per Company Abernathy Supplemental Exhibit 4 WP 1 RB-OM Summary.

2/ Column (c) minus column (a).

3/ Per Settlement.

DUKE ENERGY CAROLINAS, LLC
Docket No. E-7, Sub 1276

Public Staff Late-Filed Exhibit No. 1

Line No.	Category	Company's exhibit in Rebuttal, Page 23 (Costs thru June 2023)		Public Staff Direct Testimony, Same categories as Company (Costs thru April 2023)		Public Staff Supplemental and Settlement Testimony, Same categories as Company (Costs thru June 2023)	
		\$ in Thousands	% of total	\$ in Thousands	% of total	\$ in Thousands	% of total
1	Customer fees waived	\$45,709	28.6%	\$45,709	26.8%	\$45,709	28.6%
2	Bad debt expense	99,910	62.6%	110,567	64.8%	99,910	62.6%
3	Employee safety related costs	7,328	4.6%	7,327	4.3%	7,328	4.6%
4	Costs for remote work	891	0.6%	891	0.5%	891	0.6%
5	Employee stipends	1,145	0.7%	1,145	0.7%	1,145	0.7%
6	Other (primarily call center costs)	4,617	2.9%	5,047	3.0%	4,617	2.9%
7	Total Incremental COVID-19 Costs deferred (sum L1 through L6)	\$159,600	100.0%	\$170,687	100.0%	\$159,600	100.0%
8	Accrued carrying costs	23,301		23,698		23,301	
9	COVID Deferral projected balance as of rates effective (L7 + L8)	<u>\$182,901</u>		<u>\$194,385</u>		<u>\$182,901</u>	

I/A

Duke Energy Carolinas, LLC

Docket No. E-7, Sub 1276

Comparison of Rates of Return, Indices, and % Base Revenue				
Based on MAE Cost-of Service Methodology				
With Public Staff Adjustments				
Rate Year 0				
	Rate of Return	Rate of Return Index	% Base Revenue Change	% Revenue Change with EDIT-4 Credit
NC Retail	7.10%	1.00	2.70%	2.51%
Residential	7.31%	1.03	2.71%	2.51%
General Service	9.52%	1.34	-0.98%	-1.12%
Lighting	2.32%	0.33	21.56%	21.16%
Industrial	6.38%	0.90	2.62%	2.48%
OPT	6.11%	0.86	3.24%	3.04%

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Duke Energy Carolinas, LLC
Docket No. E-7, Sub 1276

Comparison of Rates of Return, Indices, and % Base Revenue			
Based on MAE Cost-of Service Methodology			
With Public Staff Adjustments			
Rate Year 1			
	Rate of Return	Rate of Return Index	% Base Revenue Change
NC Retail	7.22%	1.00	4.86%
Residential	7.41%	1.03	4.93%
General Service	9.53%	1.32	0.97%
Lighting	2.81%	0.39	26.87%
Industrial	6.53%	0.90	4.78%
OPT	6.27%	0.87	5.11%

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Nov 02 2023

Duke Energy Carolinas, LLC

Docket No. E-7, Sub 1276

Comparison of Rates of Return, Indices, and % Base Revenue			
Based on MAE Cost-of Service Methodology			
With Public Staff Adjustments			
Rate Year 2			
	Rate of Return	Rate of Return Index	% Base Revenue Change
NC Retail	7.33%	1.00	7.89%
Residential	7.50%	1.02	8.15%
General Service	9.44%	1.29	3.52%
Lighting	3.13%	0.43	31.81%
Industrial	6.68%	0.91	7.82%
OPT	6.48%	0.88	7.94%

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Duke Energy Carolinas, LLC
Docket No. E-7, Sub 1276

Comparison of Rates of Return, Indices, and % Base Revenue			
Based on MAE Cost-of Service Methodology			
With Public Staff Adjustments			
Rate Year 3			
	Rate of Return	Rate of Return Index	% Base Revenue Change
NC Retail	7.44%	1.00	10.68%
Residential	7.59%	1.02	11.04%
General Service	9.43%	1.27	6.04%
Lighting	3.34%	0.45	35.63%
Industrial	6.82%	0.92	10.61%
OPT	6.69%	0.90	10.62%

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Nov 02 2023

Duke Energy Carolinas, LLC
Docket No. E-7, Sub 1276

		Base Case - No Revenue Change - MAE					
		NC Retail	RES	GS	Lighting	IND	OPT
1	Total Revenues W/ Staff Adj. @ Pres. Rates	\$ 5,427,913	\$ 2,618,114	\$ 990,270	\$ 150,601	\$ 177,282	\$ 1,491,647
2	Proposed Revenue Change	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
3	Net Income Before Increase	\$ 1,256,133	\$ 667,675	\$ 310,369	\$ (1,767)	\$ 36,609	\$ 243,247
4	Change in Net Income	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
5	Total Net Income	\$ 1,256,133	\$ 667,675	\$ 310,369	\$ (1,767)	\$ 36,609	\$ 243,247
6	Rate Base W/ Staff Adj. @ Pres. Rates	\$ 19,232,800	\$ 9,859,263	\$ 3,179,513	\$ 985,910	\$ 628,729	\$ 4,579,385
7	Staff's Proposed Rate Base	\$ 19,251,683	\$ 9,868,943	\$ 3,182,634	\$ 986,878	\$ 629,346	\$ 4,583,881
8	Rate of Return (before change)	6.53%	6.77%	9.76%	-0.18%	5.82%	5.31%
9	Rate of Return Index (before change)	1.00	1.04	1.49	(0.03)	0.89	0.81
10	Rate of Return (after change)	6.52%	6.77%	9.75%	-0.18%	5.82%	5.31%
11	Rate of Return Index (after change)	1.00	1.04	1.49	(0.03)	0.89	0.81
12	Percent Change in Base Revenue	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Duke Energy Carolinas, LLC
Docket No. E-7, Sub 1276

Equal Rates of Return for all Classes - MAE

		NC Retail	RES	GS	Lighting	IND	OPT
1	Total Revenues W/ Staff Adj. @ Pres. Rates	\$ 5,427,913	\$ 2,618,114	\$ 990,270	\$ 150,601	\$ 177,282	\$ 1,491,647
2	Proposed Revenue Change	\$ 146,630	\$ 43,957	\$ (110,744)	\$ 94,466	\$ 10,648	\$ 108,304
3	Net Income Before Increase	\$ 1,256,133	\$ 667,675	\$ 310,369	\$ (1,767)	\$ 36,609	\$ 243,247
4	Change in Net Income	\$ 111,569	\$ 33,446	\$ (84,264)	\$ 71,878	\$ 8,102	\$ 82,407
5	Total Net Income	\$ 1,367,702	\$ 701,122	\$ 226,105	\$ 70,111	\$ 44,711	\$ 325,654
6	Rate Base W/ Staff Adj. @ Pres. Rates	\$ 19,232,800	\$ 9,859,263	\$ 3,179,513	\$ 985,910	\$ 628,729	\$ 4,579,385
7	Staff's Proposed Rate Base	\$ 19,251,683	\$ 9,868,943	\$ 3,182,634	\$ 986,878	\$ 629,346	\$ 4,583,881
8	Rate of Return (before change)	6.53%	6.77%	9.76%	-0.18%	5.82%	5.31%
9	Rate of Return Index (before change)	1.00	1.04	1.49	(0.03)	0.89	0.81
10	Rate of Return (after change)	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%
11	Rate of Return Index (after change)	1.00	1.00	1.00	1.00	1.00	1.00
12	Percent Change in Base Revenue	2.70%	1.68%	-11.18%	62.73%	6.01%	7.26%

Duke Energy Carolinas, LLC
Docket No. E-7, Sub 1276

Class Revenue Changes Equal to NC Retail Change - MAE

		NC Retail	RES	GS	Lighting	IND	OPT
1	Total Revenues W/ Staff Adj. @ Pres. Rates	\$ 5,427,913	\$ 2,618,114	\$ 990,270	\$ 150,601	\$ 177,282	\$ 1,491,647
2	Proposed Revenue Change	\$ 146,630	\$ 70,726	\$ 26,751	\$ 4,068	\$ 4,789	\$ 40,295
3	Net Income Before Increase	\$ 1,256,133	\$ 667,675	\$ 310,369	\$ (1,767)	\$ 36,609	\$ 243,247
4	Change in Net Income	\$ 111,569	\$ 53,814	\$ 20,355	\$ 3,096	\$ 3,644	\$ 30,660
5	Total Net Income	\$ 1,367,702	\$ 721,490	\$ 330,723	\$ 1,329	\$ 40,253	\$ 273,907
6	Rate Base W/ Staff Adj. @ Pres. Rates	\$ 19,232,800	\$ 9,859,263	\$ 3,179,513	\$ 985,910	\$ 628,729	\$ 4,579,385
7	Staff's Proposed Rate Base	\$ 19,251,683	\$ 9,868,943	\$ 3,182,634	\$ 986,878	\$ 629,346	\$ 4,583,881
8	Rate of Return (before change)	6.53%	6.77%	9.76%	-0.18%	5.82%	5.31%
9	Rate of Return Index (before change)	1.00	1.04	1.49	(0.03)	0.89	0.81
10	Rate of Return (after change)	7.10%	7.31%	10.39%	0.13%	6.40%	5.98%
11	Rate of Return Index (after change)	1.00	1.03	1.46	0.02	0.90	0.84
12	Percent Change in Base Revenue	2.70%	2.70%	2.70%	2.70%	2.70%	2.70%

