ONE-HUNDRED NINTH REPORT

OF THE

NORTH CAROLINA

UTILITIES COMMISSION

ORDERS AND DECISIONS

Volume I

ISSUED FROM
JANUARY 1, 2019 THROUGH DECEMBER 31, 2019

ONE-HUNDRED NINTH REPORT
of the
NORTH CAROLINA UTILITIES COMMISSION

ORDERS AND DECISIONS

Issued from

January 1, 2019, through December 31, 2019

*Edward S. Finley, Jr., Chairman

ToNola D. Brown-Bland, Commissioner

**Jerry C. Dockham, Commissioner

**James G. Patterson, Commissioner

Lyons Gray, Commissioner

Daniel G. Clodfelter, Commissioner

*Charlotte A. Mitchell, Commissioner

*Kimberly W. Duffley, Commissioner

*Jeffrey A. Hughes, Commissioner

North Carolina Utilities Commission
Office of the Chief Clerk
Kimberley A. Campbell
4325 Mail Service Center
Raleigh, North Carolina 27699-4300

The Statistical and Analytical Report of the North Carolina Utilities Commission is printed separately from the volume of Orders and Decisions and will be available from the Office of the Chief Clerk of the North Carolina Utilities Commission upon order.

* Chairman Finley retired May 31, 2019.
** Commissioners Dockham and Patterson retired June 30, 2019.

* Commissioner Mitchell, appointed Chair June 4, 2019.
* Commissioner Duffley, seated November 12, 2019.
* Commissioner Hughes, seated November 17, 2019.

LETTER OF TRANSMITTAL

December 31, 2019

The Governor of North Carolina
Raleigh, North Carolina

Sir:

Pursuant to the provisions of Section 62-17(b) of the General Statutes of North Carolina, providing for the annual publication of the final decisions of the Utilities Commission on and after January 1, 2019, we hereby present for your consideration the report of the Commission's significant decisions for the 12-month period beginning January 1, 2019, and ending December 31, 2019.

The additional report provided under G.S. 62-17(a), comprising the statistical and analytical report of the Commission, is printed separately from this volume and will be transmitted immediately upon completion of printing.

Respectfully submitted,

NORTH CAROLINA UTILITIES COMMISSION

Charlotte A. Mitchell, Chair

ToNola D. Brown-Bland, Commissioner

Lyons Gray, Commissioner

Daniel G. Clodfelter, Commissioner

Kimberly W. Duffley, Commissioner

Jeffrey A. Hughes, Commissioner

Kimberley A. Campbell, Chief Clerk

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DOCKET NO. E-100, SUB 101

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Petition for Approval of Revisions to Generator Interconnection Standards	))))	ORDER APPROVING REVISED INTERCONNECTION STANDARD AND REQUIRING REPORTS AND TESTIMONY

HEARD: Monday, January 28, 2019, at 2:00 p.m., in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Chairman Edward S. Finley, Jr.,[1] Presiding; Commissioners ToNola D. Brown-Bland, Jerry C. Dockham, James G. Patterson, Lyons Gray, Daniel G. Clodfelter, and Charlotte A. Mitchell

APPEARANCES:

For Duke Energy Progress, LLC and Duke Energy Carolinas, LLC:

Jack E. Jirak, Duke Energy Corporation, P.O. Box 1552/NCRH 20, Raleigh, North Carolina 27602

E. Brett Breitschwerdt, McGuireWoods, LLP, 434 Fayetteville Street, Suite 2600, Raleigh, North Carolina 27601

For Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina:

Andrea R. Kells, McGuireWoods LLP, 434 Fayetteville Street, Suite 2600, Raleigh, North Carolina 27601

For North Carolina Sustainable Energy Association:

Peter H. Ledford, General Counsel, and Benjamin Smith, Regulatory Counsel, North Carolina Sustainable Energy Association, 4800 Six Forks Road, Suite 300, Raleigh, North Carolina 27609

For Interstate Renewable Energy Council:

Laura Beaton, Shute, Mihaly & Weinberger LLP, 396 Hayes Street, San Francisco, California 94102

[1] Chairman Edward S. Finley, Jr., resigned from the Commission effective May 31, 2019, and did not participate in this decision.

Lauren Bowen, Southern Environmental Law Center, 601 West Rosemary Street, Suite 220, Chapel Hill, North Carolina 27516

For North Carolina Clean Energy Business Alliance:

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

For North Carolina Pork Council:

Kurt J. Olson, The Law Office of Kurt J. Olson, P.O. Box 10031, Raleigh, North Carolina 27605

For Cypress Creek Renewables:

Benjamin Snowden, Kilpatrick, Townsend & Stockton LLP, 4208 Six Forks Road, Suite 1400, Raleigh, North Carolina 27609

For the Attorney General:

Jennifer Harrod and Teresa Townsend, Special Deputy Attorneys General, North Carolina Department of Justice, 114 West Edenton Street, Raleigh, North Carolina 27603

For the Public Staff:

Tim R. Dodge and Layla Cummings, Staff Attorneys, Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699

BY THE COMMISSION: On May 15, 2015, the Commission issued an Order Approving Revised Interconnection Standard (2015 Order) in this docket approving a revised version of the North Carolina Interconnection Procedures, Forms and Agreements (collectively referred to as the NC Interconnection Standard). In ordering paragraph 3 of the 2015 Order, the Commission directed the Public Staff – North Carolina Utilities Commission (Public Staff) to convene a workgroup within two years after the 2015 Order to determine if the NC Interconnection Standard needs revising or whether it should remain unchanged, and to report to the Commission on any recommendations from the stakeholder group within four months from the first meeting of the group.

Pursuant to the directive of the 2015 Order, on May 9, 2017, the Public Staff convened an initial planning meeting for the stakeholder process and recommended Advanced Energy Corporation (Advanced Energy) be retained to facilitate the stakeholder discussions. Advanced Energy facilitated four larger interconnection stakeholder meetings on June 1, July 14, August 8, and September 6 of 2017.

On July 27, 2017, the Governor signed into law House Bill 589, S.L. 2017-192 (HB 589). Part VII of HB 589 amended N.C. Gen. Stat. § 62-133.8(i)(4) and directed the Commission to adopt rules to provide for an expedited interconnection review process for swine and poultry waste-to-energy facilities 2 MW or less in size to help achieve the animal waste set-aside objectives in N.C. Gen. Stat. §§ 62-133.8(e) and (f).

On September 15, 2017, the Public Staff filed a motion requesting that the Commission grant an extension of time to December 15, 2017, for the filing of its report on the stakeholder process. The motion was subsequently granted by the Commission on September 28, 2017.

On December 15, 2017, the Public Staff submitted its report to the Commission together with a redlined version of the NC Interconnection Standard that had been assembled by Advanced Energy, which identified comments and proposals from various parties.

On December 20, 2017, the Commission issued an Order Requesting Comments, requesting parties to file initial and reply comments on the Working Group Recommendations on or before January 22, 2018, and February 23, 2018, respectively.

On January 18, 2018, the North Carolina Sustainable Energy Association (NCSEA) filed a Motion for Extension of Time to file initial comments. On January 22, 2018, the Commission issued an order granting NCSEA's motion and extending the date for filing of initial comments to January 23, 2018, which the Commission amended by Errata Order on January 23, 2018, to instead extend the time period for filing initial comments to January 29, 2018.

On January 29, 2018, Initial Comments were filed by the Interstate Renewable Energy Council (IREC), the North Carolina Pork Council (NC Pork Council), and NCSEA. Duke Energy Carolinas, LLC (DEC), together with Duke Energy Progress, LLC (DEP), and Dominion Energy North Carolina (DENC) also filed Joint Initial Comments on the same date.[1]

On January 30, 2018, the Utilities filed a Revised Attachment to their Joint Initial Comments.

On February 12, 2018, the North Carolina Clean Energy Business Alliance (NCCEBA) filed a Petition to Intervene, which was granted by the Commission on February 13, 2018.

On February 21, 2018, the Duke Utilities and the Public Staff filed a Joint Motion for Extension of Time, requesting that the time to file reply comments be extended to March 12, 2018, which was granted by Commission Order issued March 1, 2018.

On March 12, 2018, Reply Comments were filed by NCCEBA, IREC, and NCSEA. On the same date, the Utilities filed Joint Reply Comments. The Duke Utilities also filed Additional Reply Comments.

On May 7, 2018, Duke Energy Renewables, Inc., filed a Petition to Intervene, which was granted by the Commission on May 22, 2018.

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[1] This Order refers to DEC and DEP jointly as "Duke" or "the Duke Utilities," and all three utilities, including DENC, jointly as "the Utilities."

GENERAL ORDERS – ELECTRIC

On July 30, 2018, the Duke Utilities filed a Motion for Approval of CPRE-Related Modifications to the North Carolina Interconnection Procedures. On August 1, 2018, NCSEA and IREC filed a Joint Response to the Duke Utilities' motion.

On August 10, 2018, the Commission issued an Order Scheduling Hearing, Requesting Comments, and Extending Tranche 1 CPRE [Competitive Procurement of Renewable Energy] RFP Solicitation Response Deadline. The Order directed all parties to file initial comments on interim modifications to the NC Interconnection Standard relating to Duke Energy's CPRE Program on or before August 24, 2018, and reply comments on or before September 10, 2018, and any petitions to intervene on or before September 21, 2018. The Order also scheduled an oral argument on the interim modifications to the NC Interconnection Standard to be held on September 17, 2018. Further, the Order required direct testimony and exhibits of the Utilities to be filed on or before September 5, 2018, direct testimony and exhibits of the Public Staff and other interveners to be filed on or before September 28, 2018, and the rebuttal testimony of the Utilities to be filed on or before October 12, 2018, and scheduled an evidentiary hearing on proposed revisions to the NC Interconnection Standard for October 22, 2018.

On August 24, 2018, the Public Staff, IREC, NCCEBA, and the Duke Utilities filed Initial Comments on the interim modifications to the NC Interconnection Standard, and DENC filed a Letter in Lieu of Comments.

On August 30, 2018, the Commission rescheduled the evidentiary hearing to January 28, 2019, extended the deadline for petitions to intervene to be filed on or before November 12, 2018, and ordered all direct testimony and exhibits to be filed on or before November 19, 2018, and all rebuttal testimony to be filed on or before December 17, 2018.

On September 6, 2018, the Duke Utilities requested an extension of time for all parties to file reply comments on the interim modifications to the NC Interconnection Standard relating to Duke Energy's CPRE Program. On September 7, 2018, the Commission granted an extension of time for all parties to file reply comments from September 10, 2018, to September 12, 2018. Also on September 7, 2018, First Solar, Inc. (First Solar), filed a Petition to Intervene, which was granted by the Commission on September 28, 2018.

On September 12, 2018, the Public Staff requested an extension of time from September 12, 2018, to September 19, 2018, for all parties to file reply comments on the interim modifications to the NC Interconnection Standard. On September 13, 2018, the Commission granted the Public Staff's motion for extension and rescheduled the oral argument on the interim modifications to the NC Interconnection Standard to September 24, 2018.

On September 19, 2018, Reply Comments on the interim modifications to the NC Interconnection Standard were filed by NCSEA, First Solar, the Public Staff, IREC, NCCEBA, and Duke. On September 20, 2018, Reply Comments were filed by the NC Pork Council.

On September 24, 2018, oral argument was held, with appearances made by the Duke Utilities, NCSEA, IREC, the NC Pork Council, NCCEBA, and the Public Staff. On September 28, 2018, Duke filed Post-Hearing Responses to Commission Questions in which it provided additional information relative to questions that had been raised during the oral argument.

Also on September 28, 2018, the Commission issued an Order entitled Request for Clarification of Statements Made During Oral Argument in which the Commission required Duke to clarify its oral argument comments by a filing due on October 1, 2018. On October 1, 2018, the Duke Utilities filed a response to the Commission's September 28 Order, as did the Public Staff.

On October 5, 2018, the Commission issued its Order Approving Interim Modifications to North Carolina Interconnection Procedures for Tranche 1 of CPRE RFP, approving modifications to the NC Interconnection Standard necessary to implement the Duke Utilities' CPRE Program. The Commission issued an Errata Order correcting the Appendices of the October 5 Order on October 9, 2018.

On November 9, 2018, Cypress Creek Renewables (Cypress Creek) filed a Petition to Intervene and a Motion for Partial Stay of the Commission's October 5, 2018 Order. On that same day, the Commission granted Cypress Creek's Petition to Intervene.

On November 13, 2018, the NC Pork Council filed a Petition to Intervene, which was granted by the Commission on November 14, 2018.

On November 19, 2018, the Commission granted Cypress Creek's motion to stay the effectiveness of ordering paragraph 2 of the Commission's October 5, 2018 Order.

On November 19, 2018, the Duke Utilities filed the direct testimony of Gary R. Freeman and the direct testimony and exhibits of Jeffrey R. Riggins and John W. Gajda; DENC filed the direct testimony and exhibit of Michael J. Nester; the Public Staff filed the direct testimony and exhibits of Jay B. Lucas and Tommy C. Williamson; NCSEA filed the direct testimony and exhibits of Paul Brucke; IREC filed the direct testimony and exhibits of Sara Baldwin Auck and Brian M. Lydic; NCCEBA filed the direct testimony of Robert J. Duke; and the NC Pork Council filed the direct testimony of Angie Maier. On November 20, 2018, NCCEBA filed the direct testimony and exhibit of Christopher Norqual.

On November 21, 2018, Cypress Creek filed a Petition for Limited Waiver, or in the Alternative, For Modification to the North Carolina Interconnection Procedures.

On December 3, 2018, the Utilities and the Public Staff filed a joint motion for extension of time to file rebuttal testimony.

On December 6, 2018, the Commission granted Cypress Creek's petition for limited waiver.

On December 7, 2018, the Commission granted the joint motion for extension of time to file rebuttal testimony.

On December 18, 2018, the Duke Utilities made their compliance filing pursuant to the Commission's October 5, 2018 Order.

On January 4, 2019, IREC filed a motion to bifurcate or continue hearing.

On January 8, 2019, the Duke Utilities, DENC, the Public Staff, NCSEA, NCCEBA, and IREC filed rebuttal testimony and exhibits of their witnesses. NCCEBA also filed the rebuttal testimony of witness Norqual as well as the rebuttal testimony of Michael R. Wallace and Luke D. O'Dea.

On January 11, 2019, the Duke Utilities filed a corrected Rebuttal Exhibit JWR-4.

On January 14, 2019, IREC filed a motion to excuse witness Lydic from the hearing Subsequently, NCCEBA and the NC Pork Council also filed motions to excuse witnesses Duke and Maier, respectively, on January 22, 2019. On January 23, 2019, the Commission granted IREC's, NCCEBA's, and the NC Pork Council's motions to excuse witnesses.

On January 25, 2019, the Duke Utilities filed an Agreement and Stipulation of Partial Settlement (Stipulation) by and between DEC, DEP, DENC, the Public Staff, and the NC Pork Council, and included a Stipulated Redline of the NC Interconnection Standard (Stipulated Redline).

On January 28, 2019, NCSEA filed a motion for postponement of hearing, and on that same day the Duke Utilities filed a response opposing that motion. The Commission orally dismissed NCSEA's motion for postponement of hearing and otherwise held the evidentiary hearing as scheduled that afternoon.

On February 26, 2019, the Duke Utilities filed responses to requests that Commissioners had made during the hearing.

On March 14, 2019, the Public Staff filed a motion for extension of time to file proposed orders and post-hearing briefs. On March 15, 2019, the Commission issued an order extending the deadline for filing proposed orders or other post-hearing filings to March 25, 2019.

On March 25, 2019, the Utilities and the Public Staff filed a Joint Proposed Order, and the Duke Utilities filed a post-hearing brief. Post-hearing briefs also were timely filed by the Attorney General's Office, IREC, NCCEBA, and NCSEA. On March 29, 2019, the Duke Utilities filed an additional version of Exhibit 1 to the Joint Proposed Order of the Utilities and the Public Staff.

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

FINDINGS OF FACT

REVISIONS TO THE NC INTERCONNECTION STANDARD

1. With the exceptions noted below, the revisions to the NC Interconnection Standard presented in the Stipulated Redline are reasonable, and it is appropriate to apply them to new and pending Interconnection Requests, as provided for in Section 1.1.3 of the NC Interconnection Standard.

2. New Section 1.8.3.4 of the Stipulated Redline is reasonable to facilitate the expedited study of Standby Generating Facilities.[1]

3. The proposed fees presented in the Stipulated Redline are a reasonable means to recover the Utilities' ongoing costs of processing generator Interconnection Requests, completing Pre-Application Reports, processing changes of control, and otherwise administering the NC Interconnection Standard. It is appropriate for the Utilities to provide a verified report by March 1 of each year detailing their annual interconnection expenses and revenues and comparing those amounts to prior years' expenses and revenues.

4. It is appropriate and necessary to modify the NC Interconnection Standard so that Interconnection Customers have 10 Business Days to cure Utility requests for information in the Facilities Study and System Impact Study processes; it is appropriate that failure to provide the requested information within 10 Business Days should result in the Interconnection Request being removed from the interconnection queue. The new policy should be effective starting July 15, 2019, and the Utilities shall inform Interconnection Customers of this new policy by mail by July 1, 2019.

5. Modifications to Section 6.5 to specifically allow the Utilities to conduct post-commissioning inspections are reasonable. It is appropriate that Interconnection Customers should reimburse the Utility for the cost of such inspections. The Utilities should be required to keep records of their inspection findings and costs.

MATERIAL MODIFICATION DEFINITION/
ADDING ENERGY STORAGE TO EXISTING SOLAR FACILITIES

6. Changes to Section 1.5 in the Stipulated Redline regarding the Material Modification standard are reasonable and appropriate to ensure that installed Generating Facilities or Interconnection Customers proposing modifications, including the addition of energy storage, are evaluated for potential impacts to the Utility's System or other customers prior to the Utility accepting for installation the modification to the Generating Facility.

7. It is appropriate for Interconnection Customers to provide hourly production profile data with their Interconnection Requests as required in the Stipulated Redline, pending the filing of additional information by the Utilities.

8. It is appropriate for the Utilities to host stakeholder meetings to discuss development of an expedited study process for energy storage being added to an existing generation site and to require the Utilities to file such a process for Commission consideration.

[1] Capitalized words are terms of art used and defined in the NC Interconnection Standard, which is attached as an Appendix to this Order.

EXPEDITED REVIEW OF INTERCONNECTIONS
FOR SMALL SWINE AND POULTRY WASTE FACILITIES

9. New Section 1.8.3.3 is reasonable to facilitate the expedited study of Small Animal Waste to Energy Facilities and implement the requirements of Part VII of HB 589, Session Law 2017-192.

FAST TRACK AND SUPPLEMENTAL REVIEW PROCESSES

10. The changes to the Section 2 and Section 3 study processes for small generator Interconnection Customers presented in the Stipulated Redline are reasonable. IREC's proposed modifications to the Fast Track and Supplemental Review processes are not warranted at this time. It is appropriate for the Duke Utilities to consult with the Electric Power Research Institute (EPRI) regarding the Section 3 Fast Track and Supplemental Review study processes and provide a report to be filed with the Commission regarding potential modifications at a Technical Standards Review Group (TSRG) meeting in the third quarter of 2019.

11. It is appropriate to require the Utilities to post information on their interconnection websites describing the technical screens and standards they apply during Supplemental Reviews. It is appropriate that the Utilities change these screens and standards as necessary to assure that new generator interconnections do not impair the safety and reliability of the electric grid.

DISPUTE RESOLUTION PROCESS

12. The Stipulated Redline's modifications to Section 6.2 of the NC Interconnection Standard result in a reasonable process to facilitate resolution of disputes between Interconnection Customers and the Utilities.

SURETY BONDS AND REFUNDS

13. It is reasonable to require the Utilities to develop a standard surety bond that is acceptable to the Utility and make it available to Interconnection Customers to use as financial security for Interconnection Facilities.

14. The Stipulated Redline's modifications to Article 6, Section 6.1.1 of the Interconnection Agreement are appropriate, with additional modifications to be made by the Commission, to provide for the refunding of unspent amounts for Interconnection Facilities if an Interconnection Customer cancels its Generating Facility.

TECHNICAL STUDY PRACTICES AND COMMUNICATIONS

15. The Duke Utilities' Method of Service Guidelines are reasonable and reflect Good Utility Practice in North Carolina. It is appropriate that these and similar DENC guidelines evolve over time with increased penetration of distributed generation in order to ensure the safety, power quality, and reliability of the power delivery system for electricity consumers. It is appropriate for the Utilities to (1) file significant new screens, studies, or major study changes in their application of the NC Interconnection Standard with the Commission for information purposes, (2) post the

information on their websites, and (3) for the Duke Utilities, to present any planned changes for discussion at TSRG meetings.

16. The Duke Utilities' formation of the TSRG in 2018 is a reasonable initiative to promote transparency and technical understanding between the Duke Utilities, Interconnection Customers, and the Public Staff.

17. The TSRG shall be an information-sharing and discussion forum convened and organized by the Duke Utilities, with continued participation by the Public Staff and generation developers. At TSRG meetings, the Duke Utilities shall make reasonable efforts to continually inform the Public Staff, Interconnection Customers, and solar developer advocates of new or changing engineering and technical standards within the interconnection process.

18. It is appropriate for the Duke Utilities to continue posting agendas, presentations, detailed meeting minutes, and other details of the TSRG to its website as promptly as possible.

TIMELINE ENFORCEMENT MECHANISM

19. It is not appropriate at this time to impose a timeline enforcement mechanism in the NC Interconnection Standard.

QUEUE MANAGEMENT REPORTING

20. The Duke Utilities' commitments to enhance queue status reporting as recommended by the Public Staff are appropriate and should be approved.

21. IREC's proposed reporting requirements should not be adopted at this time.

HOSTING CAPACITY MAPS

22. It is not necessary to require the Utilities to pursue hosting capacity maps at this time.

WORKING GROUPS

23. The Duke Utilities' commitments in the Stipulation to implement a stakeholder process to develop a group study proposal are reasonable and appropriate.

24. It is appropriate for the Utilities to conduct stakeholder meetings in 2020 to consider how to address IEEE Standard 1547-2018 in the NC Interconnection Standard, including the use of software-based controls for limiting a generator's output, and to report to the Commission as to the status of this effort by August 1, 2020.

COST OF SERVICE IMPACTS OF DISTRIBUTED GENERATION

25. All users of the distribution grid, electricity customers as well as generation interconnection customers, benefit from the distribution grid and should be responsible for the

costs of operating and maintaining it. It is appropriate to require Utilities to consider all grid users in their cost of service studies.

REVISIONS TO THE NC INTERCONNECTION STANDARD

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 1

The evidence supporting this finding of fact is contained in the Stipulation and the Stipulated Redline, and the testimony and exhibits of Duke witnesses Gajda and Freeman, DENC witness Nester, IREC witness Auck, and Public Staff witnesses Lucas and Williamson.

In the Stipulation, the Public Staff, DEC, DEP, DENC, and the NC Pork Council (the Stipulating Parties) stated that the Utilities in their January 29, 2018 Initial Comments included a set of proposed modifications to the NC Interconnection Standard. The Stipulating Parties developed additional modifications over the past year as a result of dialogue among the parties and additional changes identified by the Duke Utilities, and those further proposed modifications (Revised Modifications) were attached to the January 8, 2019 rebuttal testimony of Duke witness Gajda.

The Stipulation stated that in the interest of narrowing the issues in dispute, the Stipulating Parties sought to identify those portions of the Revised Modifications that were supported by the Stipulating Parties, and the resulting modified version of the NC Interconnection Standard was attached to the January 25, 2019 Agreement and Stipulation of Partial Settlement as the Stipulated Redline. The Stipulation stated that the Stipulated Redline is substantially the same as the Revised Modifications, with the following changes:

1) The Utilities agreed to the proposed modifications to Section 6.2 of the NC Interconnection Standard related to the dispute process that were included in Public Staff witness Lucas' direct testimony.

2) The Utilities agreed to the proposed changes to Section 1.5 of the NC Interconnection Standard that were included in Public Staff witness Lucas' rebuttal testimony.

3) The Utilities and the Public Staff agreed to support clarification of new Section 1.8.3.3 of the NC Interconnection Standard to provide that a Small Animal Waste Facility, upon being designated a Project B, shall be the next project B studied under Section 4.3, regardless of Queue Number.

The NC Pork Council also signed onto the Stipulation to support the revisions to Section 1.8.3.3, but did not take a position with regard to other proposed modifications to the NC Interconnection Standard.

Duke witness Freeman testified that the Stipulation reflected the Stipulating Parties' full agreement upon a set of modifications to the NC Interconnection Standard, and also included certain specific modifications requested by the NC Pork Council. Witness Freeman also testified that the Stipulation formalizes for the benefit of the Commission what was already self-evident from the hundreds of pages of filings made in this proceeding – that there was significant alignment among the Public Staff and the Utilities regarding reasonable and appropriate modifications to the existing NC Interconnection Standard.

DENC witness Nester testified that he believed the Stipulation to be an acceptable resolution of the issues it addresses.

IREC witness Auck testified that IREC agreed with the requirement in the Stipulation that Duke consult with EPRI on its Fast Track and Supplemental Review processes, but believed that the review should be done independently, with Commission oversight, and that other stakeholders should have the opportunity to review and comment on the findings of that review. Witness Auck indicated that IREC did not have a firm position on the other components of the Stipulation.

Public Staff witnesses Lucas and Williamson also supported the Stipulation. Witness Lucas testified that the Stipulation helped clarify the expedited review process for animal waste projects less than 2 MW in capacity. In addition, the Stipulation resulted in the Utilities agreeing to the Material Modification and dispute resolution revisions proposed by the Public Staff. Witness Williamson testified that as a result of the Stipulation, the Public Staff agreed to withdraw its recommendations for an independent review of the entire North Carolina interconnection process and a stakeholder discussion focused on the project A/B designation. He stated that in exchange, the Duke Utilities agreed to (1) initiate a stakeholder process in the first quarter of 2019 regarding a grouping study process, and (2) make filings regarding that process to FERC and the Commission by July 2019. Williamson stated further that Duke agreed to consult with EPRI about the Fast Track and Supplemental Review processes and to provide a summary report to the TSRG in the third quarter of 2019.

Witness Nester testified that the Utilities proposed to revise the timeframe under Section 5.2.4 for payment and financial security for an Interconnection Agreement from 60 calendar days to 45 Business Days after delivery of the Interconnection Agreement for signature: "While this revision may result in extending the timeframe for payment depending upon the applicable month and holiday schedule, the average duration provided for payment under the proposed 45 Business Days is effectively the same as the 60 calendar days...."

Discussion and Conclusions

As the Stipulation has not been adopted by all of the parties to this docket, its acceptance by the Commission is governed by the standards set out by the North Carolina Supreme Court in State ex rel. Utils. Comm'n v. Carolina Util. Customers Ass'n, Inc., 348 N.C. 452, 500 S.E.2d 693 (1998) (CUCA I), and State ex rel. Utils. Comm'n v. Carolina Util. Customers Ass'n, Inc., 351 N.C. 223, 524 S.E.2d 10 (2000) (CUCA II). In CUCA I, the Supreme Court held that

> a stipulation entered into by less than all of the parties as to any facts or issues in a contested case proceeding under Chapter 62 should be accorded full consideration and weighed by the Commission with all other evidence presented by any of the parties in the proceeding. The Commission must consider the nonunanimous stipulation along with all the evidence presented and any other facts the Commission finds relevant to the fair and just determination of the proceeding. The Commission may even adopt the recommendations or provisions of the

> nonunanimous stipulation as long as the Commission sets forth its reasoning and makes "its own independent conclusion" supported by substantial evidence on the record that the proposal is just and reasonable to all parties in light of all the evidence presented.

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

However, as the Court made clear in CUCA II, the fact that fewer than all of the parties have adopted a settlement does not permit a court to subject the Commission's order adopting the provisions of a nonunanimous stipulation to a "heightened standard" of review. CUCA II, 351 N.C. at 231, 524 S.E.2d at 16. Rather, the Court held that Commission approval of the provisions of a nonunanimous stipulation "requires only that the Commission ma[k]e an independent determination supported by substantial evidence on the record [and] satisf[y] the requirements of chapter 62 by independently considering and analyzing all the evidence and any other facts relevant to a determination that the proposal is just and reasonable to all parties." Id. at 231-32, 524 S.E.2d at 16.

The Commission gives substantial weight to the testimony of the Public Staff and the Utilities' witnesses regarding the Stipulation. The Commission concludes that the Stipulation is the product of the "give-and-take" of settlement negotiations between the Utilities and the Public Staff, as well as the NC Pork Council, in an effort to appropriately balance the Utilities' obligation to manage the interconnection process in a fair and efficient manner and to implement their obligations under HB 589. At the same time, the Stipulation provides improved transparency to the Commission, the Public Staff, Interconnection Customers, and other parties interested in the interconnection process in North Carolina.

Thus, the Stipulation generally strikes a fair balance between the interests of the Stipulating Parties and Interconnection Customers. As discussed above, and further detailed in the Commission's findings of fact and subsequent discussions and conclusions, the Commission has fully evaluated the provisions of the Stipulation and concludes, in the exercise of its independent judgment, that the provisions of the Stipulation are just and reasonable to all parties to this proceeding in light of the evidence presented and serve the public interest. The provisions of the Stipulation strike the appropriate balance between the interests of the Utilities' customers in receiving safe, adequate, and reliable electric service at a reasonable cost, the interests of Interconnection Customers in seeking to interconnect to the grid in an efficient and transparent fashion, the legislative goals of HB 589 in allowing for an expedited process for interconnecting Small Animal Waste to Energy Facilities, and the interests of the Utilities in meeting their obligations to interconnect distributed generation in a fair, technically feasible and non-discriminatory fashion.

Therefore, the Commission approves the Stipulation and the Stipulated Redline. The changes approved in this Order will be effective upon issuance of this Order, except that they will not apply to facilities that have a fully executed Interconnection Agreement as of the date of this Order. All facilities will be subject to this Order for the processing of Material Modifications and ownership transfers. The Commission discusses major provisions of the Stipulated Redline and makes other changes to the NC Interconnection Standard as explained below.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 2

The evidence supporting this finding of fact is found in the Stipulated Redline and in the testimony of Duke witness Riggins, DENC witness Nester, and Public Staff witness Williamson.

Duke witness Riggins outlined the Utilities' proposal to add new Section 1.8.3.4 to the NC Interconnection Standard to allow for expedited study of Standby Generating Facilities, generators that operate in parallel with the grid only momentarily. Witness Riggins testified that Standby Generating Interconnection Customers – typically hospitals and other industrial retail customers with sensitive loads – only request to operate in parallel with the grid during the time their load is transitioning back to the Utility System after a test or outage. Therefore, witness Riggins explained that the Duke Utilities do not perform as robust of a System Impact Study analysis for these Interconnection Customers as compared to "full power export" Interconnection Customers. Standby Generating Facilities are designed and operated as zero export generation, are not interdependent, and, accordingly, have no adverse effect on other Interconnection Customers' queue positions. Witness Riggins further testified that the Duke Utilities receive very few Standby Generating Facility Interconnection Requests in comparison to "full power export" Interconnection Requests. Because of these differences, witness Riggins testified that the Utilities' proposal to evaluate Standby Generating Facilities on an expedited basis apart from the traditional queue is reasonable and benefits commercial and industrial customers seeking to install this type of generator at their facilities.

DENC witness Nester supported the Utilities' proposal to expedite the study process for Standby Generating Facilities by designating such facilities as Project As and studying them ahead of other Section 4 studies, and testified that the proposal would have no adverse effect on other facilities' Queue Positions.

Public Staff witness Williamson also supported the Utilities' proposed addition of Section 1.8.3.4 in the Stipulated Redline, and explained that the proposal includes adding this definition of Standby Generating Facility to the NC Interconnection Standard:

> An electric Generating Facility primarily designed for standby or backup power in the event of a loss of power supply from the Utility. Such facilities may operate in parallel with the Utility for a brief period of time when transferring load back to the Utility after an outage, or when testing the operation of the Facility and transferring load from and back to the Utility.

Witness Williamson testified that this proposal will help customers to be prepared for unexpected, emergency, or storm-related Utility outages such as those experienced during and in the aftermath of recent Hurricanes Michael and Florence. Witness Williamson stated that moving Standby Generating Facilities ahead in the study queue allows retail customers to expedite their preparedness efforts with minimal disruption to other projects in the queue, and he agreed with the Utilities that the proposal would not materially impact the Queue Position of other Interconnection Requests. He testified that Standby Generating Facilities are not interdependent and do not have an impact on the infrastructure capacity of the distribution grid.

No party opposed the addition of Section 1.8.3.4 to the NC Interconnection Standard as proposed in the Stipulation and the Stipulated Redline.

Discussion and Conclusions

The Commission is persuaded by the evidence presented by the Utilities and the Public Staff that the addition of new Section 1.8.3.4 and the related definition of Standby Generating Facility are reasonable and will enable the Utilities' commercial and industrial retail customers to more efficiently interconnect momentarily parallel standby generators to the Utilities' Systems. The Commission agrees that due to the limited number of these types of Interconnection Requests, and the practical differences between a standby generator and other generating facilities, expedited approval of Standby Generating Facility Interconnection Requests will not materially impact other Interconnection Requests. In addition, no evidence has been presented suggesting that expedited approval of Standby Generating Facility Interconnection Requests will negatively impact the interconnection queue. Further, like the Public Staff, the Commission supports the Utilities' efforts to expedite customers' preparedness efforts for unexpected, emergency, or weather-related outages. Further, no party has opposed new Section 1.8.3.4 or the related definition as proposed in the Stipulated Redline. Therefore, the Commission approves the inclusion of new Section 1.8.3.4 and the related definition of Standby Generating Facility to the NC Interconnection Standard as recommended by the Public Staff and the Utilities.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 3

The evidence supporting this finding of fact is found in the Stipulation and the Stipulated Redline, and in the testimony and exhibits of Duke witness Riggins, DENC witness Nester, Public Staff witness Lucas, and IREC witness Auck.

The Stipulated Redline shows the following proposed fee changes:

1) The fee for filing a Pre-Application Report request would increase from $300 to $500 (Section 1.3.1 of the NC Interconnection Standard).

2) Section 1.4.1.2 would be amended to specifically allow the Utility to include its overhead costs in Interconnection Request deposits, with those deposits being applied to the Utility's costs (including overheads).

3) The Interconnection Request Application Form would be amended so that for Generating Facilities that are larger than 20 kW, but not larger than 100 kW, the fee would increase from $250 to $750. The same fee for facilities larger than 100 kW, but not larger than 2 MW, would increase from $500 to $1,000.

4) On the Interconnection Request Application Form, a deposit would be charged for Supplemental Reviews, with facilities larger than 20 kW, but not larger than 100 kW, paying a $750 deposit, and facilities larger than 100 kW, but not larger than 2 MW, paying a $1,000 deposit.

5) The same Interconnection Request Application Form would be amended to establish deposits for Standby Generating Facilities, with a facility smaller than 1 MW paying a $2,500 deposit, and a facility equal to or greater than 1 MW paying a $5,000 deposit.

6) Finally, that form would be further amended to increase the non-refundable processing fee for a change in ownership from $50 to $500.

7) The Interconnection Request Application Form For Interconnecting a Certified Inverter-Based Generating Facility No Larger Than 20 kW would be amended to increase the non-refundable processing fee from $100 to $200, and to clarify that the current (and unchanged) $50 fee for processing a change of ownership is non-refundable.

Duke witness Riggins outlined the Utilities' proposal to adjust the fees charged for small generator Interconnection Request processing under Section 2 and Section 3 of the NC Interconnection Standard as well as certain other types of work under the NC Interconnection Standard. Witness Riggins explained that the increased fees are needed to more fully recover the Utilities' costs. Witness Riggins explained that in 2016 the Commission directed DEC, and later DEP, to track and more fully recover costs incurred to interconnect renewable energy generators from Interconnection Customers. As a result, DEC and DEP implemented procedures to better track and recover interconnection-related costs from Interconnection Customers.

Witness Riggins further testified that the Duke Utilities have significantly under-recovered their interconnection-related costs due to the increasing volume of Section 2 and Section 3 Interconnection Requests, coupled with the growing complexity of the Supplemental Reviews completed under Section 3 of the NC Interconnection Standard. He stated that the Duke Utilities in 2017 had under-recovered its costs for processing Section 2 and Section 3 requests by $871,674, and similar under-recoveries through October of 2018 totaled $741,529.

Witness Riggins testified that the increasing volumes of Interconnection Requests necessitate the Utilities spending increased amounts of time and monies on the actual processing of Interconnection Requests as well as processing Pre-Application Reports and changes of ownership/control of the Generating Facility or the Interconnection Customer. In addition, witness Riggins testified that the Duke Utilities have invested in technological improvements, as well as additional staff, to more efficiently manage, track, and process Interconnection Requests.

Witness Riggins detailed the types of overhead costs that the Duke Utilities incur to support the interconnection process, including: (1) costs for personnel within Distributed Energy Technologies that indirectly support the interconnection process through accounting, technical standards, data management, and reporting; (2) processing overhead costs including costs to manage and process interconnection related calls, applications, and payments for projects not covered by fees; (3) costs for Account Management and Customer Operations, and Distribution Protection and Control to respond to Supplemental Reviews and System Impact Studies; and (4) technology costs, including Duke's Salesforce enhancement project.

DENC witness Nester testified that DENC supported the fee proposal as reflected in the Joint Utilities Redline (which was subsequently made part of the Stipulated Redline). Witness

Nester agreed that developers should bear interconnection costs because they are the causers of such costs.

In his pre-filed direct testimony, Public Staff witness Lucas testified that the Commission had previously directed the Duke Utilities not to recover interconnection-related costs through the Renewable Energy and Energy Efficiency Portfolio Standard (REPS) Rider and instead to track and more fully recover interconnection-related costs through the interconnection process. Witness Lucas stated that the Public Staff had not fully audited the proposed interconnection fees, and, therefore, he took no position on them, but reiterated the Public Staff's overarching position that the costs to process Interconnection Requests should be borne by Interconnection Customers and not shifted to retail customers. Subsequent to the filing of his testimony, the Public Staff was a signatory to the Stipulation, which includes the fee changes described above.

IREC witness Auck stated that the Utilities' proposed fee adjustments are unreasonably large and that the Utilities had not met their burden to justify the requested fee increases. Witness Auck compared the proposed fees to interconnection fees charged in certain other jurisdictions, and specifically took issue with the Utilities' proposed increase in the change-in-ownership processing fee from $50 to $500, arguing that such a change violates the regulatory principle of gradualism and will cause "rate shock." Witness Auck concluded that the Commission should require the Utilities to better explain the need for the increase in fees, the efforts the Utilities are taking to ensure that they are processing applications efficiently, and why costs have not gone down despite efficiencies having been adopted. In addition, witness Auck requested the Commission specifically require the Duke Utilities to explain the overhead costs referenced in the proposed modification to Section 1.4.1.2 regarding Interconnection Request deposit costs.

On rebuttal, Duke witness Riggins provided additional support for the Utilities' proposed revisions to the interconnection fees, including a detailed breakdown of the Duke Utilities' interconnection expenses and revenues. Rebuttal Exhibit JWR-3 showed the Duke Utilities' historic under-recovery of their interconnection-related expenses recovered through fees in 2017 and 2018 and also projected the increase in fees needed to allow the Duke Utilities to more fully recover these interconnection-related costs. Witness Riggins reiterated that the proposed fees were designed not for the Utilities to earn a profit or return, but instead only for the Utilities to recover their actually incurred interconnection-related costs.

Witness Riggins further testified that if the Commission determines it is appropriate to more closely track year-over-year changes in the Duke Utilities' interconnection-related expenses and revenues, the Duke Utilities could file a report with the Commission annually similar to his Rebuttal Exhibit JWR-3. As an alternative to establishing a new annual reporting requirement, witness Riggins stated that to the extent the Commission plans to review the NC Interconnection Standard and interconnection process again in two to three years, the Duke Utilities could instead report to the Public Staff and other stakeholders at that time whether changes in interconnection fee volumes and expenses support future adjustments to fees charged under the NC Interconnection Standard.