Duke Energy Carolinas, LLC
Docket No. E-7, Sub 1276

Public Staff **Recommended** Revenue Distribution - MAE

		NC Retail	RES	GS	Lighting	IND	OPT
1	Total Revenues W/ Staff Adj. @ Pres. Rates	\$ 5,427,913	\$ 2,618,114	\$ 990,270	\$ 150,601	\$ 177,282	\$ 1,491,647
2	Proposed Revenue Change	\$ 146,630	\$ 70,957	\$ (9,744)	\$ 32,466	\$ 4,648	\$ 48,304
3	Net Income Before Increase	\$ 1,256,133	\$ 667,675	\$ 310,369	\$ (1,767)	\$ 36,609	\$ 243,247
4	Change in Net Income	\$ 111,569	\$ 53,990	\$ (7,414)	\$ 24,703	\$ 3,537	\$ 36,754
5	Total Net Income	\$ 1,367,702	\$ 721,666	\$ 302,954	\$ 22,936	\$ 40,145	\$ 280,001
6	Rate Base W/ Staff Adj. @ Pres. Rates	\$ 19,232,800	\$ 9,859,263	\$ 3,179,513	\$ 985,910	\$ 628,729	\$ 4,579,385
7	Staff's Proposed Rate Base	\$ 19,251,683	\$ 9,868,943	\$ 3,182,634	\$ 986,878	\$ 629,346	\$ 4,583,881
8	Rate of Return (before change)	6.53%	6.77%	9.76%	-0.18%	5.82%	5.31%
9	Rate of Return Index (before change)	1.00	1.04	1.49	(0.03)	0.89	0.81
10	Rate of Return (after change)	7.10%	7.31%	9.52%	2.32%	6.38%	6.11%
11	Rate of Return Index (after change)	1.00	1.03	1.34	0.33	0.90	0.86
12	Percent Change in Base Revenue	2.70%	2.71%	-0.98%	21.56%	2.62%	3.24%
13	Additional EDIT-4 Credit	\$ (10,394)	\$ (5,267)	\$ (1,304)	\$ (601)	\$ (259)	\$ (2,963)
14	Percent Change in Revenue with EDIT-4 Credit	2.51%	2.51%	-1.12%	21.16%	2.48%	3.04%

Duke Energy Carolinas, LLC
Docket No. E-7, Sub 1276

Base Case - No Revenue Change - MAE

		NC Retail	RES	GS	Lighting	IND	OPT
1	Total Revenues W/ Staff Adj. @ Pres. Rates	\$ 5,427,913	\$ 2,618,114	\$ 990,270	\$ 150,601	\$ 177,282	\$ 1,491,647
2	Proposed Revenue Change	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
3	Net Income Before Increase	\$ 1,256,133	\$ 667,675	\$ 310,369	\$ (1,767)	\$ 36,609	\$ 243,247
4	Change in Net Income	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
5	Total Net Income	\$ 1,256,133	\$ 667,675	\$ 310,369	\$ (1,767)	\$ 36,609	\$ 243,247
6	Rate Base W/ Staff Adj. @ Pres. Rates	\$ 19,232,800	\$ 9,859,263	\$ 3,179,513	\$ 985,910	\$ 628,729	\$ 4,579,385
7	Staff's Proposed Rate Base	\$ 20,174,549	\$ 10,342,030	\$ 3,335,200	\$ 1,034,186	\$ 659,515	\$ 4,803,618
8	Rate of Return (before change)	6.53%	6.77%	9.76%	-0.18%	5.82%	5.31%
9	Rate of Return Index (before change)	1.00	1.04	1.49	(0.03)	0.89	0.81
10	Rate of Return (after change)	6.23%	6.46%	9.31%	-0.17%	5.55%	5.06%
11	Rate of Return Index (after change)	1.00	1.04	1.49	(0.03)	0.89	0.81
12	Percent Change in Base Revenue	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Duke Energy Carolinas, LLC
Docket No. E-7, Sub 1276

Equal Rates of Return for all Classes - MAE

		NC Retail	RES	GS	Lighting	IND	OPT
1	Total Revenues W/ Staff Adj. @ Pres. Rates	\$ 5,427,913	\$ 2,618,114	\$ 990,270	\$ 150,601	\$ 177,282	\$ 1,491,647
2	Proposed Revenue Change	\$ 263,755	\$ 103,999	\$ (91,381)	\$ 100,469	\$ 14,477	\$ 136,191
3	Net Income Before Increase	\$ 1,256,133	\$ 667,675	\$ 310,369	\$ (1,767)	\$ 36,609	\$ 243,247
4	Change in Net Income	\$ 200,689	\$ 79,132	\$ (69,531)	\$ 76,446	\$ 11,015	\$ 103,627
5	Total Net Income	\$ 1,456,822	\$ 746,807	\$ 240,838	\$ 74,679	\$ 47,624	\$ 346,874
6	Rate Base W/ Staff Adj. @ Pres. Rates	\$ 19,232,800	\$ 9,859,263	\$ 3,179,513	\$ 985,910	\$ 628,729	\$ 4,579,385
7	Staff's Proposed Rate Base	\$ 20,174,549	\$ 10,342,030	\$ 3,335,200	\$ 1,034,186	\$ 659,515	\$ 4,803,618
8	Rate of Return (before change)	6.53%	6.77%	9.76%	-0.18%	5.82%	5.31%
9	Rate of Return Index (before change)	1.00	1.04	1.49	(0.03)	0.89	0.81
10	Rate of Return (after change)	7.22%	7.22%	7.22%	7.22%	7.22%	7.22%
11	Rate of Return Index (after change)	1.00	1.00	1.00	1.00	1.00	1.00
12	Percent Change in Base Revenue	4.86%	3.97%	-9.23%	66.71%	8.17%	9.13%

Duke Energy Carolinas, LLC
Docket No. E-7, Sub 1276

Class Revenue Changes Equal to NC Retail Change - MAE

		NC Retail	RES	GS	Lighting	IND	OPT
1	Total Revenues W/ Staff Adj. @ Pres. Rates	\$ 5,427,913	\$ 2,618,114	\$ 990,270	\$ 150,601	\$ 177,282	\$ 1,491,647
2	Proposed Revenue Change	\$ 263,755	\$ 127,220	\$ 48,120	\$ 7,318	\$ 8,615	\$ 72,483
3	Net Income Before Increase	\$ 1,256,133	\$ 667,675	\$ 310,369	\$ (1,767)	\$ 36,609	\$ 243,247
4	Change in Net Income	\$ 200,689	\$ 96,801	\$ 36,614	\$ 5,568	\$ 6,555	\$ 55,151
5	Total Net Income	\$ 1,456,822	\$ 764,476	\$ 346,982	\$ 3,801	\$ 43,164	\$ 298,398
6	Rate Base W/ Staff Adj. @ Pres. Rates	\$ 19,232,800	\$ 9,859,263	\$ 3,179,513	\$ 985,910	\$ 628,729	\$ 4,579,385
7	Staff's Proposed Rate Base	\$ 20,174,549	\$ 10,342,030	\$ 3,335,200	\$ 1,034,186	\$ 659,515	\$ 4,803,618
8	Rate of Return (before change)	6.53%	6.77%	9.76%	-0.18%	5.82%	5.31%
9	Rate of Return Index (before change)	1.00	1.04	1.49	(0.03)	0.89	0.81
10	Rate of Return (after change)	7.22%	7.39%	10.40%	0.37%	6.54%	6.21%
11	Rate of Return Index (after change)	1.00	1.02	1.44	0.05	0.91	0.86
12	Percent Change in Base Revenue	4.86%	4.86%	4.86%	4.86%	4.86%	4.86%

Duke Energy Carolinas, LLC
Docket No. E-7, Sub 1276

Public Staff **Recommended** Revenue Distribution - MAE

		NC Retail	RES	GS	Lighting	IND	OPT
1	Total Revenues W/ Staff Adj. @ Pres. Rates	\$ 5,427,913	\$ 2,618,114	\$ 990,270	\$ 150,601	\$ 177,282	\$ 1,491,647
2	Proposed Revenue Change	\$ 263,755	\$ 128,999	\$ 9,619	\$ 40,469	\$ 8,477	\$ 76,191
3	Net Income Before Increase	\$ 1,256,133	\$ 667,675	\$ 310,369	\$ (1,767)	\$ 36,609	\$ 243,247
4	Change in Net Income	\$ 200,689	\$ 98,154	\$ 7,319	\$ 30,793	\$ 6,450	\$ 57,973
5	Total Net Income	\$ 1,456,822	\$ 765,829	\$ 317,688	\$ 29,026	\$ 43,059	\$ 301,220
6	Rate Base W/ Staff Adj. @ Pres. Rates	\$ 19,232,800	\$ 9,859,263	\$ 3,179,513	\$ 985,910	\$ 628,729	\$ 4,579,385
7	Staff's Proposed Rate Base	\$ 20,174,549	\$ 10,342,030	\$ 3,335,200	\$ 1,034,186	\$ 659,515	\$ 4,803,618
8	Rate of Return (before change)	6.53%	6.77%	9.76%	-0.18%	5.82%	5.31%
9	Rate of Return Index (before change)	1.00	1.04	1.49	(0.03)	0.89	0.81
10	Rate of Return (after change)	7.22%	7.41%	9.53%	2.81%	6.53%	6.27%
11	Rate of Return Index (after change)	1.00	1.03	1.32	0.39	0.90	0.87
12	Percent Change in Base Revenue	4.86%	4.93%	0.97%	26.87%	4.78%	5.11%