Witness Riggins rebutted witness Auck's contention that the Utilities' proposed fees were unnecessarily high as compared to other utilities' interconnection-related fees by providing examples of other utilities imposing similar or higher interconnection-related fees than those in the

Stipulated Redline. Witness Riggins also testified that it is challenging to compare interconnection fees across states and utilities due to differing eligibility and policy considerations, including whether the fees are designed to fully recover interconnection-related costs or whether some costs are permitted to be recovered through base rates. Witness Riggins provided a detailed breakdown of the time and costs incurred to execute a change of control in support of the Utilities' proposed increase to the change-of-control fee. He rebutted witness Auck's argument that the change-of-control fee change would violate the principle of gradualism by testifying that Interconnection Customers pay a one-time fee for a particular interconnection service as opposed to fixed charges for service provided on an ongoing basis.

No other witnesses discussed the proposed fee changes. In its post-hearing brief, NCSEA stated that it opposed the proposed fee changes, asserting that the Utilities have not established why they are needed. No other party took a position on the proposed fee changes.

Discussion and Conclusions

Upon review of the evidence, the Commission concludes that it is appropriate to approve the fee changes that were provided in the Stipulated Redline, along with additional revisions in the NC Interconnection Standard in order to avoid confusion.

Based on Duke witness Riggins' testimony, the Commission finds that the Duke Utilities are not recovering their costs of administering the interconnection process from Interconnection Customers, and that the Utilities' adjusted fees are reasonably designed to allow the Utilities to recover those costs more fully from Interconnection Customers. In particular, the Commission finds persuasive Duke witness Riggins' rebuttal testimony and Rebuttal Exhibit JWR-3, which detail the Duke Utilities' under-recovery of fee-related interconnection costs over the past two years. Rebuttal Exhibit JWR-3 also shows that the Utilities' adjusted fees will allow the Duke Utilities to more fully recover their direct and indirect interconnection costs through fees under the NC Interconnection Standard. The Commission finds that the information presented by witness Riggins provides reasonable support for the interconnection fee changes in the Stipulated Redline and reasonably addresses IREC witness Auck's concerns. The Commission also notes that the two parties that directly represent Interconnection Customers (NCSEA and NCCEBA) in this proceeding did not provide expert witness testimony in opposition to the fees.

The Commission recognizes that when establishing fixed fees to recover future costs, the amount of the fees is directly impacted by the volume of Interconnection Requests received, and the Duke Utilities have agreed to provide annual reporting on the year-over-year changes in interconnection-related expenses and revenues. The Commission finds that this additional reporting is appropriate and will require the Utilities to file a verified report by March 1 of each year on the volume of Interconnection Requests received, the amount of fees collected pursuant to the NC Interconnection Standard, and the Duke Utilities' actual expenses incurred for interconnection-related work.

The Commission also directs the Utilities, to the greatest extent possible, to continue to seek to recover from Interconnection Customers all expenses (including reasonable overhead expenses) associated with supporting the generator interconnection process under the NC Interconnection Standard.

Finally, the Commission notes that as drafted, the Stipulated Redline contains an internal inconsistency as regards deposits for Supplemental Reviews in the Section 3 Optional Fast Track Process. For Section 3.4, the Stipulated Redline (with changes accepted) would state:

> 3.4 Supplemental Review
>
> If the Interconnection Customer agrees to a supplemental review, the Interconnection Customer shall agree in writing within ten (10) Business Days of the offer, and submit a deposit for the estimated costs or the request shall be deemed to be withdrawn. The Interconnection Customer shall be responsible for the Utility's actual costs for conducting the supplemental review.... [Emphasis added.]

On the other hand, instead of basing the deposit on estimated costs the Interconnection Request Application Form in the Stipulated Redline would establish a fixed deposit of $750 for Supplemental Reviews if the Generating Facility is larger than 20 kW, but not larger than 100 kW. According to the Stipulated Redline, the deposit would be $1,000 if the Facility were larger than 100 kW, but not larger than 2 MW. The Commission will resolve this inconsistency by further amending Section 3.4 as follows:

> 3.4 Supplemental Review
>
> If the Interconnection Customer agrees to a supplemental review, the Interconnection Customer shall agree in writing within ten (10) Business Days of the offer, and submit a deposit of $750 (if the facility is larger than 20 kW but not larger than 100 kW) or $1,000 (if the facility is larger than 100 kW but not larger than 2 MW). ~~for the estimated costs~~ or the request shall be deemed to be withdrawn. The Interconnection Customer shall be responsible for the Utility's actual costs for conducting the supplemental review....

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 4

The evidence supporting this finding of fact is found in the Stipulation and the Stipulated Redline, and in the testimony and exhibits of Duke witnesses Freeman and Riggins.

The Stipulated Redline proposes new language to be added to the System Impact Study Agreement as follows:

> RECITALS
>
> 4. A system impact study will be based upon the technical information provided by Interconnection Customer in the Interconnection Request. The Utility reserves the right to request additional technical information from the Interconnection Customer as may reasonably become necessary consistent with Good Utility Practice during the course of the system impact study. If the information requested by the Utility is not provided by the Interconnection Customer within a reasonable timeframe to be identified by the Utility in writing, the Utility shall provide the Interconnection Customer written notice providing an opportunity to cure such failure by the close of business on the tenth (10^{th}) Business

> Day following the posted date of such notice, where failure to provide the information requested within this period shall result in the study being terminated and the Interconnection Request being deemed withdrawn. The period of time for the Utility to complete the system impact study shall be tolled during any period that the Utility has requested information in writing from the Interconnection Customer necessary to complete the study and such request is outstanding.

Similarly, the Stipulated Redline proposes new language to be added to the Facilities Study Agreement as follows:

> RECITALS
>
> 7. In cases where Upgrades are required, the facilities study must be completed within 45 Business Days of the Utility's receipt of this Agreement, or completion of the Facilities Study for an Interdependent Project A whichever is later. In cases where no Upgrades are necessary, and the required facilities are limited to Interconnection Facilities, the facilities study must be completed within 30 Business Days. The Utility reserves the right to request additional technical information from the Interconnection Customer as may reasonably become necessary consistent with Good Utility Practice during the course of the facilities study. If the information requested by the Utility is not provided by the Interconnection Customer within a reasonable timeframe to be identified by the Utility in writing, the Utility shall provide the Interconnection Customer written notice providing an opportunity to cure such failure by the close of business on the tenth (10th) Business Day following the posted date of such notice, where failure to provide the information requested within this period shall result in the study being terminated and the Interconnection Request being deemed withdrawn. The period of time for the Utility to complete the Facilities Study shall be tolled during any period that the Utility has requested information in writing from the Interconnection Customer necessary to complete the Study and such request is outstanding.

Duke witness Riggins introduced the Utilities' proposal to formalize within the context of the System Impact Study Agreement and Facilities Study Agreement the fact that the Utilities have a right to request information from the Interconnection Customer and to make clear the process in the event that the Interconnection Customer fails to respond to such request: namely, a single 10-day cure period followed by withdrawal of the Interconnection Request from the queue.

On rebuttal, Duke witness Freeman explained that the Duke Utilities have historically provided Interconnection Customers cure periods for missed deadlines in a number of circumstances during the System Impact Study process, even though this is not expressly required by the NC Interconnection Standard. Based on this historic practice of offering cure periods, witness Freeman testified that the Utilities were now proposing to modify the NC Interconnection Standard to memorialize a single 10-Business-Day cure period during both the Facilities Study and the System Impact Study processes in the event that an Interconnection Customer fails to respond to a request from the Utility.

No party opposed the Utilities' proposal to formalize a 10-Business-Day cure period in the Facilities Study and System Impact Study processes.

Discussion and Conclusions

The Commission finds persuasive the testimony of Duke witness Freeman, which details how the Duke Utilities have, in good faith, allowed cure periods for Interconnection Customers. The Commission also finds persuasive the fact that no party opposes the formalization of cure periods in the NC Interconnection Standard as provided for in the Stipulated Redline. Therefore, the Commission concludes that it is reasonable to approve formalizing the Interconnection Customer's obligation to respond to information requests, along with a standardized 10-Business-Day cure period and withdrawal right, in the System Impact Study Agreement and the Facilities Study Agreement, as presented in the Stipulated Redline.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 5

The evidence supporting this finding of fact is found in the Stipulated Redline, and in the testimony and exhibits of Duke witness Gajda and DENC witness Nester.

Duke witness Gajda explained that the Utilities realized that a rigorous inspection process is needed to ensure each generator's Interconnection Facilities have been constructed consistent with the Duke Utilities' generally applicable construction and design standards. While the NC Interconnection Standard already permits such inspections under certain circumstances, witness Gajda explained that the modifications proposed in the Stipulated Redline would expressly establish a process for ongoing inspections of Generating Facilities. Today, Section 6.5 of the NC Interconnection Standard allows the Utilities to inspect the Interconnection Customer's equipment as part of the commissioning process. With the proposed amendments to Section 6.5 (as well as parallel changes to Sections 2.1.3, 2.3, and 2.3.2 of the Interconnection Agreement), the NC Interconnection Standard would also allow the Utilities to inspect an Interconnection Customer's equipment: (1) if the Utility had not done so prior to the facility commencing operations; (2) periodically, as the Utility is inspecting its own facilities; and (3) in the event the Utility becomes aware of any condition that could cause disruption or deterioration of service to other customers or is imminently likely to endanger life or property. In all of these situations, the amendments would provide that the Interconnection Customer is to pay the Utility the actual cost of the inspection within 30 Business Days of being invoiced by the Utility.

DENC witness Nester stated that DENC supports the Duke Utilities' proposal to modify Section 6.5 to establish post-commissioning inspections.

In its post-hearing brief, NCSEA stated that it opposed the proposed changes to Sections 2.1.3 and 2.3 of the Interconnection Agreement because "neither the Utilities nor the Public Staff has provided any justification" for the changes.

Discussion and Conclusions

The Commission finds Duke witness Gajda's testimony persuasive regarding the need to modify the NC Interconnection Standard to provide for post-commissioning inspections. It is critical that the Utilities be in a position to ensure the safety and integrity of the grid, and the

Commission supports the proposed periodic inspections. The Commission notes that amendments to the Interconnection Agreement will now provide a three-day window for the Utility to perform its commissioning inspection; the Commission strongly supports the Utilities availing themselves of that opportunity to the maximum extent possible. Further, it is appropriate that Interconnection Customers reimburse the Utilities for periodic inspection costs, so long as those costs are reasonable. To that end, the Commission will require the Utilities to include information regarding the number of inspections conducted each year and their costs in the March 1 fee report required by Ordering Paragraph No. 3 of this Order. In addition, the Utilities shall keep records of their inspection findings as that information could be useful in adjusting the NC Interconnection Standard in the future.

MATERIAL MODIFICATION DEFINITION/
ADDING ENERGY STORAGE TO EXISTING SOLAR FACILITIES

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 6-8

The evidence supporting these findings of fact is found in the Stipulated Redline and in the testimony and exhibits of Duke witnesses Freeman and Gajda; DENC witness Nester; NCSEA witness Brucke; NCCEBA witnesses Norqual, O'Dea, and Wallace; and Public Staff witness Lucas.

The Stipulated Redline refines the definition of Material Modification via several lists of potential changed circumstances. If the Interconnection Customer made one of the changes listed in Section 1.5.1.1 before the System Impact Study Agreement is signed, that change would trigger a Material Modification, and the Interconnection Request would have to re-enter the queue. If the Interconnection Customer made one of the changes listed in Section 1.5.1.2 after the System Impact Study Agreement is signed, such a change would also trigger a Material Modification, and again, the Interconnection Request would have to re-enter the queue. Section 1.5.2.2 lists changes that would not be Material Modifications regardless of when they were made. That list would include this new provision:

> 1.5.2.2.5 A change in the DC system configuration to include additional equipment that does not impact the Maximum Generating Capacity, daily production profile, or the proposed AC configuration of the Generating Facility including: DC optimizers, DC-DC converters, DC charge controllers, power plant controllers, and energy storage devices such that the output is delivered during the same periods and with the same profile considered during the System Impact Study.

Similarly, this new section describes changes that would not be Material Modifications if they are made before the System Impact Study Agreement is signed:

> 1.5.2.1 The following are not indicia of a Material Modification before the System Impact Study Agreement has been executed by the Interconnection Customer:
>
> > 1.5.2.1.1 A change in the DC system configuration to include additional equipment including: DC optimizers, DC-DC converters, DC charge controllers, power plant controllers, and energy storage devices, so long as

> <u>the proposed change does not violate any of the provisions laid out in Section 1.5.1.1.</u>

Several witnesses testified that the various lists refining the definition of Material Modification were the topic of much conversation among the stakeholders, and that many of the changes were reached by consensus. However, the two provisions cited above that address energy storage were the subject of controversy.

In addition, Duke witness Gajda noted that using the System Impact Study Agreement execution date as the decision point for many Material Modification determinations was not agreed to among the Working Group 2 stakeholders.

Witness Gajda explained that any changes to the Generating Facility's production profile that are made after the System Impact Study Agreement has been executed may result in incorrect study results that do not accurately capture how the Generating Facility will operate when it is interconnected with the Utility's System.

Witness Gajda explained that the Duke Utilities support new technologies such as storage. However, for any Interconnection Requests where Duke has already begun the System Impact Study, the Utility must have assurance that the assumptions related to the production profile of the Generating Facility are not invalidated by modifications. Only where the key elements of the original Generating Facility remain unchanged, such as the facility's daily production profile, would the Duke Utilities allow the addition of equipment (such as energy storage) on the direct current (DC) portion of the facility after initiating System Impact Study and without considering the addition to be a Material Modification. Witness Gajda explained that under the Stipulated Redline, if an Interconnection Customer chose to add battery storage to an already-submitted Interconnection Request, any change to the production profile would constitute a Material Modification if the Utility had already begun the System Impact Study. Further, the Customer's execution of the System Impact Study Agreement would mark the beginning of the study. Witness Gajda testified:

> The production profile of a Generating Facility has become a more crucial component going forward as independent generators seek more flexibility on how the[y] operate their facilities. ... [F]ailing to account for generation export at 6 AM or at 8 PM, which might occur where battery storage has been added to a solar facility, would produce incorrect study results since interconnection studies for solar facilities typically do not account for operation at those times. Interconnection studies also typically do not account for large loads (such as battery charging).

He testified further that the proposed changes within the Interconnection Request Form and the Material Modifications changes described above are "designed to better accommodate energy storage technologies, while ensuring future safe and reliable interconnection operation...."

In addition to the fee changes described earlier in this Order, the Stipulated Redline version of the Interconnection Request Application Form would include a new requirement for an Interconnection Customer to provide an hourly production profile for the Generating Facility. The Form would require the Interconnection Customer to specify, for each hour of the day, the

Facility's maximum import and export in that hour, expressed as a percent of the Maximum Generating Capacity[1] being requested for the Facility. Additional Stipulated Redline revisions to the Interconnection Request Application Form state: "Power flow in excess of these [production profile] levels during the corresponding hour shall be considered an Adverse Operating Effect per Section 3.4.4 of the Interconnection Agreement." Section 3.4.4 states: "If, after notice, the Interconnection Customer fails to remedy the adverse operating effect within a reasonable time, the Utility may disconnect the Generating Facility."

DENC witness Nester testified to DENC's support for the Stipulated Redline, which includes the revisions described above.

NCCEBA witness Norqual disagreed with the addition of the phrase "and with the same output profile" to the indicia of changes to a Generating Facility that would not constitute a Material Modification after System Impact Study had begun. Witness Norqual testified that the addition of this phrase largely excludes energy storage from being added to a solar facility without triggering a Material Modification. Witness Norqual stated that based on his knowledge of the study process, there does not appear to be technical merit for the addition of the phrase as proposed by the Duke Utilities. He argued that energy storage provides benefits to ratepayers, and that therefore, Interconnection Customers should be allowed to add energy storage to their Interconnection Request and quickly be restudied without the Utility deeming the change to be a Material Modification, so long as the addition would not increase the Facility's overall output. Thus, he testified in support of a substitute provision, which he stated had been approved by Stakeholder Working Group 2, which would be in the list of items "not indicia of a Material Modification":

> A change in the DC system configuration to include additional equipment that does not impact the Maximum Generating Capacity or the proposed AC configuration of the Generating Facility including: DC optimizers, DC-DC converters, DC charge controllers, power plant controllers, and energy storage devices such that the output is delivered during the same periods considered during the System Impact Study.

NCCEBA witness Wallace testified that he had attended many of the stakeholder meetings, and that the stakeholders did not agree that changes to the DC portion of a facility would be allowed

[1] The Stipulated Redline provides the following new definition in the NC Interconnection Standard's Glossary of Terms:

> Maximum Generating Capacity – The term shall mean the maximum continuous electrical output of the Generating Facility at any time as measured at the Point of Interconnection and the maximum kW delivered to the Utility during any metering period. Requested Maximum Generating Capacity will be specified by the Interconnection Customer in the Interconnection Request and an approved Maximum Generating Capacity will subsequently be included as a limitation in the Interconnection Agreement.

The revised Interconnection Request Application Form instructs the Customer: "Production profile: provide below the maximum import and export levels (as a percentage of the Maximum Physical Export Capability Requested) for each hour of the day..." Since the Stipulated Redline deletes the current term (and its definition) for Maximum Physical Export Capability, the Commission finds the reference to Maximum Physical Export Capability to be an error and will substitute the new term, Maximum Generating Capacity.

"only if all elements of the production profile are considered because the production profile is not a typical element of the System Impact Study...." In his opinion, changes to the daily production profile of a Generating Facility do not necessitate further study of the Facility to prevent inaccurate study results for the short-circuit study, stability analysis, voltage drop and flicker analysis, and production and set point coordination studies. He further testified that even where the Duke Utilities are required to consider the power flow analysis again due to a change in production profile from the addition of energy storage, a Material Modification should not be triggered. He reasoned that since the addition of energy storage would not impact the vast majority of the System Impact Study results, and because the power flow analysis requires only a minimal time commitment of about 8 to 16 hours by the Utilities, even if the addition of DC-coupled energy storage alters the daily production profile it should not trigger a Material Modification. At the hearing, however, witness Wallace acknowledged that adding energy storage to a Facility could impact the stability analysis results of a System Impact Study.

NCSEA witness Brucke testified that the Duke Utilities' policy regarding the addition of energy storage to a solar facility is unreasonable since the Duke Utilities consider any addition of energy storage to be a Material Modification despite potential circumstances where the addition of energy storage has no impact on the cost, timing, or design of the Interconnection Facilities or Upgrades:

> For an interconnection customer to proceed with a Material Modification, they must resubmit their project and move to the back of the queue. Considering the length of the queue, the slow speed of processing projects thought [sic] the queue, and the loss of queue-priority, this is not a practical option for most projects.

Witness Brucke recommended that the Utilities evaluate whether the addition of energy storage is a Material Modification or not on a project-by-project basis, or, instead, establish a set of guidelines to define additions that would specifically not be considered Material Modifications. He recommended that the addition of DC-coupled energy storage to a solar PV project that does not increase the AC capacity of the project or generate outside the time of day considered in the project's System Impact Study be considered a non-Material Modification under the NC Interconnection Standard.

NCSEA stated in its post-hearing brief that the Commission should approve the consensus language regarding Material Modification that was developed during the 2017 stakeholder process and reject the version in the Stipulated Redline.

NCCEBA witness O'Dea testified that Duke's proposed changes to the Interconnection Request Application Form indicated "that a production profile is necessary even for new interconnection requests for an energy storage facility." He stated that this is inconsistent with Section 7 of the System Impact Study Agreement which states:

> The System Impact Study shall model the impact of the Generating Facility regardless of purpose in order to avoid the further expense and interruption of operation for reexamination of feasibility and impacts if the Interconnection Customer later changes the purpose for which the Generating Facility is being installed.

Witness O'Dea testified that a key value of energy storage is the flexibility and multiple use cases that storage can provide, and stated that limiting the operation to a production profile submitted at an early stage in the development of a facility is not supported with a technical justification, and is in conflict with the NC Interconnection Standard. He further testified that modifications to the DC system of a solar array do not modify the output profile, and that those changes are not indicia of a Material Modification. Witness O'Dea testified that NCCEBA supported the Working Group 2 language (as quoted above by witness Norqual) "with the understanding that the output of the facility should not be restricted to a specific profile and that the Maximum Physical Export Capability can be delivered at any time of day at which the studied load cases are applicable."

In rebuttal, Duke witness Gajda testified that the proposed modification to Section 1.5.2.2.5 was necessary to avoid a latent ambiguity as to whether an Interconnection Customer could generate the originally requested full output at any time between sunrise and sunset. Witness Gajda stated that the assessment of exactly what hours of the day, and to what levels, energy storage production might be a permissible modification without performing additional study would be "subjective at best." Witness Gajda emphasized that the complexity presented by Interconnection Requests is growing, not diminishing, and that an uncontrolled storage device could be in a charge state, discharge state, or neutral state at any time, which adds to this complexity. As a result, witness Gajda stated that the Duke Utilities' addition of language to Section 1.5.2.2.5 was out of an abundance of caution and to ensure that any study fully accounts for what will truly happen. Witness Gajda noted that while the NC Interconnection Standard allows some changes to DC configurations without concern for the production profile, changes that impact production profiles must be treated as material and require re-study.

Duke witness Freeman testified that battery storage introduces additional complexity because batteries "can go from instantaneous off to almost instantaneous on," with more of a spike than the intermittency experienced with solar facilities. He testified that this "has huge implications on ramping. It has huge implications on the equipment that's on the distribution circuit ... it does add a significant amount of complexity that does need to be studied in more detail."

Witness Gajda testified that, in his professional opinion, the addition of storage to a solar-only facility should only be permitted after it is fully studied, and that given the amount of "unknowns" about how batteries will be operated, it would be irresponsible of the Utilities to allow the addition of storage without further study. During the hearing, witness Gajda agreed that if DC-coupled energy were added to an existing solar facility, several of the System Impact Study analyses would not be impacted, specifically the short circuit study and the protection study. On the other hand, the thermal/voltage review and the stability study could be impacted by the addition, and would need to be studied, according to witness Gajda.

Public Staff witness Lucas testified that the Utilities currently do not request a production profile from Interconnection Customers, but that Duke uses a "standard self-generated production profile during the System Impact Study that is developed from an equipment list that the Interconnection Customer submits." He testified further, "however, Duke Energy has stated that with the addition of energy storage, production profiles can vary greatly." He stated that "changes to the direct current or DC portion of the facility, including energy storage, should not automatically constitute a material modification if the changes are requested prior to the execution of the System Impact Study Agreement." He testified that the Utilities had agreed to the Public Staff's amendments to Section 1.5.1, and that they had been included in the Stipulated Redline.

In its post-hearing brief, IREC asserted that there should be an expedited process for energy storage that is added outside the time periods already studied, arguing that storage could provide power at 8 a.m. or 6 p.m. "when Duke's system experiences its highest loading and power is needed most."

In its post-hearing brief, NCSEA stated that it opposed the Stipulated Redline's addition of production profile information on the Interconnection Request Application Form, saying it is unnecessary.

Discussion and Conclusions

Several parties noted that this issue, the appropriate way to process requests to add energy storage to existing solar generation facilities, is the most important issue in this proceeding. It is certainly the most complex.

From a technical perspective, the Commission finds persuasive the testimony of witnesses who stated that energy storage has the ability to charge, discharge, or simply be in a neutral state; these three states make energy storage fundamentally different from a generator, which typically does not act as a load (or at least, not as a large load). In addition, storage has the ability to ramp up and down extremely quickly, almost instantly, presenting new challenges for the distribution grid. The Commission finds that it is appropriate that the Utilities charged with providing a reliable system for all customers be given the opportunity to fully study all energy storage devices before interconnecting them to the grid. Therefore, the Commission will approve the Stipulated Redline's provisions regarding Material Modifications. The Commission will also approve the proposal to use the signing of the System Impact Study Agreement as the trigger date for defining Material Modifications. While it is true that there might be a delay between the signature date and actual start of the study process, the Commission finds that this milestone is straightforward and under the Interconnection Customer's control.

The Commission notes that only one witness, NCCEBA witness O'Dea, opposed the proposed new requirement in the Stipulated Redline that Interconnection Customers provide hourly production profile data in the Interconnection Request Application Form. He stated that this new requirement would be inconsistent with Section 7 of the System Impact Study Agreement which states:

> The System Impact Study shall model the impact of the Generating Facility regardless of purpose in order to avoid the further expense and interruption of operation for reexamination of feasibility and impacts if the Interconnection Customer later changes the purpose for which the Generating Facility is being installed. [Emphasis added.]

The Commission finds persuasive testimony that, as increasing numbers and types of distributed resources seek to interconnect to the grid, it will be necessary to study them in new and different ways. However, the Commission agrees with witness O'Dea that this existing Section 7 in the System Impact Study Agreement is in tension with the Stipulated Redline's proposed changes, specifically the requirement to provide hourly production profiles. In addition, in its post-hearing brief, NCSEA argued that Interconnection Customers should not be required to submit production profile information because "the Utilities have not said that they would begin using Generation Facility-specific production profiles in the study process." The Commission agrees that it is not clear from the record how the Utilities will use the production profile information in the interconnection studies. The Commission is inclined to approve the provision of the Stipulated Redline requiring the hourly production profile data. However, given the record on this issue, it is appropriate to require that the Utilities file with the Commission, within 20 business days of the date of this Order, an explanation of the purposes for which that data will be used in studying Interconnection Requests, including the anticipated impact in terms of time and dollars, on studying Interconnection Requests, as well as the anticipated results or outcomes of including these data in the study process. The Commission shall make a final decision on this issue following such filing. Further, the Commission seeks comment from the Utilities on whether Section 7 of the System Impact Study Agreement requires amendment.

Some of the testimony in this case, including from Utility witnesses, suggested that the process for re-studying an existing Generating Facility for the addition of energy storage could be less resource- and time-intensive than the initial interconnection studies, especially if the site's maximum output remains unchanged. Because there could be System and retail customer benefits if existing solar facilities were able to use energy storage to shift their output away from those times when the sun is shining, or to smooth the delivery of energy during times of sporadic sunshine, the Commission will require Duke to host stakeholder and TSRG meetings dedicated to this question and report back to the Commission by September 3, 2019. Further, the Commission will require that the report include: (1) a streamlined process for efficiently studying the addition of storage at existing generation sites and that builds upon the grouping study approach that is already under development as required by the Stipulation; and (2) details of how the addition of storage to the direct current side of an existing generator would impact the facility's original System Impact Study results.

The addition of storage at an existing qualifying facility (QF) site raises additional issues unrelated to the provision of interconnection service. The Commission will, therefore, issue a separate concurrent order in Docket No. E-100, Sub 158, Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2018, requiring the Utilities to file testimony on those related issues, to the extent that they have not already done so. Testimony by the Public Staff and other Parties is encouraged.

EXPEDITED REVIEW OF INTERCONNECTIONS
FOR SMALL SWINE AND POULTRY WASTE FACILITIES

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 9

The evidence supporting this finding of fact is found in the Stipulation and the Stipulated Redline, and in the testimony and exhibits of Duke witness Riggins, DENC witness Nester, Public Staff witness Lucas, and NC Pork Council witness Maier.

Duke witness Riggins explained that Part VII of HB 589 amended N.C. Gen. Stat. § 62-133.8(i)(4) to require an expedited interconnection review process for swine and poultry waste-to-energy projects of 2 MW or less. Section 62-133.8(i)(4), as rewritten, requires the Commission to:

> Establish standards for interconnection of renewable energy facilities and other nonutility-owned generation with a generation capacity of 10 megawatts or less to an electric public utility's distribution system; provided, however, that the Commission shall adopt, if appropriate, federal interconnection standards. The standards adopted pursuant to this subdivision shall include an expedited review process for swine and poultry waste to energy projects of two megawatts (MW) or less and other measures necessary and appropriate to achieve the objectives of subsections (e) and (f) of this section.

Duke witness Riggins testified that in light of this mandate, the Duke Utilities worked with the Public Staff, the NC Pork Council, the North Carolina Poultry Federation, and other interested parties to develop an expedited study process that is similar to the relief approved by the Commission on August 16, 2016, in Docket No. E-100, Sub 101 for certain swine and poultry Interconnection Requests in DEP's service territory. The stakeholders developed a new Section 1.8.3.3 that would make Small Animal Waste Facilities eligible for expedited study under Section 4 and place them behind only those earlier queued projects that are already being studied or have signed a System Impact Study Agreement.

NC Pork Council witness Maier testified that the new proposed Section 1.8.3.3 would provide that a swine or poultry waste-to-energy facility is to be studied prior to all other non-swine or poultry waste-to-energy facilities on a system-wide basis. She stated that that is the result required by Part VII of HB 589. In addition, she noted that Part VII of HB 589 also requires the NC Interconnection Standard to include "other measures necessary and appropriate to achieve the objectives" of the REPS swine and poultry waste set-asides. She testified that the Public Staff recommended that the Utilities be required to designate a "technical interconnection specialist" to assist animal waste-to-energy facility developers, and to publish their contact information on the Utility's website. She stated that the NC Pork Council supports these recommendations.

The parties to the Stipulation agreed to support the NC Pork Council's clarification to the section providing that a Small Animal Waste to Energy Facility, upon being designated a Project B, shall be the next Project B studied under Section 4.3, regardless of Queue Number.

Public Staff witness Lucas noted the Public Staff's agreement with the revisions to Section 1.8.3.3, as worded in the Stipulated Redline, as did Dominion witness Nester. No other party filed testimony regarding the addition of Section 1.8.3.3 to the NC Interconnection Standard.

Discussion and Conclusions

Part VII of House Bill 589 amended N.C.G.S. § 62-133.8(i)(4) to require an expedited review process for swine and poultry waste-to-energy projects of 2 MW or less. As evidenced by the Stipulation, the Utilities, Public Staff, and NC Pork Council agree that new Section 1.8.3.3, as presented in the Stipulated Redline, appropriately meets the objectives of House Bill 589. Further, no party has opposed new Section 1.8.3.3 as proposed in the Stipulated Redline. Therefore, the Commission approves new Section 1.8.3.3 to the NC Interconnection Standard as a reasonable procedure to expedite the interconnection processing of small swine and poultry waste-to-energy projects and appropriate to meet the directives of Part VII of House Bill 589.

FAST TRACK PROCESS, INCLUDING SUPPLEMENTAL REVIEW

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 10-11

The evidence supporting these findings of fact is found in the Stipulation and the Stipulated Redline, and in the testimony and exhibits of Duke witness Gajda, DENC witness Nester, IREC witnesses Auck and Lydic, and Public Staff witness Williamson.

The Section 3 Fast Track Process for Certified Generating Facilities allows for an expedited review of Interconnection Requests for Generating Facilities no larger than 2 MW. If the Facility is eligible for Fast Track review,[1] the Utility first uses technical screens to assess whether the Generating Facility can safely interconnect to the System. If the Facility passes the Fast Track screens, the Utility provides an Interconnection Agreement to the Interconnection Customer for execution. If the facility fails the Fast Track screens, the Interconnection Customer is offered a customer options meeting where they may choose whether to proceed to a Supplemental Review or move instead into the full Section 4 study process.10

Duke witness Gajda initially testified that the Duke Utilities proposed only limited changes to the Section 3 Fast Track process. He described those changes, which were included in the Stipulated Redline, as follows:

1) Changes to Section 3.1 would allow the Utility and the Interconnection Customer to mutually agree to use the Fast Track process, even if the Facility does not otherwise qualify by virtue of connecting to a line larger than 35 kV.

2) Changes to Section 3.2 would clarify that the interdependency provisions of Section 1.8 apply to Fast Track requests.

3) Changes to Section 3.4.1.3 would clarify that a Facilities Study might be required for projects approved in Supplemental Review.

In his rebuttal testimony, DENC witness Nester described additional changes to the Fast Track process that were included in the Stipulated Redline:

4) Changes to Section 3.1.1 would allow an Interconnection Customer to select both the Fast Track and Supplemental Review processes when completing the Interconnection Request Application Form. The Customer would pay both the Fast Track fee and the Supplemental Review deposit at the time they enter the Fast Track process. Thus, if the

[1] Eligibility limits are listed in the table in Section 3.1 of the NC Interconnection Standard, and they are based on the facility's size, the voltage of the line to which it would connect, whether that line is a mainline, and the facility's distance from the substation that would serve it.

Interconnection Request fails the Fast Track review, it can move quickly into Supplemental Review.

5) Elimination of Section 3.2.1.4. This provision requires all synchronous and induction machines to be connected to a distribution circuit where the local minimum load-to-generation ratio is larger than 3 to 1. The Utilities proposed to eliminate this provision due to limited occurrence of synchronous and induction machines pursuing Fast Track interconnections.

6) Changes in Section 3.4 would reduce from 15 to 10 Business Days the timeframe during which an Interconnection Customer must agree in writing to pursue a Supplemental Review or else the Interconnection Request is deemed to be withdrawn.

7) Changes in Section 3.4.1.2 would give the Interconnection Customer 10 Business Days to agree to make facility modifications. This would avoid the unnecessary preparation of an Interconnection Agreement if the Customer is not willing to make changes to their facility design to accommodate an interconnection.

8) The Utilities would no longer automatically provide the Interconnection Customer with copies of all data and analyses used to determine that the Interconnection Request cannot be approved. Rather, the Utility would provide that information to the Interconnection Customer only upon request.

DENC witness Nester stated that based on its evaluation of the Fast Track and Supplemental Review processes, DENC agreed that only the minimal revisions depicted in the Stipulated Redline are needed.

IREC witnesses Auck and Lydic recommended several significant modifications to Fast Track process, including changes to the Supplemental Review process. IREC witness Auck raised concerns with how the Fast Track screens are applied to eligible projects, citing 98.5% and 97.8% failure rates on the Fast Track technical screens for projects in DEP and DEC, respectively.

IREC witness Lydic focused in particular on the 15% of peak load screen and the Duke Utilities' interpretation of "line section" when applying the screen.

Both IREC witnesses argued that the Duke Utilities' interpretation of line section is too narrow and that, instead, the Fast Track screens should require the use of a larger feeder section that would include more customer load. IREC recommended that this clarifying footnote be added to Section 3.2.1.2:

A. If the point of common coupling is downstream of a line recloser, include those medium voltage (MV) line sections from the recloser to the end of the feeder. If the 15% criterion is passed for aggregate distributed generation and peak load at [the] first upstream recloser, then the screen is passed.

B. If the point of common coupling is upstream of all line reclosers (or none exist), include aggregate distributed generation relative to peak load of the feeder measured at the substation. If the 15% criterion is passed for the aggregate distributed generation and peak load for the whole feeder, then the screen is passed.

Witness Lydic also suggested that the following definition of "line section" be added to the NC Interconnection Standard' Glossary of Terms:

> Line Section – A portion of a distribution circuit bounded by an automatic sectionalizing device and the end of the feeder. When applying this to the 15% of peak load screen described in Section 3.2.1.2, the smallest line section to be evaluated should begin at the first line recloser or circuit breaker upstream of the Point of Interconnection.

IREC witness Lydic testified that he developed this definition in consultation with EPRI, among others.

IREC witness Lydic also took issue with the Fast Track technical screen contained at Section 3.2.1.7, which currently states as follows:

> The proposed Generating Facility, in aggregate with other generation on the distribution circuit, shall not cause any distribution protective devices and equipment (including, but not limited to, substation breakers, fuse cutouts, and line reclosers), or Interconnection Customer equipment on the system to exceed 87.5% of the short circuit interrupting capability; nor shall the interconnection be proposed for a circuit that already exceeds 87.5% of the short circuit interrupting capability.

Witness Lydic stated that this screen is intended to ensure that protective devices are not overloaded. He stated further that although Duke does not appear to be misapplying this screen, it should still be re-evaluated given the high rate of failure of the Fast Track process, and the fact that Duke typically uses protective devices up to 100% of their ratings. Witness Lydic recommended that a higher use rate be allowed in order to decrease the Fast Track fail rate. He stated that setting the metric at 96% of short circuit interrupting capability would provide a wide safety margin, "but this issue should be discussed further, considering Duke's typical voltage levels and protection ratings."

IREC witnesses Auck and Lydic also recommended that the Fast Track eligibility thresholds in Section 3.1 for lines with a voltage of less than 5 kV be raised from 100 kW to 500 kW. Witness Lydic argued that the 100-kW maximum generator size is overly conservative and may send small projects to full Section 4 study process. IREC's witnesses also testified that other states and the Federal Energy Regulatory Commission (FERC) have adopted a 500-kW eligibility threshold for projects interconnecting to lines with a voltage of less than 5 kV, regardless of location.

IREC witness Auck proposed that all Fast Track-eligible projects that fail the initial Fast Track screens should be able to proceed to a robust Supplemental Review process with defined screens. Witness Auck stated that expanding Supplemental Review in this way would allow Interconnection Customers to make more informed decisions regarding the future of their projects based on the information they receive through the Supplemental Review process.

IREC witness Lydic also advocated for a defined set of technical screens that the Utility would use during the Supplemental Review process: (1) 100% minimum load screen (using IREC's revised definition of "line section"), (2) voltage and power quality screen, and (3) safety and reliability screen. He stated that the current Supplemental Review process does not define how the Utility will determine if a project can be interconnected safely and reliably. Witness Lydic argued that defined screens would let customers make informed decisions on whether Supplemental Review or a full study is the next best step for their project if it fails the Fast Track process. Witness Lydic testified further that at a minimum, the Commission should require Utilities to provide a detailed technical report to the Interconnection Customer, which would explain the analyses the Utility conducted during Supplemental Review and their outcomes.

IREC witness Auck acknowledged that, despite the high Fast Track technical screen failure rate, nearly all of the Section 3 Fast Track projects that proceed to Supplemental Review ultimately pass and are successfully interconnected.

Witness Gajda noted that accepting IREC's proposed changes outside of a collaborative process would make sweeping assumptions about North Carolina's distribution systems and increase the complexities of managing the interconnection process. Witness Gajda also testified that the Fast Track failure rates cited by IREC do not evidence that Fast Track is "failing," but instead indicate that due to high solar penetration in North Carolina, more projects need increased scrutiny from the utility's engineers prior to interconnection.

In his rebuttal, DENC witness Nester testified that Fast Track screens should generally be designed to be conservative, with the intention that only those requests that do not impact the grid or require additional review will pass. The desired result is that no harm to the grid results from the facility's interconnection. Witness Nester stated DENC's position that the existing Fast Track process appears to be working as designed so that requests that pass the screens do not require additional study.

With regard to the 15% peak load screen, Duke witness Gajda stated that the screen is a valuable flagging step in order to identify potential uncontrolled high voltage occurrences. Witness Gajda testified that the current definition of "line section" as applied by the Duke Utilities is reasonable and efficient. He noted that IREC cites a paper to justify its recommended definition of line section, yet the paper acknowledges that a fuse is an automatic sectionalizing device, and the paper "therefore also supports the Companies' current definition and application of line section with NC Procedures section 3.2.1.2." The Companies do, however, agree that it would be appropriate to address this issue at a TSRG meeting to increase transparency as to the Duke Utilities' use of the term.

DENC witness Nester added that changing the screening zones to allow more projects to avoid triggering the screen would risk loss of visibility to technical issues closer to retail customers' premises.

The Utilities also stated that they opposed IREC's proposed change to increase Fast Track eligibility for lines under 5 kV from 100 kW to 500 kW. Duke witness Gajda explained that these circuits are of a legacy design and, while they are still able to reliably serve small areas, connecting a generator larger than 100 kW to one of these lines would be significant. Witness Gajda also explained that these small circuits comprise only about 6% of Duke's North Carolina distribution circuits. Due to the few circuits and potential reliability issues with larger generators, witness Gajda urged the Commission not to revise the current Fast Track eligibility thresholds.

DENC witness Nester testified similarly that 5-kV circuits are an older type of distribution infrastructure that require particular care to ensure interconnections are established safely and reliably. Additionally, because only three out of DENC's 108 distribution circuits in North Carolina are of this voltage class, IREC's proposal would not significantly improve DENC's Interconnection Request processing.

Duke witness Gajda opposed IREC's proposal to raise from 87.5% the loading limit for protective devices because it would be less conservative. He stated that "Fast Track screens should be conservative and designed such that only requests with no impact to the electric grid will pass without additional review."

The Utilities also opposed IREC's proposal to add standardized technical screens to the Supplemental Review process. Duke witness Gajda explained that such standardization incorrectly assumes uniformity of future interconnections and of North Carolina's distribution system as compared to the systems in other jurisdictions:

> The Companies first reject IREC's proposal because the addition of standardized screens to the Supplemental Review process implies that there is a complete and uniform understanding of every possible future design of DER [distributed energy resources] and how it might connect to the distribution system.

Instead, the Duke Utilities support the current, more flexible approach to Supplemental Reviews. Duke witness Gajda also proposed using the TSRG as a forum to evaluate whether a more defined Supplemental Review process would be beneficial.

DENC witness Nester also opposed IREC's proposed Supplemental Review screens. He explained how IREC's 100% of minimum load screen would be technically inappropriate because Utility estimates of minimum loads are "inherently less accurate for downstream zones." In addition, using a 100% of minimum load screen "would imply that minimum load levels will not decrease. Load patterns inevitably shift around on distribution circuits, making a minimum load screen at that level not appropriate...."

The Public Staff opposed IREC's proposed changes to the Section 3 Fast Track study process.

Public Staff witness Williamson recommended maintaining the 100-kW eligibility threshold for projects proposing to interconnect to lines smaller than 5 kV. He stated that it is prudent to require additional study of a 500-kW facility, and noted that the 100-kW limit is only for Fast Track eligibility, and does not hinder a larger facility proposing to connect to a 5-kV line from moving through the interconnection process.

Witness Williamson also testified that Utilities are reasonable in using a conservative definition of line section when applying the 15% of peak load screen, stating that this will result in a higher degree of grid safety and reliability. Witness Williamson testified that a technical screen should not be arbitrarily adjusted on the sole premise of allowing more projects to pass the screen and be interconnected without additional study, noting that as higher levels of DER are connected to the System, there will be a cumulative effect. The Public Staff agreed that the Utilities' interpretation of "line section" is appropriate and that the definition should not be modified as proposed by IREC. Witness Williamson noted further, however, that the Utilities should promote transparency when determining how they interpret terms within the NC Interconnection Standard and discuss any changes in interpretation with the TSRG.

Public Staff witness Williamson noted that in the Stipulation, Duke agreed to consult with EPRI regarding potential modifications to the Fast Track and Supplemental Review processes, and report back to the TSRG.

In witness Auck's rebuttal testimony, IREC agreed with some of the Utilities' minor modifications, including the revision to Section 3.1 to allow the Utility and the Interconnection Customer to agree to Section 3 Fast Track review even if the Customer seeks to interconnect to a line sized at 35 kV or greater, suggesting this flexibility would speed up the interconnection process for some Interconnection Customers.

During the Public Staff's cross examination of Duke's witnesses, counsel for the Public Staff asked Company witnesses whether the technical screens and standards applied during Supplemental Review could be made available on the Utility's website similar to how the Method of Service Guidelines are available today. Duke witness Gajda agreed that it would be reasonable to make these screens available while noting that they are subject to change in the future.

The Duke Utilities also offered to discuss further ways to improve the Fast Track process and suggested that they do so through the newly-formed TSRG. The Stipulated Redline included a commitment by the Duke Utilities to consult with EPRI regarding potential modifications to the Fast Track and the Supplemental Review processes. The Stipulation provides that the Duke Utilities will commence that process no later than April 1, 2019, and will provide a summary report regarding potential modifications at the TSRG meeting occurring in the third quarter of 2019.

IREC witness Auck expressed support for Duke's willingness to take a closer look at its Fast Track screens and its implementation of the Supplemental Review process: "However, we think this should be done as an independent review overseen by the Commission and/or its staff with the opportunity for IREC and other stakeholders ... to review and comment...."

In its post-hearing brief, NCSEA opposed the Stipulated Redline's change to Section 3.4 to shorten the time period from 15 days to 10 days for an Interconnection Customer to agree to pursue Supplemental Review. NCSEA stated that the Utilities had not shown why such a change is necessary.

Discussion and Conclusions

Based on the evidence presented, the Commission finds that the modifications to the Fast Track process, including Supplemental Reviews, as stated in the Stipulated Redline, are appropriate and will approve them. These changes are reasonable and useful modifications to the NC Interconnection Standard that should help move Interconnection Requests along more quickly. That said, the Commission is concerned that the new provision in Section 3.1 allowing the Utility and the Interconnection Customer to mutually agree to use the Fast Track process on lines 35 kV or larger has the potential to create arbitrary exceptions to the NC Interconnection Standard. The Commission will require the Utilities to retain documentation of their rationale for each instance when they invoke this new provision, such documentation to be available for future consideration as to whether the eligibility criteria in Section 3.1 should be changed and applied to all Fast Track applications.

The Commission agrees with the Utilities and the Public Staff that, due to the limited number and age of distribution lines that are smaller than 5 kV, the Fast Track eligibility threshold should continue to limit to 100 kW the size of facilities connecting to those lines under the Fast Track process.

The Commission is not persuaded that IREC's proposal to increase the Section 3.2.1.7 screen to allow for protective device utilization greater than the current 87.5% would be appropriate at this time. The Commission agrees with those witnesses who advocated for a conservative approach in order to maintain reliable and safe operations for retail electricity consumers.

The Commission notes that IREC and the Duke Utilities agreed that a significant percentage of projects are failing the Fast Track screens, specifically, the 15% peak load screen. These parties disagree, however, on whether these failure rates are representative of deficiencies in the current Fast Track screening process reflective of an overly conservative application of the 15% screen. The Commission finds Public Staff witness Williamson's testimony persuasive that Utilities are reasonable in using a conservative approach to defining line section and applying the 15% screen because this approach will result in a higher degree of grid safety and reliability.

The Commission has carefully considered IREC's proposal to define specific technical screens to be used during Supplemental Reviews. While IREC argued that precise screens would provide transparency and certainty for Interconnection Customers, the Utilities and the Public Staff instead preferred the current Supplemental Review process. That process allows the Utility to tailor its analyses to the specific system topology and generator in question. The Commission finds it is not necessary to impose the IREC screens at this time, but will instead await the results of the EPRI review that Duke agreed to pursue in the Stipulation as discussed below. The Commission will, however, direct Duke to post on its websites a brief description of the technical evaluations and screens that it typically applies during the Supplemental Review process, noting that they are subject to change.

The Commission recognizes the Duke Utilities' commitment in the Stipulation to consult with EPRI regarding potential modifications to the Fast Track and Supplemental Review processes during 2019. Duke agreed to provide a summary report regarding potential modifications at the third quarter 2019 TSRG meeting. The Commission will also require Duke to file that report with the Commission and to serve copies on parties to this proceeding. Parties may file comments within 30 days thereafter. In addition, the Commission will require Duke to discuss its definition of "line section" and its implementation of the peak load screen at a TSRG meeting in 2019.

Based upon the foregoing, the Commission finds that the proposed modifications to the Section 3 study processes included in the Stipulated Redline are reasonable and the NC Interconnection Standard should be modified accordingly.

DISPUTE RESOLUTION PROCESS

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 12

The evidence supporting this finding of fact is found in the Stipulation and the Stipulated Redline, and in the testimony of Duke witnesses Riggins and Freeman, DENC witness Nester, IREC witness Auck, and Public Staff witness Lucas.

DENC witness Nester described the current dispute resolution process from Section 6.2 of the NC Interconnection Standard. He testified that this provision allows an Interconnection Customer to submit an informal Notice of Dispute to the Utility. If the dispute is not resolved within ten days, the process provides for the Public Staff's assistance in informally resolving the dispute. Witness Nester further testified that Section 6.2 provides that an Interconnection Customer may file a formal complaint with the Commission if the parties, with the help of the Public Staff, are unable to resolve the dispute. Witness Nester stated that DENC has successfully resolved disputes under Section 6.2.

Duke witness Riggins similarly stated that the Duke Utilities' experience resolving informal disputes under the current process has been largely successful. He stated that most disputes are resolved early and do not require the involvement of the Public Staff or the Commission. Witness Riggins testified that the Public Staff's involvement, technical understanding, and perspective have been valuable in this process, and, in nearly all instances, have enabled the Duke Utilities and Interconnection Customers to successfully resolve the dispute.

That said, witness Riggins noted that the increasing number and complexity of Interconnection Requests appear to be causing more disputes because developers are required to either commit to costly Upgrades or reduce their project's capacity in order to safely interconnect. Witness Freeman also testified that disputes by developers have become more common, consume more of Duke's resources, and cause delay in studying other projects. In rebuttal, witness Freeman described how notices of dispute inevitably and unavoidably impact other projects and are an example of a factor outside of the Utilities' control that contributes to delays.

Witness Riggins testified to specific challenges and concerns the Duke Utilities have with the current Section 6.2 dispute resolution process. Witness Riggins explained that the lack of enforceable timeframes makes it difficult to determine when an Interconnection Customer has "abandoned the process," which is the trigger for when the Utility may withdraw an Interconnection Request from the queue. Witness Riggins explained that an Interconnection Request hypothetically could remain in dispute in perpetuity with no recourse for the Utility, which could negatively impact interdependent Interconnection Customers. Witness Riggins provided the example of one Interconnection Customer who initiated a dispute regarding the Duke Utilities' voluntary mitigation options for the customer's project. Witness Riggins testified that the Interconnection Customer took about one year before making a decision on the mitigation options, challenging the Duke Utilities' technical conclusions, filing a dispute, and requesting multiple dispute resolution meetings, which Duke obliged. Witness Riggins noted that Duke and the Public Staff spent a significant amount of time with this customer only to then wait extended periods for the customer to make a decision. Ultimately, this project was withdrawn from the queue when the customer failed to comply with an express requirement in the NC Interconnection Standard.

Witness Riggins testified that as currently drafted, Section 6.2 states that "any disputed loss of Queue Number shall not be final until Interconnection Customer abandons the process set out in this section or a final Commission Order is entered." He stated that Duke believes that once a dispute has been initiated by the Customer, failure of the customer to pursue the dispute resolution remedies within a reasonable timeframe would constitute "abandonment of the process." However, witness Riggins testified that developers have asserted that it is solely up to the customer to determine when it has "abandoned the process," which leads to the "absurd conclusion that an Interconnection Customer could remain in dispute in perpetuity with no recourse for the Companies or interdependent Interconnection Customers awaiting a decision...."

Witness Riggins testified that because of this problem the Utilities proposed revisions, which are included in the Stipulated Redline, that would establish clear timeframes for both parties to diligently pursue dispute resolution. Revisions to Section 6.2.3 state that the parties shall seek to resolve a dispute within 20 Business Days after receipt of the notice of dispute, and could mutually agree to negotiate for another 20 Business Days. In addition, either Party could contact the Public Staff for assistance to resolve the dispute informally within 20 Business Days. Section 6.2.4 contains new language that would allow the parties, upon mutual agreement, to seek the help of a dispute resolution service within 20 Business Days, with the opportunity to extend this timeline "upon mutual agreement." Similar to the current process, the new Section 6.2.5 would provide:

> If the Parties are unable to informally resolve the dispute within the timeframe provided ... either Party may then file a formal complaint with the Commission, and may exercise whatever rights and remedies it may have in equity or law consistent with the terms of these procedures.

Finally, new provision 6.2.6 would address the question of when the Utility could withdraw from the queue an Interconnection Request that is the subject of a dispute. That provision would state:

> 6.2.6 The Queue Number assigned to an Interconnection Customer seeking to resolve a dispute shall not be withdrawn ... unless: (1) the Interconnection Request is deemed withdrawn by the Utility and the Interconnection Customer fails to take advantage of any express opportunity to cure; (2) the informal dispute processes described in Sections 6.2.3 and 6.2.4 does [sic] not resolve the dispute and the Interconnection Customer does not indicate its intent to file a formal complaint within ten (10) Business Days following the completion of the informal dispute process and file a formal complaint within [thirty] (30) Business Days; (3) the Commission issues a final order on a formal complaint process stating that the Interconnection Request is deemed withdrawn; or (4) the Interconnection Customer voluntarily submits a written request for withdrawal.

Public Staff witness Lucas testified that the Public Staff agreed that it should continue to be involved in the dispute process in order to protect the interests of the using and consuming public, as well as to promote efficient resolution of informal disputes where possible. Witness Lucas stated that the Public Staff, however, should not be the only option to resolve disputes between the Utilities and Interconnection Customers. Witness Lucas proposed modifications to Section 6.2 (as described above and included in the Stipulated Redline) that would allow the parties, upon mutual agreement, to use a third-party dispute resolution service. Witness Lucas also noted the Public Staff's support for inclusion of express timeframes within the dispute resolution process.

Witness Lucas testified that in 2017 the Public Staff was involved with 11 interconnection-related informal complaints, and that they were involved with a similar number in 2018. He stated, "Sometimes they are very simple net metering-type complaints that we solve in just a few telephone calls and emails, but if it's a problem with a utility-scale solar, it could take many hours of dealing with the attorneys and engineer that are involved in the complaint."

IREC witness Auck proposed revisions to the Section 6.2 dispute resolution process in her Exhibit SBA-Direct-2, which she testified adopted features from the dispute resolution processes in California and Massachusetts. Witness Auck testified that the "central feature" of these revisions is the inclusion of an "interconnection ombudsperson" at the Commission who would facilitate the resolution of disputes. Under IREC's proposal, "if parties are unable to resolve disputes by working together, they may seek assistance from the interconnection ombudsperson or an outside mediator...." Witness Auck testified that "recent disputes regarding queue management and implementation of new study guidelines highlight the need for a clearly defined dispute resolution process in North Carolina."[1] On cross examination, witness Auck explained that the ombudsperson would be hired by the Commission to oversee interconnection disputes in a neutral fashion. Witness Auck also stated that IREC is open to alternate dispute resolution approaches to further define the current process.

In rebuttal, witness Lucas noted the Utilities' opposition to an ombudsperson as proposed by IREC witness Auck, but did not oppose such an idea if it helped to facilitate the resolution of disputes between the Utilities and Interconnection Customers. However, he testified that the role of the ombudsperson should not be assigned to the Public Staff because "it is the Public Staff's mission and statutory obligation to advocate before the Commission for the using and consuming public, and a dispute resolution settlement between the Utilities and interconnection customers may not necessarily be in the best interest of the using and consuming public." He supported allowing parties to use a third party dispute resolution service, and his proposal in that regard was included in the Stipulated Redline. Finally, witness Lucas recommended that the Commission require any dispute resolution reached under Section 6.2.4 (via a dispute resolution service) be filed for information purposes with the Commission.

In its post-hearing brief, NCSEA asserted that the Public Staff's responsibility to represent the using and consuming public prevents the Public Staff from being a neutral arbiter in the dispute

[1] The "recent disputes" cited by witness Auck involved four docketed matters before this Commission dating back several years. Three were formal complaints, and one was a notice of settlement that was filed in the instant docket. All of the complaints were resolved by the parties, and none required action by the Commission. No complaints or disputes relative to the NC Interconnection Standard are currently pending.

resolution process. NCSEA stated that while it supports the use of a dispute resolution service, the language in Section 6.2.4 of the Stipulated Redline is insufficient to protect Interconnection Customers because Utilities have no incentive to use a dispute resolution service. NCSEA cited testimony by Duke witness Riggins to the effect that the Utility would only agree to use a dispute resolution service if the Public Staff "couldn't handle the volume" of disputes. NCSEA noted that FERC recently mandated the use of third-party dispute resolution in its Large Generator Interconnection Procedures. For these reasons, NCSEA supported IREC's proposal to establish an interconnection ombudsperson at the Commission who could facilitate resolution of disputes.

Witness Nester opposed the modifications to Section 6.2 as proposed by IREC witness Auck. He stated that the introduction of an ombudsperson would be inconsistent with the way disputes with retail customers are handled. Witness Riggins expressed concern that the addition of a dispute resolution service could extend the time for resolving disputes. He also stated that Duke believes the Public Staff has informally facilitated the role of "interconnection ombudsperson" and that no further formalization of this role is needed.

While the Attorney General's Office (AGO) did not sponsor any expert witnesses in this proceeding, it nonetheless filed a post-hearing brief in which it advocated that the Commission appoint a "special master" to oversee all technical and procedural stakeholder processes in this docket.

> Because of the rapid pace of change in the landscape of distributed generation interconnection, it is difficult and impractical for the Commission to effectively exercise its oversight solely through the hearing process. At the same time, the AGO appreciates that the Commission may lack the resources necessary to directly manage interconnection stakeholder processes."

The AGO recommended that stakeholder processes be overseen by a special master, "who would be a neutral subject matter expert employed by the Commission." The AGO recommended that the Commission research whether a publicly funded institution such as the NC State Clean Energy Technology Center, the National Renewable Energy Laboratory, or the Lawrence Livermore National Laboratory would be willing to serve this function. If that was not possible, the AGO recommended following a procedure similar to that in Commission Rule R8-71(d) which allowed the Commission to select an Independent Administrator for the CPRE program.

Discussion and Conclusions

The Commission finds that the current dispute resolution process, with the engaged support of the Public Staff, has been largely effective. Very few formal complaints have been filed with the Commission, and all of those were withdrawn when the parties were able to settle their differences. The Commission believes it is unnecessary and inappropriate to assign a Commission staff person as ombudsperson to settle interconnection-related disputes. The Commission's formal complaint process remains the appropriate path for securing a decision from the Commission about a dispute between an Interconnection Customer and a Utility.

The Commission is not troubled by the Public Staff's dispute resolution role, despite the Public Staff's obligation to represent the using and consuming public in matters before the

Commission. The Public Staff has the expertise and perspective to consider the disparate interests of the parties, and is uniquely qualified to help Utilities and Interconnection Customers resolve their differences. The Commission notes that N.C. Gen. Stat. § 62-15(g) states:

> Upon request, the executive director shall employ the resources of the public staff to furnish the Commission ... such information and reports or conduct such investigations and provide such other assistance as may reasonably be required in order to supervise and control the public utilities of the State as may be necessary to carry out the laws providing for their regulation. [Emphasis added.]

The Commission acknowledges the significant assistance that the Public Staff has provided by helping Utilities and Interconnection Customers to resolve their disputes.

Nonetheless, the Commission recognizes that such disputes could become more common for the reasons cited by witnesses. The changes included in the Stipulated Redline should help the Utilities and the Interconnection Customers, as well as the Public Staff, by providing a more defined dispute resolution process with clear timelines. The Commission agrees with the parties to the Stipulation that these revisions should help remedy ambiguity and delays. The modified process continues to involve the Public Staff in the dispute resolution process, but also gives the parties the option, upon mutual agreement, to seek the assistance of a dispute resolution service before ultimately filing a formal complaint with the Commission if those efforts are not successful. In addition to accepting these changes as reasonable and appropriate, the Commission will amend "Article 10. Disputes" in the Interconnection Agreement to make clear that Parties may mutually agree to seek the help of a dispute resolution service.

The Commission notes that the Commission is typically unaware of interconnection-related disputes unless a formal complaint or settlement agreement is filed directly with the Commission. In order to better monitor the volume of interconnection disputes and the subject areas involved in those disputes, the Commission requests that the Public Staff periodically on its own timetable make informational filings with the Commission in this docket regarding interconnection disputes. Such filings should be general in nature so as not to prejudice the Commission in the event a dispute eventually becomes a formal complaint. In addition, as suggested by the Public Staff, the Commission will add the following requirement to Section 6.2.4:

> Upon resolution of the dispute, the parties shall jointly make an informational filing with the Commission.

As to the AGO's proposal that the Commission establish a special master to lead interconnection-related stakeholder processes, the Commission is not convinced that such a proposal would be effective. Significant efficiencies would be lost while the selected person learned the NC Interconnection Standard. Further, the Commission speaks through its orders, and only through its orders.

Therefore, based on all of the evidence presented, the Commission concludes that it is not necessary or appropriate to adopt IREC's proposal for an ombudsperson at this time, or to establish a special master. Instead the Commission concludes that it is appropriate to approve the modifications to Section 6.2, the dispute resolution provisions of the NC Interconnection Standard, as provided in the Stipulated Redline.

SURETY BONDS AND REFUNDS

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 13-14

The evidence supporting these findings of fact is found in the Stipulated Redline and in the testimony and exhibits of Duke witnesses Freeman, Riggins, and Gajda; DENC witness Nester; and NCCEBA witnesses Duke and Norqual.

NCCEBA witness Duke explained that a suretyship is a specialized line of insurance that is created when one party guarantees the performance of an obligation by another party. He testified that there are three parties to a surety agreement: (1) the principal undertakes the obligation; (2) the surety guarantees that the obligation will be performed; and (3) the obligee receives the benefit of the bond. The surety provides financial protection in the event the principal defaults in its performance.

Witness Duke testified that a surety bond is a contract, and the form of the bond is generally prescribed by the obligee. He stated further that the terms and conditions of the bond may be written to provide for the non-cancellability of the bond and may set the conditions under which a surety pays. Witness Duke testified that the surety will underwrite accordingly based on the terms and conditions of the bond. He stated further that a surety seeks to avoid a loss by making an assessment of the bond principal's experience, capabilities, and financial resources, and provides a bond only to those entities that are capable of performing the obligation that is bonded.

Witness Duke recommended that the Commission allow surety bonds as a form of financial security for Interconnection Facilities under Provision 6.3 of the Interconnection Agreement, which is part of the NC Interconnection Standard. He stated that not allowing acceptance of surety bonds unnecessarily deprives the parties of the valuable services provided by a surety bond.

NCCEBA witness Norqual testified that NCCEBA and NCSEA believe that a surety bond should be an allowable form of financial security for Interconnection in all circumstances. He stated that DENC accepts surety bonds for Interconnection facilities in North Carolina, and provided a copy of the approved bond form from Dominion. Witness Norqual testified further that allowing performance security for Interconnection Facilities in only the forms currently accepted by the Duke Utilities – cash or a cash-collateralized letter of credit – is burdensome to Interconnection Customers and serves no legitimate public purpose. He stated that surety bonds could potentially be obtained by Interconnection Customers for a fee of about 1 percent annually, "whereas the cost of capital for cash or a letter of credit could be in the 5 to 10 percent range."

Witness Norqual further stated that until the Utility has a need to incur costs for the design or construction of the Interconnection Facilities, there is no need for the payment of the costs to be secured. He asserted that neither Duke, nor other parties, nor ratepayers are at risk if an interconnection fails to go forward. He also testified that other Interconnection Customers would not be prejudiced if a project was cancelled after posting a surety bond, and that if a project is not constructed, any unspent funds should be returned to the Interconnection Customer. Norqual testified that the Utility should not be permitted to retain the funds of Interconnection Customers for unconstructed Interconnection Facilities. He testified further that if Duke allowed a surety, yet needed to buy materials during the construction process, it could invoice the customer, who could pay cash as Duke requires it. In conclusion, witness Norqual stated that a surety bond would provide sufficient financial protection to the Duke Utilities in the event the Interconnection Customer fails to pay the Utility for the Interconnection Facility, because the surety would step in to satisfy the claim on the bond and provide payment.

On rebuttal, witness Norqual testified that he believed the Commission should consider FERC's policies in weighing whether surety bonds should be accepted as financial security. He testified that the Interconnection Customer should not have to provide cash or a cash-collateralized letter of credit if the Utility does not yet need the funds to begin construction of the Interconnection Facility. Witness Norqual further testified that Duke's policy of requiring that 100% of the construction cost for the Interconnection Facility be paid up front is inconsistent with FERC's Large Generator Interconnection Agreement, and that Duke should not be entitled to keep any unspent funds. Witness Norqual recommended that Section 6.1.1 of the Interconnection Agreement be modified to enable the Interconnection Customer to "pay-as-you-go" for Interconnection Facilities.

Duke witness Riggins testified that Duke had previously committed to accept surety bonds from Interconnection Customers that contain terms that are reasonably acceptable to the Duke Energy credit and risk management department under three interconnection-related scenarios:

1) As security pursuant to Section 4.3.9 in the case of an executed Facilities Study Agreement with identified Network Upgrades.

2) For an executed Interconnection Agreement with identified Interconnection Facilities (but no Network Upgrades) when the project is participating in the CPRE evaluation process, until the outcome of the CPRE Tranche 1 RFP is determined.

3) For an Interconnection Agreement with Interconnection Facilities and Network Upgrades that will not be completed for three to five years and where Duke would not begin final design, procurement and scheduling for the Interconnection Facilities for an extended period of time.

He testified further that Duke is willing to accept surety bonds in any circumstance in which there is a material lag between the execution of the Interconnection Agreement and the time when Duke incurs costs for Interconnection Facilities. He stated that any surety bond must contain terms that are acceptable to Duke. Those terms include the requirement that payment be within a short period, such as 10 days, and the surety bond must be irrevocable.

Witness Riggins disagreed with witness Norqual's contention that surety bonds are "widely accepted" in the utility industry and stated that NCCEBA was only able to identify one other utility that had accepted a surety bond in the interconnection context. He opined that this was most likely because surety bonds generally contain terms and conditions that provide less security than letters of credit, are less standardized and more complex than letters of credit, and, therefore, require more case-by-case analysis to confirm acceptability.

Contrary to the testimony of witness Duke, witness Riggins testified that Duke has been unable to secure any material changes in bond form language in the few instances where they have determined surety bonds to be acceptable.

Despite these issues, witness Riggins testified that in the interest of compromise and because the financial risk to other customers is lessened in the case of Interconnection Facilities if the security arrangement is properly structured, Duke would accept surety bonds containing terms and conditions acceptable to the Company's credit/risk department.

Witness Riggins explained that Duke typically commences work (such as design and procurement), and, therefore, incurs costs, immediately after execution of the Interconnection Agreement even though construction might not begin until a later date. Witness Riggins testified that interconnection facilities are generally paid for under the "extra facilities methodology," and those methods differ from DEP to DEC. In DEP there's a "contributory plan" that would require an up-front pre-payment. In DEC, customers typically choose the monthly payment approach, which involves a deposit followed by monthly payments after the facility is built.

Witness Riggins stated that the Duke Utilities have never retained unspent money for Interconnection Facilities where the Interconnection Customer terminated the Interconnection Agreement, and noted that Cypress Creek had failed to identify any instance in which this had occurred. Witness Riggins stated that Duke proposed to modify Section 6.1.1 of the Interconnection Agreement to memorialize this practice. The Stipulated Redline shows the following:

> 6.1.1 The Interconnection Customer shall pay 100% of required Interconnection Facilities and any other charges are required in Appendix 2 pursuant to the milestones specified in Appendix 4.
>
> The Interconnection Customer shall pay 100% of required Upgrades and any other charges as required in Appendix 6 pursuant to the milestones specified in Appendix 4.
>
> Upon receipt of 100% of the foregoing pre-payment charges <u>for Upgrades</u>, the payment is not refundable due to cancellation of the Interconnection Request for any reason.

DENC witness Nester stated that DENC accepts surety bonds from Interconnection Customers because DENC accepts surety bonds as financial security for electric service deposits, and the Company seeks to align its policies regarding financial security generally. However, witness Nester clarified that DENC Provides a surety bond form to customers, and, upon return of that form, submits it to the DENC system credit department for review to determine if it is acceptable financial security or not.

In its post-hearing brief, NCSEA stated that it opposed the Stipulated Redline's changes to Section 6.1.1 "to make pre-payment for Upgrades non-refundable," stating that the Utilities had presented no evidence to support this change.

Discussion and Conclusions

Duke's proposal to accept surety bonds for Interconnection Facilities under certain circumstances, including when there is a material lag between the execution of an Interconnection Agreement and the time when Duke incurs costs for the Interconnection Facilities, is helpful. However, the Duke Utilities failed to present any compelling reasons as to why they cannot accept surety bonds as a form of financial security for Interconnection Facilities, as is done by DENC. Because a surety bond is a contract, Duke has full control over its terms. Therefore the Commission will require Duke to develop a standard form surety bond with terms that are acceptable to the Company and make it available to Interconnection Customers.

The Commission recognizes that the Utilities typically incur some costs immediately upon execution of an Interconnection Agreement and, therefore, need to ensure that adequate financial protection is in place at that time. Further, requiring upfront payments/security helps to ensure that non-viable projects leave the queue as soon as possible. The Commission declines to adopt a "pay as you go" payment arrangement for Interconnection Facilities at this time, as such a change would represent a substantial departure from current practice, is not adequately supported in the record, and would impose an unnecessary administrative burden on the Utilities, thereby working against efforts to improve their efficiency.

Regarding the proposed changes to Section 6.1.1 of the Interconnection Agreement, the Commission finds that NCSEA's position misunderstands the current NC Interconnection Standard, which already provides that pre-payments for Upgrades are non-refundable. The purpose of the amendment in the Stipulated Redline is to clarify that unspent funds for Interconnection Facilities shall be refunded if the Interconnection Agreement is cancelled. In order to further clarify the proposed changes, the Commission will amend the third paragraph of Section 6.1.1 to read as follows:

> Upon receipt of 100% of the foregoing pre-payment charges <u>for Upgrades</u>, the payment is not refundable due to cancellation of the Interconnection Request for any reason. <u>However, if an Interconnection Customer terminates its Interconnection Agreement and cancels its facility, it shall be entitled to a refund of any unspent amounts that had been collected by the Utility for Interconnection Facilities.</u>

TECHNICAL STUDY PRACTICES AND COMMUNICATIONS

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 15-18

The evidence supporting these findings of fact is found in the Stipulated Redline and in the testimony and exhibits of Duke witness Gajda, DENC witness Nester, NCSEA witness Brucke, IREC witness Lydic, and Public Staff witness Williamson.

NCSEA witness Brucke testified in opposition to several Duke interconnection policies, asserting that they do not represent Good Utility Practice and that increased oversight of Duke's technical restrictions to interconnection are needed.

For example, witness Brucke stated that Duke introduced a "circuit stiffness review" in 2016 to determine the relative strength of the grid compared to the size of an interconnecting Facility. He stated that Duke originally announced that projects with a stiffness factor below 25 at the Point of Interconnection or the substation would not be allowed to interconnect. He stated that Duke revised its approach and now instead performs an advanced study for those kinds of Facilities. He stated that Duke's circuit stiffness review was not Good Utility Practice, and that it was not technically justified.

Witness Brucke criticized Duke's policy of no longer allowing generators to interconnect beyond a line voltage regulator. He testified that Duke wanted to reserve the ability to use double-circuiting to serve future load. Witness Brucke stated that a universal prohibition of double-circuiting is a convenience for Duke, but Duke could instead make a project-specific determination of whether they might need double circuits to serve future load growth in an area, or find other ways to serve future load growth.

NCSEA witness Brucke also criticized Duke's Method of Service Guidelines. He stated that the guidelines are overly restrictive, citing especially Duke's requirement that the aggregated capacity of all generators on a substation cannot exceed the nameplate rating of the substation transformer. He testified that Duke has defined the nameplate rating for this purpose as the lowest of three ratings that are typically available, and that DEP used to allow the highest rating on the transformer to be determinative. He stated that Duke has not given a technical justification for this policy. Witness Brucke stated that the technical standards in the Method of Service Guidelines are overly restrictive, not typical compared to those in other states, and not technically justified.

Witness Brucke testified that the Commission should review Duke's application of Good Utility Practice via a technical working group with direct oversight by the Commission or the Public Staff.

IREC witness Lydic similarly advocated for the Commission to convene an Interconnection Technical Working Group with representatives from all stakeholders. This group would review any new issues or proposed changes to the interconnection process and requirements that might arise between major revisions to the NC Interconnection Standard. Lydic stated that no changes should be able to go into effect unless there is consensus within the group or the Commission approves the changes.

Duke witness Gajda testified that Good Utility Practice is defined in the NC Interconnection Standard as follows:

> Any of the practices, methods and acts engaged in or approved by a significant portion of the electric industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods or acts generally accepted in the region.

He explained that the Duke Utilities had each developed Good Utility Practices for serving retail customers before the term was implemented under the NC Interconnection Standard in the context of generator interconnections. Witness Gajda highlighted that due to the Duke Utilities' responsibility for safety, reliability, and power quality, Duke continuously and deliberately considers what technical standards to implement; and why, how, and when to change its standards. Witness Gajda testified that the Duke Utilities develop their technical standards through involvement in organizations like the Institute of Electrical and Electronics Engineers (IEEE) and the National Electrical Safety Code (NESC); the sharing of technical information with other utilities, and the careful application of power system theory and engineering. He testified that the majority of Duke engineers involved in decisions to change the standards are licensed professional engineers with deep understanding of Duke's systems.

Witness Gajda explained that as a result of North Carolina's unparalleled growth of solar Interconnection Requests, the concept of Good Utility Practice and how the Utilities apply it has had to rapidly evolve. He testified that in 2016 Duke applied significant distribution engineering resources to evaluate whether Good Utility Practice required that additional study criteria be used during System Impact Studies. He testified:

> I and other engineers within the Companies were increasingly recognizing that historically valid "steady state" engineering studies were inadequate to properly predict power quality issues associated with utility-scale solar projects connected to the distribution system and, as such, more robust and dynamic models and standards were needed.....

Witness Gajda testified that Duke's DER Method of Service Guidelines, which took effect October 1, 2017, illustrates the Companies' adaptation of Good Utility Practice to the evolving interconnection landscape in North Carolina. He stated that these guidelines "allow for sustainable methods of interconnection for all sizes of DER while maintaining the Companies' ability to provide reliable retail electric service for current and future retail customers."

Witness Gajda testified that the Method of Service Guidelines provide guidance in these areas: (1) the appropriate method and Point of Interconnection based on the generator's size; (2) configuration options for line design and construction on the distribution system; (3) appropriate voltage regulation zones (also known as the line voltage regulator policy); (4) the construction of line extensions; and (5) methods for screening and assessing the potential for power quality impacts to retail customers (also known as the circuit stiffness review). Witness Gajda testified:

> Importantly, Interconnection Customers proposing new projects that are now impacted by the Method of Service Guidelines are presented an alternative point of interconnection or method of service during System Impact Study, such as a direct-to-substation connection or a transmission-level interconnection, that more appropriately reflects the ability of the System to accommodate the ... Facility.

He specifically pointed to the Duke Utilities' determination in 2016 that Good Utility Practice supported requiring Interconnections Customers to interconnect ahead of the first line voltage regulator and also to eliminate the use of "partial double circuits" to interconnect to the

Utility's system. Witness Gajda testified that the Method of Service Guidelines serve to ensure that Generating Facilities are interconnected in a manner that would not force retail customers to bear higher costs due to engineering limitations caused by non-standardized interconnection practices.

Witness Gajda explained that accommodating utility-scale projects with non-standard methods on a quantity basis, when a growing number of technical parameters may not yet be well-understood, shifts cost and reliability risk to the Duke Utilities' retail customers and can become unsustainable over time. Witness Gajda testified that because of evolving challenges with high penetrations of DER, the Duke Utilities intend to continue refining Good Utility Practice to ensure adequate system safety, power quality, and reliability are maintained for all customers.

DENC witness Nester testified that the Utility should be responsible for determining what constitutes Good Utility Practice for its service territory within the definition of the term in the NC Interconnection Standard. He noted that:

> the Utility is the most consistent party associated with the interconnection process, since, in the Company's experience, many developers of interconnection projects that desire to participate in the determination of Good Utility Practice have no intent to operate their generating facilities for any significant length of time but, rather, intend to sell their generating facilities ....

In his rebuttal testimony, witness Nester objected to "attempt[s] to socialize the determination of Good Utility Practice. DENC believes that the determination of Good Utility Practice is a critical area in which the Utility needs to remain predominantly responsible."

Public Staff witness Williamson testified that the definition of Good Utility Practice "clearly contemplates ... changing over time." He testified further that "The Utilities are responsible for determining the practices, methods and acts necessary to meet the rules and standards established by the relevant regulatory bodies." Witness Williamson testified that, in his professional opinion, Duke's Method of Service Guidelines are "reasonable guidelines for the Duke Utilities to apply in meeting their obligation to provide safe, reliable electric service to the using and consuming public." He testified further that "Duke Energy retains the right to make the final decision on all technical standards or evolving GUP [Good Utility Practice] revisions, subject to Commission review as part of its general regulatory power and the dispute resolution process defined in the NCIP [NC Interconnection Procedures]."

With regard to the communication of new study criteria, witness Williamson recommended that if a new screen, study, or major modification in the application of the NC Interconnection Standard is developed, the Utilities should be required to file it with the Commission in this docket for informational purposes only, post information regarding the new screen, study, or modification on the Utility's website, and present the topic for discussion at the next TSRG stakeholder meeting. Witness Williamson testified further that when the Utilities file such a revision with the Commission, they should be required to inform the Commission of any potential queue impacts such as impacts to processing time, potential for projects to withdraw from the queue, and increased costs to be incurred by the Applicant.

Witness Gajda rebutted NCSEA witness Brucke's assertion that the Duke Utilities have denied interconnections outright, instead noting that as penetrations of DER have increased, the cost to interconnect facilities has increased, which may make some interconnection projects financially infeasible. Witness Gajda explained that the Duke Utilities have always sought to identify the simplest and most reasonable interconnection solution, at the least cost, consistent with Good Utility Practice, and the Duke Utilities should not alter their conclusions simply because the outcome may not be financially feasible for each Interconnection Customer. Duke witness Freeman made a similar point that many Interconnection Customers request the Utilities consider one-off, "non-standard" methods to interconnect their projects. Witness Freeman noted that this shifts cost and reliability risk to the Utilities' retail customers and can become unsustainable and incompatible with the Utilities' obligation to plan and operate the system in a safe and reliable manner for all customers.

At the hearing, NCSEA witness Brucke conceded that the Duke Utilities have never denied an interconnection outright but sometimes offered options that were financially infeasible.

In response to Public Staff witness Williamson's proposal for publicizing revisions to study criteria, Duke witness Gajda clarified that the Duke Utilities agree to (1) file any significant new screens, studies, or major modifications in their application of the NC Interconnection Standard with the Commission in this docket for informational purposes only; (2) post information on the Utility's website regarding the change; and (3) present the topic for discussion at the next TSRG stakeholder meeting.

DENC witness Nester stated in his rebuttal that in DENC's experience, the communications processes that already exist in the NC Interconnection Standard allows study parameters to be presented and explained to Interconnection Customers with the opportunity to dispute those parameters should the customer desire. He stated that DENC already communicates interconnection information to customers regarding particular requests that could not be shared publicly due to confidentiality concerns. Finally, he noted that since DENC does not participate in the TSRG, any requirement to present information at TSRG meetings should not apply to DENC. Witness Nester testified that DENC believes the best way for it to communicate study criteria to customers is through the actual interconnection study process, and that it is helpful to have a real Interconnection Request to frame such discussions.

Discussion and Conclusions

Good Utility Practice is a defined term in Attachment 1 of the NC Interconnection Standard. No party in this proceeding proposed to modify the term. Rather, some parties chose to use this proceeding to criticize Duke's application of Good Utility Practice and to advocate for increased Commission oversight or a stakeholder-driven consensus process for determining whether a Utility's practices meet the definition of Good Utility Practice.

The Commission agrees with those witnesses who asserted that increased levels of DER will necessitate evolving practices as regards Good Utility Practice. The Commission finds that Duke and DENC both have reasonable practices in place for communicating policy changes to Interconnection Customers, and the Commission will take no further action in that regard except, as recommended by the Public Staff, to require Utilities to notify the Commission of changes in their practices and policies relative to reviewing Interconnection Requests, and to inform the Commission of any potential impacts to Interconnection Request processing time, the potential for projects to withdraw from the queue, and increased costs to be incurred by Applicants.