Duke Energy Carolinas, LLC
Docket No. E-7, Sub 1276

		Base Case - No Revenue Change - MAE					
		NC Retail	RES	GS	Lighting	IND	OPT
1	Total Revenues W/ Staff Adj. @ Pres. Rates	\$ 5,427,913	\$ 2,618,114	\$ 990,270	\$ 150,601	\$ 177,282	\$ 1,491,647
2	Proposed Revenue Change	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
3	Net Income Before Increase	\$ 1,256,133	\$ 667,675	\$ 310,369	\$ (1,767)	\$ 36,609	\$ 243,247
4	Change in Net Income	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
5	Total Net Income	\$ 1,256,133	\$ 667,675	\$ 310,369	\$ (1,767)	\$ 36,609	\$ 243,247
6	Rate Base W/ Staff Adj. @ Pres. Rates	\$ 19,232,800	\$ 9,859,263	\$ 3,179,513	\$ 985,910	\$ 628,729	\$ 4,579,385
7	Staff's Proposed Rate Base	\$ 21,591,639	\$ 11,068,469	\$ 3,569,469	\$ 1,106,828	\$ 705,840	\$ 5,141,032
8	Rate of Return (before change)	6.53%	6.77%	9.76%	-0.18%	5.82%	5.31%
9	Rate of Return Index (before change)	1.00	1.04	1.49	(0.03)	0.89	0.81
10	Rate of Return (after change)	5.82%	6.03%	8.70%	-0.16%	5.19%	4.73%
11	Rate of Return Index (after change)	1.00	1.04	1.49	(0.03)	0.89	0.81
12	Percent Change in Base Revenue	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Duke Energy Carolinas, LLC
Docket No. E-7, Sub 1276

Equal Rates of Return for all Classes - MAE

		NC Retail	RES	GS	Lighting	IND	OPT
1	Total Revenues W/ Staff Adj. @ Pres. Rates	\$ 5,427,913	\$ 2,618,114	\$ 990,270	\$ 150,601	\$ 177,282	\$ 1,491,647
2	Proposed Revenue Change	\$ 428,405	\$ 188,403	\$ (64,161)	\$ 108,910	\$ 19,859	\$ 175,395
3	Net Income Before Increase	\$ 1,256,133	\$ 667,675	\$ 310,369	\$ (1,767)	\$ 36,609	\$ 243,247
4	Change in Net Income	\$ 325,970	\$ 143,354	\$ (48,820)	\$ 82,868	\$ 15,111	\$ 133,456
5	Total Net Income	\$ 1,582,103	\$ 811,030	\$ 261,549	\$ 81,102	\$ 51,720	\$ 376,703
6	Rate Base W/ Staff Adj. @ Pres. Rates	\$ 19,232,800	\$ 9,859,263	\$ 3,179,513	\$ 985,910	\$ 628,729	\$ 4,579,385
7	Staff's Proposed Rate Base	\$ 21,591,639	\$ 11,068,469	\$ 3,569,469	\$ 1,106,828	\$ 705,840	\$ 5,141,032
8	Rate of Return (before change)	6.53%	6.77%	9.76%	-0.18%	5.82%	5.31%
9	Rate of Return Index (before change)	1.00	1.04	1.49	(0.03)	0.89	0.81
10	Rate of Return (after change)	7.33%	7.33%	7.33%	7.33%	7.33%	7.33%
11	Rate of Return Index (after change)	1.00	1.00	1.00	1.00	1.00	1.00
12	Percent Change in Base Revenue	7.89%	7.20%	-6.48%	72.32%	11.20%	11.76%

Duke Energy Carolinas, LLC
Docket No. E-7, Sub 1276

Class Revenue Changes Equal to NC Retail Change - MAE

		NC Retail	RES	GS	Lighting	IND	OPT
1	Total Revenues W/ Staff Adj. @ Pres. Rates	\$ 5,427,913	\$ 2,618,114	\$ 990,270	\$ 150,601	\$ 177,282	\$ 1,491,647
2	Proposed Revenue Change	\$ 428,405	\$ 206,638	\$ 78,158	\$ 11,886	\$ 13,992	\$ 117,730
3	Net Income Before Increase	\$ 1,256,133	\$ 667,675	\$ 310,369	\$ (1,767)	\$ 36,609	\$ 243,247
4	Change in Net Income	\$ 325,970	\$ 157,229	\$ 59,470	\$ 9,044	\$ 10,647	\$ 89,580
5	Total Net Income	\$ 1,582,103	\$ 824,905	\$ 369,839	\$ 7,277	\$ 47,255	\$ 332,827
6	Rate Base W/ Staff Adj. @ Pres. Rates	\$ 19,232,800	\$ 9,859,263	\$ 3,179,513	\$ 985,910	\$ 628,729	\$ 4,579,385
7	Staff's Proposed Rate Base	\$ 21,591,639	\$ 11,068,469	\$ 3,569,469	\$ 1,106,828	\$ 705,840	\$ 5,141,032
8	Rate of Return (before change)	6.53%	6.77%	9.76%	-0.18%	5.82%	5.31%
9	Rate of Return Index (before change)	1.00	1.04	1.49	(0.03)	0.89	0.81
10	Rate of Return (after change)	7.33%	7.45%	10.36%	0.66%	6.69%	6.47%
11	Rate of Return Index (after change)	1.00	1.02	1.41	0.09	0.91	0.88
12	Percent Change in Base Revenue	7.89%	7.89%	7.89%	7.89%	7.89%	7.89%

Duke Energy Carolinas, LLC
Docket No. E-7, Sub 1276

Public Staff **Recommended** Revenue Distribution - MAE

		NC Retail	RES	GS	Lighting	IND	OPT
1	Total Revenues W/ Staff Adj. @ Pres. Rates	\$ 5,427,913	\$ 2,618,114	\$ 990,270	\$ 150,601	\$ 177,282	\$ 1,491,647
2	Proposed Revenue Change	\$ 428,405	\$ 213,403	\$ 34,839	\$ 47,910	\$ 13,859	\$ 118,395
3	Net Income Before Increase	\$ 1,256,133	\$ 667,675	\$ 310,369	\$ (1,767)	\$ 36,609	\$ 243,247
4	Change in Net Income	\$ 325,970	\$ 162,376	\$ 26,508	\$ 36,454	\$ 10,545	\$ 90,086
5	Total Net Income	\$ 1,582,103	\$ 830,052	\$ 336,877	\$ 34,687	\$ 47,154	\$ 333,332
6	Rate Base W/ Staff Adj. @ Pres. Rates	\$ 19,232,800	\$ 9,859,263	\$ 3,179,513	\$ 985,910	\$ 628,729	\$ 4,579,385
7	Staff's Proposed Rate Base	\$ 21,591,639	\$ 11,068,469	\$ 3,569,469	\$ 1,106,828	\$ 705,840	\$ 5,141,032
8	Rate of Return (before change)	6.53%	6.77%	9.76%	-0.18%	5.82%	5.31%
9	Rate of Return Index (before change)	1.00	1.04	1.49	(0.03)	0.89	0.81
10	Rate of Return (after change)	7.33%	7.50%	9.44%	3.13%	6.68%	6.48%
11	Rate of Return Index (after change)	1.00	1.02	1.29	0.43	0.91	0.88
12	Percent Change in Base Revenue	7.89%	8.15%	3.52%	31.81%	7.82%	7.94%

Duke Energy Carolinas, LLC
Docket No. E-7, Sub 1276

		Base Case - No Revenue Change - MAE					
		NC Retail	RES	GS	Lighting	IND	OPT
1	Total Revenues W/ Staff Adj. @ Pres. Rates	\$ 5,427,913	\$ 2,618,114	\$ 990,270	\$ 150,601	\$ 177,282	\$ 1,491,647
2	Proposed Revenue Change	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
3	Net Income Before Increase	\$ 1,256,133	\$ 667,675	\$ 310,369	\$ (1,767)	\$ 36,609	\$ 243,247
4	Change in Net Income	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
5	Total Net Income	\$ 1,256,133	\$ 667,675	\$ 310,369	\$ (1,767)	\$ 36,609	\$ 243,247
6	Rate Base W/ Staff Adj. @ Pres. Rates	\$ 19,232,800	\$ 9,859,263	\$ 3,179,513	\$ 985,910	\$ 628,729	\$ 4,579,385
7	Staff's Proposed Rate Base	\$ 22,822,630	\$ 11,699,509	\$ 3,772,973	\$ 1,169,931	\$ 746,082	\$ 5,434,134
8	Rate of Return (before change)	6.53%	6.77%	9.76%	-0.18%	5.82%	5.31%
9	Rate of Return Index (before change)	1.00	1.04	1.49	(0.03)	0.89	0.81
10	Rate of Return (after change)	5.50%	5.71%	8.23%	-0.15%	4.91%	4.48%
11	Rate of Return Index (after change)	1.00	1.04	1.49	(0.03)	0.89	0.81
12	Percent Change in Base Revenue	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Duke Energy Carolinas, LLC
Docket No. E-7, Sub 1276