The Commission takes judicial notice of its review of a settlement agreement between the Duke Utilities and a group of "late-stage Interconnection Customers" relating to the circuit stiffness review and related comments filed in this docket in 2016. At that time the Commission determined that the Duke Utilities were taking appropriate steps to ensure electric service to retail customers is not degraded due to the operations of newly interconnected Generation Facilities.[1] The Commission similarly now finds that the Duke Utilities have applied reasonable judgment and have taken appropriate steps in light of the facts known to establish the Method of Service Guidelines and other technical standards, as a reasonable implementation of Good Utility Practice.

Consistent with the Public Staff's testimony, the Commission finds that the Utilities should continue to take a conservative view when evaluating impacts of generator interconnections and assigning costs associated with Interconnection Requests. When evaluating an Interconnection Customer's impact to the System under Good Utility Practice, Utilities should ensure that electric service is not degraded or adversely impacted. Utilities should continue to evolve Good Utility Practice, when needed, to ensure that electric service to existing and future retail customers is not adversely impacted.

The Commission agrees with the Public Staff that the definition of Good Utility Practice provides the Utilities necessary flexibility to make changes, when needed, to ensure safe and reliable operation of the electric System going forward.

The Commission also agrees with Duke witness Gajda that the Utilities should continue to develop and implement Good Utility Practice in a sustainable and scalable manner that applies equally to all Interconnection Customers, while ensuring that adequate long-term system safety, power quality, and reliability of the power delivery system is maintained for all customers. Deviating from Good Utility Practice to accommodate a single Interconnection Customer with non-standard methods and interconnection solutions could shift cost and reliability risk to retail customers and is, therefore, unacceptable.

To the extent an Interconnection Customer does not agree with the Utilities' application of Good Utility Practice, it may pursue the informal dispute process in Section 6.2 of the NC Interconnection Standard. If that proves unsuccessful, the Interconnection Customer can pursue a complaint before the Commission.

The Commission declines to adopt IREC's recommendation that changes to Utility study methods should be agreed to via consensus in a stakeholder process. As DENC witness Nester testified, while Utilities have long-term responsibility to serve customers reliably and safely, DER developers are often transitory and potentially have little or no long-term commitment to the electric system whose design they would like to influence. Further, it is possible that prudent electric system management would require the speedy adoption of new policies as DER penetrations increase and new technologies are adopted. Because the Commission will continue to

[1] Order Regarding Duke Settlement Agreement with Generation Interconnection Customers, Docket No. E-100, Sub 101 (Nov. 1, 2016).

hold North Carolina's Utilities to high operational standards, it is not appropriate for the Commission to hobble them with a requirement to make important System design decisions by committee.

The Commission rejects NCSEA's assertion in its post-hearing brief "that the Commission has not exercised oversight over Good Utility Practice since its 2015 Order." That Order set the stage for the instant proceeding, which was delayed to give Parties an opportunity to reach consensus, which was accomplished to some degree. The Commission notes that not a single complaint has been filed with the Commission relative to the question of "Good Utility Practice," no Interconnection-related complaints are pending before the Commission today, and the Commission is holding the Utilities to high operational standards. The purpose of the instant proceeding is to consider changes to the NC Interconnection Standard that would make it more effective. Not a single party proposed changes to the definition of Good Utility Practice. In conclusion, the Commission will require the Utilities to (1) file any significant new screens, studies, or major modifications in their application of the NC Interconnection Standard with the Commission in this docket for informational purposes; (2) post information on the Utility's website regarding the change; and (3) Duke shall present the topic for discussion and feedback at a TSRG stakeholder meeting prior to implementing the change.

TIMELINE ENFORCEMENT MECHANISM

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 19

The evidence supporting this finding of fact is found in the testimony and exhibits of Duke witness Riggins, DENC witness Nester, IREC witness Auck, and Public Staff witness Lucas.

IREC witness Auck recommended that the Commission adopt a timeline enforcement mechanism (TEM) similar to one adopted in Massachusetts, which would provide positive and negative earnings adjustments for Utilities in order to encourage compliance with the NC Interconnection Standard's timelines. Witness Auck testified that under the TEM proposal, each Utility would calculate the total aggregate average time that it had taken to interconnect projects over the past year, and then compare those results to the timelines outlined in the NC Interconnection Standard to determine the appropriate penalty or reward. Witness Auck explained that when the Utility's calculations show that its performance has deviated from the aggregate allowed timeframes by more than five percent in one direction or the other, the Utility would either incur a penalty or earn an offset to carry forward to the next year. Witness Auck stated that the TEM would not require strict compliance with the timelines in the NC Interconnection Standard for every project, since the proposed TEM method tracks and bases the penalty or credit on overall compliance, and argued that this TEM approach would work well in North Carolina.

Public Staff witness Lucas stated that the Public Staff did not support the adoption of a TEM. He stated that the Utilities appear to have made good faith efforts to interconnect Interconnection Customers, as evidenced by North Carolina having over 3,000 MW of solar interconnected to its system, and that this unprecedented amount of growth in solar could only have been brought about by the cooperation of the Utilities.

Duke witness Riggins testified that the Company opposes the adoption of a TEM because it is inappropriately punitive. He testified that the Duke Utilities have already made significant investments in staffing, technology, and process improvements to address delays in the interconnection process that were identified by NCCEBA and IREC. He testified that the unprecedented and unparalleled number of utility-scale solar generators already connected by the Duke Utilities validates their reasonable and good faith efforts to adhere to deadlines in the NC Interconnection Standard.

Witness Riggins further testified that IREC's recommendation to impose a TEM is based upon the flawed assumption that the Duke Utilities have complete control over the amount of time it takes to interconnect a project, and additionally fails to account for the complexity of North Carolina's interconnection process. Witness Riggins stated that under IREC's TEM proposal, the Utilities could be penalized for delays caused by interdependent projects, even though the Utilities would actually be adhering to the terms of the NC Interconnection Standard. Additionally, witness Riggins opined that the TEM proposal could actually create an incentive for the Utilities to refuse to grant extensions or cure periods, or allow even the slightest accommodation for Interconnection Customers. Witness Riggins concluded that the TEM was unreasonable in light of the Utilities' good faith efforts and unparalleled success in interconnecting projects, as well as the current complexities of the interconnection process in North Carolina, and should be rejected.

DENC witness Nester also opposed IREC's TEM proposal and testified that the Utilities had made reasonable efforts to administer the timelines in the NC Interconnection Standard as evidenced by North Carolina's status as second in the nation in installed solar capacity. He also stated that the NC Interconnection Standard already contains communication and dispute provisions by which timeline issues for specific Interconnection Requests can be addressed.

Discussion and Conclusions

The Commission is not persuaded by the testimony of IREC witness Auck that a timeline enforcement mechanism is reasonable or necessary to address delays in North Carolina's interconnection queue. As witness Riggins testified, the Utilities in North Carolina have a large number of interdependent projects in their queues, making strict adherence to the deadlines in the NC Interconnection Standard difficult. In addition, as discussed in the final section of this Order, Duke offers Interconnection Customers mitigation options when an Interconnection Request results in expensive Upgrades. While the developer community appears to support the mitigation options step, it does have the effect of delaying the process. Based on the large amounts of solar generation that the Utilities have successfully interconnected, and the lack of formal complaints pending before the Commission, the Commission finds that the Utilities have made reasonable efforts to adhere to the timelines outlined in the NC Interconnection Standard and concludes that a timeline enforcement mechanism is not necessary or appropriate. The Commission reiterates that it expects the Utilities to meet those deadlines that are within their control.

QUEUE MANAGEMENT REPORTING

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

The evidence supporting these findings of fact is found in the testimony and exhibits of Duke witnesses Freeman, Riggins, and Gajda; DENC witness Nester; IREC witness Auck; and Public Staff witness Lucas.

Public Staff witness Lucas testified that since the 2015 proceeding, the Duke Utilities have improved the transparency and communications with Interconnection Customers. Witness Lucas described the Duke Utilities' initial use of the PowerClerk online software platform for the submission and tracking of interconnection requests for small interconnection projects, and their current transition to the use of Salesforce as the system of record for tracking all interconnection data. He recommended that the Utilities evaluate the cost of developing and operating an online portal that would allow developers to track the status of their projects as well as provide a record of the date on which a project completes each step in the interconnection process. Witness Lucas recommended that the Utilities provide a cost estimate for an online portal to the Commission and the Public Staff for review and consideration. Witness Lucas commended the Duke Utilities on their efforts to make additional information available to Interconnection Customers through semimonthly distribution and transmission queue status reports, and encouraged the Utilities to continue to provide that information on all projects in the interconnection queue.

In addition, witness Lucas explained that, due to the rapid increase in the amount of DER being built, and the anticipated distributed generation to be constructed as a result of HB 589, the Public Staff recommended that the Utilities modify the information filed with the Commission in their annual queue reports and begin filing the reports on a quarterly basis. Specifically, the Public Staff recommended the reports be modified to include interconnections that are under the jurisdiction of FERC, since those projects result in potential interdependency issues with State-jurisdictional interconnections, and to use the operational status definitions used in the Utilities' online distribution and transmission queue reports.

Duke witness Riggins testified that the Duke Utilities had improved their reporting and communication related to the interconnection process. He testified that the Duke Utilities voluntarily provide public semimonthly updates to queue reports on the Duke Energy Renewables website. The reports provide information for each interconnection request, including operational status and interdependency status. He stated that the Duke Utilities recently began providing information about each project's System Impact Study. Witness Riggins also testified that because of the Duke Utilities' expanded use of Salesforce, they will be able to create reminders of milestones and deadlines for both themselves and the Interconnection Customers so that timelines can be more proactively managed. The Companies also added additional account managers and customer account specialists to make the process more transparent.

Duke witness Riggins testified that the Duke Utilities were already in the process of developing an online Interconnection Customer portal. Witness Riggins committed to share with the Public Staff the plans for the online portal, and to identify additional features that may need to be evaluated. Witness Riggins further testified that the Duke Utilities agreed with the Public Staff's recommendations with respect to the annual queue reports. He explained that, due to the significant increase in the number of generator interconnections; the Duke Utilities did not oppose reporting this information to the Commission quarterly instead of annually, and to add each facility's their operational status, including identifying FERC-jurisdictional projects.

Witness Nester testified that DENC has complied with the reporting requirements in the 2015 Order. He did not propose any changes because the current requirements strike a reasonable balance between providing information to developers and not burdening Utilities. Witness Nester stated that DENC Processes its reports manually, and while it is investigating queue-reporting platforms, he was not able to commit to those technologies. He explained that more reporting could divert resources away from processing Interconnection Requests. He noted that Interconnection Customers can and do contact DENC directly to inquire about their projects. DENC witness Nester testified that DENC did not support any of the proposals to increase reporting frequency and content. He testified that for DENC, these added obligations would impose a significant burden given that DENC administers its queue manually. He stated that DENC does not necessarily oppose the Public Staff's proposal that the Utilities evaluate the cost to develop and operate an online portal. However, DENC opposed requiring software development in the NC Interconnection Standard at this time, due to the lack of clarity regarding timing and cost. He clarified that DENC did not oppose the Public Staff's proposal that queue reports include FERC-jurisdictional requests, so long as it is limited to the FERC interconnections that are placed into operation. He explained that at the request of the Public Staff, DENC has already been including FERC-jurisdictional interconnections that have been placed into operation. Witness Nester further explained that data concerning Interconnection Requests submitted to PJM can be found on PJM's website. In conclusion, he stated that DENC's quarterly queue status reports already contain preliminary interdependency status of state projects which incorporate interdependency with FERC projects, and that DENC's queue reporting was sufficient.

IREC witness Auck recommended that the Commission require Utilities to publish monthly a public distribution queue on their websites in a downloadable and sortable format. She recommended 23 specific items of information to be included in the public distribution queue, and testified that this information would increase efficiency, reduce costs, and help lighten the burden on the queue, as customers would make better-informed decisions. She suggested that this requirement should not burden the Utilities as they already track the majority of the items she recommended be included in the public distribution queue.

Witness Auck also recommended that Utilities be required to modify their annual queue reports because they do not provide information necessary to determine why the queue remains clogged. She recommended the reports be filed quarterly, and that the reports provide summary queue data and data about the Pre-Application process. Witness Auck testified that currently these reports only include information on larger projects, so there is little visibility as to how projects eligible for Supplemental Review, Fast Track, and small inverter-based projects, are being processed. In conclusion, she testified that additional reporting would illuminate why projects are getting stuck in the queue, how often this occurs, and what opportunities there are to improve the process.

With respect to IREC's request for additional information to be included in quarterly reports, witness Riggins testified that the administrative burden and expense would significantly outweigh any benefit to Interconnection Customers or the overall interconnection process. He explained that adopting IREC's reporting recommendations would require the Utilities to dedicate additional engineering and administrative resources to reporting versus actually studying Interconnection Requests. He, therefore, recommended the Commission reject IREC's proposed modifications to the Utilities' reports.

Witness Riggins also opposed IREC's proposal to require Utilities to publish public distribution queue reports. He explained that the Duke Utilities already voluntarily publish Queue Snapshot reports on its website in a downloadable format twice a month; more frequently than IREC requested. He stated that some of the information requested by IREC to be published was inappropriate to publicly disclose. Witness Riggins also testified that adopting IREC's proposal would require additional investments and significant manual effort, further increasing costs. In sum, witness Riggins testified that the Duke Utilities' current voluntary queue tracking and reporting is sufficient.

Discussion and Conclusions

Since the 2015 Proceeding, the Utilities have made significant efforts to increase the transparency of the interconnection process through the quarterly and annual reporting requirements required by the Commission, as well as through their voluntary efforts. The reports filed in this docket, Docket No. E-100, Sub 101A, and Docket No. E-100, Sub 113B, are providing useful information.

Based on the evidence presented, the Commission concludes that the Public Staff's recommended new reporting requirements, as agreed to by Duke witness Riggins, are reasonable and strike the appropriate balance between promoting transparency and burdening the Utilities. The Duke Utilities' agreement to identify all projects above 20 kW requesting interconnection, including designating operational status, in the quarterly queue status reports submitted in Docket No. E-100, Sub 101A appropriately addresses the desire for more detailed information without overly burdening the Utilities.

Since DENC already provides operational status in its quarterly queue status and annual interconnection reports, this new requirement will only impact the Duke Utilities. The Commission agrees with Duke witness Riggins that for administrative efficiency, Utilities should continue to file the small generator report annually in Docket No. E-100, Sub 113B. With respect to the Public Staff's proposal that this list include all FERC-jurisdictional projects, the Duke Utilities shall be required to add this information to their quarterly reports. As noted by witness Nester, DENC already provides FERC information, and the Commission finds it appropriate that DENC continue to report this information annually as it does now.

In addition to these changes, the Commission is encouraged by the ongoing voluntary efforts being considered or implemented by Utilities to make additional information available.

The additional reporting requirements proposed by IREC would place an undue burden on Utilities that is not supported by the record. Accordingly, the Commission declines to adopt IREC's recommendation at this time.

HOSTING CAPACITY MAPS

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 22

The evidence supporting this finding of fact is found in the testimony and exhibits of Duke witness Riggins, DENC witness Nester, IREC witness Auck, and Public Staff witness Lucas.

IREC witness Auck described hosting capacity map (HCM) tools and recommended that the Utilities be required to implement a hosting capacity analysis based on proposals developed by a Commission-initiated working group. She testified that the ideal HCMs would include detailed hosting capacity modeling and the public posting of available capacity for each node, along with substation, circuit, and feeder information. She testified that the maps could help indicate circuits where the transformer capacity has been exceeded, as well as help customers to avoid incompatible sites and/or would help them plan for a longer duration review process by being able to anticipate needed upgrades.

Witness Auck stated that without an HCM, Interconnection Customers have no information regarding the best and worst locations for new distributed generation facilities. Witness Auck referred to the Commission's guidance in its October 5, 2018 Order Approving Interim Modifications to the NC Interconnection Procedures for Tranche 1 of CPRE RFP in which the Commission expressed interest in "options for Duke to more specifically direct generators to locations on the system that will not involve major network upgrades." She noted that projects participating in CPRE are more likely to interconnect to the utility's transmission system, and that hosting capacity maps focus exclusively on the distribution system.

Public Staff witness Lucas testified that a distribution level HCM would provide little benefit due to the shift towards larger, transmission-connected projects in North Carolina. Witness Lucas recommended instead that the Duke Utilities be required to build on the grid location guidance provided for CPRE Tranche 1 to provide basic information on the transmission system and identify those areas that are at or near their hosting capacity limit. He further recommended that the Duke Utilities provide the Commission and the Public Staff a detailed estimate of the cost to develop and maintain HCMs utilizing existing data and tools, and noted that all costs associated with HCMs should be recovered from Interconnection Customers through charges and fees

DENC witness Nester testified that it is unreasonable and inappropriate to require the Utilities to develop HCMs at this time. He noted that the Section 1.2 and Section 1.3 Pre-Request Response and Pre-Application Report in the NC Interconnection Standard already provide more site-specific data than an HCM would. He also expressed DENC's concern that IREC's proposal does not provide clarity as to the timeframe or cost to develop such maps, address the confidentiality of sensitive utility grid infrastructure information, or provide any detail as to the frequency of updates necessary to ensure that information is relevant. Witness Nester stated that DENC is not opposed to investigating potential development of an HCM tool, but that DENC does not support including an HCM requirement in the NC Interconnection Standard. He agreed with the Public Staff that the cost of any HCM development should be recovered from developers, as they would receive the primary benefit.

Duke witness Riggins agreed with Public Staff witness Lucas that there has been a shift such that transmission-connected Interconnection Requests are now more common that those at the distribution level. He testified that in 2018, for solar projects larger than one megawatt, the Duke Utilities received 44 transmission-connected Interconnection Requests compared to just 16 distribution-connected Interconnection Requests.

Witness Riggins also testified that the Duke Utilities annually receive thousands of Interconnection Requests for customer-sited net metering projects, but since customer-sited net metering projects cannot change their location in response to information provided through an HCM, there would be a limited audience for a distribution level HCM in North Carolina.

Additionally, witness Riggins agreed with the Public Staff that Duke should continue to refine the transmission grid location guidance required by CPRE. He stated that the Company posts information "for the benefit of larger transmission projects," in formation about where there are constrained areas on the grid so as to "direct projects to areas where there's not constraints."

Witness Riggins disagreed with IREC witness Auck's assertion that an HCM is the only way for customers to evaluate locations for new DER. He explained that Section 1.2 of the NC Interconnection Standard requires Utilities to provide free basic distribution system information to Interconnection Customers for a potential Point of Interconnection. Also, Section 1.3 allows an Interconnection Customer to request a Pre-Application Report for $300.[1] The Utility must respond within 10 Business Days by providing extensive distribution system information, including the capacity of the substation/area bus, bank, or circuit for a given Point of Interconnection, and the amount of queued or existing generation currently served by the substation/area bus, bank, or circuit.

Witness Riggins further testified that in addition to these reports, the Duke Utilities publicly post their respective interconnection queues through semimonthly Queue Snapshot reports as well as transmission grid locational guidance.

Witness Riggins also testified that Duke had performed a preliminary analysis of the costs to develop an HCM. He testified that Duke estimated that it would cost between $2 million and $8 million for Duke to develop HCMs, with an additional $1 million to $5 million each year to maintain them. In conclusion, witness Riggins recommended the Commission reject IREC's HCM proposal.

IREC witness Auck testified on rebuttal that IREC believes it is appropriate at this time for the Utilities to develop hosting capacity analyses that can help customers better site their projects and predict the outcomes of the interconnection process. She further testified it is reasonable to expect that small projects, which are likely to connect to the distribution system, will comprise the vast majority of the Interconnection Requests that the Duke Utilities receive in the coming years, and, therefore, recommended the Commission direct the Duke Utilities to prepare a hosting capacity analyses of its distribution system to facilitate the smart siting and efficient interconnection of those projects. IREC took no position on whether the Duke Utilities should be required to prepare a transmission level HCM.

[1] The Stipulated Redline would increase this fee to $500.

Witness Auck testified that IREC did not agree with the Public Staff's cost-recovery proposal for HCM costs, because IREC believed that an HCM provides benefits to all customers. Witness Auck further testified imposing HCM costs only on Interconnection Customers would require a complex cost allocation methodology which could prove difficult to implement. In conclusion, witness Auck stated that IREC was not aware of any other state that asks Interconnection Customers to pay the costs of a distribution-level HCM, and therefore, the Commission should reject the Public Staff's cost-recovery proposal for an HCM, and instead allocate HCM costs the same way as utilities allocate the costs of other distribution system planning tools.

Witness Auck acknowledged that the value of hosting capacity maps is based on their ability to be used in a real-time basis, which requires that they be updated with some regular frequency that may result in ongoing costs.

Discussion and Conclusions

The Commission has considered the evidence in this proceeding concerning the development of HCMs, and for the following reasons concludes that it is not necessary or appropriate to require Utilities to pursue such an effort at this time.

The Commission is persuaded that the information already available to Interconnection Customers via the Section 1.3 Pre-Application Reports is more extensive than an HCM would likely provide, is targeted to Points of Interconnection of actual interest to specific Interconnection Customers, and can be provided at a fraction of the cost of an HCM. Further, as several witnesses testified, HCMs would have no value to smaller customers who want to net meter and have no choice as to where to locate their solar installation. Also, HCMs would be expensive to develop, and would require costly ongoing revisions. In addition, it appears that the distribution grid is increasingly less likely to see further growth in large solar installations. As the Public Staff and Duke testified, North Carolina is seeing a shift as large solar projects choose to interconnect on the transmission system instead of on the distribution system. Refining the locational guidance maps that Duke provided in Tranche 1 of the CPRE solicitations, which included extensive lists of constrained transmission facilities, would appear to be of higher value than creating detailed HCMs for the distribution grid. Those maps are publicly available on the website for the CPRE solicitation process.

For these reasons, and based on the evidence in this case, the Commission concludes that it is not appropriate or necessary to adopt IREC's HCM proposal.

STAKEHOLDER WORKING GROUPS

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 23

The evidence supporting this finding of fact is found in the Stipulation, and the testimony of Duke witness Freeman, IREC witness Auck, and Public Staff witnesses Lucas and Williamson.

Duke witness Freeman testified that although the Utilities proposed only limited changes to the NC Interconnection Standard at this time, a more comprehensive reform is needed in the near term to address the continued growth of the interconnection queue. Witness Freeman testified that because the interconnection queue and study complexities continue to increase, the current serial study process is not sustainable, and that it would likely require decades to serially study and potentially connect the 14,000 MW of renewable generating facilities that are in the current North and South Carolina Duke Utilities' queues.

Witness Freeman explained that when larger transmission network upgrades are triggered by an Interconnection Request, the serial study process results in large upgrade costs being assigned to one project even though it is extremely unlikely that a single project could absorb such significant cost. This will result in paralysis in certain areas, as project after project will be forced to withdraw from the queue. Witness Freeman testified that Duke believed that it is now necessary to transition from a serial study process to a cluster study process, like that used by an increasing number of regional transmission organizations (RTOs) and utilities in other areas of the country.

Witness Freeman testified that the Duke Utilities hosted an initial stakeholder meeting in June 2018 to receive feedback regarding transitioning to a cluster study approach. Witness Freeman stated that stakeholders seemed to agree that queue reform is needed, and that several issues would need to be addressed prior to implementation of a cluster study approach. Witness Freeman testified that in parallel with supporting the modifications to the NC Interconnection Standard presented to the Commission for approval now, the Duke Utilities are also now working on a queue reform proposal to share with the Public Staff and other stakeholders to develop a more sustainable approach to studying projects, assigning upgrade costs, and collecting the costs of those upgrades. Witness Freeman concluded that the Duke Utilities anticipate requesting Commission approval of additional revisions to the NC Interconnection Standard to accomplish this reform, which reform would also need to align with Duke's FERC-jurisdictional open access transmission tariff, to solve challenges associated with administering both a state- and FERC-jurisdictional interconnection queue.

Public Staff witness Lucas recommended that within three months from the final order in this proceeding, or three months after issuance of the CPRE Tranche 1 report, whichever occurs later, interested parties should convene a stakeholder discussion focused solely on revisiting the Project A/B process and the optional grouping study process to determine how they might be used together to more efficiently manage the large number of projects in the queue. Witness Lucas further testified that the Public Staff recommended that the Utilities file a report with the Commission with recommendations and any consensus among the parties within six months from the start of these stakeholder discussions.

IREC witness Auck agreed with witness Freeman that the current interconnection process is unsustainable, and did not oppose consideration of a cluster study process. Witness Auck testified that a useful cluster study must be developed and vetted through a collaborative stakeholder process that ensures projects are treated fairly and in a non-discriminatory manner. Witness Auck stated that, based upon IREC's experience in other states that have developed group and cluster studies, at a minimum any proposed cluster study process should (1) define timelines for each step of the process, (2) define what happens if projects drop out of the study group, (3) explain how costs will be allocated among projects in a group, and (4) explain how groups would be formed.

In his rebuttal, witness Freeman explained that grouping studies would make the interconnection process more efficient from a transmission-level perspective and would allow costly transmission network upgrades to be allocated to multiple projects rather than burdening individual projects with the entire upgrade costs. He testified that the Duke Utilities are committed to an extensive stakeholder engagement process beginning in the first quarter of 2019, and that the Duke Utilities are developing a strawman proposal that will be used as a starting point for the stakeholder process. He stated that the Duke Utilities envision an iterative process that allows for multiple meetings with stakeholders with a goal to complete the stakeholder process by late June 2019, which would result in redline changes to the State and Federal interconnection procedures, which would be filed with both FERC and the Commission. Witness Freeman recommended the Commission allow the Duke Utilities to implement the aforementioned steps for transitioning to a grouping study approach rather than adopting the Public Staff's recommended stakeholder and reporting requirements at this time.

In the Stipulation, the Duke Utilities agreed to undertake efforts to fully implement a grouping study as detailed in witness Freeman's rebuttal testimony, including a stakeholder process in the first quarter of 2019, with the goal of completing the stakeholder process by June 2019 and making filings with both FERC and the Commission in July 2019. Public Staff witness Williamson testified that the Public Staff agreed to withdraw its recommendation for an independent review of the entire interconnection process and a stakeholder discussion focused on the Project A/B process. "In exchange, DEP and DEC have agreed to undertake efforts to fully implement a grouping study process...."

Discussion and Conclusions

The Commission has reviewed the evidence submitted by the parties concerning implementation of a grouping study process in North Carolina. The Commission notes that no party disputed that the current serial study process is unsustainable for the Duke Utilities based upon the current and growing volumes of utility scale Interconnection Requests. The Commission, therefore, agrees with the Duke Utilities, the Public Staff, and IREC that it is necessary to evaluate whether the Duke Utilities' transition to a grouping study process in North Carolina should be pursued.

In its post-hearing brief, NCSEA stated that the Commission should hold technical conferences with stakeholders to discuss a transition to cluster studies. NCSEA appears to believe that this level of direct involvement is necessary for the Commission to provide oversight. The Commission disagrees, finding instead that parties will be able to speak more freely and that there will be no potential for inappropriate ex parte communications under the process outlined in the Stipulation.

Therefore, the Commission concludes that it is reasonable for the Duke Utilities to establish a stakeholder process to discuss the potential to transition their North Carolina queues to a grouping study process, and that the Duke Utilities shall report to the Commission no later than July 31, 2019, as to the status of that stakeholder process. The stakeholder process should allow for all participants to contribute to the joint development of meeting agendas, including topics to be addressed, and for all participants to have reasonable opportunity to contribute to the discussion of all issues or items on the agendas.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT 24

The evidence for this finding of fact is found in the testimony of Duke witness Gajda, DENC witness Nester, IREC witness Lydic, and Public Staff witness Williamson.

Public Staff witness Williamson testified that IEEE Standard 1547 (IEEE 1547) is a technical standard published by the Institute of Electrical and Electronics Engineers (IEEE) for the uniform interconnecting and interoperability of distributed energy resources with electric power systems. He testified that a revised IEEE 1547 was released in January of 2018, and that Duke and IREC had agreed to continue discussions about IEEE 1547 in the quarterly TSRG meetings.

Witness Williamson testified that IEEE 1547 is not a mandatory requirement, but it does provide guidance for incorporating DER into the grid.

Duke witness Gajda agreed that the TSRG is Duke's intended forum to specifically address the new IEEE 1547 standards, and that the Companies are working to determine if and when some of the standard's new provisions may be appropriate to adopt. He stated that its use will require coordination with, and action by, interconnection developers.

DENC witness Nester testified that the Energy Policy Act of 2005 established IEEE 1547 as the national standard for the interconnection of distributed generation resources. He stated that in the most recent revision, smart inverters are required to be capable of supporting the grid for specific functionality. Witness Nester testified further that the Utility should decide when to apply IEEE 1547's inverter ride-through and power factor capabilities in accordance with Good Utility Practice. He stated further:

> My understanding is that work is still ongoing to revise the IEEE 1547.1 standard ... which is essential in determining how to test and certify any DER and their smart functions, such as ride-through, in the laboratory and in the field .... [T]he Company anticipates the revision of the IEEE 1547.1 standard to be completed by mid to late 2019 or early 2020.

IREC witness Lydic testified that "the IEEE update and smart inverters will address many issues that have arisen in interconnections in North Carolina." He stated further:

> The updates to the standard include voltage and frequency ride-through (for both bulk system reliability and distribution effects for high penetration), voltage regulation capabilities, standardized communications/control capabilities, and updated power quality requirements .... The related testing standard, IEEE 1547.1, is expected to be published in late 2019 or early 2020, with UL [Underwriters Laboratory] ... adopting new requirements soon thereafter. Certified inverters and other equipment could then be available on the market about 18 months later.
>
> Adopting these standards ... will allow smart inverters and other DER to offer meaningful grid services that can help mitigate the impacts of increased DER growth. The standards will allow states and utilities to implement voltage regulation so high penetration effects can be mitigated. ... wide application of the standard

> should help increase hosting capacity of DER and reduce negative effects on the distribution system or other customers....
>
> Since there is no one default requirement in IEEE 1547-2018, interconnecting customers will need clear direction on what requirements their project will need to meet. The Commission should thus set forth a clear path for their rollout. The discussions about this process should begin immediately....

Discussion and Conclusions

The Commission finds that IEEE 1547-2018 offers technical standards that could allow for higher penetrations of DER on the distribution grid. However, the costs and benefits of implementing various aspects of this new standard are not well understood. Since Duke has already committed to discuss the standard within its TSRG, the Commission will task Duke with hosting stakeholder meetings on this topic and filing a report with the Commission by April 1, 2020. Parties may file comments on that report by June 1, 2020. The stakeholder process should allow for all participants to contribute to the joint development of meeting agendas, including topics to be addressed, and for all participants to have a reasonable opportunity to contribute to the discussion of all issues or items on the agendas.

COST OF SERVICE IMPACTS OF DISTRIBUTED GENERATION

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 25

The evidence supporting this finding is contained in the testimony and exhibits of Public Staff witness Lucas.

Public Staff witness Lucas testified that as more and more distributed generation is interconnected, that capacity is straining the grid's ability to accommodate additional, future capacity without requiring significant investments. He stated:

> Those additional facilities could be characterized as either additional interconnection facilities, network upgrades, or customary transmission and distribution system investment and capacity. With those additional facilities comes additional grid operation and maintenance expenses. The decision as to who will pay these costs will continue going forward.

Witness Lucas testified further that the interconnection fees currently paid by distributed generators are designed to recover: (1) the costs of the actual studies and facilities needed to interconnect the generator to the grid, and (2) the necessary upgrades to accommodate the capacity. "It is the Public Staff's understanding that the fees associated with network upgrades do not include costs associated with future grid investment or ongoing operation and maintenance of the grid." He stated that as a result, these costs are generally borne by the Utilities' consumers. He testified further:

> as network hosting capacity has been limited in recent years due to [the] sheer volume of DGs and consumer load, the issue of future grid capacity expansion and the need to update the grid to accommodate ever higher density of both DGs and

> consumer loads has given rise to a question of fairness regarding the drivers behind the need for future grid costs and who pays them.
>
> ...
>
> Under today's cost recovery paradigm, only consumer load is responsible for the recovery of grid related investments and expenses.

Witness Lucas cited the example of storm recovery costs:

> We have had lots of storm damage the past few years. Many millions of dollars expended. That storm cost recovery is only passed on to the load customers. However, distributed generators are using the grid .... Storm cost recovery is one example where the using and consuming public is bearing almost all those costs.

Witness Lucas recommended that the Commission direct the Utilities to evaluate the long-term operations and maintenance (O&M) costs resulting from distributed generation and incorporate these costs into their cost of service studies.

<u>Discussion and Conclusions</u>

Witness Lucas raises a potentially significant issue regarding the future of the distribution grid, the costs of operating and maintaining that grid, the benefits provided by distributed generation on the grid, and how those costs and benefits are to be apportioned to grid users and recovered.

The Commission notes that Section 6.1.3 of the Interconnection Agreement that is part of the NC Interconnection Standard states as follows:

> 6.1.3 The Utility shall also bill the Interconnection Customer for the costs associated with operating, maintaining, repairing and replacing the Utility's System Upgrades, as set forth in Appendix 6 of this Agreement ...

It appears that the Utilities currently have the ability to bill an Interconnection Customer for the ongoing costs of Upgrades that were built specifically to allow the interconnection of their Facility. But, if no such construction was needed, the Interconnection Customer has no ongoing financial obligation to support the System.

The Commission concludes that the Utilities should address this issue in testimony filed in their next general rate cases. The Commission especially requires testimony characterizing the benefits that distributed generators are receiving from the Utility's Systems, estimating their share of the related costs, and providing options for fully recovering those costs from distributed generators. The testimony should also explain the impact that shifting these costs to distributed generators would have on other customer classes.

MISCELLANEOUS

The Commission laid the foundation for this proceeding four years ago, anticipating that the changes being made to the NC Interconnection Standard at that time might need revisions. The Public Staff subsequently enlisted the assistance of Advanced Energy, whose staff facilitated multiple stakeholder meetings. While consensus was not reached on all issues, the Stipulated Redline itself was not the source of much controversy, nor were the 2015 changes. Rather, in this proceeding Parties expressed wide-ranging opinions on how best to evolve not only the NC Interconnection Standard but also the role of the Commission in its oversight of the Utilities. Many of the policies being advocated pointed toward the need to fashion a transition to ever higher penetrations of DER while wrestling with emerging technical and equity issues. The Commission acknowledges that these issues will require substantial attention over the next several years. Hence this Order requires the Utilities to host a series of stakeholder efforts targeted at specific questions, with the requirement to report back to the Commission.

The Commission notes that on October 5, 2018, the Commission issued an Order Approving Interim Modifications to North Carolina Interconnection Procedures for Tranche 1 of CPRE RFP. As no party advocated for changes to the CPRE modifications, the Commission reaffirms its October 5, 2018 Order. The revisions made in that Order remain in place and will no longer be considered "interim."

Finally, the Commission acknowledges the testimony of Duke witnesses regarding the mitigation options that the Duke Companies now provide Interconnection Customers when interconnecting a generator at a specific Point of Interconnection will require costly upgrades. This typically involves the Utility determining how the customer could downsize their project so as to avoid the upgrades. Duke witness Riggins testified that the Duke Utilities began offering mitigation options following the implementation of new technical standards, including the Method of Service Guidelines. This "mitigation options step" occurs during the System Impact Study process, but is not part of the NC Interconnection Standard, and it has the effect of delaying Duke from studying other pending Interconnection Requests. Duke witness Freeman acknowledged this delaying impact when he said, "we can deliver a fast no or a slow yes." No party spoke against Duke's practice of providing mitigation options, nor did any party advocate that this practice should be formalized in the NC Interconnection Standard. Therefore, the Commission will take no action except to state that it expects Duke to treat all Interconnection Customers in a similar fashion.

IT IS, THEREFORE, ORDERED as follows:

1. That the Stipulated Redline version of the NC Interconnection Standard, with additional modifications as discussed in this Order, and attached as Appendix A to this Order, shall be, and hereby is, adopted as the generator interconnection standard for North Carolina, except that provisions related to production profile information are delayed pending the Commission's review of the information required in Ordering Paragraph 4 below. The changes approved in this Order will be effective upon issuance of this Order, except that they will not apply to Facilities that have a fully executed Interconnection Agreement as of the date of this Order. All Facilities will be subject to this Order for the processing of Material Modifications and ownership transfers.

2. That Interconnection Customers shall have 10 Business Days to cure Utility requests for information in the Facilities Study and System Impact Study processes; failure to provide the requested information within 10 Business Days shall result in the Interconnection Request being removed from the interconnection queue, effective starting July 15, 2019. The Utilities shall inform Interconnection Customers of this new policy by mail by June 28, 2019.

3. That the Utilities shall file with the Commission, not later than March 1 of each year, a verified report showing interconnection-related expenses and revenues associated with fee-related work for the prior year. The report shall include information on the number of inspections conducted pursuant to new Sections 6.5.2, 6.5.3, and 6.5.4, an explanation of the related costs, and the revenues billed to and collected from the Interconnection Customers for these inspections.

4. That within 20 business days of this Order, the Utilities shall file the additional information regarding generator hourly production profile information as discussed in this Order. Parties may file responsive comments within 10 business days thereafter.

5. That the Duke Utilities shall consult with EPRI regarding the Section 3 Fast Track and Supplemental Review processes and provide a summary report regarding potential modifications at the TSRG meeting occurring in the third quarter of 2019. Duke shall also file the report with the Commission.

6. That the Duke Utilities shall post a brief description of the technical evaluations conducted during a Section 3.4 Supplemental Review on their interconnection websites within 60 days of this Order.

7. That Duke shall host stakeholder and TSRG meetings dedicated to the question of whether a process for re-studying an existing Generating Facility for the addition of energy storage could be more efficient than requiring the Facility to submit a new Interconnection Application. On or before September 3, 2019, the Utilities shall file a streamlined process for efficiently studying the addition of storage at existing generation sites that builds upon the grouping study approach that is already under development as required by the Stipulation.

8. That the Duke Utilities shall file any significant new screens, studies, or major modifications in their application of the NC Interconnection Standard, and information about the implications of those changes, with the Commission in this docket for informational purposes only. The Utilities shall post information regarding the new screen, study, or modification on their applicable websites, and Duke shall present the topic for discussion at a TSRG meeting in advance of implementation.

9. That the Utilities shall include in their Quarterly Queue Status and Interconnection Performance Reports filed in Docket No. E-100, Sub 101A all projects above 20 kW requesting interconnection and their operational status.

10. That the Duke Utilities shall post the current version of the grid locational guidance provided for CPRE purposes on each Utility's website in the same location as its Queue Status reports.

11. That the Duke Utilities shall establish a stakeholder process within the first quarter of 2019 to discuss the process of transitioning their North Carolina queues to a grouping study process, and that the Duke Utilities shall report to the Commission no later than July 31, 2019, as to the status of that stakeholder process.

12. That the Utilities shall host stakeholder meetings on IEEE-1547 and file a report with the Commission by April 1, 2020. Parties may file comments on that report by June 1, 2020.

13. That the Utilities shall file testimony in their next general rate case applications regarding the benefits that distributed generators are receiving from the Utility's System, estimating their share of the related costs, and providing options for recovering those costs from distributed generators.

14. That the Public Staff shall adopt a procedure for periodically filing summary information regarding interconnection disputes in this docket.

ISSUED BY ORDER OF THE COMMISSION.
This the 14th day of June, 2019.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

APPENDIX A

NORTH CAROLINA

INTERCONNECTION PROCEDURES, FORMS, AND AGREEMENTS

For State-Jurisdictional Generator Interconnections

Effective June 14, 2019

Docket No. E-100, Sub 101

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Section 1. General Requirements

1.1 Applicability

1.1.1 This Standard contains the requirements, in addition to applicable tariffs and service regulations, for the interconnection and parallel operation of Generating Facilities with Utility Systems in North Carolina. These procedures apply to Generating Facilities that are interconnecting to Utility Systems in North Carolina where the Interconnection Customer is not selling the output of its Generating Facility to an entity other than the Utility to which it is interconnecting.