Equal Rates of Return for all Classes - MAE

		NC Retail	RES	GS	Lighting	IND	OPT
1	Total Revenues W/ Staff Adj. @ Pres. Rates	\$ 5,427,913	\$ 2,618,114	\$ 990,270	\$ 150,601	\$ 177,282	\$ 1,491,647
2	Proposed Revenue Change	\$ 579,639	\$ 265,929	\$ (39,160)	\$ 116,662	\$ 24,803	\$ 211,404
3	Net Income Before Increase	\$ 1,256,133	\$ 667,675	\$ 310,369	\$ (1,767)	\$ 36,609	\$ 243,247
4	Change in Net Income	\$ 441,043	\$ 202,343	\$ (29,796)	\$ 88,767	\$ 18,873	\$ 160,856
5	Total Net Income	\$ 1,697,175	\$ 870,019	\$ 280,572	\$ 87,000	\$ 55,481	\$ 404,102
6	Rate Base W/ Staff Adj. @ Pres. Rates	\$ 19,232,800	\$ 9,859,263	\$ 3,179,513	\$ 985,910	\$ 628,729	\$ 4,579,385
7	Staff's Proposed Rate Base	\$ 22,822,630	\$ 11,699,509	\$ 3,772,973	\$ 1,169,931	\$ 746,082	\$ 5,434,134
8	Rate of Return (before change)	6.53%	6.77%	9.76%	-0.18%	5.82%	5.31%
9	Rate of Return Index (before change)	1.00	1.04	1.49	(0.03)	0.89	0.81
10	Rate of Return (after change)	7.44%	7.44%	7.44%	7.44%	7.44%	7.44%
11	Rate of Return Index (after change)	1.00	1.00	1.00	1.00	1.00	1.00
12	Percent Change in Base Revenue	10.68%	10.16%	-3.95%	77.46%	13.99%	14.17%

Duke Energy Carolinas, LLC
Docket No. E-7, Sub 1276

Class Revenue Changes Equal to NC Retail Change - MAE

		NC Retail	RES	GS	Lighting	IND	OPT
1	Total Revenues W/ Staff Adj. @ Pres. Rates	\$ 5,427,913	\$ 2,618,114	\$ 990,270	\$ 150,601	\$ 177,282	\$ 1,491,647
2	Proposed Revenue Change	\$ 579,639	\$ 279,585	\$ 105,749	\$ 16,082	\$ 18,932	\$ 159,291
3	Net Income Before Increase	\$ 1,256,133	\$ 667,675	\$ 310,369	\$ (1,767)	\$ 36,609	\$ 243,247
4	Change in Net Income	\$ 441,043	\$ 212,734	\$ 80,464	\$ 12,237	\$ 14,405	\$ 121,203
5	Total Net Income	\$ 1,697,175	\$ 880,409	\$ 390,833	\$ 10,470	\$ 51,014	\$ 364,450
6	Rate Base W/ Staff Adj. @ Pres. Rates	\$ 19,232,800	\$ 9,859,263	\$ 3,179,513	\$ 985,910	\$ 628,729	\$ 4,579,385
7	Staff's Proposed Rate Base	\$ 22,822,630	\$ 11,699,509	\$ 3,772,973	\$ 1,169,931	\$ 746,082	\$ 5,434,134
8	Rate of Return (before change)	6.53%	6.77%	9.76%	-0.18%	5.82%	5.31%
9	Rate of Return Index (before change)	1.00	1.04	1.49	(0.03)	0.89	0.81
10	Rate of Return (after change)	7.44%	7.53%	10.36%	0.89%	6.84%	6.71%
11	Rate of Return Index (after change)	1.00	1.01	1.39	0.12	0.92	0.90
12	Percent Change in Base Revenue	10.68%	10.68%	10.68%	10.68%	10.68%	10.68%

Duke Energy Carolinas, LLC
Docket No. E-7, Sub 1276

Public Staff **Recommended** Revenue Distribution - MAE

		NC Retail	RES	GS	Lighting	IND	OPT
1	Total Revenues W/ Staff Adj. @ Pres. Rates	\$ 5,427,913	\$ 2,618,114	\$ 990,270	\$ 150,601	\$ 177,282	\$ 1,491,647
2	Proposed Revenue Change	\$ 579,639	\$ 288,929	\$ 59,840	\$ 53,662	\$ 18,803	\$ 158,404
3	Net Income Before Increase	\$ 1,256,133	\$ 667,675	\$ 310,369	\$ (1,767)	\$ 36,609	\$ 243,247
4	Change in Net Income	\$ 441,043	\$ 219,844	\$ 45,532	\$ 40,831	\$ 14,307	\$ 120,528
5	Total Net Income	\$ 1,697,175	\$ 887,519	\$ 355,901	\$ 39,064	\$ 50,916	\$ 363,775
6	Rate Base W/ Staff Adj. @ Pres. Rates	\$ 19,232,800	\$ 9,859,263	\$ 3,179,513	\$ 985,910	\$ 628,729	\$ 4,579,385
7	Staff's Proposed Rate Base	\$ 22,822,630	\$ 11,699,509	\$ 3,772,973	\$ 1,169,931	\$ 746,082	\$ 5,434,134
8	Rate of Return (before change)	6.53%	6.77%	9.76%	-0.18%	5.82%	5.31%
9	Rate of Return Index (before change)	1.00	1.04	1.49	(0.03)	0.89	0.81
10	Rate of Return (after change)	7.44%	7.59%	9.43%	3.34%	6.82%	6.69%
11	Rate of Return Index (after change)	1.00	1.02	1.27	0.45	0.92	0.90
12	Percent Change in Base Revenue	10.68%	11.04%	6.04%	35.63%	10.61%	10.62%

I/A

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1276

In the Matter of Duke Energy	)	
Carolinas, LLC's Application for	)	PUBLIC STAFF'S RESPONSE TO
Adjustment of Rates and Charges	)	THE FIRST DATA REQUEST OF
Applicable to Electric Utility Service	)	CIGFUR III TO PUBLIC STAFF
in North Carolina and Performance-	)	
Based Regulation	)	

- 1-1. Please provide all workpapers associated with Exhibits 1 and 2 for David M. Williamson's Supplemental Testimony filed on October 13, 2023 in native electronic format with all formulas intact.**

RESPONSE:

Please see the items provided with this data request which include the supporting workpapers for D. Williamson's supplemental testimony exhibits.

Additionally, in responding to discovery requests, the Public Staff noticed an error in its revenue apportionment spreadsheet. This error resulted from the use of incorrect values for Operating Expenses related to the projected portions of the MYRP. This error has been corrected and corrected exhibits have been filed in the docket. The corrected workpaper and the associated exhibits are also included with this data request.

O

Sub 1276 - Revenue
Increase Exhibit - PS

O

Sub 1276 - Revenue
Increase Exhibit - Co

Response provided by David M. Williamson, Energy Division

- 1-2. To the extent not already provided, please provide all Public Staff's cost of service models in native electronic format with all formulas intact and their outputs that support Exhibits 1 and 2.**

RESPONSE:

The Public Staff did not create a separate cost-of-service model. The Public Staff utilized the Modified Average and Excess cost-of-service model filed by DEC as part of the E-1 Item 45a rate case filing requirements for purposes of developing its recommended revenue apportionment to each rate class. Please see the Company's E-1 item 45a for further insight into the Company's cost-of-service.

Response provided by David M. Williamson, Energy Division

- 1-3. Please explain in detail how the Public Staff cost of service models were developed that support Exhibits 1 and 2.
- A. For example, did Public Staff modify DEC's cost of service models to develop its own models? If so, please describe all modifications made by Public Staff to the Company's models.

RESPONSE:

The Public Staff did not create a separate cost-of-service model. Please see the response to DR 1-2 above.

Response provided by David M. Williamson, Energy Division

- 1-4. Please provide a complete explanation of all the changes in approach to revenue distribution to classes from the Company's proposed revenue distribution.

RESPONSE:

The Public Staff did not modify the Company's approach, but rather created its own apportionment of revenues to the customer classes. Public Staff's approach to apportioning the revenue requirement to each class is described within the "Instructions" tab of the supporting workpaper provided as part of DR 1-1, as well as in the pre-filed direct and supplemental testimony of Public Staff witness D. Williamson. Please see the response to DR 1-1 above.

Response provided by David M. Williamson, Energy Division

- 1-5. Explain the extent to which the Public Staff modified its approach to revenue apportionment as compared to Duke's 10% subsidy reduction method.

RESPONSE:

Please see page 10 of witness D. Williamson's supplemental testimony.

Response provided by David M. Williamson, Energy Division

- 1-6. Regarding Exhibit 1, please describe in detail all "Staff Adjustments" to the MAE Cost of Service Methodology as noted on the exhibit.

RESPONSE:

"Staff Adjustments" are the Public Staff Accounting Adjustments to the overall Revenue Requirement. The Staff Adjustments are used to create a revenue requirement, based on updated revenues, operating expenses, and rate base to determine the necessary revenue requirement for each rate year. Please see the "Supplemental and Settlement Accounting Exhibits 1, 2, and 3" for more information regarding the "Staff Adjustments."

Response provided by David M. Williamson, Energy Division

- 1-7. Provide all studies, reports or written communication done by or for the Public Staff that relates the four guiding rate principles contained in the Williamson testimony to the HB 951 law.

RESPONSE:

The Public Staff has for many years, and in several general rate case proceedings, advocated for the four guiding rate principles described in witness D. Williamson's testimony in this case, in an effort to provide the Commission with a reasonable approach to apportioning any revenue requirement changes authorized by the Commission. These principles represent policy decisions of the Public Staff, and we believe they provide a reasonable approach to apportioning the revenue requirement by customer class to ensure that assignment of revenue responsibility is reasonable without causing undue rate shock. HB 951 did not cause the Public Staff to amend the guiding rate principles themselves, but the Public Staff now takes into consideration the requirements enacted by HB 951 when it applies its guiding principles to its recommended rate apportionment.

Response provided by David M. Williamson, Energy Division

- 1-8. Provide all reports, studies and any documentation prepared by Public Staff or on its behalf that reviews how the principles set forth by Mr. Williamson associated with revenue apportionment comply with HB 951.

RESPONSE:

Please see response to DR 1-7.

Response provided by David M. Williamson, Energy Division

- 1-9. Provide the subsidy level paid/received by each class that corresponds to Mr. Williamson's recommendations in Exhibits 1 and 2.

RESPONSE:

This request seeks the production of documents that are not in the Public Staff's possession. The Public Staff objects to this request because it would require the creation of a new work product that does not currently exist.

Without waiving this objection, and relying specifically thereon: This response can be determined from Public Staff witness D. Williamson's Exhibit 2. Cross subsidization can be viewed as a dollar of revenue that is applied to a class that is above or below the level needed to achieve a 1.0 ROR index. The Public Staff notes that its preference is to allow for flexibility when determining how revenues should be apportioned and has historically advocated for a $\pm 10\%$ band of reasonableness for such determinations, which it considers to be a reasonable approximation of rate parity.

Response provided by David M. Williamson, Energy Division

- 1-10. Please reconcile the differences in Public Staff's cost of service results and those of the Company. In particular, please explain why Public Staff's cost of service results indicate that the OPT class is producing a rate of return at current rates that is below the system average rate of return.

RESPONSE:

This request seeks the production of documents that are not in the Public Staff's possession. The Public Staff objects to this request because it would require the creation of a new work product that does not currently exist. Without waiving said objection, and relying specifically thereon: As stated in previous responses, the Public Staff did not create a separate cost of service for use in this proceeding. The Public Staff, when applying its revenue distribution applied a review of ROR movement for each class and for each rate year. This approach was applied

because after rates are approved by the Commission and go into effect, customers are being charged those rates and the Company will be receiving those associated revenues. The Company's ROR analysis for each rate year is a cumulative look at the impacts to ROR from before the case was filed. That is, the Company's approach disregards the fact that customers will be paying new rates over the MYRP. The Public Staff disagrees with this approach and has instead adjusted revenues based (and in turn the ROR for each class) on the incremental increases associated with each rate year, since each rate year will be increasing an already active set of rates that customers will be paying and the Company will be receiving those updated revenues as a result.

Response provided by David M. Williamson, Energy Division

- 1-11. Please explain in detail why under the Staff's class revenue distribution, the OPT class receives an above system average increase under Public Staff's recommendations in Exhibits 1 and 2.

RESPONSE:

The Public Staff's ROR movement has the OPT class at less than the overall system by the conclusion of the MYRP. Base revenue percentage increases are tied to the amount of revenue needed by the respective class to move it closer to parity and/or within the $\pm 10\%$ band. ROR is a function of the class's contribution to the total revenue requirement based on the COSS. In the Public Staffs methodology, movement has been made by all customer classes in order to achieve RORs within the band of reasonableness without undue rate shock, with the exception of the lighting class, which made substantial, and necessary, movement toward the band.

Response provided by David M. Williamson, Energy Division

- 1-12. At page 4, lines 15-22 of his Supplemental Testimony, Mr. Williamson states the following:

I utilized the Company's E-1, Item 45A, which is the per books MAE COSS, to develop a distribution framework that incorporates the overall base revenues, expenses, net income, and rate base for the test year. I applied this framework to the adjusted present and proposed revenues, expenses, and rate base provided by Public Staff witnesses Zhang, Boswell, and Metz, to develop the Public Staff's recommended revenue changes by retail rate class for each Rate Year of the multi-year rate plan (MYRP).

Please provide the following information:

- a. Please explain in detail why Mr. Williamson utilized the per books MAE COSS to develop his “distribution framework”.
- b. Is it Mr. Williamson’s understanding that DEC utilized the per books MAE COSS to develop its proposed class revenue distribution? Please explain in detail.
- c. Did Mr. Williamson make any adjustments to the Company’s per books MAE COSS when developing his “distribution framework” and measuring each class’s cost of service? Please describe all adjustments made by Public Staff to the per books MAE COSS results when developing its class revenue distribution.
- d. Please explain in detail how the “distribution framework” was developed by Mr. Williamson.
- e. Did Mr. Williamson develop a distribution framework for the subclasses of OPT? If yes, please provide the Public Staff’s recommended revenue distribution for the OPT subclasses. If no, please explain why not.
- f. Did the development of Mr. Williamson’s “distribution framework” include developing an actual cost of service model to be used in his “distribution framework”? Please explain in detail.

RESPONSE:

- a. Each rate case requires a COSS to base the updated allocations for capital and expense items being requested to be added to the revenue requirement. The “per books MAE COSS” is the test year result that utilized the total dollars (capital and O&M) and their allocation using the settled and agreed upon Modified Average and Excess COSS analysis.
- b. Yes. Please see the response to question 1-12a.
- c. No, the “Company’s per books MAE COSS” was not adjusted. The Company’s E-1 Item 45a (Company’s per books MAE COSS) is the same information that the Public Staff used to start the process of apportioning revenues. Public Staff witness D. Williamson was provided the Accounting workpapers from Public Staff witnesses Zhang, Boswell, and Metz which updated revenues, expenses, and rate base since the last rate case and through the end of the MYRP, including certain settled items between the Public Staff and other parties. This update modified the values in the test year based on the Public Staff’s audit, which in turn updated the Company’s per books determination and created the Public Staff’s version of E-1 Item 45b.

- d. The Public Staff's approach to apportioning the revenue requirement to each class is described within the "Instructions" tab of the supporting workpaper provided as part of DR 1-1. Please see the response to DR 1-1.
- e. Public Staff witness D. Williamson focused on the five broad classes for his revenue apportionment. This is consistent with the presentation provided as part of Company witness Beveridge's Exhibit 4, where the Company outlines the total increase for each class and the ROR changes associated with the increase.
- f. Please see the responses provided in question 1-12c and 1-12e.

Response provided by David M. Williamson, Energy Division

- 1-13. At page 7 lines 15-17 of his Supplemental Testimony, Mr. Williamson states the following:

The revenue apportionment illustrated in my exhibits shows a reasonable level of progress toward achieving all the guiding principles, without introducing the risk of rate shock.

Please provide the following information:

- a. Please explain in detail how Mr. Williamson measured a reasonable level of progress was made towards Public Staff's guiding principles.
- b. In this instance, how did Mr. Williamson define rate shock? Please explain in detail.

RESPONSE:

- a. The first step was for witness D. Williamson to update the revenue apportionment spreadsheet to the final revenue requirement numbers provided by the Public Staff's Accounting witness panel of Zhang, Boswell, and Metz. After updating the inputs reflected in the "Inputs" tab, the revenue increases and ROR made movement to adjust for each Rate Year. Given that certain rate classes were far outside of the ROR band of reasonableness, in order to ensure that certain rate classes would not experience rate shock, a level of gradualism was taken into account for the ROR movement for each class as they progressed toward the band of reasonableness across the MYRP.

A goal of the Public Staff was to accomplish the following with apportioning the additional revenues for the projected rate years of MYRP:

- 1. That each class moved closer to ROR parity compared to its ROR from the previous Rate Year;
- 2. That no class moved from having a ROR index of less than 1.0 to above 1.0, and vice versa; and

3. That each class experienced an increase in base revenues.

- b. The Public Staff has historically viewed rate shock as experiencing a substantial revenue requirement increase as a result of the movement in ROR to achieve a ROR within the band of reasonableness. However, what constitutes as "substantial" is situational to each case.

Response provided by David M. Williamson, Energy Division

- 1-14. Regarding Exhibits 1 and 2, please provide Mr. Williamsons' results for all subclasses, including those results for the subclasses of the OPT class.

RESPONSE:

This request seeks the production of documents that are not in the Public Staff's possession. The Public Staff objects to this request because it would require the creation of a new work product that does not currently exist. Public Staff witness D. Williamson only focused on the five broad classes for his revenue apportionment. This is consistent with the presentation provided as part of Company witness Beveridge's Exhibit 4, in which the Company outlines the total increase for each class and the ROR changes associated with the increase.

Response provided by David M. Williamson, Energy Division

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1276

In the Matter of Duke Energy	)	
Carolinas, LLC's Application for	)	PUBLIC STAFF'S RESPONSE TO
Adjustment of Rates and Charges	)	THE THIRD DATA REQUEST OF
Applicable to Electric Utility Service	)	CIGFUR III TO PUBLIC STAFF
in North Carolina and Performance-	)	
Based Regulation	)	

- 3-1. In preparing its revenue apportionment recommendations as corrected, did the Public Staff or witness D. Williamson collaborate or confer with any other party regarding same? If yes, with whom did the Public Staff or witness D. Williamson collaborate or confer? Provide copies of all such correspondence or communications. If no, why not?

RESPONSE:

Neither the Public Staff, nor witness Williamson, collaborated or conferred with other parties to prepare the revenue apportionment recommendations provided as part of witness Williamson's exhibits. Public Staff recommendations made in rate cases are generally developed internally.