Interconnection Requests for new Generating Facilities shall be submitted to the Utility for approval at the final design stage and prior to the beginning of construction.

The submission of a written request for a Section 1.2 Pre-Request Response and/or Section 1.3 Pre-Application Report is encouraged to identify potential interconnection issues unforeseen by the Interconnection Customer.

Revised Interconnection Requests for equipment or design changes should be submitted pursuant to Section 1.5.

Notification by the Interconnection Customer to the Utility of change of ownership or change in control should be submitted pursuant to Section 6.11.

1.1.1.1 A request to interconnect a certified inverter-based Generating Facility no larger than 20 kW shall be evaluated under the Section 2, 20 kW Inverter Process. (See Attachments 4 and 5 for certification criteria.)

1.1.1.2 A request to interconnect a certified Generating Facility no larger than the capacity specified in Section 3.1 shall be evaluated under the Section 3 Fast Track Process. (See Attachments 4 and 5 for certification criteria.)

1.1.1.3 A request to interconnect a Generating Facility larger than the capacity stated in Section 3.1, or a Generating Facility that does not qualify for or pass the Fast Track Process or qualify for the 20 kW Inverter Process, shall be evaluated under the Section 4 Study Process. Interconnection Customers that qualify for Section 2 or Section 3 may also choose to proceed directly to Section 4 if they believe Section 4 review is likely to be necessary.

1.1.2 Capitalized terms used herein shall have the meanings specified in the Glossary of Terms in Attachment 1 or the body of these procedures.

1.1.3 The 201~~8~~9 revisions to ~~the Commission's~~ this interconnection S~~s~~tandard shall not apply to Generating Facilities ~~already interconnected~~ having a fully executed Interconnection Agreement as of the effective date of the 201~~5~~9 revisions to this Standard, unless the Interconnection Customer proposes a Material Modification, transfers ownership of the Generating Facility, or application of the 20159 revisions to the Commission's interconnection standard are agreed to in writing by the Utility and the Interconnection Customer. This Standard shall apply if the Interconnection Customer does not have a fully executed Interconnection Agreement for ~~has not actually interconnected~~ the Generating Facility as of the effective date of the 2015 2019 revisions. Revised fees and new deposits will apply to new Interconnection Requests and future transactions involving existing Interconnection Requests occurring after the effective date of the 2019 revisions.

Any Interconnection Customer that has not executed an I~~i~~nterconnection A~~a~~greement with the Utility prior to the effective date of the ~~2015~~ 2019 revisions to this Standard shall have ~~30 Calendar Days~~ 45 Business Days following the later of the effective date of the Standards or the posted date of notice in writing from the Utility to ~~demonstrate site control pursuant to Section 1.6, and to post the deposit outlined in Section 1.4~~ make prepayment or provide Financial Security in a form reasonably acceptable to the Utility for any Network Upgrades identified in the Interconnection Customer's System Impact Study Report as required by Section 4.3.9 of the Procedures.

~~Any Interconnection Customer that has executed an interconnection agreement with the Utility prior to the effective date of this Standard but the Utility has not actually interconnected the Generating Facility, shall have 60 Calendar Days to submit Upgrade and Interconnection Facility payments (or Financial Security acceptable to the Utility for Interconnection Facilities only) required pursuant to Section 5.2. Any amounts previously paid by the Interconnection Customer at the time deposit or payment is due under this Section shall be credited towards the deposit amount or other payment required under this Section.~~

~~1.1.4 Prior to submitted its Interconnection Request, the Interconnection Customer may ask the Utility's interconnection contact employee or office whether the proposed interconnection is subject to these procedures. The Utility shall respond within 10 Business Days.~~

1.1.4~~5~~ Infrastructure security of electric system equipment and operations and control hardware and software is essential to ensure day-to-day reliability and operational security. All Utilities are expected to meet basic standards for electric system infrastructure and operational security, including physical, operational, and cyber-security practices.

1.1.5~~6~~ References in these procedures to Interconnection Agreement are to the North Carolina Interconnection Agreement. (See Attachment 9.)

1.2 Pre-Request Response

1.2.1 The Utility shall designate an employee or office from which information on the application process can be obtained through informal requests from the Interconnection Customer presenting a proposed project for a specific site. The name, telephone number, and e-mail address of such contact employee or office shall be made available on the Utility's Internet web site.

1.2.2 The Interconnection Customer may request a Pre-Request Response by providing the Utility details of a potential project in writing, including site address, grid coordinates, project size, project developer name, and proposed Point of Interconnection.

Electric system information provided to the Interconnection Customer should include number of phases and voltage of closest circuit, distance to existing source, distance to substation, and other information and/or materials useful to an understanding of an interconnection at a particular point on the Utility's System, to the extent such provision does not violate confidentiality provisions of prior agreements or critical infrastructure requirements. The Utility shall comply with reasonable requests for such information in a timely manner, not to exceed ten (10) Business Days. The Pre-Request Response produced by the Utility is non-binding and does not confer any rights. The Interconnection Customer must still meet the Section 1.4 requirements to apply to interconnect to the Utility's Ssystem and to obtain a Queue Number. Any one developer shall have no more than five (5) requests for Pre-Request Responses in the Pre-Request Response queue at one time.

1.3 Pre-Application Report

1.3.1 In addition to, or instead of, requesting an informal Pre-Request Response, an Interconnection Customer may submit a formal written Pre-Application Report request form (see Attachment 3) along with a non-refundable fee of $500 ~~$300~~ for a Pre-Application Report on a proposed project at a specific site. The Utility shall provide the Pre-Application data described in Section 1.3.2 to the Interconnection Customer within ten (10) Business Days of receipt of the completed request form and payment of the $500 ~~$300~~ fee. The Pre-Application Report produced by the Utility is non-binding, does not confer any rights, and the Interconnection Customer must still successfully apply to interconnect to the Utility's S~~s~~ystem and to obtain a Queue Number. The written Pre-Application Report request form shall include the information in Sections 1.3.1.1 through 1.3.1.8 below to clearly and sufficiently identify the location of the proposed Point of Interconnection. Any one developer shall have no more than five (5) requests for Pre-Application Reports in the Pre-Application Report queue at one time.

1.3.1.1 Project contact information, including name, address, phone number, and email address.

1.3.1.2 Project location (street address, location map with nearby cross streets and town, grid coordinates of anticipated Point of Interconnection, etc.);

1.3.1.3 Meter number, pole number, location map or other equivalent information identifying proposed Point of Interconnection, if available;

1.3.1.4 Generator or Storage Type (e.g., solar, wind, combined heat and power, battery, etc.)

1.3.1.5 Size (alternating current kW, and for Storage kWh).

1.3.1.6 Single or three phase generator configuration.

1.3.1.7 Stand-alone generator (no onsite load, not including station service – Yes or No?)

1.3.1.8 Is new service requested? Yes or No? If there is existing service, include the customer account number, site minimum and maximum current or proposed electric loads in kW (if available) and specify if the load is expected to change.

1.3.2. Using the information provided by the Interconnection Customer in the Pre-Application Report request form pursuant to ~~in~~ Section 1.3.1, the Utility shall identify the substation/area bus, bank or circuit likely to serve the proposed Point of Interconnection. This selection by the Utility does not necessarily indicate, after application of the screens and/or study, that this would be the circuit the project ultimately connects to. The Interconnection Customer must request additional Pre-Application Reports if information about multiple Points of Interconnection is requested. Subject to Section 1.3.3, the Pre-Application Report shall include the following information:

1.3.2.1 Total capacity (in MW) of substation/area bus, bank or circuit based on normal or operating ratings likely to serve the proposed Point of Interconnection.

1.3.2.2 Existing aggregate generation capacity (in MW) interconnected to a substation/area bus, bank or circuit (i.e., amount of generation online) likely to serve the proposed Point of Interconnection.

1.3.2.3 Aggregate queued generation capacity (in MW) for a substation/area bus, bank or circuit (i.e., amount of generation in the queue) likely to serve the proposed Point of Interconnection.

1.3.2.4 Substation nominal distribution voltage and/or transmission nominal voltage if applicable.

1.3.2.5 Nominal distribution circuit voltage at the proposed Point of Interconnection.

1.3.2.6 Approximate circuit distance between the proposed Point of Interconnection and the substation.

1.3.2.7 Relevant line section(s) actual or estimated peak load and minimum load data, including daytime minimum load and absolute minimum load, when available.

1.3.2.8 Number, <u>location,</u> and rating of protective devices, and number, <u>location,</u> and type (standard, bi-directional) of voltage regulating devices between the proposed Point of Interconnection and the substation/area. Identify whether the substation has a load tap changer.

1.3.2.9 Number of phases available at the proposed Point of Interconnection. If a single phase, distance from the three-phase circuit.

1.3.2.10 Limiting conductor ratings from the proposed Point of Interconnection to the distribution substation.

1.3.2.11 Whether the Point of Interconnection is located on a spot network, grid network, or radial supply.

1.3.2.12 Based on the proposed Point of Interconnection, existing or known constraints such as, but not limited to, electrical dependencies at that location, short circuit interrupting capacity issues, power quality or stability issues on the circuit, capacity constraints, or secondary networks.

1.3.2.13 Other information regarding an Affected System the Utility deems relevant to the Interconnection Customer.

1.3.3 The Pre-Application Report need only include existing data. A Pre-Application Report request does not obligate the Utility to conduct a study or other analysis of the proposed generator in the event that data is not readily available. If the Utility cannot complete all or some of the Pre-Application Report due to lack of available data, the Utility shall provide the Interconnection Customer with a Pre-Application Report that includes the data that is readily available. Notwithstanding any of the provisions of this section, the Utility shall, in good faith, include data in the Pre-Application Report that represents the best available information at the time of reporting. Further, the total capacity provided in Section 1.3.2.1 does not indicate that an interconnection of aggregate generation up to this level may be completed without impacts since there are many variables studied as part of the interconnection review process, and data provided in the Pre-Application Report may become outdated at the time of the submission of the complete Interconnection Request.

1.4 Interconnection Request

1.4.1 The Interconnection Customer shall submit its Interconnection Request to the Utility, and the Utility shall notify the Interconnection Customer confirming receipt of the Interconnection Request within three (3) Business Days of receiving the Interconnection Request.

The Interconnection Request Application Form shall be date- and time-stamped upon receipt of the following:

1.4.1.1 A substantially complete Interconnection Request Application Form contained in Attachment 2 submitted by a valid legal entity registered with the North Carolina Secretary of State, and signed by the Interconnection Customer.

1.4.1.2 The applicable fee or Interconnection Request Deposit. The applicable fee is specified in the Interconnection Request Application Form and applies to a certified inverter-based Generating Facility no larger than 20 kW reviewed under Section 2 and to any certified Generating Facility no larger than the capacity specified in Section 3.1 to be evaluated under the Section 3 Fast Track Process.

For all other Generating Facilities, including those that do not qualify for the 20 kW Inverter Process or the Fast Track Process ,or that, fail the Fast Track and Supplemental Review Process under Section 3.0 and are to be evaluated under the Section 4 Study Process, an Interconnection Request Deposit is required. The Interconnection Request Deposit shall equal $20,000 plus one dollar ($1.00) per kWac of capacity specified in the Interconnection Request Application Form, not to exceed an aggregate Interconnection Request Deposit of $100,000. The Interconnection Request Deposit is intended to cover the Utility's reasonably anticipated costs including overheads for conducting the System Impact Study and the Facilities Study. Such deposit shall, however, be applicable towards the cost of all studies, Upgrades and Interconnection Facilities including overheads.

1.4.1.3 A Site Control Verification letter (sample included within Attachment 2).

1.4.1.4 A site plan indicating the location of the project, the property lines and the desired Point of Interconnection.

1.4.1.5 An electrical one-line diagram for the Generating Facility.

1.4.1.6 Inverter specification sheets for the Interconnection Customer's equipment that will be utilized.

1.4.2 The original date- and time-stamp applied to the Interconnection Request Application Form shall be accepted as the qualifying date- and time-stamp

for the purposes of establishing Queue Position and any timetable in these procedures.

1.4.3 The Utility shall notify the Interconnection Customer in writing within ten (10) Business Days of the receipt of the Interconnection Request Application Form as to whether the Form and initial supporting documentation specified in Sections 1.4.1.1 through 1.4.1.6 are complete or incomplete. An Interconnection Request will be deemed complete upon submission of the listed information in Section 1.4.1 to the Utility.

1.4.4 If the Interconnection Request Application Form and/or the initial supporting documentation or any other information requested by the Utility is incomplete, the Utility shall provide, along with notice that the information is incomplete, a written list detailing all information that must be provided. The Interconnection Customer will have ten (10) Business Days after receipt of the notice to submit the listed information. If the Interconnection Customer does not provide the listed information or a written request for an extension of time, not to exceed ten (10) additional Business Days, within the deadline, the Interconnection Request will be deemed withdrawn.

1.5 Modification of the Interconnection Request

"Material Modification" means a modification to machine data or equipment configuration or to the interconnection site of the Generating Facility that has a material impact on the cost, timing or design of any Interconnection Facilities or Upgrades. or that may adversely impact other Interdependent Interconnection Requests with higher Queue Numbers. Material Modifications include certain project revisions ~~proposed at any time after receiving notification by the Utility of a complete Interconnection Request pursuant to Section 1.4.3 that 1) alters the size or output characteristics of the Generating Facility from its Utility-approved Interconnection Request submission; or 2) may adversely impact other Interdependent Interconnection Requests with higher Queue numbers.~~, as defined in Section 1.5.1, but excludecertain project revisions as defined in Section 1.5.2.

1.5.1 Changes Iindicia of a Material Modification ~~include but are not limited to:~~ are described as follows:

1.5.1.1 Indicia of a Material Modification before the System Impact Study Agreement has been executed by the Interconnection Customer include only:

1.5.1.1.1 A change in Point of Interconnection (POI) to a new location, unless the change in a POI is on the same circuit less than two (2) poles away from the original location, and the new POI is within the same protection zone as the original location;

~~1.5.1.2 A change or replacement of generating equipment such as generator(s), inverter(s), transformers, relaying, controls, etc. that is not a like-kind substitution in size, ratings, impedances, efficiencies or capabilities of the equipment specified in the original or preceding Interconnection Request;~~

1.5.1.~~3.~~1.2 A change from certified to non-certified devices ("certified" means certified by an OSHA recognized Nationally Recognized Test Laboratory (NRTL), to relevant UL and IEEE standards, authorized to perform tests to such standards);

~~1.5.1.4 A change of transformer connection(s) or grounding from that originally proposed;~~

~~1.5.1.5 A change to certified inverters with different specifications or different inverter control specifications or set-up than originally proposed;~~

1.5.1.~~6.~~1.3 An increase of the AC output Maximum Generating Capacity of a Generating Facility; or

1.5.1.~~6.~~1.4 A change reducing the AC output of the GgeneratingFfacility by more than 10%.

1.5.1.2 Indicia of a Material Modification after the System Impact Study Agreement has been executed by the Interconnection customer include, but are not limited to:

1.5.1.2.1 A change in the POI to a new location, unless the new POI is on the same circuit less than two (2) poles away from the original location, and the new POI is within the same protection zone as the original location;

1.5.1.2.2 A change or replacement of generating equipment such as generator(s), inverter(s), transformers, relaying, controls, etc. that is not a like-kind substitution in size, ratings, impedances, efficiencies or capabilities of the equipment specified in the original or preceding Interconnection Request;

1.5.1.2.3 A change from certified to non-certified devices ("certified" means certified by an OSHA recognized Nationally Recognized Test Laboratory (NRTL), to relevant UL and IEEE standards, authorized to perform tests to such standards);

1.5.1.2.4 A change of transformer connection(s) or grounding from that originally proposed;

1.5.1.2.5 A change to certified inverters with different specifications or different inverter control specifications or set-up than originally proposed;

1.5.1.2.6 An increase of the Maximum Generating Capacity of a Generating Facility; or

1.5.1.2.7 A change reducing the Maximum Generating Capacity of the Generating Facility by more than 10%.

1.5.2 Changes ~~The following are~~ not indicia of a Material Modification are described as follows:

1.5.2.1 The following are not indicia of a Material Modification before the System Impact Study Agreement has been executed by the Interconnection Customer:

1.5.2.1.1 A change in the DC system configuration to include additional equipment including: DC optimizers, DC-DC converters, DC charge controllers, power plant controllers, and energy storage devices, so long as the proposed change does not violate any of the provisions laid out in Section 1.5.1.1.

1.5.2.2 Except as provided for in Section 1.5.2.1, the~~The~~ following are not indicia of a Material Modification at any time:

1.5.2.2.1 A change in ownership of a Generating Facility; the new owner, however, will be required to execute a new Interconnection Agreement and Study agreement(s) for any Study which has not been completed and the Report issued by the Utility;

1.5.2.2.2 A change or replacement of generating equipment such as generator(s), inverter(s), solar panel(s), transformers, relaying controls, etc. that is a like-kind substitution in size, ratings, impedances, efficiencies or capabilities of the equipment specified in the original or preceding Interconnection Request;

1.5.2.2.3 An increase in the DC/AC ratio that does not increase the maximum AC output capability of the G~~g~~enerating F~~f~~acility;

1.5.2.2.4 A decrease in the DC/AC ratio that does not reduce the AC output capability of the G~~g~~enerating F~~f~~acility by more than 10%.

1.5.2.2.5 A change in the DC system configuration to include additional equipment that does not impact the Maximum Generating Capacity, daily production profile or the proposed AC configuration of the Generating Facility including: DC optimizers, DC-DC converters, DC charge controllers, power plant controllers, and energy storage devices such that the output is delivered during the same periods and with the same profile considered during the System Impact Study.

1.5.3 To the extent Interconnection Customer proposes to modify any information provided in the Interconnection Request deemed complete by the Utility, the Interconnection Customer shall submit any such modifications to the Utility in writing. If the Utility determines that the proposed modification(s) constitutes a Material Modification, the Utility shall notify the Interconnection Customer in writing within ten (10) Business Days that the modification is a Material Modification and the Interconnection Request shall be withdrawn from the qQueue unless the Interconnection Customer withdraws the proposed Material Modification within 15 Calendar Days of receipt of the Utility's

written notification. If the modification is determined by the Utility not to be a Material Modification, then the Utility shall notify the Interconnection Customer in writing that the modification has been accepted and that the Interconnection Customer shall retain its Queue Number. Any dispute as to the Utility's determination that a modification constitutes a Material Modification shall proceed in accordance with Section 6.2 below.

1.5.4 Modification Inquiry

1.5.4.1 Prior to making any modification, the Interconnection Customer may first submit an informal modification inquiry in writing that requests the Utility to evaluate whether such modification to the original or most recent Interconnection Request is a Material Modification. The Interconnection Customer shall provide specific details on all changes that are to be considered by the Utility.

1.5.4.2 In response to Interconnection Customer's informal request, if the Utility evaluates the proposed modification(s) and determines that the changes are not Material Modifications, the Utility shall inform the Interconnection Customer in writing within ten (10) Business Days. If the Interconnection Customer wishes to proceed with the proposed modification(s), the Interconnection Customer shall submit a revised Interconnection Request Application Form that reflects the approved modifications.

1.6 Site Control

Documentation of site control shall be submitted to the Uutility with the Interconnection Request using the sample site control verification form included in the Interconnection Request in Attachment ~~3~~2.

Site control may be demonstrated through:

1. Ownership of, a leasehold interest in, or a right to develop a site for the purpose of constructing the Generating Facility;

2. An option to purchase or acquire a leasehold site for such purpose; or

3. An exclusivity or other business relationship between the Interconnection Customer and the entity having the right to sell, lease, or grant the Interconnection Customer the right to possess or occupy a site for such purpose.

Should Interconnection Customer's site control lapse at any point in time prior to interconnection and such lapse is brought to the attention of Utility, the Utility shall notify the Interconnection Customer in writing of the alleged lapse in site control. The Interconnection Customer shall have ten (10) Business Days from the posted date on the notice from the Utility to cure and submit documentation of re-established site control, where failure to cure the lapse will result in the Interconnection Request being deemed withdrawn.

1.7 Queue Number

1.7.1 The Utility shall assign a Queue Number pursuant to Section 1.4.2. Subject to an Interconnection Customer's election to participate in an optional Utility-sponsored System Impact Grouping Study, as described in Section 4.3.4, the Queue Number of each Interconnection Request shall be used to determine the cost responsibility for the Upgrades necessary to accommodate the interconnection. Subject to Sections 1.7.3, 1.8, and Section 4.3.4, the Queue Number of each Interconnection Request shall also determine the order in which each Interconnection Request is studied.

1.7.2 Subject to the provisions of Sections 1.4, 1.5, and 1.6, Generating Facilities shall retain the Queue Number assigned to their initial Interconnection Request throughout the review process, including when ~~where~~ moving through the processes covered by Sections 2, 3, and 4.

1.7.3 A Queue Number established for purposes of administering a Competitive Resource Solicitation under Section 4.3.4 shall not be subject to the Interdependency provisions of Section 1.8. Any Interconnection Customer that elects to participate in the System Impact Grouping Study and is selected through the Competitive Resource Solicitation shall complete the Section 4 Study process based upon the Queue Position designated to administer the Competitive Resource Solicitation and the Interconnection Customer's cost responsibility shall be determined based upon the terms of the Competitive Resource Solicitation. Any Interconnection Customer that elects to participate in the System Impact Grouping Study established in Section 4.3.4 but is not selected through the Competitive Resource Solicitation shall be deemed subordinate to the designated Competitive Resource Solicitation Queue Number or an Interconnection Customer that has completed System Impact Study and committed to Upgrades under Section 4.3.9, but shall maintain its original Queue Position for purposes of determining cost responsibility for Upgrades in relation to (i) other Interconnection Customers that elected to participate in the System Impact Grouping Study, but were not selected through the Competitive Resource Solicitation; and (ii) projects that were assigned a Queue Number after the date on which the Queue Number was designated by the Utility to administer the System Impact Grouping Study.

1.8 Interdependent Projects

"Interdependent Customer" (or "Project"), "Project A", "Project B", and "Project C" are defined in the g~~G~~lossary of t~~T~~erms (see Attachment 1).

1.8.1 Upon an Interconnection Customer's submission of a Section 1.4 Interconnection Request for the Section 3 Fast Track Process or Section 4 Study Process, the Utility shall review the Interconnection Request and make a preliminary determination whether any known Interdependency exists between the Interconnection Customer's proposed Generating Facility and any other Interconnection Customer with a lower Queue Number. Any preliminary determination by the Utility that the Generating Facility does not create an Interdependency will result in the Interconnection Request being

preliminarily designated as a Project A and the Utility shall proceed immediately to either the Section 3 Fast Track Process or the Section 4 Study process, as applicable. The Utility shall advise the Interconnection Customer in writing or at the Section 4.2 ~~S~~scoping ~~M~~meeting, if requested by the Interconnection Customer, regarding its preliminary determination of whether Interdependency would be created by the Generating Facility. A Generating Facility designated and reviewed for system impacts as a Project A may still be determined to create an Interdependency and may be designated by the Utility as an Interdependent Project during the Section 4.3 System Impact Study Process. Once the System Impact Study ~~R~~report is issued by the Utility designat~~ed~~ing a Generating Facility as a Project A for purposes of the Section 4.4 Facilities Study, the Interconnection Request shall retain this designation without change.

1.8.2 If the Utility determines that that the Interconnection Customer's proposed Generating Facility is Interdependent with one (1) other Interconnection Request with a lower Queue Number, the Utility shall notify the Interconnection Customer in writing or at the Section 4.2 ~~S~~scoping ~~M~~meeting that the Interconnection Request is designated as a Project B.

1.8.2.1 Following the Section 4.2 ~~S~~scoping ~~M~~meeting and execution of the System Impact Study Agreement, the Project B shall proceed to the Section 4.3 Study process. Project B shall receive a System Impact Study ~~R~~report that assumes the interdependent Project A Interconnection Request with the lower Queue Number completes construction and interconnection and another System Impact Study ~~R~~report that assumes the interdependent Project A Interconnection Request with the lower Queue Number is not constructed and is withdrawn.

1.8.2.2 The Utility shall not proceed to a Project B Facilities Study until after the Project B Interconnection Customer returns a signed Facilities Study Agreement to the Utility and the Utility has issued the Section 4.4.4 Facilities Study Rreport for the Interdependent Project A. The Project B Interconnection Customer shall then have the option of whether to proceed with a Facility Study, or wait until the Interdependent Project A executes an Interconnection Agreement and makes payment for any required Upgrade, Interconnection Facilities, and other charges under Section 5.2. If the Project B Interconnection Customer ~~with a~~ signed a Facilities Study Agreement prior to Interdependent Project A committing to Section 5 construction, the Project B's Facility Study shall assume that the Iinterdependent Project A Interconnection Request with the lower Queue Number completes construction and interconnection. If Project A is later cancelled prior to the Project A Interconnection Customer making payment for the required Upgrade, the Utility will revise the Project B Facility Study at Project B Interconnection Customer's expense. If Project B Interconnection Customer chooses to wait to request the Project B Facility Study, Project B is not required to adhere to the timeline in Section 4.4.1 until Project A has signed an Interconnection

Agreement and paid the ~~payment~~ charges specified in Section 5.2.4 of these Interconnection Procedures or withdrawn.

1.8.3 If the Utility determines ~~that~~ that the Interconnection Customer's proposed Generating Facility is Interdependent with more than one (1) other Interconnection Request with lower Queue Numbers, the Utility shall make a preliminary determination and notify the Interconnection Customer in writing or at the Section 4.2 scoping meeting, if requested by the Interconnection Customer, describing generally the number and type of Interdependencies of Interconnection Requests with lower Queue Numbers.

1.8.3.1 Except as provided in Section 1.8.3.3 below, t~~T~~he Utility shall not study a project if it is interdependent with more than one project, each of which has a lower Queue Number. The U~~u~~tility will study a project when interdependency with only one lower Queue Number project exists. The removal of interdependency with multiple projects may be the result of 1) upgrades to the Utility System which eliminate the cause of the interdependency, 2) withdrawal of interdependent project(s) with lower Queue Numbers, or 3) a lower Queue Number project signing an Interconnection Agreement and making payments required in Section 5.2.4.

1.8.3.2 Within five (5) Business Days of an Interconnection Request becoming a Project B Interconnection Request that is Interdependent with only one (1) other Interconnection Request with a lower Queue Number, the Utility shall ~~schedule the Section 4.2 Scoping Meeting~~ notify the

Interconnection Customer in writing and provide the new Project B an executable System Impact Study Agreement. Upon being designated by the Utility as a Project B, the Interconnection Customer may request a Section 4.2 scoping meeting on or before the date that the System Impact Study Agreement must be returned to the Utility pursuant to Section 4.2.1. The new Project B ~~the~~ Interconnection Customer's Queue Number will be used to determine the order in which the Interconnection Request is studied under S~~s~~ection 4.3 relative to all other Interconnection Requests.

1.8.3.3 When an Interconnection Customer is proposing to interconnect a Small Animal Waste Facility and that facility is interdependent with more than one project, each of which has a lower Queue Number, the Utility shall designate the Small Animal Waste Facility for expedited Section 4 study ahead of other interdependent Interconnection Customers that have not commenced the Section 4 Study Process pursuant to Section 1.8.3.1, as either (i) Project B, if the project with the next lowest Queue Number to Project A has not completed the Section 4.2 scoping meeting or executed a System Impact Study Agreement; or (ii) Project C, if a Project B has already been designated by the Utility, completed the Section 4.2 scoping meeting, or executed a System Impact Study Agreement. Upon being designated by the Utility as a Project C, the Small

Animal Waste Facility shall be the next facility to become a Project B, regardless of whether another interdependent Interconnection Request with a lower Queue Number exists and notwithstanding Section 1.8.3.2. Upon being designated a Project B, a Small Animal Waste Facility shall be the next Project B studied under Section 4.3 regardless of Queue Number.

1.8.3.4 When an Interconnection Customer is proposing to interconnect a Standby Generating Facility with zero export requested, the Utility shall designate the Standby Generating Facility for expedited Section 4 study as a Project A and also ahead of all other Section 4 studies currently underway in the Utility study queue, unless there are other Standby Generating Facilities currently under study, in which case such Standby Generating Facilities shall be studied in their own queue order. Notwithstanding Section 1.7.1, a Standby Generating Facility will be responsible for Interconnection Facilities and any Upgrades arising from its designated Project A position in the Queue as provided for in this section.

1.9 Interconnection Requests Submitted Prior to the Effective Date of these Procedures

Other than as set forth in Section 1.1.3, nothing in this Standard affects an Interconnection Customer's Queue Number assigned before the effective date of these procedures. Interconnection Requests which have received a System Impact Study report as of the effective date of these procedures that did not identify any interdependency with another project shall be deemed a Project A. Any Interconnection Requests for which the Utility has not completed the System Impact Study and issued a System Impact Study Rreport to the Interconnection Customer as of the effective date of these procedures shall be reviewed for Interdependency pursuant to Section 1.8.

~~Should an Interconnection Customer fail to comply with Section 1.1.3 following receipt of written notice specifying how the Interconnection Customer failed to comply and the expiration of an opportunity to cure by the close of business on the tenth (10th) Business Day following the posted date of such notice to cure, such Interconnection Customer will lose its Queue Number and such Interconnection Request shall be deemed withdrawn.~~

Section 2. Optional 20 kW Inverter Process for Certified Inverter-Based Generating Facilities No Larger than 20 kW

2.1 Applicability

The 20 kW Inverter Process is available to an Interconnection Customer proposing to interconnect its inverter-based Generating Facility with the Utility's System if the Generating Facility is no larger than 20 kW and if the Interconnection Customer's proposed Generating Facility meets the codes, standards, and certification requirements of Attachments 4 and 5 of these procedures, or the Utility has reviewed the design or tested the proposed Generating Facility and is satisfied that it is safe to operate.

The Utility may require the Interconnection Customer to install a manual load- break disconnect switch or safety switch as a clear visible indication of switch position between the Utility System and the Interconnection Customer. When the installation of the switch is not otherwise required (e.g. National Electric Code, state or local building code) and is deemed necessary by the Utility for certified, inverter-based generators no larger than 10 kW, the Utility shall reimburse the Interconnection Customer for the reasonable cost of installing a switch that meets the Utility's specifications (see also Section 6.16).

2.2 Interconnection Request

The Interconnection Customer shall complete the Interconnection Request Application Form for a certified inverter-based Generating Facility no larger than20 kW in the form provided in Attachment 6 and submit it to the Utility, together with the non-refundable processing fee specified in the Interconnection Request Application Form and the documentation required pursuant to Section 1.4.1.

2.2.1 The Utility shall verify that the Generating Facility can be interconnected safely and reliably using the screens contained in the Fast Track Process. (See Section 3.2.1.) The Utility has 15 Business Days to complete this process. Unless the Utility determines and demonstrates that the Generating Facility cannot be interconnected safely and reliably, the Utility shall approve the Interconnection Request upon fulfillment of all requirements in Section 1.4 and return the Interconnection Request Application Form to the Interconnection Customer.

2.2.1.2 If the proposed interconnection passes the screens but the Utility determines that minor Utility construction is required to interconnect the Generating Facility to the Utility's Ssystem, the Interconnection Request shall be approved and the Utility will provide the Interconnection Customer a non-binding good faith estimate of the cost of interconnection along with the Interconnection Request Application Form within 15 Business Days after the determination.

2.2.1.3 If the proposed interconnection passes the screens, but the costs of interconnection including System Upgrades and Interconnection Facilities cannot be determined without further study or review, the Utility will notify the Interconnection Customer that the Utility will need to complete a Facilities Study under Section 4.4 to determine the necessary costs of interconnection and will charge the actual cost of the Facilities Study to the Interconnection Customer.

2.2.2 Screens failure: Despite the failure of one or more screens, the Utility, at its sole option, may approve the interconnection provided such approval is consistent with safety and reliability. If the Utility cannot determine that the Generating Facility may be interconnected consistent with safety, reliability, and power quality standards, the Utility shall provide the Interconnection

Customer with detailed information on the reasons for failure in writing. In addition, the Utility shall either:

2.2.2.1 Notify the Interconnection Customer in writing that the Utility is continuing to evaluate the Generating Facility under Section 3.4 Supplemental Review if the Utility concludes that the Supplemental Review might determine that the Generating Facility could continue to qualify for interconnection pursuant to Fast Track; or

2.2.2.2 Offer to continue evaluating the Interconnection Request under the Section 4 Study Process.

2.3 Certificate of Completion

2.3.1 After installation of the Generating Facility, the Interconnection Customer shall submit the Certificate of Completion in the form provided in Attachment 6 to the Utility. Prior to parallel operation, the Utility may inspect the Generating Facility for compliance with standards including a witness test and the scheduling of an appropriate metering replacement, if necessary.

2.3.2 The Utility shall notify the Interconnection Customer in writing that interconnection of the Generating Facility is authorized. If the witness test is not satisfactory, the Utility has the right to disconnect the Generating Facility. The Interconnection Customer has no right to operate in parallel with the Utility until a witness test has been performed, or previously waived on the Interconnection Request. The Utility is obligated to complete this witness test within ten (10) Business Days of the receipt of the Certificate of Completion. If the Utility does not inspect within ten (10) Business Days or by mutual agreement of the Parties, the witness test is deemed waived.

2.3.3 Interconnection and parallel operation of the Generating Facility is subject to the Terms and Conditions stated in Attachment 6 of these procedures.

2.4 Contact Information

The Interconnection Customer must provide its contact information. If another entity is responsible for interfacing with the Utility, that contact information must also be provided on the Interconnection Request Application Form.

2.5 Ownership Information

The Interconnection Customer shall provide the legal name(s) of the owner(s) of the Generating Facility.

2.6 UL 1741 Listed

The Underwriters' Laboratories (UL) 1741 standard (Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources) addresses the electrical interconnection design of various

forms of generating equipment. Many manufacturers submit their equipment to a nationally recognized testing laboratory that verifies compliance with UL 1741. This "listing" is then marked on the equipment and supporting documentation.

Section 3. Optional Fast Track Process for Certified Generating Facilities

3.1 Applicability

The Fast Track Process is available to an Interconnection Customer proposing to interconnect its Generating Facility with the Utility's System if the Generating Facility's capacity does not exceed the size limits identified in the table below. Generating Facilities below these limits are eligible for Fast Track review. However, Fast Track eligibility is distinct from the Fast Track Process itself, and eligibility does not imply or indicate that a

Generating Facility will pass the Fast Track screens in Section 3.2 below or the Supplemental Review screens in Section 3.4 below.

Fast Track eligibility is determined based upon the generator type, the size of the generator, voltage of the line and the location of and the type of line at the Point of Interconnection. All Generating Facilities connecting to lines greater or equal to 35 kilovolt (kV) are ineligible for the Fast Track Process regardless of size, unless mutually agreed to in writing between the Interconnection Customer and the Utility. ~~For inverter-based systems,~~ Only certified inverter-based systems are eligible for the Fast Track Process and the size limit varies according to the voltage of the line at the proposed Point of Interconnection. Certified inverter-based Generating Facilities located within 2.5 electrical circuit miles of a substation and on a mainline (as defined in the table below) are eligible for the Fast Track Process under the higher thresholds set forth in the table below. In addition to the size threshold, the Interconnection Customer's proposed Generating Facility must meets the codes, standards, and certification requirements of Attachments 4 and 5 of these procedures, or the Utility has to have reviewed the design or tested the proposed Generating Facility and be satisfied that it is safe to operate.

Fast Track Eligibility for Inverter-Based Systems[1]		
Line VMoltage	Fast Track Eligibility Regardless of Location	Fast Track Eligibility on a Mainline[2] and ≤ 2.5 Electrical Circuit Miles from Substation[3]
< 5 kV	≤ 100 kW	≤ 500 kW
≥ 5 kV and < 15 kV	≤ 1 MW	≤ 2 MW
≥ 15 kV and < 35 kV	≤ 2 MW	≤ 2 MW

[1] Must be an UL certified inverter.

[2] For purposes of this table, a mainline is the three-phase backbone of a circuit. It will typically constitute lines with wire sizes of 4/0 American wire gauge, 336.4 kcmil, 397.5 kcmil, 477 kcmil, and 795 kcmil.

[3] An Interconnection Customer can determine this information about its proposed interconnection location in advance by requesting a Pre-Application Report pursuant to Section 1.3~~2~~.

3.1.1 The Interconnection Customer may elect in the Interconnection Request Application Form to proceed directly to Supplemental Review, in order to minimize overall processing time in the event the Utility deems Supplemental Review is appropriate. This is accomplished by selecting both the Fast Track and Supplemental Review options on the Interconnection Request Application Form and paying the applicable Fast Track fee and Supplemental Review deposit.

3.2 Initial Review

Within 15 Business Days after the Utility notifies the Interconnection Customer it has received a complete Interconnection Request pursuant to Section 1.4 and the Utility has preliminarily determined that the Interconnection Request is not interdependent with more than one Interconnection Request with lower Queue Numbers under Section 1.8, the Utility shall perform an initial review using the screens set forth below, shall notify the Interconnection Customer of the results, and include with the notification copies of the analysis and data underlying the Utility's determinations under the screens.

3.2.1 Screens

3.2.1.1 The proposed Generating Facility's Point of Interconnection must be on a portion of the Utility's Distribution System.

3.2.1.2 For interconnection of a proposed Generating Facility to a radial distribution circuit, the aggregated generation, including the proposed Generating Facility, on the circuit shall not exceed 15% of the line section annual peak load as most recently measured at the substation. A line section is that portion of a Utility's System connected to a customer bounded by automatic sectionalizing devices or the end of the distribution line.

3.2.1.3 For interconnection of a proposed Generating Facility to a radial distribution circuit, the aggregated generation, including the proposed Generating Facility, on the circuit shall not exceed 90% of the circuit and/or bank minimum load at the substation.

~~3.2.1.4 All synchronous and induction machines must be connected to a distribution circuit where the local minimum load to generation ratio on the circuit line segment is larger than 3 to 1. A 3-1 load to generation ratio screen utilizes actual recorded data that is sufficient to establish the minimum threshold.~~

3.2.1.4~~5~~ For interconnection of a proposed Generating Facility to the load side of spot network protectors, the proposed Generating Facility must utilize an inverter-based equipment package and, together with the aggregated other inverter-based generation, shall not exceed the smaller of 5% of a spot network's maximum load or 50 kW.

3.2.1.5~~6~~ The proposed Generating Facility, in aggregation with other generation on the distribution circuit, shall not contribute more than 10% to the distribution circuit's maximum fault current at the point on the high voltage (primary) level nearest the proposed point of change of ownership.

3.2.1.6~~7~~ The proposed Generating Facility, in aggregate with other generation on the distribution circuit, shall not cause any distribution protective devices and equipment (including, but not limited to, substation breakers, fuse cutouts, and line reclosers), or Interconnection Customer equipment on the system to exceed 87.5% of the short circuit interrupting capability; nor shall the interconnection be approved proposed for a circuit that already exceeds 87.5% of the short circuit interrupting capability.

3.2.1.7~~8~~ Using the table below, determine the type of interconnection to a primary distribution line. This screen includes a review of the type of electrical service to be provided to the Interconnection Customer, including line configuration and the transformer connection for the purpose of limiting the potential for creating over-voltages on the Utility's System due to a loss of ground during the operating time of any anti-islanding function.

Primary Distribution Line Type	**Type of Interconnection to Primary Distribution Line**	**Result/Criteria**
Three-phase, three wire	3-phase or single phase, phase-to-phase	Pass Screen
Three-phase, four wire	Effectively-grounded three-phase or single phase, line-to-	Pass Screen

3.2.1.8~~9~~ If the proposed Generating Facility is to be interconnected on a single-phase shared secondary, the aggregate Generating Facility capacity on the shared secondary, including the proposed Generating Facility, shall not exceed 65% of the transformer nameplate rating.

3.2.1.9~~10~~ If the proposed Generating Facility is single-phase and is to be interconnected on a center tap neutral of a 240 volt service, its addition shall not create an imbalance between the two sides of the 240 volt service of more than 20% of the nameplate rating of the service transformer.

3.2.1.10~~1~~ The Generating Facility, in aggregate with other generation interconnected to the transmission side of a substation transformer feeding the circuit where the Generating Facility proposes to interconnect shall not exceed 10 MW in an area where there are known, or posted, transient stability limitations to generating units located in the general electrical vicinity (e.g., three or four transmission busses from the point of interconnection).

3.2.2 Screen Results

3.2.2.1 If the proposed interconnection passes the screens and requires no construction by the Utility on its own System, the Interconnection Request shall be approved and the Utility will provide the Interconnection Customer an executable Interconnection Agreement within ten (10) Business Days after the determination.

3.2.2.2 If the proposed interconnection passes the screens and the Utility is able to determine without further study or review that only minor Utility construction is required to interconnect the Generating Facility to the Utility's Ssystem, the Interconnection Request shall be approved and the Utility will provide the Interconnection Customer a non-binding good faith estimate of the cost of interconnection along with an executable Interconnection Agreement within 15 Business Days after the determination.

3.2.2.3 If the proposed interconnection passes the screens, but the costs of interconnection including System Upgrades and Interconnection Facilities cannot be determined without further study or review, the Utility will notify the Interconnection Customer that the Utility will need to complete a Facilities Study under Section 4.4 to determine the necessary costs of interconnection.

3.2.2.4 If the proposed interconnection fails the screens, but the Utility determines that the Generating Facility may nevertheless be interconnected consistent with safety, reliability, and power quality standards, and requires no construction by the Utility on its own System, the Interconnection Request shall be approved and the Utility shall provide the Interconnection Customer an executable Interconnection Agreement within ten (10) Business Days after the determination.

3.2.2.5 If the proposed interconnection fails the screens, but the Utility determines that the Generating Facility may nevertheless be interconnected consistent with safety, reliability, and power quality standards and the Utility is able to determine without further study or review that only minor Utility construction is required to interconnect with the Generating Facility, the Interconnection Request shall be approved and the Utility will provide the Interconnection Customer a non-binding good faith estimate of the cost of interconnection along with an executable Interconnection Agreement within 15 Business Days after the determination.

3.2.2.6 If the proposed interconnection fails the screens, and the Utility does not or cannot determine from the initial review that the Generating Facility may nevertheless be interconnected consistent with safety, reliability, and power quality standards

unless the Interconnection Customer is willing to consider minor modifications or further study, the Utility shall provide the Interconnection Customer with the opportunity to attend a customer options meeting as described in Section 3.3 below.

3.3 Customer Options Meeting

If the Utility determines the Interconnection Request cannot be approved without (1) minor modifications at minimal cost, (2) a supplemental study or other additional studies or actions, or (3) incurring significant cost to address safety, reliability, or power quality problems, the Utility shall notify the Interconnection Customer of that determination within five (5) Business Days after the determination, and upon request provide copies of all data and analyses underlying its conclusion. Within ten (10) Business Days of the Utility's determination, the Utility shall offer to convene a customer options meeting to review possible Interconnection Customer facility modifications or the screen analysis and related results, to determine what further steps are needed to permit the Generating Facility to be connected safely and reliably. At the time of notification of the Utility's determination, or at the customer options meeting, the Utility shall:

3.3.1 Offer to perform facility modifications or minor modifications to the Utility's System (e.g., changing meters, fuses, relay settings) and provide a non-binding good faith estimate of the limited cost to make such modifications to the Utility's System. The Interconnection Customer shall have ten (10) Business Days to agree to pay for the modifications to the Utility's electric Ssystem or the Interconnection Request shall be deemed to be withdrawn. If the Interconnection Customer agrees to pay for the modifications to the Utility's electric Ssystem, the Utility will provide the Interconnection Customer with an executable Interconnection Agreement within ten (10) Business Days of the Interconnections Customer's agreement to pay; or

3.3.2 Offer to perform a S~~s~~upplemental R~~r~~eview under Section 3.4 if the Utility concludes that the S~~s~~upplemental R~~r~~eview might determine that the Generating Facility could continue to qualify for interconnection pursuant to the Fast Track Process, and provide a non-binding good faith estimate of the costs of such review. The Interconnection Customer shall have ten (10) Business Days to accept in writing the Utility's offer to perform a Supplemental Review and post any deposit requirement for the Supplemental Review, or the Interconnection Request shall be deemed to be withdrawn; or

3.3.3 Offer to continue evaluating the Interconnection Request under the Section 4 Study Process. The Interconnection Customer shall have ten (10) Business Days to agree in writing to its Interconnection Request continuing to be evaluated under the Section 4 Study Process, and post any deposit requirement for the Study Process, or the Interconnection Request shall be deemed to be withdrawn.

3.4 Supplemental Review

If the Interconnection Customer agrees to a S~~s~~upplemental R~~r~~eview, the Interconnection Customer shall agree in writing within ~~15~~ ten (10) Business Days of the offer, and submit a deposit of $750 (if the facility is larger than 20 kW but not larger than 100 kW) or $1,000 (if the facility is larger than 100 kW but not larger than 2 MW); ~~for the estimated costs~~ or the request shall be deemed to be withdrawn. The Interconnection Customer shall be responsible for the Utility's actual costs for conducting the S~~s~~upplemental R~~r~~eview. The Interconnection Customer must pay any review costs that exceed the deposit within 20 Business Days of receipt of the invoice or resolution of any dispute. If the deposit exceeds the invoiced costs, the Utility will return such excess within 20 Business Days of the invoice without interest.

3.4.1 Within ten (10) Business Days following receipt of the deposit for a S~~s~~upplemental R~~r~~eview, the Utility will determine if the Generating Facility can be interconnected safely and reliably.

3.4.1.1 If so, the Utility shall forward an executable Interconnection Agreement to the Interconnection Customer within ten (10) Business Days.

3.4.1.2 If so, and Interconnection Customer facility modifications are required to allow the Generating Facility to be interconnected consistent with safety, reliability, and power quality standards under these procedures, the Utility shall ask if the customer agrees to make the necessary modifications. The customer will be given 10 Business Days to agree, in writing, to the required modifications. The Utility will forward an executable Interconnection Agreement to the Interconnection Customer within 15 Business Days after confirmation that the Interconnection Customer has agreed to make the necessary modifications at the Interconnection Customer's cost.

3.4.1.3 If so, and minor modifications to the Utility's System are required to allow the Generating Facility to be interconnected consistent with safety, reliability, and power quality standards under these procedures, the Utility shall forward an executable Interconnection Agreement to the Interconnection Customer within ten (10) Business Days that requires the Interconnection Customer to pay the costs of such System modifications prior to interconnection.

3.4.1.4 If so, but the costs of interconnection including System Upgrades and Interconnection Facilities cannot be determined without further study or review, the Utility will notify the Interconnection Customer that the Utility will need to complete a Facilities Study under Section 4.4 to determine the necessary costs of interconnection.

3.4.1.5 If not, the Interconnection Request will continue to be evaluated under the Section 4 Study Process, provided the Interconnection

Customer indicates it wants to proceed and submits the required deposit within 15 Business Days.

Section 4. Study Process

4.1 Applicability

The Study Process shall be used by an Interconnection Customer proposing to interconnect its Generating Facility with the Utility's System if the Generating Facility exceeds the size limits for the Section 3 Fast Track Process, is not certified, or is certified but did not pass the Fast Track Process or the 20 kW Inverter Process. The Interconnection Customer may be required to submit additional information or documentation, as may be requested by the Utility in writing, during the Study Process.

4.2 Scoping Meeting

4.2.1 A scoping meeting will be held within ten (10) Business Days after the Interconnection Request is deemed complete, unless the Interconnection Customer is preliminarily designated as interdependent with more than one (1) Interconnection Request pursuant to Section 1.8.3.1, or as otherwise mutually agreed to by the Parties. The Utility and the Interconnection Customer will bring to the meeting personnel, including system engineers and other resources as may be reasonably required to accomplish the purpose of the meeting. The scoping meeting may be omitted by mutual agreement in writing.

4.2.2 The purpose of the scoping meeting is to discuss the Interconnection Request and review existing studies relevant to the Interconnection Request. The Parties shall further discuss whether the Utility should perform a System Impact Study, a Facilities Study, or proceed directly to an Interconnection Agreement.

4.2.3 If the Utility, after consultation with the Interconnection Customer, determines the project should proceed to a System Impact Study or Facilities Study, the Utility shall provide the Interconnection Customer, no later than ten (10) Business Days after the scoping meeting, either a System Impact Study Agreement (Attachment 7) or a Facilities Study Agreement (Attachment 8), as appropriate, including an outline of the scope of the study or studies and a nonbinding good faith estimate of the cost to perform the study or studies, which cost shall be subtracted from the deposit outlined in Section 1.4.1.2.

4.2.4 If the Parties agree not to perform a System Impact Study or Facilities Study, but to proceed directly to an Interconnection Agreement, the Parties shall proceed to the Construction Planning Meeting as called for in Section 5.

4.3 System Impact Study

4.3.1 In order to retain its Queue Position the Interconnection Customer must return a System Impact Study Agreement signed by the Interconnection Customer within 15 Business Days of receiving an executable System Impact Study Agreement as provided for in Section 4.2.3.

4.3.2 The scope of and cost responsibilities for a System Impact Study are described in the System Impact Study Agreement. The time allotted for completion of the System Impact Study shall be as set forth in the System Impact Study Agreement.

4.3.3 The System Impact Study shall identify and detail the electric Ssystem impacts that would result if the proposed Generating Facility were interconnected without project modifications or electric Ssystem modifications, or to study potential impacts, including, but not limited to, those identified in the scoping meeting. The System Impact Study shall evaluate the impact of the proposed interconnection on the reliability of the electric Ssystem, including the distribution and transmission systems, if required.

4.3.4 At the Utility's option, and solely for purposes of administering a Commission-approved Competitive Resource Solicitation, a Utility may designate a Queue Number and act as authorized representative for Interconnection Customer(s) proposing a Generating Facility requesting to interconnect to the Utility's System for evaluation through the Solicitation. The Utility shall evaluate combinations of such Interconnection Requests for purposes of conducting the System Impact Grouping Study(ies) of combinations of Generating Facilities within the Queue Number in order to achieve the resource need identified in the Competitive Resource Solicitation. Such studies in connection with a Competitive Resource Solicitation shall be implemented based upon the Queue Number relative to the Queue Position of all other Interconnection Requests. The Utility may also study an Interconnection Request separately to the extent provided for under the terms of the Competitive Resource Solicitation or if otherwise warranted by Good Utility Practice such as to evaluate the locational remoteness of a proposed Generating Facility.

Through completing the System Impact Grouping Study(ies) of the requested combinations of Interconnection Requests, the Utility must select one of the studied combinations that achieves the capacity solicited through the Competitive Resource Solicitation Process prior to the start of any Interconnection Facilities Study. While conducting the Interconnection Facilities Study(ies) for the selected combination of resources, the Utility may suspend further study of the Interconnection Customers that have opted in to the System Impact Grouping Study that are not included in the selected combination and such customers may elect during this period to return to their original Queue Position, subject to 1.7.3, or participate in a new Competitive Resource Solicitation, if available.

4.3.5 The System Impact Study Rreport will provide the Preliminary Estimated Upgrade Charge, which is a preliminary indication of the cost and length of time that would be necessary to correct any System problems identified in those analyses and implement the interconnection.

4.3.6 The System Impact Study Rreport will provide the Preliminary Estimated Interconnection Facilities Charge, which is a preliminary non-binding indication of the cost and length of time that would be necessary to provide the Interconnection Facilities.

4.3.7 If the Utility has determined that an Interdependency exists and the Project is designated as a Project B, the Project B Interconnection Request shall receive a System Impact Study report, addressing a scenario assuming Project A is constructed and a second scenario assuming Project A is not constructed.

4.3.8 After receipt of the System Impact Study R~~r~~eport(s), the Interconnection Customer shall inform the Utility in writing if it wishes to withdraw the Interconnection Request and to request an accounting of any remaining deposit amount pursuant to Section 6.3.

~~4.3.8 If requested by the Interconnection Customer following delivery of the System Impact Study report, the Utility shall provide the Interconnection Customer an executable Interim Interconnection Agreement within ten (10) Business Days. The Interim Interconnection Agreement shall be identical in form and content to the Final Interconnection Agreement, but will not include Detailed Estimated Upgrade Charges, Detailed Estimated Interconnection Facility Charge, Appendix 4 (Construction Milestone schedule listing tasks, dates and the party responsible for completing each task), and other information that otherwise would be determined in Section 5.~~

4.3.9 At the time the System Impact Study Report is provided to the Interconnection Customer, the Utility shall also deliver an executable Facilities Study Agreement to the Interconnection Customer. After receipt of the System Impact Study Report and Facilities Study Agreement, when the Interconnection Customer is ready to proceed with the design and construction of the Upgrades and Interconnection Facilities, the Interconnection Customer shall return the signed Facilities Study Agreement to the Utility in accordance with Section 4.4 and shall also submit payment or Financial Security reasonably acceptable to the Utility equal to the cost of any Network Upgrades identified in the Preliminary Estimated Upgrade Charge, as set forth in the System Impact Study Report, that would be borne by the Interconnection Customer under a future Interconnection Agreement. This payment or Financial Security shall be held by the Utility as a non-refundable pre-payment for the estimated cost of Network Upgrades to be designed by the Utility in the Section 4.4 Facilities Study. The preliminary Network Upgrade pre-payment amount shall be trued up by the Utility in the Detailed Estimated Upgrade Charges included in a future Interconnection Agreement or shall be forfeited to the Utility to construct the Network Upgrades if the Interconnection Request is subsequently withdrawn by the Interconnection Customer. ~~For Interconnection Customers that have already received their system impact studies, and have proceeded to the facilities study phase, the non refundable pre-payment for network upgrades shall be~~

~~due within 30 business days of this requirement being adopted by the Commission.~~ Failure to timely make such pre-payments will result in the Utility removing the Interconnection Request from the queue.

4.4 Facilities Study

4.4.1 A solar Interconnection Customer must request a Facilities Study by returning the signed Facilities Study Agreement within 60 Calendar Days of the date the Facilities Study Agreement was provided. Any other Interconnection Customer must request a Facility Study by returning the signed Facilities Study Agreement within 180 Calendar Days of the date the Facilities Study Agreement was provided. Failure to return the signed Facilities Study Agreement within the foregoing applicable time period will result in the Interconnection Request being deemed withdrawn.

4.4.2 When an Interdependent Project A exists, a Project B Interconnection Request will not be required to comply with Section 4.4.1 until Project A has signed the Interconnection Agreement, and made payments and provided Financial Security as specified in Section 5.2 or withdrawn. If Project B has not provided written notice of its intent to proceed to a Facilities Study under Section 1.8.2.2, upon the Project A fulfilling the requirements in Section 5.2 or withdrawing the Interconnection Request, the Utility shall notify the Project B Interconnection Customer that it has the time specified in Section 4.4.1 to return the signed Facilities Study Agreement or the Interconnection Request shall be deemed withdrawn.

4.4.3 The scope of and cost responsibilities for the Facilities Study are described in the Facilities Study Agreement. The time allotted for completion of the Facilities Study is described in the Facilities Study Agreement.

4.4.4 The Facilities Study Rreport shall specify and estimate the cost of the equipment, engineering, procurement and construction work (including overheads) needed to implement the System Impact Studies and to allow the Generating Facility to be interconnected and operated safely and reliably.

4.4.5 The Utility shall design any required Interconnection Facilities and/or Upgrades under the Facilities Study Agreement. The Utility may contract with consultants to perform activities required under the Facilities Study Agreement. The Interconnection Customer and the Utility may agree to allow the Interconnection Customer to separately arrange for the design of some of the Interconnection Facilities. In such cases, facilities design will be reviewed and/or modified prior to acceptance by the Utility, under the provisions of the Facilities Study Agreement. If the Parties agree to separately arrange for design and construction, and provided that critical infrastructure security and confidentiality requirements can be met, the Utility shall make sufficient information available to the Interconnection Customer in accordance with confidentiality and critical infrastructure requirements to permit the Interconnection Customer to obtain an independent design and cost estimate for any necessary facilities.

Section 5. Interconnection Agreement and Scheduling

5.1. Construction Planning Meeting

5.1.1. Within ten (10) Business Days of receipt of the Facilit~~y~~ies Study ~~r~~Report, the Interconnection Customer shall request a Construction Planning Meeting, where failure to comply shall result in the Interconnection Request being deemed withdrawn. The Construction Planning Meeting request shall be in writing and shall include the Interconnection Customer's reasonably requested date for completion of the construction of the Upgrades and Interconnection Facilities.

5.1.2. The Construction Planning Meeting shall be scheduled within ten (10) Business Days of the Section 5.1.1 request from the Interconnection Customer, or as otherwise mutually agreed to in writing by the parties.

5.1.3. The purpose of the Construction Planning Meeting is to identify the tasks for each party and discuss and determine the milestones for the construction of the Upgrades and Interconnection Facilities. Agreed upon milestones shall be specific as to scope of action, responsible party, and date of deliverable and shall be recorded in the ~~Final~~ Interconnection Agreement (see Appendix 4 to Attachment 9) to be provided to Interconnection Customer pursuant to Section 5.2.1 below.

5.1.4. If the Utility cannot complete the installation of the required Upgrades and Interconnection Facilities within two (2) months of the Interconnection Customer's reasonably requested In-Service Date, the Interconnection Customer shall have the option of payment for work outside of normal business hours or hiring a Utility-approved subcontractor to perform the distribution Upgrades. Any Utility-approved subcontractor performance remains subject to Utility oversight during construction. The Utility shall make a list of Utility-approved subcontractors available to the Interconnection Customer promptly upon request.

5.2. ~~Final~~ Interconnection Agreement

5.2.1. Within fifteen (15) Business Days of the Construction Planning Meeting, the Utility shall provide an executable ~~Final~~ Interconnection Agreement containing the Detailed Estimated Upgrade Charges, Detailed Estimated Interconnection Facility Charge, Appendix 4 (Construction Milestone and payment schedule listing tasks, dates and the party responsible for completing each task), and other appropriate information, requirements, and charges. ~~The Final Interconnection Agreement will replace any Interim Interconnection Agreement, which shall terminate upon execution of the Final Interconnection Agreement by the Interconnection Customer and the Utility.~~

5.2.2. Within ten (10) Business Days of receiving the ~~Final~~ Interconnection Agreement, the Interconnection Customer must execute and return the Final Interconnection Agreement, where failure to comply results in the Interconnection Request being deemed withdrawn.

5.2.3. After the Parties execute the ~~Final~~ Interconnection Agreement, the Utility shall return a copy of the ~~Final~~ Interconnection Agreement to the Interconnection Customer and interconnection of the Generating Facility shall proceed under the provisions of the ~~Final~~ Interconnection Agreement.

5.2.4. The Final Interconnection Agreement shall specify milestones for payment for Upgrades and Interconnection Ffacilities and/or, provision of Financial Security for Interconnection Ffacilities, if acceptable to the Utility, that are required prior to the start of design and construction of Upgrades and Interconnection Facilities. Payment and Financial Security must be received by close of business forty-five (45) ~~sixty (60)~~ Business Days after the date the Interconnection Agreement is delivered to the Interconnection Customer for signature, where failure to comply results in the Interconnection Request being deemed withdrawn.

5.3 Interconnection Construction

Construction of the Upgrades and Interconnection Facilities will proceed as called for in the Interconnection Agreement and Appendices.

Section 6. Provisions that Apply to All Interconnection Requests

6.1 Reasonable Efforts

The Utility shall make reasonable efforts to meet all time frames provided in these procedures unless the Utility and the Interconnection Customer agree to a different schedule. If the Utility cannot meet a deadline provided herein, it shall at its earliest opportunity notify the Interconnection Customer, explain the reason for the failure to meet the deadline, and provide an estimated time by which it will complete the applicable interconnection procedure in the process.

6.2 Disputes

6.2.1 The Parties agree to attempt to resolve all disputes arising out of the interconnection process according to the provisions of this section. ~~Where an Interconnection Customer seeks to resolve a dispute involving its Queue Number according to the provisions of this section, any disputed loss of Queue Number shall not be final until Interconnection Customer abandons the process set out in this section or a final Commission order is entered.~~ Each Party agrees to conduct all negotiations in good faith.

6.2.2 In the event of a dispute, either Party shall provide the other Party with a written Notice of Dispute. Such Notice shall describe in detail the nature of the dispute. A copy of the Notice of Dispute shall also be served on the Public Staff.

6.2.3 ~~If the dispute has not been resolved within ten (10) Business Days after receipt of the Notice, either Party may contact the Public Staff for assistance in informally resolving the dispute.~~ The Parties shall seek to resolve a dispute within twenty (20) Business Days after receipt of the Notice. ~~If the Parties are unable to informally resolve the dispute, either Party may then file a formal complaint with the~~

~~Commission.~~ If a resolution is not reached, the Parties may 1) if mutually agreed, continue negotiations for up to an additional twenty (20) Business Days; or 2) either Party may contact the Public Staff for assistance in informally resolving the dispute within twenty (20) Business Days with the opportunity to extend this timeline upon mutual agreement.

6.2.4 ~~Each Party agrees to conduct all negotiations in good faith.~~ In the alternative, the parties may, upon mutual agreement, seek the assistance of a dispute resolution service to resolve the dispute within twenty (20) Business Days, with the opportunity to extend this timeline upon mutual agreement. The dispute resolution service will assist the parties in either resolving the dispute or in selecting an appropriate dispute resolution venue (e.g., mediation, settlement judge, early neutral evaluation, or technical expert) to assist the parties in resolving their dispute. Each Party will be responsible for one-half of any costs paid to neutral third-parties. Upon resolution of the dispute, the parties shall jointly make an informational filing with the Commission.

6.2.5 If the Parties are unable to informally resolve the dispute within the timeframe provided in Sections 6.2.3 or 6.2.4, either Party may then file a formal complaint with the Commission, and may exercise whatever rights and remedies it may have in equity or law consistent with the terms of these procedures.

6.2.6 The Queue Number assigned to an Interconnection Customer seeking to resolve a dispute shall not be withdrawn pursuant to Section 6.3 unless: (1) the Interconnection Request is deemed withdrawn by the Utility and the Interconnection Customer fails to take advantage of any express opportunity to cure; (2) the informal dispute processes described in Sections 6.2.3 and 6.2.4 do not resolve the dispute and the Interconnection Customer does not indicate its intent to file a formal complaint within ten (10) Business Days following the completion of the informal dispute process and file a formal complaint within (30) Business Days; (3) the Commission issues a final order in a formal complaint process stating that the Interconnection Request is deemed withdrawn; or (4) the Interconnection Customer voluntarily submits a written request for withdrawal.

6.3 Withdrawal of An Interconnection Request

6.3.1 An Interconnection Customer may withdraw an Interconnection Request at any time prior to executing a Final Interconnection Agreement by providing the Utility with a written request for withdrawal.

6.3.2 An Interconnection Request shall be deemed withdrawn if the Interconnection Customer fails to meet its obligations specified in the Interconnection Procedures, System Impact Study Agreement or Facilityies Study Agreement or to take advantage of any express opportunity to cure.

6.3.3 Within 90 60 Calendar Business Days of any voluntary or deemed withdrawal of the Interconnection Request, the Utility will provide the Interconnection Customer with a final accounting report of any difference between (1) the Interconnection Customer's cost responsibility for the actual cost of such work performed, and (2) the Interconnection Customer's previous aggregate Interconnection Facility Request Deposit payments to the Utility for such work. If the Interconnection Customer's cost responsibility exceeds its

previous aggregate payments, the Utility shall invoice the Interconnection Customer for the amount due and the Interconnection Customer shall make payment to the Utility within 30 Calendar Days. If the Interconnection Customer's previous aggregate payments exceed its cost responsibility under this Agreement, the Utility shall refund to the Interconnection Customer an amount equal to the difference within 30 Calendar Days of the final accounting report.

6.4 Interconnection Metering

Any metering necessitated by the use of the Generating Facility shall be installed at the Interconnection Customer's expense in accordance with all applicable regulatory requirements or the Utility's specifications.

6.5 Commissioning and Post-Commissioning Inspections

6.5.1 Commissioning tests of the Interconnection Customer's installed equipment shall be performed pursuant to applicable codes and standards. If the Interconnection Customer is not proceeding under Section 2.3.2, the Utility must be given at least ten (10) Business Days written notice, or as otherwise mutually agreed to in writing by the Parties, of the tests and may be present to witness the commissioning tests.

6.5.2 In the case of any Generating Facility that was not inspected prior to commencing parallel operation, the Utility shall be authorized to conduct an inspection of the medium voltage AC side of each Generating Facility (including assessing that the anti-islanding process is operational). The Interconnection Customer shall pay the actual cost of such inspection within 30 Business Days after the Utility provides a written invoice for such costs.

6.5.3 The Utility shall also be entitled, on a periodic basis, to inspect the medium voltage AC side of each Interconnected Generating Facility on a reasonable schedule determined by the Utility in accordance with the inspection cycles applicable to its own distribution system. The Interconnection Customer shall pay the actual cost of such inspection within 30 Business Days after the Utility provides a written invoice for such costs.

6.5.4 The Utility shall also be entitled to inspect the medium voltage AC side of an Interconnected Generating Facility in the event that the Utility identifies or becomes aware of any condition that (1) has the potential to either cause disruption or deterioration of service to other customers served from the same electric system or cause damage to the Utility's System or Affected Systems, or (2) is imminently likely to endanger life or property or cause a material adverse effect on the security of, or damage to the Utility's System, the Utility's Interconnection Facilities or the systems of others to which the Utility's System is directly connected. The Interconnection Customer shall pay the actual cost of such inspection within 30 Business Days after the Utility provides a written invoice for such costs.

6.6 Confidentiality

6.6.1 Confidential Information shall mean any confidential and/or proprietary information provided by one Party to the other Party that is clearly marked or otherwise designated "Confidential." For purposes of these procedures all design, operating specifications, and metering data provided by the Interconnection Customer shall be deemed Confidential Information regardless of whether it is clearly marked or otherwise designated as such.

6.6.2 Confidential Information does not include information previously in the public domain, required to be publicly submitted or divulged by Governmental Authorities (after notice to the other Party and after exhausting any opportunity to oppose such publication or release), or necessary to be divulged in an action to enforce these procedures. Each Party receiving Confidential Information shall hold such information in confidence and shall not disclose it to any third party nor to the public without the prior written authorization from the Party providing that information, except to fulfill obligations under these procedures, or to fulfill legal or regulatory requirements.

6.6.2.1 Each Party shall employ at least the same standard of care to protect Confidential Information obtained from the other Party as it employs to protect its own Confidential Information.

6.6.2.2 Each Party is entitled to equitable relief, by injunction or otherwise, to enforce its rights under this provision to prevent the release of Confidential Information without bond or proof of damages, and may seek other remedies available at law or in equity for breach of this provision.

6.6.3 If information is requested by the Commission from one of the Parties that is otherwise required to be maintained in confidence pursuant to these procedures, the Party shall provide the requested information to the Commission within the time provided for in the request for information. In providing the information to the Commission, the Party may request that the information be treated as confidential and non-public in accordance with North Carolina law and that the information be withheld from public disclosure.

6.6.4 All information pertaining to a project will be provided to the new owner in the case of a change of control of the existing legal entity or a change of ownership to a new legal entity.

6.7 Comparability

The Utility shall receive, process, and analyze all Interconnection Requests received under these procedures in a timely manner, as set forth in these procedures. The Utility shall use the same reasonable efforts in processing and analyzing Interconnection Requests from all Interconnection Customers, whether the Generating Facility is owned or operated by the Utility, its subsidiaries or affiliates, or others.

6.8 Record Retention

The Utility shall maintain for three (3) years records, subject to audit, of all Interconnection Requests received under these procedures, the times required to complete Interconnection Request approvals and disapprovals, and justification for the actions taken on the Interconnection Requests.

6.9 Coordination with Affected Systems

<u>The Utility shall develop an Affected System communication protocol with potential Affected Systems, upon request by the Affected System, such that reciprocal notification of Interconnection Requests, as applicable per the specified communication protocol, between the Utility and the Affected System can be addressed and implemented.</u>

The Utility shall coordinate the conduct of any studies required to determine the impact of the Interconnection Request on Affected Systems with Affected System operators and, if possible, include those results (if available) in its applicable studies within the time frame specified in these procedures. The Utility will include such Affected System operators in all meetings held with the Interconnection Customer as required by these procedures. The Interconnection Customer will cooperate with the Utility in all matters related to the conduct of studies and the determination of modifications to Affected Systems. A Utility which may be an Affected System shall cooperate with the Utility with whom interconnection has been requested in all matters related to the conduct of studies and the determination of modifications to Affected Systems.

6.10 Capacity of the Generating Facility

6.10.1 If the Interconnection Request is for a Generating Facility that includes multiple energy production devices at a site for which the Interconnection Customer seeks a single Point of Interconnection, the Interconnection Request shall be evaluated on the basis of the aggregate capacity of the multiple devices, unless otherwise agreed to by the Utility and the Interconnection Customer.

6.10.2 For the purposes of this Standard, the capacity of the Generating Facility shall be considered the maximum rated capacity of the Generating Facility, except where the gross generating capacity of the Generating Facility is limited (e.g., through the use of a control system, power relay(s), or other similar device settings or adjustments as mutually agreed upon by the Utility and Interconnection customer). The Generating Facility's capacity shall be considered the Maximum Generating Capacity specified by the Interconnection Customer in the Interconnection Request. The Maximum Generating Capacity approved in the Study Process will subsequently be included as a limitation in the Interconnection Agreement. ~~The Interconnection Request shall be evaluated using the maximum rated capacity of the Generating Facility, unless otherwise agreed to by the Utility and the Interconnection Customer.~~

6.11 Sale of an Existing or Proposed Generationng Facility

6.11.1 The Interconnection Customer shall notify the Utility of the pending sale of a proposed Generationng Facility in writing. The Interconnection Customer shall provide the Utility with information regarding whether the sale is a change of ownership of the Generationng Facility to a new legal entity, or a change of control of the existing legal entity.

The Interconnection Customer shall promptly notify the Utility of the final date of sale and transfer date of ownership in writing. The purchaser of the Generationng Facility shall confirm to the Utility the final date of sale and transfer date of ownership in writing, and submit an Interconnection Request requesting transfer control or change of ownership together with the $500 change of ownership fee listed in Attachment 2.

6.11.2 Existing Interconnection Agreements are non-transferable. If the Generationng Facility is sold to a new legal entity, a new Interconnection Agreement must be executed by the new legal entity prior to the interconnection or for the continued interconnection of the Generating Facility to the Utility's Ssystem. The Utility shall not withhold or delay the execution of an Interconnection Agreement with the new owner provided the Generationng facility or proposed Generationng Ffacility complies with requirements of 6.11.

6.11.3 The technical requirements in the Interconnection Agreement shall be grandfathered for subsequent owners as long as (1) the Generating Facility's maximum rated capacity has not been changed; (2) the Generating Facility has not been modified so as to change its electrical characteristics; and (3) the interconnection system has not been modified.

6.12 Isolating or Disconnecting the Generating Facility

6.12.1 The Utility may isolate the Interconnection Customer's premises and/or Generating Facility from the Utility's System when necessary in order to construct, install, repair, replace, remove, investigate or inspect any of the Utility's System, or if the Utility determines that isolation of the Interconnection Customer's premises and/or Generating Facility from ~~form~~ the Utility's System is necessary because of emergencies, forced outages, force majeure or compliance with prudent electrical practices.

6.12.2 Whenever feasible, the Utility shall give the Interconnection Customer reasonable notice of the isolation of the Interconnection Customer's premises and/or Generating Facility from ~~form~~ the Utility's System.

6.12.3 Notwithstanding any other provision of this Standard, if at any time the Utility determines that the continued operation of the Generating Facility may endanger either (1) the Utility's personnel or other persons or property or (2) the integrity or safety of the Utility's System, or otherwise cause unacceptable power quality problems for other electric consumers, the Utility shall have the right to isolate the Interconnection Customer's premises and/or Generating Facility from the Utility's System

6.12.4 The Utility may disconnect from the Utility's System any Generating Facility determined to be malfunctioning, or not in compliance with this Standard. The Interconnection Customer must provide proof of compliance with this Standard before the Generating Facility will be reconnected

6.13 Limitation of Liability

Each Party's liability to the other Party for any loss, cost, claim, injury, liability, or expense, including reasonable attorney's fees, relating to or arising from any act or omission hereunder, shall be limited to the amount of direct damage actually incurred. In no event shall either Party be liable to the other Party for any indirect, special, incidental, consequential, or punitive damages of any kind.

6.14 Indemnification

The Parties shall at all times indemnify, defend and save the other Party harmless from any and all damages, losses, claims, including claims and actions relating to injury or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney's fees, and all other obligations by or to third parties, arising out of or resulting from the other Party's action or inaction of its obligations hereunder on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the indemnified Party.

6.15 Insurance

The Interconnection Customer shall obtain and retain, for as long as the Generating Facility is interconnected with the Utility's System, liability insurance which protects the

Interconnection Customer from claims for bodily injury and/or property damage. The amount of such insurance shall be sufficient to insure against all reasonably foreseeable direct liabilities given the size and nature of the generating equipment being interconnected, the interconnection itself, and the characteristics of the system to which the interconnection is made. This insurance shall be primary for all purposes. The Interconnection Customer shall provide certificates evidencing this coverage as required by the Utility. Such insurance shall be obtained from an insurance provider authorized to do business in North Carolina. The Utility reserves the right to refuse to establish or continue the interconnection of the Generating Facility with the Utility's System, if such insurance is not in effect.

6.15.1 For an Interconnection Customer that is a residential customer of the Utility proposing to interconnect a Generating Facility no larger than 250 kW, the required coverage shall be a standard homeowner's insurance policy with liability coverage in the amount of at least $100,000 per occurrence.

6.15.2 For an Interconnection Customer that is a non-residential customer of the Utility proposing to interconnect a Generating Facility no larger than 250 kW, the required coverage shall be comprehensive general liability insurance with coverage in the amount of at least $300,000 per occurrence.

6.15.3 For an Interconnection Customer that is a non-residential customer of the Utility proposing to interconnect a Generating Facility greater than

250 kW, the required coverage shall be comprehensive general liability insurance with coverage in the amount of at least $1,000,000 per occurrence.

6.15.4 An Interconnection Customer of sufficient credit-worthiness may propose to provide this insurance via a self-insurance program if it has a self- insurance program established in accordance with commercially acceptable risk management practices, and such a proposal shall not be unreasonably rejected.

6.16 Disconnect Switch

The Utility may require the iInterconnection Customer to install a manual load- break disconnect switch or safety switch as a clear visible indication of switch position between the Utility System and the iInterconnection Customer. The switch must have padlock provisions for locking in the open position. The switch must be visible to, and accessible to Utility personnel. The switch must be in close proximity to, and on the Interconnection Customer's side of the point of electrical interconnection with the Utility's Ssystem. The switch must be labeled "Generator Disconnect Switch." The switch may isolate the Interconnection Customer and its associated load from the Utility's System or disconnect only the Generator from the Utility's System and shall be accessible to the Utility at all times. The Utility, in its sole discretion, determines if the switch is suitable and necessary. When the installation of the switch is not otherwise required (e.g. National Electric Code, state or local building code) and is deemed necessary by the Utility for certified, inverter-based generators no larger than 10 kW, the Utility shall reimburse the

Interconnection Customer for the reasonable cost of installing a switch that meets the Utility's specifications.

6.17 Certification Codes and Standards

Attachment 4 specifies codes and standards the Generating Facility must comply with.

6.18 Certification of Generator Equipment Packages

Attachment 5 specifies the certification requirements for the Generating Facility.

ATTACHMENT 1

Glossary of Terms

20 kW Inverter Process - The procedure for evaluating an Interconnection Request for a certified inverter-based Generating Facility no larger than 20 kW that uses the Section 3 screens. The application process uses an all-in-one document that includes a simplified Interconnection Request Application Form, simplified procedures, and a brief set of Terms and Conditions. (See Attachment 6.)

Affected System – A Utility ~~An electric system~~ other than the interconnecting Utility's System that may be affected by the proposed interconnection. The owner of an Affected System might be a Party to the Interconnection Agreement or other study agreements needed to interconnect the Generating Facility.

Applicable Laws and Regulations - All duly promulgated applicable federal, state and local laws, regulations, rules, ordinances, codes, decrees, judgments, directives, or judicial or administrative orders, permits and other duly authorized actions of any Governmental Authority.

Auxiliary Load - The term "Auxiliary Load" shall mean power used to operate auxiliary equipment in the facility necessary for power generation (such as pumps, blowers, fuel preparation machinery, exciters, etc.)

Business Days - Monday through Friday, excluding State Holidays.

Calendar Days – Sunday through Saturday, including all holidays.

Commission - The North Carolina Utilities Commission.

Competitive Resource Solicitation - A competitive generation procurement process through which a Utility solicits, or Utilities jointly solicit, new Generating Facilities offering to deliver energy to the Utility for the purpose of meeting the requirements of applicable laws or regulations, including but not limited to G.S. § 62-110.8.

Default - The failure of a breaching Party to cure its breach under the Interconnection Agreement.

Detailed Estimated Interconnection Facilities Charge - The estimated charge for Interconnection Facilities that is based on field visits and/or detailed engineering cost calculations and is presented in the Facilit~~y~~ies Study R~~r~~eport and ~~Final~~ Interconnection Agreement. This charge is not final.

Detailed Estimated Upgrade Charge - The estimated charge for Upgrades that is based on field visits and/or detailed engineering cost calculations and is presented in the Facilit~~y~~ies Study R~~r~~eport and ~~Final~~ Interconnection Agreement.

Distribution System - The Utility's facilities and equipment used to transmit electricity to ultimate usage points such as homes and industries from nearby generators or from interchanges with higher voltage transmission networks which transport bulk power over longer distances. The voltage levels at which Distribution Systems operate differ among areas.

Distribution Upgrades - The additions, modifications, and upgrades to the Utility's Distribution System at or beyond the Point of Interconnection to facilitate interconnection of the Generating Facility and render the service necessary to allow the Generating Facility to operate in parallel with the Utility and to inject electricity onto the Utility's System. Distribution Upgrades do not include Interconnection Facilities.

<u>**Electric Generator Lessor** - The owner of a solar energy facility who leases the facility to a customer generator lessee, including any agents who act on behalf of the electric generator lessor.</u>

Fast Track Process - The procedure for evaluating an Interconnection Request for a certified Generating Facility no larger than 2 MW that meets the eligibility requirements of Section 3.1~~, customer options meeting, and optional supplemental review~~.

~~**Final Interconnection Agreement** - The Interconnection Agreement that specifies the Detailed Estimated Upgrade Charge, Detailed Interconnection Facility Charge, mutually agreed upon Milestones, etc. and terminates and replaces the Interim Interconnection Agreement.~~

Financial Security -- A letter of credit or other financial arrangement that is reasonably acceptable to the Utility and is consistent with the Uniform Commercial Code of North Carolina that is sufficient to cover the costs for constructing, designing, procuring, and installing the applicable portion of the Utility's Interconnection Facilities. Where appropriate, the Utility may deem Financial Security to exist where its credit policies show that the financial risks involved are de minimus, or where the Utility's policies allow the acceptance of an alternative showing of credit-worthiness from the Interconnection Customer.

Generating Facility - The Interconnection Customer's device for the production and/or storage for later injection of electricity identified in the Interconnection Request, but shall not include the Interconnection Customer's Interconnection Facilities.

Good Utility Practice - Any of the practices, methods and acts engaged in or approved by a significant portion of the electric industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region.

Governmental Authority - Any federal, state, local or other governmental regulatory or administrative agency, court, commission, department, board, or other governmental subdivision, legislature, rulemaking board, tribunal, or other governmental authority having jurisdiction over the Parties, their respective facilities, or the respective services they provide, and exercising or entitled to exercise any administrative, executive, police, or taxing authority or power; provided, however, that such term does not include the Interconnection Customer, the Utility, or any affiliate thereof.