Response provided by David M. Williamson, Energy Division

- 3-2. At any time since preparing its revenue apportionment recommendations as corrected, has the Public Staff or witness D. Williamson collaborated or conferred with any other party regarding same? If yes, with whom did the Public Staff or witness D. Williamson collaborate or confer? Provide copies of all such correspondence or communications. If no, why not?

RESPONSE:

After witness Williamson developed his Public Staff revenue apportionment, the Public Staff reached out to DEC to "walk through" his recommendations. Specifically, the Public Staff talked with DEC employees Jonathan Byrd and Morgan Beveridge.

Response provided by David M. Williamson, Energy Division

- 3-3. Did the Public Staff perform any studies or analysis comparing the Summer Coincident Peak methodology to the stipulated Modified Average and Excess methodology when developing its revenue apportionment methodology and recommendations as corrected? If yes, provide the results of such analysis including all relevant workpapers. If no, why not?

RESPONSE:

No. The MAE Cost of Service Study methodology was a settled matter heading into the DEP and DEC rate cases, a settlement to which CIGFUR II and III were parties. There was no reason for the Public Staff to conduct such an analysis utilizing the SCP, or any other non-MAE, methodology.

Response provided by David M. Williamson, Energy Division

- 3-4. Admit that the Public Staff's recommended revenue apportionment methodology set forth in D. Williamson's corrected supplemental exhibits departs from the Public Staff's historical approach to revenue apportionment, including the approach recommended by the Public Staff—and ultimately approved by the Commission—in Docket No. E-2, Sub 1300.

RESPONSE:

The Public Staff did not depart from its revenue apportionment methodology. The revenue apportionment recommendation made in this case is substantially similar to the revenue apportionment illustrations or examples that were offered by witness Williamson in his first supplemental testimony in the DEP Sub 1300 case. The Public Staff admits the revenue apportionment approach it used in this DEC case is different than the final approach that the Public Staff ultimately agreed with in the DEP Sub 1300 case.

Response provided by David M. Williamson, Energy Division

- 3-5. Admit that the Public Staff's revenue apportionment methodology used in D. Williamson's corrected supplemental exhibits effectively alters the results of DEC's Cost of Service Study relied upon in this pending general rate case.

RESPONSE:

No, the corrected supplemental exhibits do not alter the results of DEC's Cost of Service Study. As always is its practice, the Public Staff relied upon the Company's E-1 Item 45a, which is the Company's test year per books application of the Modified Average and Excess COSS, and then incorporated Public Staff adjustments to revenues, plant, and expenses. The Public Staff then adhered to North Carolina law and then to its four guiding principles to the greatest extent practicable.

Response provided by David M. Williamson, Energy Division

- 3-6. Admit that the recommendations contained in D. Williamson's corrected supplemental exhibits are subjective and include modifications to the methodology for policy reasons known only to the Public Staff.

RESPONSE:

No, the Public Staff has applied the same four guiding principles that it has historically used in past general rates cases. The application of these four guiding principles has been well explained in this docket and in numerous past rate case dockets. The application of these principles results in just and reasonable rates that are in compliance with Chapter 62 of the North Carolina General Statutes.

Response provided by David M. Williamson, Energy Division

- 3-7. If the Public Staff disagrees with any of the testimony contained within the DEC Byrd and Beveridge Supplemental Testimony filed on October 24, 2023, state with particularity what exactly the Public Staff disagrees with and why.

RESPONSE:

This request is objectionable to the extent that it seeks information subject to attorney client privilege, information prepared in anticipation of litigation, and/or the impressions of counsel. Without waiving said objection and relying specifically thereon: Please refer to the pre-filed testimony of witness Williamson and DEC witnesses Byrd and Beveridge for the apparent differences between the two parties. The Public Staff disagrees with DEC's general arguments that there is no basis in the record to support the methodology recommended by the Public Staff or that the methodology is not replicable.

Response provided by David M. Williamson, Energy Division

I/A

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Nov 02 2023

Modified Average and Excess Method

Present Rate Revenues Annualized with Public Staff Adjustments

Dollars in Thousands

	NC Juris ¹	Res	GS	Lighting	IND	OPT	Checks
Rate Schedule Revenues	\$ 5,429,359	\$ 2,618,712	\$ 990,457	\$ 150,710	\$ 177,338	\$ 1,492,142	\$5,429,359
Other Revs	\$ (1,446)	(598)	(187)	(109)	(56)	(496)	(1,446)
Operating Expenses	\$ 4,171,780	1,950,438	679,901	152,368	140,673	1,248,400	4,171,780
Net Income	1,256,133	667,675	310,369	(1,767)	36,609	243,247	1,256,133
		0.5315	0.2471	(0.0014)	0.0291	0.1936	
Target Return	1,256,133	643,928	207,660	64,392	41,064	299,089	1,256,133
		0.5126	0.165	0.051	0.033	0.238	
Rate Base	\$ 19,232,800	9,859,263	3,179,513	985,910	628,729	4,579,385	19,232,800
ROR	6.53%	6.77%	9.76%	-0.18%	5.82%	5.31%	6.53%
Index of ROR	1.00	1.04	1.49	-0.03	0.89	0.81	1.00

Class ROR Index between 0.9 and 1.1?

TRUE

FALSE

FALSE

FALSE

FALSE

Notes

1 Direct Input From Boswell Exhibit 1, Schedules 2 & 3, columns (c) as appropriate.

2 Assignment to rate classes done on the basis of the MAE "per books" data [E-1, Item 45A].

Modified Average and Excess Method

Present Rate Revenues Annualized with Public Staff Adjustments

Dollars in Thousands

	NC Juris ¹	Res	GS	Lighting	IND	OPT	Checks
Rate Schedule Revenues	\$ 5,429,359	\$ 2,618,712	\$ 990,457	\$ 150,710	\$ 177,338	\$ 1,492,142	\$5,429,359
Other Revs	\$ (1,446)	(598)	(187)	(109)	(56)	(496)	(1,446)
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Index of ROR	1.00	1.04	1.49	-0.03	0.89	0.81	1.00

Class ROR Index between 0.9 and 1.1?

TRUE

FALSE

FALSE

FALSE

FALSE

Notes

1 Direct Input From Boswell Exhibit 1, Schedules 2 & 3, columns (c) as appropriate.

2 Assignment to rate classes done on the basis of the MAE "per books" data [E-1, Item 45A].

Modified Average and Excess Method

Present Rate Revenues Annualized with Public Staff Adjustments

Dollars in Thousands

	NC Juris ¹	Res	GS	Lighting	IND	OPT	Checks
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Other Revs	\$ (1,446)	(598)	(187)	(109)	(56)	(496)	(1,446)
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ROR	6.53%	6.77%	9.76%	-0.18%	5.82%	5.31%	6.53%
Index of ROR	1.00	1.04	1.49	-0.03	0.89	0.81	1.00

Class ROR Index between 0.9 and 1.1?

TRUE

FALSE

FALSE

FALSE

FALSE

Notes

1 Direct Input From Boswell Exhibit 1, Schedules 2 & 3, columns (c) as appropriate.

2 Assignment to rate classes done on the basis of the MAE "per books" data [E-1, Item 45A].

Modified Average and Excess Method

Present Rate Revenues Annualized with Public Staff Adjustments

Dollars in Thousands

	NC Juris ¹	Res	GS	Lighting	IND	OPT	Checks
Rate Schedule Revenues	\$ 5,429,359	\$ 2,618,712	\$ 990,457	\$ 150,710	\$ 177,338	\$ 1,492,142	\$5,429,359
Other Revs	\$ (1,446)	(598)	(187)	(109)	(56)	(496)	(1,446)
Operating Expenses	\$ 4,171,780	1,950,438	679,901	152,368	140,673	1,248,400	4,171,780
Net Income	1,256,133	667,675	310,369	(1,767)	36,609	243,247	1,256,133
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Target Return	1,256,133	643,928	207,660	64,392	41,064	299,089	1,256,133
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Rate Base	\$ 19,232,800	9,859,263	3,179,513	985,910	628,729	4,579,385	19,232,800
ROR	6.53%	6.77%	9.76%	-0.18%	5.82%	5.31%	6.53%
Index of ROR	1.00	1.04	1.49	-0.03	0.89	0.81	1.00

Class ROR Index between 0.9 and 1.1?