In-Service Date – The date upon which the construction of the Utility's facilities is completed and the facilities are capable of being placed into service.

Interconnection Agreement -- The Interconnection Agreement that specifies the Detailed Estimated Upgrade Charge, Detailed Interconnection Facility Charge, mutually agreed upon Milestones, etc. See Attachment 9 of the NC Procedures.

Interconnection Customer - Any valid legal entity, including the Utility, that proposes to interconnect its Generating Facility with the Utility's System.

Interconnection Facilities – Collectively, the Utility's Interconnection Facilities and the Interconnection Customer's Interconnection Facilities. Collectively, Interconnection Facilities include all facilities and equipment between the Generating Facility and the Point of Interconnection, including any modification, additions or upgrades that are necessary to physically and electrically interconnect the Generating Facility to the Utility's System. Interconnection Facilities are sole use facilities and shall not include Upgrades.

Interconnection Facilities Delivery Date – The Interconnection Facilities Delivery Date shall be the date upon which the Utility's Interconnection Facilities are first made operational for the purposes of receiving power from the Interconnection Customer.

Interconnection Request - The Interconnection Customer's written request, in accordance with these procedures, to interconnect a new Generating Facility, or make changes to a prior Interconnection Request (such as items including but not limited to changes in capacity, equipment substitution requests, etc.), or ~~to change the capacity of or make a Material Modification to~~ to make changes to an existing Generating Facility that is interconnected with the Utility's System.

Interdependent Customer (or Interdependent Project) means an Interconnection Customer (or Project) whose Upgrade or Interconnection Facilities requirements are impacted by another Generating Facility, as determined by the Utility.

"Material Modification" means a modification to machine data or equipment configuration or to the interconnection site of the Generating Facility that has a material impact on the cost, timing or design of any Interconnection Facilities or Upgrades or that may adversely impact other Interdependent Interconnection Requests with higher Queue Numbers. Material Modifications include certain project revisions as defined in Section 1.5.1. ~~proposed at any time after receiving notification by the Utility of a complete Interconnection Request pursuant to Section 1.4.3 that 1) alters the size or~~

~~output characteristics of the Generating Facility from its Utility approved Interconnection Request submission; or 2) may adversely impact other Interdependent Interconnection Requests with higher Queue Numbers.~~

~~Indicia of a Material Modification, include, but are not limited to:~~

- ~~A change in Point of Interconnection (POI) to a new location, unless the change in POI is on the same circuit less than two (2) poles away from the original location, and the new POI is within the same protection zone as the original location;~~

- ~~A change or replacement of generating equipment such as generator(s), inverter(s), transformers, relaying, controls, etc. that is not a like kind substitution in size, ratings, impedances, efficiencies or capabilities of the equipment specified in the original or preceding Interconnection Request;~~

- ~~A change of transformer connection(s) or grounding from that originally proposed;~~

- ~~A change to certified inverters with different specifications or different inverter control specifications or set-up than originally proposed;~~

- ~~An increase of the AC output of a Generating Facility; or~~

- ~~A change reducing the AC output of the generating facility by more than 10%.~~

~~The following are not indicia of a Material Modification:~~

- ~~A change in ownership of a Generating Facility; the new owner, however, will be required to execute a new Interconnection Agreement and Study agreement(s) for any Study which has not been completed and the Report issued by the Utility.~~

- ~~A change or replacement of generating equipment such as generator(s), inverter(s), solar panel(s), transformer, relaying, controls, etc. that is a like kind substitution in size, ratings, impedances, efficiencies or capabilities of the equipment specified in the original or preceding Interconnection Request.~~

- ~~An increase in the DC/AC ratio that does not increase the maximum AC output capability of the generating facility;~~

- ~~A decrease in the DC/AC ratio that does not reduce the AC output capability of the generating facility by more than 10%.~~

Maximum Generating Capacity - The term shall mean the maximum continuous electrical output of the Generating Facility at any time as measured at the Point of Interconnection and the maximum kW delivered to the Utility during any metering period. Requested Maximum Generating Capacity will be specified by the

<u>Interconnection Customer in the Interconnection Request and an approved Maximum Generating Capacity will subsequently be included as a limitation in the Interconnection Agreement.</u>

~~**Maximum Physical Export Capability Requested** – The term shall mean the maximum continuous electrical output of the Generating Facility at any time at a power factor of approximately unity as measured at the Point of Interconnection and the maximum kW delivered to the Utility during any metering period.~~

Month – The term "Month" means the period intervening between readings for the purpose of routine billing, such readings usually being taken once per month.

Nameplate Capacity – The term "Nameplate Capacity" shall mean the manufacturer's nameplate rated output capability of the generator. For multi-unit generator facilities, the "Nameplate Capacity" of the facility shall be the sum of the individual manufacturer's nameplate rated output capabilities of the generators.

Net Capacity – The term "Net Capacity" shall mean the Nameplate Capacity of the Customer's generating facilities, less the portion of that capacity needed to serve the Generating Facility's Auxiliary Load.

Net Power - The term "Net Power" shall mean the total amount of electric power produced by the Customer's Generating Facility less the portion of that power used to supply the Generating Facility's Auxiliary Load.

Network Upgrades - Additions, modifications, and upgrades to the Utility's Transmission System required to accommodate the interconnection of the Generating Facility to the Utility's System. Network Upgrades do not include Distribution Upgrades.

North Carolina Interconnection Procedures – The term "North Carolina Interconnection Procedures" shall refer to the <u>most recent</u> North Carolina Interconnection Procedures, Forms, and Agreements for State-Jurisdictional Generator Interconnections as approved by the North Carolina Utilities Commission.

Operating Requirements - Any operating and technical requirements that may be applicable due to Regional Reliability Organization, Independent System Operator, control area, or the Utility's requirements, including those set forth in the Interconnection Agreement.

Party or Parties - The Utility, Interconnection Customer, and possibly the owner of an Affected System, or any combination of the above.

Point of Interconnection - The point where the Interconnection Facilities connect with the Utility's System.

Preliminary Estimated Interconnection Facilities Charge - The estimated charge for Interconnection Facilities that is developed using ~~unit costs~~ <u>high level estimates, including overheads</u> and is presented in the System Impact Study <u>R</u>~~r~~eport ~~and Interim~~

~~Interconnection Agreement~~. This charge is not based on field visits and/or detailed engineering cost calculations.

Preliminary Estimated Upgrade Charge - The estimated charge for Upgrades that is developed using ~~unit costs~~ high level estimates including overheads and is presented in the System Impact Study R~~r~~eport ~~and Interim Interconnection Agreement~~. This charge is not based on field visits and/or detailed engineering cost calculations.

Project A - An Interconnection Customer that has a lower Queue Number than Interdependent Project B.

Project B - An Interconnection Customer that has a higher Queue Number than Interdependent Project A.

Project C – An Interconnection Customer that has a higher Queue Number than Interdependent Project B.

Public Staff - The Public Staff of the North Carolina Utilities Commission.

Queue Number - The number assigned by the Utility that establishes an ~~Customer's~~ Interconnection Request's position in the study queue relative to all other valid Interconnection Requests. Generally, an Interconnection Request with a ~~A~~ lower Queue Number will be studied prior to one with a higher Queue Number. ~~, except in the case of Interdependent Projects and Interconnection Requests participating in a Competitive Resource Solicitation.~~ The Queue Number of each Interconnection Request shall be used to determine the cost responsibility for the Upgrades necessary to accommodate the interconnection.

Queue Position - The order of a valid Interconnection Request, relative to all other pending valid Interconnection Requests, based on Queue Number.

Reasonable Efforts - With respect to an action required to be attempted or taken by a Party under the Interconnection Agreement, efforts that are timely and consistent with Good Utility Practice and are otherwise substantially equivalent to those a Party would use to protect its own interests.

Small Animal Waste to Energy Facility – An electric generating facility 2 MW or less in capacity that uses swine or poultry waste as its energy source, and is eligible for an expedited study process pursuant to G.S. 62-133.8(i)(4).

Standard - The interconnection procedures, forms and agreements approved by the Commission for interconnection of Generating Facilities to Utility Systems in North Carolina when the Generating Facility is selling its output to the Utility.

Standby Generating Facility – An electric Generating Facility primarily designed for standby or backup power in the event of a loss of power supply from the Utility. Such Facilities may operate in parallel with the Utility for a brief period of time when transferring load back to the Utility after an outage, or when testing the operation of the Facility and transferring load from and back to the Utility.

Study Process - The procedure for evaluating an Interconnection Request that includes the Section 4 scoping meeting, System Impact Study, including optional system Impact Grouping Study(ies), and Facilities Study.
System - The facilities owned, controlled or operated by the Utility that are used to provide electric service in North Carolina.

Utility - The entity that owns, controls, or operates facilities used for providing electric service in North Carolina.

Transmission System - The facilities owned, controlled or operated by the Utility that are used to transmit electricity in North Carolina.

Upgrades - The required additions and modifications to the Utility's System at or beyond the Point of Interconnection. Upgrades may be Network Upgrades or Distribution Upgrades. Upgrades do not include Interconnection Facilities.

ATTACHMENT 2

NORTH CAROLINA
INTERCONNECTION REQUEST APPLICATION FORM

Utility: ______________________________

Designated Utility Contact: ______________________________

E-Mail Address: ______________________________

Mailing Address: ______________________________

City: ______________ State: __________ Zip: ________

Telephone Number: ______________________________

Fax: ______________________________

An Interconnection Request Application Form is considered complete when it provides all applicable and correct information required below.

Preamble and Instructions

An Interconnection Customer who requests a North Carolina Utilities Commission jurisdictional interconnection must submit this Interconnection Request Application Form by hand delivery, mail, e-mail, or fax to the Utility.

Request for: Fast Track Process ____ Supplemental Review ______

Study Process ____ Standby Generator / Closed Transition ______

(Refer to Section 3 of the Interconnection Standards for guidance in selecting Fast Track Review options. All Generating Facilities larger than 2 MW must use the Section 4 Study Process.)

Processing Fee or Deposit

Fast Track Process – Non-Refundable Processing Fees

- ~~If the Generating Facility is 20 kW or smaller, the fee is $100.~~
- If the Generating Facility is larger than 20 kW but not larger than 100 kW, the fee is ~~$250~~$750.
- If the Generating Facility is larger than 100 kW but not larger than 2 MW, the fee is ~~$500~~$1,000.

Supplemental Review - Deposit

- If the Generating Facility is larger than 20 kW but not larger than 100 kW, the deposit is $750.
- If the Generating Facility is larger than 100 kW but not larger than 2 MW, the deposit is $1,000.

Study Process – Deposit
If the Interconnection Request is submitted under the Study Process, whether a new submission or an Interconnection Request that did not pass the Fast Track Process, the

Interconnection Customer shall submit to the Utility an Interconnection Facilities Deposit Charge of $20,000 plus $1.00 per kW_{AC}.

Standby Generator / Closed Transition - Deposit
- If the Facility is less than 1 MW, deposit is $2,500.
- If the Facility is equal to or greater than 1 MW the deposit is $5,000.

Change in Ownership – Non-Refundable Processing Fee
- If the Interconnection Request is submitted solely due to a transfer of ownership or change of control of the Generating Facility, the fee is ~~$50~~ $500.

Interconnection Customer Information

Legal Name of the Interconnection Customer (or, if an individual, individual's name)

Name: ____________________

Primary Contact Name: ____________________

Title: ____________________

E-Mail Address: ____________________

Mailing Address: ____________________

City: ____________ State: ____________ Zip: ____________

County: ____________

Telephone (Day): ____________ (Evening): ____________

Fax: ____________

Secondary Contact Name: ____________________

Title: ____________________

E-Mail Address: ____________________

Mailing Address: ____________________

City: ____________ State: ____________ Zip: ____________

County: ____________

Telephone (Day): ____________ (Evening): ____________

Fax: ____________

Facility Location (if different from above):

Project Name: ____________________

Address: ____________________

City: ____________ State: ____________ Zip: ____________

County: ____________

Alternative Contact Information (if different from the Interconnection Customer)

Contact Name: ____________________

Title: ____________________

E-Mail Address: ____________________

Mailing Address: ____________________

City: ____________________ State: ______________ Zip: ______________

Telephone (Day) ________________ (Evening) ________________

Fax: ________________________

Application is for: ______ New Generating Facility

______ Capacity Change to a Proposed or Existing Generating Facility

______ Change of Ownership of a Proposed or Existing Generating Facility to a new legal entity

______ Change of Control of a Proposed or Existing Generating Facility of the existing legal entity.

______ Equipment Substitution

______ Other

~~If capacity addition to existing Generating Facility, please describe:~~ Please provide additional information regarding the proposed change(s): ____________________

____

____

Will the Generating Facility be used for any of the following?

Net Metering? Yes _____ No _____

To Supply Power to the Interconnection Customer? Yes _____ No _____

To Supply Power to the Utility? Yes _____ No _____

To Supply Power to Others? Yes _____ No _____

(If yes, discuss with the Utility whether the interconnection is covered by the NC Interconnection Standard.)

Is the Generating Facility owned by the Interconnection Customer or Leased from an Electric Generator Lessor in NC?

Owned ________

Leased ________ NCUC Docket No.: __________

Requested Point of Interconnection:

____

Requested In-Service Date:

____

For installations at locations with existing electric service to which the proposed Generating Facility will interconnect, provide:

Local Electric Service Provider*: ________________________________

Existing Account Number: ______________________________

To be provided by the Interconnection Customer if the local electric service provider is different from the Utility

Contact Name: ______________________________

Title: ______________________________

E-Mail Address: ______________________________

Mailing Address: ______________________________

City: ______________ State: __________ Zip: __________

Telephone (Day): ______________ (Evening): ______________

Fax: ______________

<u>Generating Facility Information</u>

Data applies only to the Generating Facility, not the Interconnection Facilities.

<u>Prime Mover Information (Refer to U.S. EIA Form 860 Instructions, Table 2 Prime Mover Codes and Descriptions at: https://www.eia.gov/survey/form/eia_860/instructions.pdf)</u>

<u>Prime Mover Code</u> ________

<u>Prime Mover Description</u> ______________________________

~~Prime Mover: Photovoltaic (PV) ____ Fuel Cell ____ Reciprocating Engine ____~~
~~Gas Turbine ____ Steam Turbine ____ Micro-turbine ____~~
~~Other ______________________________~~

~~Energy Source:~~

~~Renewable~~

- ~~☐ Solar – Photovoltaic~~
- ~~☐ Solar – thermal~~
- ~~☐ Biomass – landfill gas~~
- ~~☐ Biomass – manure digester gas~~
- ~~☐ Biomass – directed biogas~~
- ~~☐ Biomass – solid waste~~
- ~~☐ Biomass – sewage digester gas~~
- ~~☐ Biomass – wood~~
- ~~☐ Biomass – other (specify below)~~
- ~~☐ Hydro power – run of river~~
- ~~☐ Hydro power – storage~~
- ~~☐ Hydro power – tidal~~
- ~~☐ Hydro power – wave~~

~~Non-Renewable~~

- ~~☐ Fossil Fuel – Diesel~~
- ~~☐ Fossil Fuel – Natural Gas (not waste)~~
- ~~☐ Fossil Fuel – Oil~~
- ~~☐ Fossil Fuel – Coal~~
- ~~☐ Fossil Fuel – Other (specify below)~~
- ~~☐ Other (specify below)~~

☐ ~~Wind~~
☐ ~~Geothermal~~
☐ ~~Other (specify below)~~

Energy Source Information (Refer to U.S. EIA Form 860 Instructions, Table 28 Energy Source Codes and Heat Content at: https://www.eia.gov/survey/form/eia_860/instructions.pdf)

Fuel Type	Energy Source Code	Energy Source Description

Type of Generator: Synchronous ____ Induction ____ Inverter ____

Total Generator/Storage Nameplate ~~Rating~~ Capacity: _____ kW_{AC} (Typical)________ kVAR

Storage Nameplate Energy: ____________ kWh

Interconnection Customer or Customer-Site Load:___________ kW_{AC} (if none, so state)

Interconnection Customer Generator Auxiliary Load:___________ kW_{AC}

Typical Reactive Load (if known): ___________ kVAR

Maximum ~~Physical Export Capability~~ Generating Capacity Requested:___________ kW_{AC}

(The maximum continuous electrical output of the Generating Facility at any time at a power factor of approximately unity as measured at the Point of Interconnection and the maximum kW delivered to the Utility during any metering period)

Production profile: provide below the maximum import and export levels (as a percentage of the Maximum Generating Capacity Requested) for each hour of the day, as measured at the Point of Interconnection. Power flow in excess of these levels during the corresponding hour shall be considered an Adverse Operating Effect per section 3.4.4. of the Interconnection Agreement.

Maximum import and export, hour ending:

0100 imp: exp: %	0200 imp: exp: %	0300 imp: exp. %

0400 imp: exp: %	0500 imp: exp: %	0600 imp: exp: %
0700 imp: exp: %	0800 imp: exp: %	0900 imp: exp: %
1000 imp: exp: %	1100 imp: exp: %	1200 imp: exp: %
1300 imp: exp: %	1400 imp: exp: %	1500 imp: exp: %
1600 imp: exp: %	1700 imp: exp: %	1800 imp: exp: %
1900 imp: exp: %	2000 imp: exp: %	2100 imp: exp: %
2200 imp: exp: %	2300 imp: exp: %	2400 imp: exp: %

Please provide any additional pertinent information regarding the daily operating characteristics of the facility here or attached as noted. Also note information about intended reactive flows:

____

____

____

____

List components of the Generating Facility equipment package that are currently certified:

Number	Equipment Type	Certifying Entity
1. _____	____________________	______________
2. _____	____________________	______________
3. _____	____________________	______________
4. _____	____________________	______________
5. _____	____________________	______________

Generator (or solar panel information)

Manufacturer, Model & Quantity: ______________________________

____

Nameplate Output Power Rating in kW_{AC}: Summer ________ Winter ___________

Nameplate Output Power Rating in kVA: Summer ________ Winter ___________

Individual Generator Rated Power Factor: _______ Leading ______ Lagging

Total Number of Generators in wind farm to be interconnected pursuant to this Interconnection Request (if applicable): ________ Elevation: _______

Inverter Manufacturer, Model & Quantity: ______________________________

~~For solar projects provide the following information:~~

Latitude: ______ Degrees ~~Minutes North~~ (decimal format, to at least 4 places)

Longitude: ______ Degrees ~~Minutes West~~ (decimal format, to at least 4 places)

For solar projects provide the following information:

Orientation: ______ Degrees (Due South=180°)

☐ Fixed Tilt Array ☐ Single Axis Tracking Array ☐ Double Axis Tracking Array

Fixed Tilt Angle: ________ Degrees

Impedance Diagram - If interconnecting to the Utility System at a voltage of 44-kV or greater, provide an Impedance Diagram. An Impedance Diagram may be required by the Utility for proposed interconnections at lower interconnection voltages. The Impedance Diagram shall provide, or be accompanied by a list that shall provide, the collector system impedance of the generation plant. The collector system impedance data shall include equivalent impedances for all components, starting with the inverter transformer(s) up to the utility level Generator Step-Up transformer.

Load Flow Data Sheet - If interconnecting to the Utility System at a voltage of 44-kV or greater, provide a completed Power Systems Load Flow data sheet. A Load Flow data sheet may be required by the Utility for proposed interconnections at lower interconnection voltages.

Excitation and Governor System Data for Synchronous Generators – If interconnecting to the Utility System at a voltage of 44-kV or greater, provide appropriate IEEE model block diagram of excitation system, governor system and power system stabilizer (PSS) in accordance with the regional reliability council

criteria. A PSS may be required at lower interconnection voltages. A copy of the manufacturer's block diagram may not be substituted.

Generating Facility Characteristic Data (for inverter-based machines)

Max design fault contribution current: ________ Instantaneous ______ or RMS ________

Harmonics Characteristics:

____

Start-up requirements:

____

Inverter Short-Circuit Model Data

Model and parameter data required for short-circuit analysis is specific to each PV inverter make and model. All data to be provided in per-unit ohms, on the equivalent inverter MVA base.
Inverter Equivalent MVA Base: __________ MVA

Values below are valid for initial 2 to 6 cycles:

Short-Circuit Equivalent Pos. Seq. Resistance (R1): ____________ p.u.

Short-Circuit Equivalent Pos. Seq. Reactance (XL1): ____________ p.u.

Short-Circuit Equivalent Neg. Seq. Resistance (R2): ____________ p.u.

Short-Circuit Equivalent Neg. Seq. Reactance (XL2): ____________ p.u.

Short-Circuit Equivalent Zero Seq. Resistance (R0): ____________ p.u.

Short-Circuit Equivalent Zero Seq. Reactance (XL0): ____________ p.u.

Special notes regarding short-circuit modeling assumptions:

____

____

Generating Facility Characteristic Data (for rotating machines)

RPM Frequency: ____________
(*) Neutral Grounding Resistor (if applicable): ____________

Synchronous Generators:

Direct Axis Synchronous Reactance, Xd: ____________ P.U.

Direct Axis Transient Reactance, X'_d: ____________ P.U.

Direct Axis Subtransient Reactance, X''_d: ____________ P.U.

Negative Sequence Reactance, X_2: ____________ P.U.

Zero Sequence Reactance, X_0: ____________________ P.U.
KVA Base: ______________

Field Volts: ______________________________

Field Amperes: ____________

Induction Generators:

Motoring Power (kW): ______________________

I_2^2t or K (Heating Time Constant): ________________

Rotor Resistance, Rr: ______________________

Stator Resistance, Rs: ______________________

Stator Reactance, Xs: ______________________

Rotor Reactance, Xr: ______________________

Magnetizing Reactance, Xm: ________________

Short Circuit Reactance, Xd'': ________________

Exciting Current: __________________________

Temperature Rise: __________________________

Frame Size: _______________________________

Design Letter: _____________________________

Reactive Power Required In Vars (No Load): __________

Reactive Power Required In Vars (Full Load): __________

Total Rotating Inertia, H: __________ Per Unit on kVA Base

Note: Please contact the Utility prior to submitting the Interconnection Request to determine if the specified information above is required.

Interconnection Facilities Information

Will more than one transformer be used between the generator and the point of common coupling?

Yes ____ No ____ (If yes, copy this section and provide the information for each transformer used. This information must match the single-line drawing and transformer specification sheets.)

Will the transformer be provided by the Interconnection Customer? Yes ____ No _____

Transformer Data (if applicable, for Interconnection Customer-owned transformer):

Is the transformer: Single phase ___ Three phase ___ Size: _________ kVA

Transformer Impedance: ________ % on _________ kVA Base

If Three Phase:

Transformer Primary Winding ______________________________ Volts,

❑ Delta ❑ WYE, grounded neutral ❑ WYE, ungrounded neutral

Primary Wiring Connection

❑ 3-wire ❑ 4-wire, grounded neutral

Transformer Secondary Winding ______________________ Volts,

❑ Delta ❑ WYE, grounded neutral ❑ WYE, ungrounded neutral

Secondary Wiring Connection

❑ 3-wire ❑ 4-wire, grounded neutral

Transformer Tertiary Winding ______________________ Volts,

❑ Delta ❑ WYE, grounded neutral ❑ WYE, ungrounded neutral

Transformer Fuse Data (if applicable, for Interconnection Customer-owned fuse):

(Attach copy of fuse manufacturer's Minimum Melt and Total Clearing Time-Current Curves)
Manufacturer: ________________ Type: __________ Size: _____ Speed: ______

Interconnecting Circuit Breaker (if applicable):

Manufacturer: ____________________________ Type: ______________________

Load Rating (Amps): ____ Interrupting Rating (Amps): __________
Trip Speed (Cycles): ________

Interconnection Protective Relays (if applicable):
If Microprocessor-Controlled:

List of Functions and Adjustable Setpoints for the protective equipment or software:

	Setpoint Function	Minimum	Maximum
1.			
2.			
3.			
4.			
5.			
6.			

If Discrete Components:

(Enclose Copy of any Proposed Time-Overcurrent Coordination Curves)

Manufacturer	Type:	Style/Catalog No.	Proposed Setting

Current Transformer Data (if applicable):

(Enclose Copy of Manufacturer's Excitation and Ratio Correction Curves)

Manufacturer: ______________________ Type: ______________________

Accuracy Class: __________ Proposed Ratio Connection: ______________________

Manufacturer: ______________________ Type: ______________________

Accuracy Class: __________ Proposed Ratio Connection: ______________________

Potential Transformer Data (if applicable):

Manufacturer: ______________________ Type: ______________________

Accuracy Class: __________ Proposed Ratio Connection: ______________________

Manufacturer: ______________________ Type: ______________________

Accuracy Class: __________ Proposed Ratio Connection: ______________________

General Information

1. One-line diagram
   Enclose site electrical one-line diagram showing the configuration of all Generating Facility equipment, current and potential circuits, and protection and control schemes.
   - The one-line diagram should include the project owner's name, project name, project address, model numbers and nameplate sizes of equipment, including number and nameplate electrical size information for solar panels, inverters, wind turbines, disconnect switches, latitude and longitude of the project location, and tilt angle and orientation of the photovoltaic array for solar projects.
   - The diagram should also depict the metering arrangement required whether installed on the customer side of an existing meter ("net metering/billing") or directly connected to the grid through a new or separate delivery point requiring a separate meter.
   - List of adjustable set points for the protective equipment or software should be included on the electrical one-line drawing.
   - This one-line diagram must be signed and stamped by a licensed Professional Engineer if the Generating Facility is larger than 50 kW.
   - Is One-Line Diagram Enclosed? Yes ___ No ___
2. Site Plan
   - Enclose copy of any site documentation that indicates the precise physical location of the proposed Generating Facility (Latitude & Longitude Coordinates and USGS topographic map, or other diagram) and the proposed Point of Interconnection.
   - Proposed location of protective interface equipment on property (include address if different from the Interconnection Customer's address) ________________

   ____
   - Is Site Plan Enclosed? Yes ___ No ___
3. Is Site Control Verification Form Enclosed? Yes ___ No ___
4. Equipment Specifications
   Include equipment specification information (product literature) for the solar panels and inverter(s) that provides technical information and certification information for the equipment to be installed with the application.
   - Are Equipment Specifications Enclosed? Yes ___ No ___
5. Protection and Control Schemes
   - Enclose copy of any site documentation that describes and details the operation of the protection and control schemes.
   - Is Available Documentation Enclosed? Yes ___ No ___
   - Enclose copies of schematic drawings for all protection and control circuits, relay current circuits, relay potential circuits, and alarm/monitoring circuits (if applicable).
   - Are Schematic Drawings Enclosed? Yes ___ No ___
6. Register with North Carolina Secretary of State (if not an individual)

Applicant Signature

I hereby certify that, to the best of my knowledge, all the information provided in this Interconnection Request Application Form is true and correct.

For Interconnection Customer:
Signature ______________________________________ Date: ______________
(Authorized Agent of the Legal Entity)

Print Full Name ______________________________________

Company Name ______________________________________

Title With Company ______________________________________

E-Mail Address ______________________________________

Mailing Address: ______________________________________

City: ____________________ State: ______________ Zip: ______________

County: ____________________

Telephone (Day): ______________ (Evening): ______________

Fax: ______________

In the Matter of the Application of [Developer Name] for an Interconnection Agreement with [Utility Name]	))))	**SITE CONTROL VERIFICATION**

I, [Authorized Signatory Name], [Title] of [Developer Name], under penalty of perjury, hereby certify that, [Developer Name] or its affiliate has executed a written contract with the landowner(s) noted below, concerning the property described below. I further certify that our written contract with the landowner(s) specifies the agreed rental rate or purchase price for the property, as applicable, and allows [Developer Name] or its affiliates to construct and operate a renewable energy power generation facility on the property described below.

This verification is provided to [Utility Name] in support of our application for an Interconnection Agreement.

Landowner Name(s): ____

Land Owner Contact information (Phone or e-mail): ___________________________

Parcel or PIN Number: ______________________

County: _________________

Site Address: ____

Number of Acres under Contract (state range, if applicable): ______________________

Date Contract was executed ________________________

Term of Contract ______________________

_____[signature]____________

[Authorized Signatory Name]

[Authorized Signatory Name], being first duly sworn, says that [he/she] has read the foregoing verification, and knows the contents thereof to be true to [his/her] actual knowledge.
Sworn and subscribed to before me this _______ day of __________________, 201___.

________[signature]___________________
[Authorized Signatory Name]

[Title], [Developer Name]

__________[Signature of Notary Public]______
Notary Public

____
Name of Notary Public [typewritten or printed]
My Commission expires________

ATTACHMENT 3

Generating Facility Pre-Application Report Form

Preamble and Instructions

An Interconnection Customer who requests a Pre-Application Report must submit this Pre-Application Report Request by hand delivery, mail, e-mail, or fax to the Utility along with the non-refundable fee of ~~$300~~$500:

DISCLAIMER: Be aware that this Pre-Application Report is simply a snapshot in time and is non-binding. System conditions can and do change frequently.

☐ Check here if payment is enclosed. Fee is required for application to be considered complete.

Date:
____

Interconnecting Customer Name (print): ______________

Contact Person: ______________

Mailing Address: ______________

City: ______________ State: ______________ Zip Code: ______________

Telephone (Daytime): ______________

E-Mail Address: ______________

Alternative Contact Information (e.g., system installation contractor or coordinating company)

Name (print):

____

Role: ______________

____

Contact Person: ______________

____

Mailing Address: ______________

____

City: ______________ State: ______________ Zip Code: ______________

Telephone (Daytime): ______________________________

E-Mail Address: ____

Facility Information:

1) Proposed Facility Location

Address (or cross-roads): ______________________________

____

City: ______________________ State: ______ Zip Code: ________

☐ Site Map provided (Google, MapQuest, etc.)

☐ Grid Coordinates (decimal) - Latitude: ________ Longitude: ________

☐ Pole or Tower number if available: ____________________

2) Primary Energy Source (Refer to U.S. EIA Form 860 Instructions, Table 28 Energy Source Codes and Heat Content at https://www.eia.gov/survey/form/eia_860/instructions.pdf)

Fuel Type	Energy Source Code	Energy Source Description

~~Choose one:~~

~~Renewable~~	~~Non Renewable~~
☐ ~~1. Solar – Photovoltaic~~	☐ ~~17. Fossil Fuel – Diesel~~
☐ ~~2. Solar – thermal~~	☐ ~~18. Fossil Fuel – Natural Gas (not waste)~~
☐ ~~3. Biomass – landfill gas~~	☐ ~~19. Fossil Fuel – Oil~~
☐ ~~4. Biomass – manure digester gas~~	☐ ~~20. Fossil Fuel – Coal~~
☐ ~~5. Biomass – directed biogas~~	☐ ~~21. Fossil Fuel – Other (specify below)~~
☐ ~~6. Biomass – solid waste~~	☐ ~~22. Other (specify below)~~
☐ ~~7. Biomass – sewage digester gas~~	
☐ ~~8. Biomass – wood~~	
☐ ~~9. Biomass – other (specify below)~~	
☐ ~~10. Hydro power – run of river~~	
☐ ~~11. Hydro power – storage~~	
☐ ~~12. Hydro power – tidal~~	
☐ ~~13. Hydro power – wave~~	
☐ ~~14. Wind~~	
☐ ~~15. Geothermal~~	
☐ ~~16. Other (specify below)~~	

3) Prime Mover (Refer to U.S. EIA Form 860 Instructions, Table 2 Prime Mover Codes and Descriptions at https://www.eia.gov/survey/form/eia_860/instructions.pdf)

Prime Mover Code ______

Prime Mover Description ______________________

~~**Choose one:**~~

~~1. ☐ Photovoltaic (PV)~~ ~~2. ☐ Fuel Cell~~ ~~3. ☐ Reciprocating Engine~~ ~~4. ☐ Gas Turbine~~	~~5. ☐ Steam Turbine~~ ~~6. ☐ Micro-turbine~~ ~~7. ☐ Other, including Combined Heat and Power (specify below)~~

4) Type of Generator

Choose one:

1. ☐ Inverter-based Machine 2. ☐ Rotating Machine 3. ☐ Rotating Machine with Inverters	

~~5) Size: ______ kW_{AC}~~

5) Generator/Storage Nameplate Capacity: ______ kW

Maximum Generating Capacity requested: ______ kW_{AC}

Storage Nameplate Energy: ______ kWh

6) Generator Configuration:

☐ Single-phase ☐ Three Phase

7) Interconnection Configuration

☐ New Generation

☐ Stand-alone

☐ Addition to existing commercial or industrial customer's delivery

Customer's Electric Utility account number: ______________

Customer's Electric meter number: ______________

Is Customer's kW load going to increase ~~or decrease~~?

☐ No

☐ Yes, Details ______________________________

Is Customer's kW load going to decrease?

☐ No

☐ Yes, Details ______________________________

Proposed Point of Interconnection on Customer-side of Utility meter

____

OR

☐ Addition to existing generation
- ☐ Stand-alone
- ☐ Addition to existing commercial or industrial customer's delivery
  - Customer's Electric Utility account number: ______________
  - Customer's Electric meter number: ______________

Is Customer's kW load going to increase ~~or decrease~~?

☐ No

☐ Yes, Details ______________________________

Is Customer's kW load going to decrease?

☐ No

☐ Yes, Details ______________________________

Type of Existing Generation: ______________________

Size of Existing Generation: __________ kW_{AC}

Proposed Point of Interconnection on Customer-side of Utility meter

____

Additional Comments

____

____

____

Attachment 4

Certification Codes and Standards

ANSI C84.1-1995 Electric Power Systems and Equipment – Voltage Ratings (60 Hertz)

IEEE 1547, Standard for Interconnecting Distributed Resources with Electric Power Systems (including use of IEEE 1547.1 testing protocols to establish conformity)

IEEE Std 100-2000, IEEE Standard Dictionary of Electrical and Electronic Terms

IEEE Std 519-1992, IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems

IEEE Std C37.108-1989 (R2002), IEEE Guide for the Protection of Network Transformers

IEEE Std C37.90.1-1989 (R1994), IEEE Standard Surge Withstand Capability (SWC) Tests for Protective Relays and Relay Systems

IEEE Std C37.90.2 (1995), IEEE Standard Withstand Capability of Relay Systems to Radiated Electromagnetic Interference from Transceivers

IEEE Std C57.12.44-2000, IEEE Standard Requirements for Secondary Network Protectors

IEEE Std C62.41.2-2002, IEEE Recommended Practice on Characterization of Surges in Low Voltage (1000V and Less) AC Power Circuits

IEEE Std C62.45-1992 (R2002), IEEE Recommended Practice on Surge Testing for Equipment Connected to Low-Voltage (1000V and Less) AC Power Circuits

NEMA MG 1-1998, Motors and Small Resources, Revision 3

NEMA MG 1-2003 (Rev 2004), Motors and Generators, Revision 1

NFPA 70 (2002), National Electrical Code

UL1741, Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources

Certification of Generator Equipment Packages

1.0 Generating Facility equipment proposed for use separately or packaged with other equipment in an interconnection system shall be considered certified for interconnected operation if (1) it has been tested in accordance with industry standards for continuous utility interactive operation in compliance with the appropriate codes and standards referenced below by any Nationally Recognized Testing Laboratory (NRTL) recognized by the United States Occupational Safety and Health Administration to test and certify interconnection equipment pursuant to the relevant codes and standards listed in Attachment 4 of the North Carolina Interconnection Procedures, (2) it has been labeled and is publicly listed by such NRTL at the time of the Interconnection Request, and (3) such NRTL makes readily available for verification all test standards and procedures it utilized in performing such equipment certification, and, with consumer approval, the test data itself. The NRTL may make such information available on its website and by encouraging such information to be included in the manufacturer's literature accompanying the equipment.

2.0 The Interconnection Customer must verify that the intended use of the equipment falls within the use or uses for which the equipment was tested, labeled, and listed by the NRTL.

3.0 Certified equipment shall not require further type-test review, testing, or additional equipment to meet the requirements of this interconnection procedure; however, nothing herein shall preclude the need for an on-site commissioning test by the Parties to the interconnection nor follow-up production testing by the NRTL.

4.0 If the certified equipment package includes only interface components (switchgear, inverters, or other interface devices), then an Interconnection Customer must show that the generator or other electric source being utilized with the equipment package is compatible with the equipment package and is consistent with the testing and listing specified for this type of interconnection equipment.

5.0 Provided the generator or electric source, when combined with the equipment package, is within the range of capabilities for which it was tested by the NRTL, and does not violate the interface components' labeling and listing performed by the NRTL, no further design review, testing or additional equipment on the Interconnection Customer's side of the point of common coupling shall be required to meet the requirements of the North Carolina Interconnection Procedures.

6.0 An equipment package does not include equipment provided by the Utility.

Attachment 6

Interconnection Request Application Form for Interconnecting a Certified Inverter-Based Generating Facility No Larger than 20 kW

This Interconnection Request Application Form is considered complete when it provides all applicable and correct information required below. Additional information to evaluate the Interconnection Request may be required.

Processing Fee

A non-refundable processing fee of ~~$100~~ $200 must accompany this Interconnection Request Application Form.

If the Interconnection Request is submitted solely due to a transfer of ownership of the Generating Facility, the non-refundable fee is $50.

Interconnection Customer

Name: ______________________________

Primary Contact Person: ______________________________

Title ______________________________

E-Mail Address: ______________________________

Mailing Address: ______________________________

City: ______________ State: ______ Zip: ______________

County: ______________________________

Telephone (Day): ______________ (Evening): ______________

Fax: ______________

Secondary Contact Name: ______________________________

Title: ______________________________

E-Mail Address: ______________________________

Mailing Address: ______________________________

City: ______________ State: ______________ Zip: ______________

County: ______________

Telephone (Day): ______________ (Evening): ______________

Fax: ______________

Contact (if different than Interconnection Customer)

Name: ______________________________

E-Mail Address: ______________________________

Address: ______________________________

City: ______________ State: ______ Zip: ______________

County: ______________________________

Telephone (Day): ______________ (Evening): ______________

Fax: ______________

Owner(s) of the Generating Facility: ______________________________

Generating Facility Information

Facility Location (if different from above):

Address: ______________________________

City: ______________ State: ______ Zip: ______________

County: ______________________________

Utility: ______________________________

Account Number: ______________________________

Is the Generating Facility owned by the Interconnection Customer or Leased from an Electric Generator Lessor in NC?

Owned ________
Leased ________ NCUC Docket No.: __________

Inverter Manufacturer: ______________ Model: ______________

Nameplate Rating (each inverter): ______________ $kW_{(AC)}$ (each inverter)

______________ $kVA_{(AC)}$ (each inverter)

______________ $Volts_{(AC)}$ (each inverter)

Single Phase: ______ Three Phase: ______

System Design Capacity[9]: ______________ $kW_{(AC)}$ (system total)

______________ $kVA_{(AC)}$ (system total)

[9] Total inverter capacity.

For photovoltaic sources only:

Total panel capacity: ______________ kW $_{(DC)}$ (system total)

Maximum ~~Physical Export Capability~~ Generating Capacity Rquested:[10]

(calculated)[11] kW $_{(AC)}$

For other sources:

Maximum ~~Physical Export Capability~~ Generating Capacity Requested:[2]

___________ kW $_{(AC)}$

~~Prime Mover: Photovoltaic ☐ Reciprocating Engine ☐~~

~~Fuel Cell ☐ Turbine ☐ Other ☐~~

~~ENERGY SOURCE TABLE~~

~~Renewable~~	~~Non-Renewable~~
~~H-1. Solar – Photovoltaic~~	~~H-17. Fossil Fuel – Diesel~~
~~H-2. Solar – thermal~~	~~H-18. Fossil Fuel – Natural Gas (not waste)~~
~~H-3. Biomass – landfill gas~~	~~H-19. Fossil Fuel – Oil~~
~~H-4. Biomass – manure digester gas~~	~~H-20. Fossil Fuel – Coal~~
~~H-5. Biomass – directed biogas~~	~~H-21. Fossil Fuel – Other (specify below)~~
~~H-6. Biomass – solid waste~~	~~H-22. Other (specify below)~~
~~H-7. Biomass – sewage digester gas~~	
~~H-8. Biomass – wood~~	
~~H-9. Biomass – other (specify below)~~	
~~H-10. Hydro power – run of river~~	
~~H-11. Hydro power – storage~~	
~~H-12. Hydro power – tidal~~	
~~H-13. Hydro power – wave~~	
~~H-14. Wind~~	
~~H-15. Geothermal~~	
~~H-16. Other (specify below)~~	

~~Energy Source: ______________ (choose from list above)~~

Prime Mover Information (Refer to U.S. EIA Form 860 Instructions, Table 2 Prime Mover Codes and Descriptions at https://www.eia.gov/survey/form/eia_860/instructions.pdf)

[10] At the Point of Interconnection, this is the maximum possible export power that could flow back to the ~~U~~utility. Unless special circumstances apply, load should not be subtracted from the System Design Capacity.