TRUE

FALSE

FALSE

FALSE

FALSE

Notes

1 Direct Input From Boswell Exhibit 1, Schedules 2 & 3, columns (c) as appropriate.

2 Assignment to rate classes done on the basis of the MAE "per books" data [E-1, Item 45A].

I/A

Duke Energy Carolinas, LLC

Docket No. E-7, Sub 1276

Change
Inputs Here

Modified Average and Excess - Per Books

Item 45(a) - (Test Year 12-months ended December 31, 2021)

Dollars in Thousands

	Inputs	NC Juris	Res	GS	Lighting	IND	OPT
Rate Schedule (Billed) Revenues	R602	\$4,705,437 V	\$2,269,546 48.232%	\$858,395 18.243%	\$130,615 2.776%	\$153,693 3.266%	\$1,293,188 27.483%
Other Revs	Q035	\$118,522 V	\$49,012 41.353%	\$15,362 12.961%	\$8,939 7.542%	\$4,595 3.877%	\$40,614 34.267%
Operating Expenses	OPEX	\$3,539,360 V	\$1,654,762 46.753%	\$576,832 16.298%	\$129,270 3.652%	\$119,348 3.372%	\$1,059,149 29.925%
Net Income (Ret. On Rate Base)	R751	\$1,284,599 V	\$663,796	\$296,925	\$10,284	\$38,940	\$274,653
Desired Return	calculated	\$1,284,599 V	\$658,521	\$212,366	\$65,851	\$41,994	\$305,867
Rate Base	RB99	\$17,596,163 V	\$9,020,278 51.263%	\$2,908,949 16.532%	\$902,013 5.126%	\$575,227 3.269%	\$4,189,697 23.810%
ROR	calculated	7.30% V	7.36%	10.21%	1.14%	6.77%	6.56%
Index of ROR	calculated	1.00	1.01	1.40	0.16	0.93	0.90

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NC League of Municipalities Cross Examination Williamson Supplemental Ex. 1

Public Staff Recommended Retail Rate Allocation

Source: Williamson Corrected Supplemental Ex. 1

Class	YearO	Year 1	Year 2	Year 3
Resi	2.71%	4.93%	8.15%	11.04%
General	-0.98%	0.97%	3.52%	6.04%
Industrial	2.62%	4.75%	7.82%	10.61%
OPT	3.24%	5.11%	7.94%	10.62%
Lighting	21.56%	26.87%	31.81%	35.63%
NC Retail	2.70%	4.86%	7.89%	10.68%

% Lighting over NC Retail	18.86%	22.01%	23.92%	24.95%
Ratio of Lighting to NC Retail	7.99	5.53	4.03	3.34
Ratio of Lighting to next highest class	6.65	5.26	3.90	3.23

DEC Recommended Retail Rate Allocation

Source: Beveridge Ex 4 (Col L)

Class	Year 0	Year 1	Year 2	Year 3
Resi	7.70%	10.70%	14.60%	18.10%
General	5.80%	8.40%	11.70%	14.80%
Industrial	7.20%	9.80%	13.00%	15.80%
OPT	5.30%	7.20%	9.30%	10.80%
Lighting	22.90%	28.40%	33.60%	36.70%
NC Retail	7.10%	9.70%	13.00%	15.90%

% Lighting over NC Retail	15.80%	18.70%	20.60%	20.80%
Ratio of Lighting to NC Retail	3.23	2.93	2.58	2.31
Ratio of Lighting to next highest class	4.32	3.94	2.30	2.03

I/A

**Duke Energy Carolinas
Response to
Carolina Industrial Group for Fair Utility Rates IE's
Fifth Set of Data Requests**

Docket No. E-7, Sub 1276

**Date of Request: October 26, 2023
Date of Response: October 27, 2023**

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The attached response to CIGFUR III's Fourth Data Request No.5-1, was provided to me by the following individual(s): Morgan Beveridge, Manager of Rates and Regulatory Strategy, and was provided to CIGFUR III under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Carolinas

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Nov 02 2023

CIGFUR III
Data Request No. 5
DEC Docket No. E-7, Sub 1276
Item No. 5-1
Page 1 of 1

Request:

- 5-1. At page 6, line 9 of DEC witnesses Byrd and Beveridge's Supplemental Rebuttal Testimony, witnesses Byrd and Beveridge note that they were surprised by the recommended revenue apportionment detailed in Public Staff witness D. Williamson's supplemental testimony, as corrected. Did DEC have any discussions with the Public Staff about the Public Staff's revenue apportionment methodology or recommendations offered in this DEC rate case prior to the filing of witness D. Williamson's supplemental testimony? If yes, please provide the dates of each such conversation and a brief summary of what was discussed during each such conversation; please further provide copies of any and all related written correspondence between DEC and the Public Staff. If no, why not?

Response:

The Company engages Public Staff and all parties to a proceeding on a regular basis and remains open to any and all discussions on any topic during a proceeding. The Company does not keep records of all such engagements.

To the best of the Company's knowledge, the Public Staff first presented the apportionment methodology recommended by witness D. Williamson in a call at 11 a.m. on Friday, October 13th, which was the date of the filing of the proposal with the NCUC. The Company expressed concerns similar to those raised in the Company's Supplemental Rebuttal Testimony.

Aside from email correspondence between David Williamson and Morgan Beveridge setting a time for that call (which did not divulge or otherwise discuss the Public Staff's apportionment methodology), the Company has not identified any other written correspondence responsive to this request.

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Nov 02 2023

**Duke Energy Carolinas
Response to
Carolina Industrial Group for Fair Utility Rates III's
Fifth Set of Data Requests**

Docket No. E-7, Sub 1276

**Date of Request: October 26, 2023
Date of Response: October 27, 2023**

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The attached response to CIGFUR III's Fourth Data Request No.5-2, was provided to me by the following individual(s): Morgan Beveridge, Manager of Rates and Regulatory Strategy, and was provided to CIGFUR III under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Carolinas

CIGFUR III
Data Request No. 5
DEC Docket No. E-7, Sub 1276
Item No. 5-2
Page 1 of 1

Request:

- 5-2. In Docket No. E-2, Sub 1300, the Public Staff worked collaboratively with DEP to form its revenue apportionment recommendations. To DEC's knowledge, did the Public Staff work collaboratively with any other party in the DEC rate case to form its recommended revenue apportionment as put forth in witness D. Williamson's supplemental testimony?

Response:

The Company does not agree with the assertion that the "Public Staff worked collaboratively with DEP to form its revenue apportionment recommendations" in the DEP proceeding. As discussed in the Company's response to 5-1, The Company engages Public Staff and all parties to a proceeding a regular basis and remains open to any and all discussions on any topic during a proceeding (and the same is true with respect to DEP in the DEP proceeding). In the DEP proceeding, the Public Staff ultimately reached the same revenue apportionment recommendation as the Company, but did so through its own investigation and analysis and not through a collaborative process with DEP.

See the Company's response to 5-1 describing the Company's engagement with Public Staff on revenue apportionment issues in this case. DEC has no knowledge of Public Staff's engagement with other parties on this issue in the DEC proceeding.

**Duke Energy Carolinas
Response to
Carolina Industrial Group for Fair Utility Rates III's
Fifth Set of Data Requests**

Docket No. E-7, Sub 1276

**Date of Request: October 26, 2023
Date of Response: October 27, 2023**

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The attached response to CIGFUR III's Fourth Data Request No.5-3, was provided to me by the following individual(s): Morgan Beveridge, Manager of Rates and Regulatory Strategy, and was provided to CIGFUR III under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Carolinas

CIGFUR III
Data Request No. 5
DEC Docket No. E-7, Sub 1276
Item No. 5-3
Page 1 of 1

Request:

- 5-3. At page 7, line 15 of DEC witnesses Byrd and Beveridge's supplemental rebuttal testimony, witnesses Byrd and Beveridge note that "Public Staff manually adjusted the rate increase for each rate class independently to 'apply the Public Staff's revenue assignment principles as practicably as possible.'" Does DEC take the position that D. Williamson's approach to revenue apportionment is subjective? Arbitrary? Problematic? Concerning? Prejudicial? Discriminatory? Please answer yes or no as to each and provide a rationale for each such answer.

Response:

The Company believes witness D. Williamson's approach is not formulaic, in that specific outcomes by rate class were based on subjective adjustments of the revenue apportionment amounts by class. As such, replicating the apportionment methodology for any other approved revenue requirement would be impossible. The Company does not view the Public Staff's approach as prejudicial or discriminatory, but it does view the approach as problematic and concerning from a practical, process perspective.

**Duke Energy Carolinas
Response to
Carolina Industrial Group for Fair Utility Rates III's
Fifth Set of Data Requests**

Docket No. E-7, Sub 1276

**Date of Request: October 26, 2023
Date of Response: October 27, 2023**

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The attached response to CIGFUR III's Fourth Data Request No.5-4, was provided to me by the following individual(s): Morgan Beveridge, Manager of Rates and Regulatory Strategy, and was provided to CIGFUR III under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Carolinas

CIGFUR III
Data Request No. 5
DEC Docket No. E-7, Sub 1276
Item No. 5-4
Page 1 of 1

Request:

- 5-4. Please explain whether the methodology relied upon in apportioning an electric public utility's total revenue requirement should be replicable? Verifiable? Easily reproduced? Formulaic? Consistent? Reliable? Please answer yes or no as to each and provide a rationale for each such answer. Please further opine as to whether DEC believes the revenue apportionment methodology utilized by witness D. Williamson satisfies any of the aforementioned criteria.

Response:

The apportionment methodology should be clear and able to be applied in a straightforward manner based on a final NCUC order. In other words, the approach should not be subject to interpretation. For Compliance Rates, informed parties should be able to easily verify that the Company followed the NCUC order in apportioning revenues by class. In the Company's opinion, witness D. Williamson's apportionment methodology relies on a subjective "optimization" approach based on certain Public Staff principles that could easily result in different outcomes from informed parties seeking to apply those same principles. Such approach is therefore not replicable or easily reproducible.

**Duke Energy Carolinas
Response to
Carolina Industrial Group for Fair Utility Rates III's
Fifth Set of Data Requests**

Docket No. E-7, Sub 1276

**Date of Request: October 26, 2023
Date of Response: October 27, 2023**

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The attached response to CIGFUR III's Fourth Data Request No.5-5, was provided to me by the following individual(s): Morgan Beveridge, Manager of Rates and Regulatory Strategy, and was provided to CIGFUR III under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Carolinas

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CIGFUR III
Data Request No. 5
DEC Docket No. E-7, Sub 1276
Item No. 5-5
Page 1 of 1

Request:

- 5-5. Is D. Williamson's recommended revenue apportionment and underlying methodology capable of being tested by the Company or other parties? Why or why not?

Response:

The Company believes other parties could review D. Williamson's approach and determine whether or not the Public Staff apportionment methodology, as applied to the Public Staff's recommended revenue requirement, is seeking to balance and achieve the Public Staff's general principles. The Company notes, however, that reasonable rate designers could apply the Public Staff's principles and reach multiple different conclusions even if they all were using the same revenue requirement.

Importantly, the Company's concern is not with testing or validating witness D. Williamson's specific recommendation, per se. The challenge is that witness D. Williamson's approach is not replicable or applicable to any other potential revenue requirement that might be approved by the NCUC, such as the Company's recommended revenue requirement. In contrast, the Company's recommended apportionment methodology could be consistently applied and validated for the Company's proposed revenues, the Public Staff's proposed revenues, or anything in between.

**Duke Energy Carolinas
Response to
Carolina Industrial Group for Fair Utility Rates III's
Fifth Set of Data Requests**

Docket No. E-7, Sub 1276

**Date of Request: October 26, 2023
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The attached response to CIGFUR III's Fourth Data Request No.5-6, was provided to me by the following individual(s): Morgan Beveridge, Manager of Rates and Regulatory Strategy, and was provided to CIGFUR III under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Carolinas

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CIGFUR III
Data Request No. 5
DEC Docket No. E-7, Sub 1276
Item No. 5-6
Page 1 of 1

Request:

- 5-6. To the Company's knowledge, has the revenue apportionment methodology employed by D. Williamson been utilized by the Public Staff in any other proceeding before the NC Utilities Commission? If not, is the Company aware of any instance in any jurisdiction in the country in which the revenue apportionment methodology employed by D. Williamson has been recommended or approved by a Public Utilities Commission?

Response:

The Public Staff has articulated its general rate design principles in other cases, but the Company is not aware of other cases in which Public Staff employed the specific revenue apportionment methodology employed by witness D. Williamson in this case.

The Company is not aware of any other jurisdictions in which D. Williamson's specific revenue apportionment methodology has been recommended or approved.

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**Duke Energy Carolinas
Response to
Carolina Industrial Group for Fair Utility Rates III's
Fifth Set of Data Requests**

Docket No. E-7, Sub 1276

**Date of Request: October 26, 2023
Date of Response: October 27, 2023**

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The attached response to CIGFUR III's Fourth Data Request No.5-7, was provided to me by the following individual(s): Morgan Beveridge, Manager of Rates and Regulatory Strategy, and was provided to CIGFUR III under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Carolinas

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Nov 02 2023

CIGFUR III
Data Request No. 5
DEC Docket No. E-7, Sub 1276
Item No. 5-7
Page 1 of 1

Request:

- 5-7. To the Company's knowledge, are there any standards controlling the use of the methodology for revenue apportionment being recommended by D. Williamson in this proceeding? If yes, please state all such standards with specificity. If no, does the Company agree that it is problematic that D. Williamson's revenue apportionment methodology has no such standards?

Response:

Witness D. Williamson has stated that his apportionment methodology is seeking to achieve the Public Staff's rate design principles, which could be interpreted as a standard for developing his proposed apportionment recommendation. However, reasonable rate designers could apply those same rate design principles to reach many different outcomes.

**Duke Energy Carolinas
Response to
Carolina Industrial Group for Fair Utility Rates III's
Fifth Set of Data Requests**

Docket No. E-7, Sub 1276

**Date of Request: October 26, 2023
Date of Response: October 27, 2023**

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The attached response to CIGFUR III's Fourth Data Request No.5-8, was provided to me by the following individual(s): Morgan Beveridge, Manager of Rates and Regulatory Strategy, and was provided to CIGFUR III under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Carolinas

CIGFUR III
Data Request No. 5
DEC Docket No. E-7, Sub 1276
Item No. 5-8
Page 1 of 1

Request:

- 5-8. Is the revenue apportionment methodology utilized by D. Williamson in the instant case generally accepted in the electric public utility industry? Please provide any supporting documentation.

Response:

The revenue apportionment methodology employed by witness D. Williamson is specifically tailored to the Public Staff's revenue recommendations in the instant case and therefore not generalizable to the industry.

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**Duke Energy Carolinas
Response to
Carolina Industrial Group for Fair Utility Rates III's
Fifth Set of Data Requests**

Docket No. E-7, Sub 1276

**Date of Request: October 26, 2023
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Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to CIGFUR III's Fourth Data Request No.5-9, was provided to me by the following individual(s): Morgan Beveridge, Manager of Rates and Regulatory Strategy, and was provided to CIGFUR III under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Carolinas

CIGFUR III
Data Request No. 5
DEC Docket No. E-7, Sub 1276
Item No. 5-9
Page 1 of 1

Request:

- 5-9. To the Company's knowledge, are there any publications addressing the revenue apportionment methodology utilized by D. Williamson? If yes, please provide copies of all such publications. If no, please state whether the Company takes the position that it is problematic to rely on a revenue apportionment methodology that has not been tested or peer reviewed.

Response:

No. See response to DR 5-8.

**Duke Energy Carolinas
Response to
Carolina Industrial Group for Fair Utility Rates III's
Fifth Set of Data Requests**

Docket No. E-7, Sub 1276

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The attached response to CIGFUR III's Fourth Data Request No.5-10, was provided to me by the following individual(s): Morgan Beveridge, Manager of Rates and Regulatory Strategy, and was provided to CIGFUR III under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Carolinas

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CIGFUR III
Data Request No. 5
DEC Docket No. E-7, Sub 1276
Item No. 5-10
Page 1 of 1

Request:

5-10. Is the technique utilized by D. Williamson in providing his recommendations for apportioning the Company's total revenue requirement valid? Statistically reliable? Testable?

Response:

See response to DR 5-5.

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**Duke Energy Carolinas
Response to
Carolina Industrial Group for Fair Utility Rates III's
Fifth Set of Data Requests**

Docket No. E-7, Sub 1276

**Date of Request: October 26, 2023
Date of Response: October 27, 2023**

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The attached response to CIGFUR III's Fourth Data Request No.5-11, was provided to me by the following individual(s): Morgan Beveridge, Manager of Rates and Regulatory Strategy, and was provided to CIGFUR III under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Carolinas

CIGFUR III
Data Request No. 5
DEC Docket No. E-7, Sub 1276
Item No. 5-11
Page 1 of 1

Request:

5-11. At page 7, lines 1-5 of DEC witnesses Byrd and Beveridge's supplemental rebuttal testimony, witnesses Byrd and Beveridge indicate that "Witness Williamson's recommended allocation of the revenue requirement in this case differs from that of the Company (as well as any other intervenor), resulting in substantially different percentage increases to the various customer classes than any of the rate design approaches litigated during the course of the evidentiary hearing in this case."

- a. Does witness D. Williamson's cost of service analysis at present rates indicate that the OPT class produces a rate of return that is below system average rate of return? If yes, does this differ from the Company's results? If so, how does it differ?
- b. As a result of his cost of service analysis, does witness D. Williamson's recommended increase for the OPT class relative to the system average increase differ from the Company's approach and recommendations with respect to the OPT class's increase? If so, how does it differ?
- c. Does the Company agree with witness D. Williamson's cost of service results and resulting percentage increases for the OPT class? Why or why not?

Response:

- a. Yes. Witness D. Williamson's analysis produces a lower rate of return at present rates for the OPT class relative to the class average. This differs from the Company's analysis which indicates a higher rate of return for the OPT class relative to the class average.
- b. Yes. Witness D. Williamson's recommended revenue apportionment results in higher rate increases for the OPT class relative to the system average in each rate year. The Company's recommended revenue apportionment results in lower rate increases for the OPT class relative to the system average in each rate year.
- c. No. It is unclear to the Company why D. Williamson's results differ. The Company continues to support its own cost of service results and maintains that the Company's 10% variance reduction approach is the most appropriate revenue apportionment methodology for this case.

**Duke Energy Carolinas
Response to
Carolina Industrial Group for Fair Utility Rates III's
Fifth Set of Data Requests**

Docket No. E-7, Sub 1276

**Date of Request: October 26, 2023
Date of Response: October 27, 2023**

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CONFIDENTIAL

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NOT CONFIDENTIAL

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to CIGFUR III's Fourth Data Request No.5-12, was provided to me by the following individual(s): Morgan Beveridge, Manager of Rates and Regulatory Strategy, and was provided to CIGFUR III under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Carolinas

CIGFUR III
Data Request No. 5
DEC Docket No. E-7, Sub 1276
Item No. 5-12
Page 1 of 1

Request:

- 5-12. Given the non-replicable rate increase modifications that witness D. Williamson employed on an *ex post facto* basis, does the Company agree that the results of witness D. Williamson's revenue apportionment results are invalid? Does the Company take the position that witness D. Williamson's revenue apportionment recommendations should or should not be approved by the Commission? Explain your answer.

Response:

The Company is concerned that witness D. Williamson's revenue apportionment results are inextricably linked to the Public Staff's revenue recommendation. In short, if the NCUC were to approve revenue requirements that at all differ from the Public Staff's recommendation in conjunction with approving the Public Staff's recommended revenue apportionment approach, following the NCUC order would be subject to interpretation and informed parties may easily disagree as to whether the Company implemented rates in conformance to the NCUC order. Accordingly, the Company takes the position that the Commission should not approve D. Williamson's apportionment recommendations.