[11] For a photovoltaic installation, the Uutility will calculate this value as the lesser of (1) the total kW inverter capacity and (2) the total kW panel capacity (no DC to AC losses included, for simplicity).

Prime Mover Code ________

Prime Mover Description

____

Energy Source Information (Refer to U.S. EIA Form 860 Instructions, Table 28 Energy Source Codes and Heat Content at https://www.eia.gov/survey/form/eia_860/instructions.pdf)

Fuel Type	Energy Source Code	Energy Source Description

Is the equipment UL 1741 Listed? Yes ____ No ____

If Yes, attach manufacturer's cut-sheet showing UL 1741 listing

Estimated Installation Date: ________ Estimated In-Service Date: ________

The 20 kW Inverter Process is available only for inverter-based Generating Facilities no larger than 20 kW that meet the codes, standards, and certification requirements of Attachments 3 and 4 of the North Carolina Interconnection Procedures, or the Utility has reviewed the design or tested the proposed Generating Facility and is satisfied that it is safe to operate.

List components of the Generating Facility equipment package that are currently certified:

Number	Equipment Type	Certifying Entity
1. ______	______________	______________
2. ______	______________	______________
3. ______	______________	______________
4. ______	______________	______________
5. ______	______________	______________

Interconnection Customer Signature

I hereby certify that, to the best of my knowledge, the information provided in this Interconnection Request Application Form is true. I agree to abide by the Terms and Conditions for Interconnecting a Certified Inverter-Based Generating Facility No Larger than 20 kW and return the Certificate of Completion when the Generating Facility has been installed.

Signed:

Full Name ______________________________

Company Name

____

Title With Company

____

E-Mail Address

____

Mailing Address: ______________________________

City: ______________ State: ______________ Zip: ______________

County: ______________

Telephone (Day): ______________ (Evening): ______________

Fax: ______________

Contingent Approval to Interconnect the Generating Facility (For Utility use only)

Interconnection of the Generating Facility is approved contingent upon the Terms and Conditions for Interconnecting a Certified Inverter-Based Generating Facility No Larger than 20 kW and return of the Certificate of Completion.

Utility Signature:

Title: ______________________________ Date:

____

Interconnection Request ID number:

____

Utility waives inspection/witness test? Yes _______No

Certificate of Completion
for Interconnecting a Certified Inverter-Based
Generating Facility No Larger than 20 kW

Is the Generating Facility owner-installed? Yes ________ No _____

Interconnection Customer

Name: ______________________________

Contact Person: ______________________________

E-Mail Address: ______________________________

Address: ______________________________

City: ______________ State: ______ Zip: ______________

County: ______________________________

Telephone (Day): ______________ (Evening): ______________

Fax: ______________

Location of the Generating Facility (if different from above)

Address: ______________________________

City: ______________ State: ______ Zip: ______________

Electrician

Name: ______________________________

Company: ______________________________

E-Mail Address: ______________________________

Address: ______________________________

City: ______________ State: ______ Zip: ______________

County: ______________________________

Telephone (Day): ______________ (Evening): ______________

Fax: ______________

License Number: ______________

Date Approval to Install Generating Facility granted by the Utility: ______________

Interconnection Request ID Number: ______________________________

Inspection:

The Generating Facility has been installed and inspected in compliance with the local building/electrical code of ______________________________

Signed (Local electrical wiring inspector, or attach signed electrical inspection):

Signature: ______________________________

Print Name: ______________________ Date: ______________

As a condition of interconnection, you are required to send/ email/ fax a copy of this form along with a copy of the signed electrical permit to (insert Utility information below):

Utility Name: ______________________________

Attention: ______________________________

E-Mail Address: ______________________________

Address: ______________________________

City: ______________ State: ________ Zip: ______________

Fax: ______________

Approval to Energize the Generating Facility (For Utility use only)

Energizing the Generating Facility is approved contingent upon the Terms and Conditions for Interconnecting a Certified Inverter-Based Generating Facility No Larger than 20 kW.

Utility Signature:

Title: ______________________ Date: ______________

Terms and Conditions
for Interconnecting a Certified Inverter-Based
Generating Facility No Larger than 20 kW

1.0 Construction of the Facility

The Interconnection Customer (Customer) may proceed to construct (including operational testing not to exceed two hours) the Generating Facility when the Utility approves the Interconnection Request and returns it to the Customer.

2.0 Interconnection and Operation

The Customer may interconnect the Generating Facility with the Utility's System and operate in parallel with the Utility's System once all of the following have occurred:

2.1 Upon completing construction, the Customer will cause the Generating Facility to be inspected or otherwise certified by the appropriate local electrical wiring inspector with jurisdiction, ~~and~~

2.2 The Customer returns the Certificate of Completion to the Utility, and

2.3 The Utility has either:

2.3.1 Completed its inspection of the Generating Facility to ensure that all equipment has been appropriately installed and that all electrical connections have been made in accordance with applicable codes. All inspections must be conducted by the Utility, at its own expense, within ten Business Days after receipt of the Certificate of Completion and shall take place at a time agreeable to the Parties. The Utility shall provide a written statement that the Generating Facility has passed inspection or shall notify the Customer of what steps it must take to pass inspection as soon as practicable after the inspection takes place; or

2.3.2 If the Utility does not schedule an inspection of the Generating Facility within ten Business Days after receiving the Certificate of Completion, the witness test is deemed waived (unless the Parties agree otherwise); or

2.3.3 The Utility waives the right to inspect the Generating Facility.

2.4 The Utility has the right to disconnect the Generating Facility in the event of improper installation or failure to return the Certificate of Completion.

2.5 Revenue quality metering equipment must be installed and tested in accordance with applicable American National Standards Institute (ANSI) standards and all applicable regulatory requirements.

3.0 <u>Safe Operations and Maintenance</u>

The Customer shall be fully responsible to operate, maintain, and repair the Generating Facility as required to ensure that it complies at all times with the interconnection standards to which it has been certified.

<u>The Customer shall not operate the Generating Facility in such a way that the Generating Facility would exceed the Maximum Generating Capacity.</u>

4.0 <u>Access</u>

The Utility shall have access to the disconnect switch (if a disconnect switch is required) and metering equipment of the Generating Facility at all times. The Utility shall provide reasonable notice to the Customer, when possible, prior to using its right of access.

5.0 <u>Disconnection</u>

The Utility may temporarily disconnect the Generating Facility upon the following conditions:

5.1 For scheduled outages upon reasonable notice.

5.2 For unscheduled outages or emergency conditions.

5.3 If the Generating Facility does not operate in a manner consistent with these Terms and Conditions.

5.4 The Utility shall inform the Customer in advance of any scheduled disconnection, or as soon as is reasonable after an unscheduled disconnection.

6.0 <u>Indemnification</u>

The Parties shall at all times indemnify, defend, and save the other Party harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the other Party's action or inactions of its obligations hereunder on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the indemnified Party.

7.0 Insurance

All insurance policies must be maintained with insurers authorized to do business in North Carolina. The Parties agree to the following insurance requirements:

7.1 If the Customer is a residential customer of the Utility, the required coverage shall be a standard homeowner's insurance policy with liability coverage in the amount of at least $100,000 per occurrence.

7.2 For an Interconnection Customer that is a non-residential customer of the Utility proposing to interconnect a Generating Facility no larger than 250 kW, the required coverage shall be comprehensive general liability insurance with coverage in the amount of at least $300,000 per occurrence.

7.3 The Customer may provide this insurance via a self-insurance program if it has a self-insurance program established in accordance with commercially acceptable risk management practices.

8.0 Limitation of Liability

Each Party's liability to the other Party for any loss, cost, claim, injury, or expense, including reasonable attorney's fees, relating to or arising from any act or omission hereunder, shall be limited to the amount of direct damage actually incurred. In no event shall either Party be liable to the other Party for any indirect, special, incidental, consequential, or punitive damages of any kind.

9.0 Termination

The agreement to interconnect and operate in parallel may be terminated under the following conditions:

9.1 By the Customer

By providing written notice to the Utility and physically and permanently disconnecting the Generating Facility.

9.2 By the Utility

If the Generating Facility fails to operate for any consecutive 12-month period or the Customer fails to remedy a violation of these Terms and Conditions.

9.3 Permanent Disconnection

In the event this Agreement is terminated, the Utility shall have the right to disconnect its facilities or direct the Customer to disconnect its Generating Facility.

9.4 Survival Rights

This Agreement shall continue in effect after termination to the extent necessary to allow or require either Party to fulfill rights or obligations that arose under the Agreement.

10.0 Assignment/Transfer of Ownership of the Facility

10.1 This Agreement shall not survive the transfer of ownership of the Generating Facility to a new owner.

10.2 The new owner must complete and submit a new Interconnection Request agreeing to abide by these Terms and Conditions for interconnection and parallel operations within 20 Business Days of the transfer of ownership. The Utility shall acknowledge receipt and return a signed copy of the Interconnection Request Application Form within ten Business Days.

10.3 The Utility shall not study or inspect the Generating Facility unless the new owner's Interconnection Request Application Form indicates that a Material Modification has occurred or is proposed.

ATTACHMENT 7

System Impact Study Agreement

THIS AGREEMENT ("Agreement") is made and entered into this ____ day of ________, 20__, by and between ______________________________, a __________ organized and existing under the laws of the State of ________________, ("Interconnection Customer"), and ______________________________, a ______________________________ existing under the laws of the State of ________________________, ("Utility"). The Interconnection Customer and the Utility each may be referred to as a "Party," or collectively as the "Parties."

RECITALS

WHEREAS, the Interconnection Customer is proposing to develop a Generating Facility or generating capacity addition to an existing Generating Facility consistent with the Interconnection Request completed by the Interconnection Customer, dated ________ and received by the Utility on ________________; and

WHEREAS, the Interconnection Customer desires to interconnect the Generating Facility with the Utility's System; and

WHEREAS, the Interconnection Customer has requested the Utility to perform a S~~s~~ystem I~~i~~mpact S~~s~~tudy to assess the impact of interconnecting the Generating Facility with the Utility's System, and of any Affected Systems;

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein the Parties agree as follows:

1. When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated or the meanings specified in the North Carolina Interconnection Procedures.

2. The Interconnection Customer elects and the Utility shall cause to be performed a S~~s~~ystem I~~i~~mpact S~~s~~tudy consistent with the North Carolina Interconnection Procedures.

3. The scope of the S~~s~~ystem I~~i~~mpact S~~s~~tudy shall be subject to the assumptions set forth in Appendix A to this Agreement.

4. A S~~s~~ystem I~~i~~mpact S~~s~~tudy will be based upon the technical information provided by Interconnection Customer in the Interconnection Request. The Utility reserves the right to request additional technical information from the Interconnection Customer as may reasonably become necessary consistent with Good Utility Practice during the course of

the S~~s~~ystem I~~i~~mpact S~~s~~tudy. If the information requested by the Utility is not provided by the Interconnection Customer within a reasonable

timeframe to be identified by the Utility in writing, the Utility shall provide the Interconnection Customer written notice providing an opportunity to cure such failure by the close of business on the tenth (10th) Business Day following the posted date of such notice, where failure to provide the information requested within this period shall result in the study being terminated and the Interconnection Request being deemed withdrawn. The period of time for the Utility to complete the System Impact Study shall be tolled during any period that the Utility has requested information in writing from the Interconnection Customer necessary to complete the study and such request is outstanding.

5. In performing the study, the Utility shall rely, to the extent reasonably practicable, on existing studies of recent vintage. The Interconnection Customer shall not be charged for such existing studies; however, the Interconnection Customer shall be responsible for charges associated with any new study or modifications to existing studies that are reasonably necessary to perform the ~~feasibility~~ System Impact ~~s~~Study.

6. The System Impact Study Report shall provide the following analyses for the purpose of identifying any potential adverse system impacts that would result from the interconnection of the Generating Facility as proposed:

   6.1. Initial identification of any circuit breaker short circuit capability limits exceeded as a result of the interconnection, considering the Nameplate Capacity of the Generating Facility;

   6.2. Initial identification of any thermal overload or voltage limit violations resulting from the interconnection, considering the Maximum Generating Capacity of the Generating Facility; and

   6.3. Initial review of grounding requirements and electric system protection.

7. The System Impact Study shall model the impact of the Generating Facility regardless of purpose in order to avoid the further expense and interruption of operation for reexamination of feasibility and impacts if the Interconnection Customer later changes the purpose for which the Generating Facility is being installed.

8. The S~~s~~tudy shall include the feasibility of any interconnection at a proposed project site where there could be multiple potential Points of Interconnection,

as requested by the Interconnection Customer and at the Interconnection Customer's cost.

9. A System Impact Study shall consist of a short circuit analysis, a stability analysis, a power flow analysis, voltage drop and flicker studies,

protection and set point coordination studies, and grounding reviews, as necessary.

10. The System Impact Study will also include an analysis of distribution and transmission impacts as may be necessary to understand the impact of the proposed Generati~~on~~ing Facility on electric system operation.

11. A System Impact Study shall state the assumptions upon which it is based, state the results of the analyses, and provide the requirement or potential impediments to providing the requested interconnection service.

12. The System Impact Study will provide the Preliminary Estimated Upgrade Charge, which is a preliminary indication of the cost and length of time that would be necessary to correct any System problems identified in those analyses and implement the interconnection.

13. The System Impact Study will provide the Preliminary Estimated Interconnection Facilities Charge, which is a preliminary indication of the cost and length of time that would be necessary to provide the Interconnection Facilities.

~~14. A system impact study shall provide the information outlined in Section 1.3.2 of the Interconnection Procedures.~~

14~~5.~~ A distribution System Impact Study shall incorporate a distribution load flow study, an analysis of equipment interrupting ratings, protection coordination study, voltage drop and flicker studies, protection and set point coordination studies, grounding reviews, and the impact on electric system operation, as necessary.

15~~6~~. Affected Systems may participate in the preparation of a System Impact Study, with a division of costs among such entities as they may agree. All Affected Systems shall be afforded an opportunity to review and comment upon a System Impact Study that covers potential adverse system impacts on their electric systems, and the Utility has 20 additional Business Days to complete a S~~s~~ystem I~~i~~mpact S~~s~~tudy requiring review by Affected Systems.

16~~7~~. The Utility shall have an additional 15 Business Days from the time set forth in Section 18 of ~~19.0~~ the System Impact Study Agreement to complete the dual scenario System Impact Study reports for a Project B.

17~~8~~. If the Utility uses a queuing procedure for sorting or prioritizing projects and their associated cost responsibilities for any required Network Upgrades, the System Impact Study shall consider all generating facilities (and with respect to paragraph ~~18.3~~ 17.3 below, any identified

Upgrades associated with such interconnection with a lower Queue Number) that, on the date the S~~s~~ystem I~~i~~mpact S~~s~~tudy is commenced –

17~~8~~.1. Are directly interconnected with the Utility's electric System; or

17~~8~~.2. Are interconnected with Affected Systems and may have an impact on the proposed interconnection; and

17~~8~~.3. Have a pending Interconnection Request to interconnect with the Utility's electric S~~s~~ystem with a lower Queue Number.

18~~9~~. The System Impact Study shall be completed within a total of 65 Business Days if transmission system impacts are studied, and 50 Business Days if distribution system impacts are studied, but in any case, shall not take longer than a total of 65 Business Days unless the study involves Affected Systems per Section 15~~16.0~~ or the studied Interconnection Request is a Project B per Section 16 ~~17.0~~ or the System Impact Study is a Grouping Study implemented pursuant to Section 4.3.4 of the Interconnection Procedures, which shall be completed during the timeframe of the Competitive Resource Solicitation. The period of time for the Utility to complete the System Impact Study shall be tolled during any period that the Utility has requested information in writing from the Interconnection Customer necessary to complete the Study and such request is outstanding.

~~20~~19. Any study fees shall be based on the Utility's actual costs and will be deducted from the Interconnection Facilities deposit made by the Interconnection Customer at the time of the Interconnection Request. After the study is completed, the Utility shall deliver a summary of costs incurred ~~professional time~~.

20~~21~~. The Interconnection Customer must pay any S~~s~~tudy costs that exceed the Interconnection Request Deposit without interest within 20 Business Days of receipt of the invoice. If the deposit exceeds the invoiced fees or the Interconnection Customer's costs exceed the aggregate deposits received and the Interconnection Customer withdraws the Interconnection Request, the amount of funds equal to the difference will be settled in accordance with Section 6.3 of the NC Interconnection Standard.

2~~2~~1. Governing Law, Regulatory Authority, and Rules

The validity, interpretation and enforcement of this Agreement and each of its provisions shall be governed by the laws of the State of North Carolina, without regard to its conflicts of law principles. This Agreement is subject to all Applicable Laws and Regulations. Each Party expressly reserves the right to seek changes in, appeal, or otherwise contest any laws, orders, or regulations of a Governmental Authority.

2~~3~~2. Amendment

The Parties may amend this Agreement by a written instrument duly executed by both Parties.

2~~4~~3. No Third-Party Beneficiaries

This Agreement is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest and where permitted, their assigns.

2~~5~~4. Waiver

2~~5~~4.1. The failure of a Party to this Agreement to insist, on any occasion, upon strict performance of any provision of this Agreement will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party.

2~~5~~4.2. Any waiver at any time by either Party of its rights with respect to this Agreement shall not be deemed a continuing waiver or a waiver with respect to any other failure to comply with any other obligation, right, or duty of this Agreement. Termination or default of this Agreement for any reason by Interconnection Customer shall not constitute a waiver of the Interconnection Customer's legal rights to obtain an interconnection from the Utility. Any waiver of this Agreement shall, if requested, be provided in writing.

2~~6~~5. Multiple Counterparts

This Agreement may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

27~~6~~. No Partnership

This Agreement shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation or partnership liability upon either Party. Neither Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Party.

28~~7~~. Severability

If any provision or portion of this Agreement shall for any reason be held or adjudged to be invalid or illegal or unenforceable by any court of competent jurisdiction or other Governmental Authority, (1) such portion or provision shall be deemed separate and independent, (2) the Parties shall negotiate in good faith to restore insofar as practicable the benefits to each Party that were affected by such ruling, and (3) the remainder of this Agreement shall remain in full force and effect.

29~~8~~. Subcontractors

Nothing in this Agreement shall prevent a Party from utilizing the services of any subcontractor as it deems appropriate to perform its obligations under this Agreement; provided, however, that each Party shall require its subcontractors to comply with all applicable terms and conditions of this Agreement in providing such services and each Party shall remain primarily liable to the other Party for the performance of such subcontractor.

29~~8~~.1. The creation of any subcontract relationship shall not relieve the hiring Party of any of its obligations under this Agreement. The hiring Party shall be fully responsible to the other Party for the acts or omissions of any subcontractor the hiring Party hires as if no subcontract had been made; provided, however, that in no event shall the Utility be liable for the actions or inactions of the Interconnection Customer or its subcontractors with respect to obligations of the Interconnection Customer under this Agreement. Any applicable obligation imposed by this Agreement upon the hiring Party shall be equally binding upon, and shall be construed as having application to, any subcontractor of such Party.

2~~9~~8.2. The obligations under this article will not be limited in any way by any limitation of subcontractor's insurance.

~~29~~30. Reservation of Rights

The Utility shall have the right to make a unilateral filing with the Commission to modify this Agreement with respect to any rates, terms and conditions, charges, or classifications of service, and the Interconnection Customer shall have the right to make a unilateral filing with the Commission to modify this Agreement; provided that each Party shall have the right to protest any such filing by the other Party and to participate fully in any proceeding before the Commission in which such modifications may be considered. Nothing in this Agreement shall limit the rights of the Parties except to the extent that the Parties otherwise agree as provided herein.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be duly executed by their duly authorized officers or agents on the day and year first above written.

[Insert name of Utility]	**[Insert name of Interconnection Customer]**
______________________	______________________
Signed ______________________	Signed: ______________________
Name (Printed):	Name (Printed):
______________________	______________________
Title ______________________	

Assumptions Used in Conducting the System Impact Study

The S~~s~~ystem I~~i~~mpact S~~s~~tudy shall be based upon the Interconnection Request subject to any modifications in accordance with the Interconnection Procedures, and the following assumptions:

1) Designation of Point of Interconnection and configuration to be studied (to be completed by the Interconnection Customer and the Utility).

~~2) Designation of alternative Points of Interconnection and configuration.~~

2) ~~1) and 2) are to be completed by the Interconnection Customer.~~ Other assumptions (listed below) are to be provided by the Interconnection Customer and the Utility.

ATTACHMENT 8

Facilities Study Agreement

THIS AGREEMENT ("Agreement") is made and entered into this _________ day of _______________, 20____, by and between _______________________________, a _________________________ organized and existing under the laws of the State of _____________________________, ("Interconnection Customer,"), and, ____, a _______________ existing under the laws of the State of ________ ("Utility"). The Interconnection Customer and the Utility each may be referred to as a "Party," or collectively as the "Parties."

RECITALS

WHEREAS, the Interconnection Customer is proposing to develop a Generating Facility or generating capacity in addition to an existing Generating Facility consistent with the Interconnection Request Application Form completed by the Interconnection Customer, dated __________________ and received by the Utility on _________________; and the single-line drawing provided by the Interconnection Customer, dated _________________ and received by the Utility on _________________; and

WHEREAS, the Interconnection Customer desires to interconnect the Generating Facility with the Utility's System; and

WHEREAS, the Utility has completed a System Impact Study and provided the results of said Sstudy to the Interconnection Customer (this recital to be omitted if the Parties have agreed to forego the Ssystem Iimpact Sstudy); and

WHEREAS, the Interconnection Customer has requested the Utility to perform a Facilities Study to specify and estimate the cost of the equipment, engineering, procurement and construction work needed to implement the conclusions of the Ssystem Iimpact Sstudy and/or any other relevant studies in accordance with Good Utility Practice to physically and electrically connect the Generating Facility with the Utility's System;.

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein the Parties agree as follows:

1. When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated or the meanings specified in the North Carolina Interconnection Procedures.

2. The Interconnection Customer elects and the Utility shall cause to be performed a Ffacilities Sstudy consistent with the North Carolina Interconnection Procedures.

3. The scope of the Ffacilities Sstudy shall be subject to data provided in Appendix A to this Agreement.

4. The Ffacilities Sstudy shall specify and estimate the cost of the equipment, engineering, procurement and construction work (including overheads)

needed to implement the conclusions of the system impact studies. The Ffacilities Sstudy shall also identify (1) the electrical switching configuration of the equipment, including, without limitation, transformer, switchgear, meters, and other station equipment, (2) the nature and estimated cost of the Utility's Interconnection Facilities and Upgrades necessary to accomplish the interconnection, and (3) an estimate of the construction time required to complete the installation of such facilities.
If the study is for a Project B, the Sstudy shall assume the interdependent Project A is interconnected.

5. The Utility may propose to group facilities required for more than one Interconnection Customer in order to minimize facilities costs through economies of scale, but any Interconnection Customer may require the installation of facilities required for its own Generating Facility if it is willing to pay the costs of those facilities.

6. A deposit of the good faith estimated Ffacilities Sstudy cost is required from the Interconnection Customer. If the unexpended portion of the Interconnection Request deposit made for the Interconnection Request exceeds the estimated cost of the Ffacilities Sstudy, no payment will be required of the Interconnection Customer.

7. In cases where Upgrades are required, the Ffacilities Sstudy must be completed within 45 Business Days of the Utility's receipt of this Agreement, or completion of the Facilities Study for an Interdependent Project A whichever is later. In cases where no Upgrades are necessary, and the required facilities are limited to Interconnection Facilities, the Ffacilities Sstudy must be completed within 30 Business Days. The Utility reserves the right to request additional technical information from the Interconnection Customer as may reasonably become necessary consistent with Good Utility Practice during the course of the Facilities Study. If the information requested by the Utility is not provided by the Interconnection Customer within a reasonable timeframe to be identified by the Utility in writing, the Utility shall provide the Interconnection Customer written notice providing an opportunity to cure such failure by the close of business on the tenth (10^{th}) Business Day following the posted date of such notice, where failure to provide the information requested within this period shall result in the Sstudy being terminated and the Interconnection Request being deemed withdrawn. The period of time for the Utility to complete the Facilities Study shall be tolled during any period that the Utility has requested information in writing from the Interconnection Customer necessary to complete the Study and such request is outstanding.

8. Once the Ffacilities Sstudy is completed, a Ffacilities Sstudy Rreport shall be prepared and transmitted to the Interconnection Customer.

9. Any study fees shall be based on the Utility's actual costs and will be deducted from the Interconnection Request deposit made by the Interconnection Customer at the time of the Interconnection Request. After the Sstudy is

completed the Utility shall deliver a summary of costs incurred ~~professional time.~~

10. The Interconnection Customer must pay any S~~s~~tudy costs that exceed the Interconnection Request deposit without interest within 20 Business Days of receipt of the invoice. If the unexpended portion of the Interconnection Request deposit exceeds the invoiced fees and the Interconnection Customer withdraws the Interconnection Request, the Utility shall make refund to the Customer pursuant to Section 6.3 of the North Carolina Interconnection Procedures.

11. If the Interconnection Customer submitted prepayment or Financial Security reasonably acceptable to the Utility for Network Upgrades under Section 4.3.9 of the North Carolina Interconnection Procedures, the Parties agree that this pre-payment or Financial Security shall be held by the Utility as a non-refundable pre-payment for the estimated cost of Network Upgrades and Interconnection Customer expressly agrees this pre-payment amount shall be forfeited to the Utility to construct the Network Upgrades if the Interconnection Request is subsequently withdrawn. The Network Upgrades pre-payment amount shall be trued up by the Utility in the Detailed Estimated Upgrade Charges amount calculated during the Facilities Study and identified in a Facilities Study Report to be included in a future Interconnection Agreement.

~~11~~12. Governing Law, Regulatory Authority, and Rules

The validity, interpretation and enforcement of this Agreement and each of its provisions shall be governed by the laws of the State of North Carolina, without regard to its conflicts of law principles. This Agreement is subject to all Applicable Laws and Regulations. Each Party expressly reserves the right to seek changes in, appeal, or otherwise contest any laws, orders, or regulations of a Governmental Authority.

~~12~~13. Amendment

The Parties may amend this Agreement by a written instrument duly executed by both Parties.

~~13~~14. No Third-Party Beneficiaries

This Agreement is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest and where permitted, their assigns.

~~14~~15. Waiver

The failure of a Party to this Agreement to insist, on any occasion, upon strict performance of any provision of this Agreement will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party.

Any waiver at any time by either Party of its rights with respect to this Agreement shall not be deemed a continuing waiver or a waiver with respect to any other failure to comply with any other obligation, right, or duty of this Agreement. Termination or default of this Agreement for any reason by Interconnection Customer shall not constitute a waiver of the Interconnection Customer's legal rights to obtain an interconnection from the Utility. Any waiver of this Agreement shall, if requested, be provided in writing.

~~15~~16. Multiple Counterparts

This Agreement may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

~~16~~17. No Partnership

This Agreement shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation or partnership liability upon either Party. Neither Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Party.

~~17~~18. Severability

If any provision or portion of this Agreement shall for any reason be held or adjudged to be invalid or illegal or unenforceable by any court of competent jurisdiction or other Governmental Authority, (1) such portion or provision shall be deemed separate and independent, (2) the Parties shall negotiate in good faith to restore insofar as practicable the benefits to each Party that were affected by such ruling, and (3) the remainder of this Agreement shall remain in full force and effect.

~~18~~19. Subcontractors

Nothing in this Agreement shall prevent a Party from utilizing the services of any subcontractor as it deems appropriate to perform its obligations under this Agreement; provided, however, that each Party shall require its subcontractors to comply with all applicable terms and conditions of this Agreement in providing such services and each Party shall remain primarily liable to the other Party for the performance of such subcontractor.

The creation of any subcontract relationship shall not relieve the hiring Party of any of its obligations under this Agreement. The hiring Party shall be fully responsible to the other Party for the acts or omissions of any subcontractor the hiring Party hires as if no subcontract had been made; provided, however, that in no event shall the Utility be liable for the actions or inactions of the Interconnection Customer or its subcontractors with respect to obligations of the Interconnection Customer under this Agreement. Any applicable obligation imposed by this Agreement upon the hiring Party shall be equally binding upon, and shall be construed as having application to, any subcontractor of such Party.

The obligations under this article will not be limited in any way by any limitation of subcontractor's insurance.

~~19~~20. Reservation of Rights

The Utility shall have the right to make a unilateral filing with the Commission to modify this Agreement with respect to any rates, terms and conditions, charges, or classifications of service, and the Interconnection Customer shall have the right to make a unilateral filing with the Commission to modify this Agreement; provided that each Party shall have the right to protest any such filing by the other Party and to participate fully in any proceeding before the Commission in which such modifications may be considered. Nothing in this Agreement shall limit the rights of the Parties except to the extent that the Parties otherwise agree as provided herein.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be duly executed by their duly authorized officers or agents on the day and year first above written.

For the Utility

Name: ______________________________

Print Name: ______________________________

Title: ______________________________

Date ______________________________

For the Interconnection Customer

Name: ______________________________

Print Name: ______________________________

Title: ______________________________

Date ______________________________

Data to Be Provided by the Interconnection Customer with the Facilities Study Agreement

Provide location plan and simplified one-line diagram of the plant and station facilities. For staged projects, please indicate future generation, circuits, etc.

On the one-line diagram, indicate the Maximum Generating ~~generation c~~Capacity attached at each metering location. (Maximum load on CT/PT)

On the one-line diagram, indicate the location of auxiliary power. (Minimum load on CT/PT) Amps

One set of metering is required for each generation connection to the new ring bus or existing Utility station. Number of generation connections: ______________________________

Will an alternate source of auxiliary power be available during CT/PT maintenance?

Yes _________ No _________

Will a transfer bus on the generation side of the metering require that each meter set be designed for the total plant generation? Yes _________ No _________

(Please indicate on the one-line diagram).

What type of control system or PLC will be located at the Generating Facility?

____

____

What protocol does the control system or PLC use?

____

____

Please provide a 7.5-minute quadrangle map of the site. Indicate the plant, station, distribution line, and property lines.

Physical dimensions of the proposed interconnection station:

____

Bus length from generation to interconnection station:

____

Line length from interconnection station to Utility's System.

____

Tower number observed in the field (Painted on tower leg)*:

____

Number of third party easements required for lines*:

____

* To be completed in coordination with Utility.

Is the Generating Facility located in Utility's service area?

Yes __________ No _________ If No, please provide name of local provider:

____

Please provide the following proposed schedule dates:

Begin Construction	Date: ____________________
Generator step-up transformers receive back feed power	Date: ____________________
Generation Testing	Date: ____________________
Commercial Operation	Date: ____________________

ATTACHMENT 9

NORTH CAROLINA

INTERCONNECTION AGREEMENT

For State-Jurisdictional Generator Interconnections

Effective June ___, 2019
Docket No. E-100, Sub 101

Between

Utility Name
And
Customer Name
"Project Name"

|

|

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Page No.

This Interconnection Agreement ("Agreement") is made and entered into this day of

_____, 20 _____, by ____

("Utility"), and ____

("Interconnection Customer") each hereinafter sometimes referred to individually as "Party" or both referred to collectively as the "Parties."

Utility Information

Utility: ____

Attention: ______________________________________

Address: _______________________________________

City: ____________________ State: _________ Zip: _______

Phone: _______________ Fax: _______________________

Interconnection Customer Information

Name: ____

Project Name: ____________________________________

Attention: ______________________________________

E911 Address: ___________________________________

City: ____________________ State: _________ Zip: _______

Phone: _______________ Fax: _______________________

County: _________________________

In consideration of the mutual covenants set forth herein, the Parties agree as follows:

Article 1. Scope and Limitations of Agreement

1.1 Applicability

This Agreement shall be used for all Interconnection Requests submitted under the North Carolina Interconnection Procedures except for those submitted under the 20 kW Inverter Process in Section 2 of the Interconnection Procedures.

1.2 Purpose

~~If an Interim Interconnection Agreement, this Agreement documents the Utility's ability to interconnect the Generating Facility and provides the Preliminary Estimated Interconnection Facilities Charge and the Preliminary Estimated System Upgrade Charge that was developed in the System Impact Study. Milestones have not been established and the Utility offers no estimate on when the required facilities might be installed.~~

~~If a Final t~~This Agreement governs the terms and conditions under which the Interconnection Customer's Generating Facility will interconnect with, and operate in parallel with, the Utility's System.

1.3 No Agreement to Purchase or Deliver Power or RECs

This Agreement does not constitute an agreement to purchase or deliver the Interconnection Customer's power or Renewable Energy Certificates (RECs). The purchase or delivery of power, RECs that might result from the operation of the Generating Facility, and other services that the Interconnection Customer may require will be covered under separate agreements, if any. The Interconnection Customer will be responsible for separately making all necessary arrangements (including scheduling) for delivery of electricity with the applicable Utility.

1.4 Limitations

Nothing in this Agreement is intended to affect any other agreement between the Utility and the Interconnection Customer.

1.5 Responsibilities of the Parties

1.5.1 The Parties shall perform all obligations of this Agreement in accordance with all Applicable Laws and Regulations, Operating Requirements, and Good Utility Practice.

1.5.2 The Interconnection Customer shall construct, interconnect, operate and maintain its Generating Facility and construct, operate, and maintain its

Interconnection Facilities in accordance with the applicable manufacturer's recommended maintenance schedule, and in accordance with this Agreement, and with Good Utility Practice.

1.5.3 The Utility shall construct, operate, and maintain its System and Interconnection Facilities in accordance with this Agreement, and with Good Utility Practice.

1.5.4 The Interconnection Customer agrees to construct its facilities or systems in accordance with applicable specifications that meet or exceed those provided by the National Electrical Safety Code, the American National Standards Institute, IEEE, Underwriters' Laboratories, and Operating Requirements in effect at the time of construction and other applicable national and state codes and standards. The Interconnection Customer agrees to design, install, maintain, and operate its Generating Facility so as to reasonably minimize the likelihood of a disturbance adversely affecting or impairing the System or equipment of the Utility and any Affected Systems.

1.5.5 Each Party shall operate, maintain, repair, and inspect, and shall be fully responsible for the facilities that it now or subsequently may own unless otherwise specified in the Appendices to this Agreement. Each Party shall be responsible for the safe installation, maintenance, repair and condition of their respective lines and appurtenances on their respective sides of the point of change of ownership. The Utility and the Interconnection Customer, as appropriate, shall provide Interconnection Facilities that adequately protect the Utility's System, personnel, and other persons from damage and injury. The allocation of responsibility for the design, installation, operation, maintenance and ownership of Interconnection Facilities shall be delineated in the Appendices to this Agreement.

1.5.6 The Utility shall coordinate with all Affected Systems to support the interconnection.

1.5.7 The Customer shall not operate the Generating Facility in such a way that the Generating Facility would exceed the Maximum Generating Capacity.

1.6 Parallel Operation Obligations

Once the Generating Facility has been authorized to commence parallel operation, the Interconnection Customer shall abide by all rules and procedures pertaining to the parallel operation of the Generating Facility in the applicable control area, including, but not limited to: 1) any rules and procedures concerning the operation of generation set forth in Commission-approved tariffs or by the applicable system operator(s) for the Utility's System and; 2) the Operating Requirements set forth in Appendix 5 of this Agreement.

1.7 Metering

The Interconnection Customer shall be responsible for the Utility's reasonable and necessary cost for the purchase, installation, operation, maintenance, testing, repair, and replacement of metering and data acquisition equipment specified in Appendices 2 and 3 of this Agreement. The Interconnection Customer's metering (and data acquisition, as required) equipment shall conform to applicable industry rules and Operating Requirements.

1.8 Reactive Power

1.8.1 The Interconnection Customer shall design its Generating Facility to maintain a composite power delivery at continuous rated power output at the Point of Interconnection at a power factor within the range of 0.95 leading to 0.95 lagging, unless the Utility has established different requirements that apply to all similarly situated generators in the control area on a comparable basis. The requirements of this paragraph shall not apply to wind generators.

1.8.2 The Utility is required to pay the Interconnection Customer for reactive power that the Interconnection Customer provides or absorbs from the Generating Facility when the Utility requests the Interconnection Customer to operate its Generating Facility outside the range specified in Article 1.8.1 or outside the range established by the Utility that applies to all similarly situated generators in the control area. In addition, if the Utility pays its own or affiliated generators for reactive power service within the specified range, it must also pay the Interconnection Customer.

1.8.3 Payments shall be in accordance with the Utility's applicable rate schedule then in effect unless the provision of such service(s) is subject to a regional transmission organization or independent system operator FERC-approved rate schedule. To the extent that no rate schedule is in effect at the time the Interconnection Customer is required to provide or absorb reactive power under this Agreement, the Parties agree to expeditiously file such rate schedule and agree to support any request for waiver of any prior notice requirement in order to compensate the Interconnection Customer from the time service commenced.

1.9 Capitalized Terms

Capitalized terms used herein shall have the meanings specified in the Glossary of Terms in Attachment 1 of the North Carolina Interconnection Procedures or the body of this Agreement.

Article 2. Inspection, Testing, Authorization, and Right of Access

2.1 Equipment Testing and Inspection

2.1.1 The Interconnection Customer shall test and inspect its Generating Facility and Interconnection Facilities prior to interconnection. The Interconnection Customer shall notify the Utility of such activities no fewer than ten (10) Business Days (or as may be agreed to by the Parties) prior to such testing and inspection. Testing and inspection shall occur on a Business Day, unless otherwise agreed to by the Parties. The Utility may, at its own expense, send qualified personnel to the Generating Facility site to inspect the interconnection and observe the testing. The Interconnection Customer shall provide the Utility a written test report when such testing and inspection is completed.

2.1.2 The Utility shall provide the Interconnection Customer written acknowledgment that it has received the Interconnection Customer's written test report. Such written acknowledgment shall not be deemed to be or construed as any representation, assurance, guarantee, or warranty by the Utility of the safety, durability, suitability, or reliability of the Generating Facility or any associated control, protective, and safety devices owned or controlled by the Interconnection Customer or the quality of power produced by the Generating Facility.

2.1.3 In addition to the Utility's observation of the Interconnection Customer's testing and inspection of its Generating Facility and Interconnection Facilities pursuant to this Section, the Utility may also require inspection and testing of Interconnection Facilities that can impact the integrity or safety of the Utility's System or otherwise cause adverse operating effects, as described in Section 3.4.4. Such inspection and testing activities will be performed by the Utility or a third-party independent contractor approved by the Utility and at a time mutually agreed to by the Interconnection Customer and will be performed at the Interconnection Customer's expense. The scope of required inspection and testing will be consistent across similar types of generating facilities.

2.2 Authorization Required Prior to Parallel Operation

2.2.1 The Utility shall use Reasonable Efforts to list applicable parallel operation requirements in Appendix 5 of this Agreement. Additionally, the Utility shall notify the Interconnection Customer of any changes to these requirements as soon as they are known. The Utility shall make Reasonable Efforts to cooperate with the Interconnection Customer in meeting requirements necessary for the Interconnection Customer to commence parallel operations by the in-service date.

2.2.2 The Interconnection Customer shall not operate its Generating Facility in parallel with the Utility's System without prior written authorization of the Utility. The Utility will provide such authorization once the Utility receives notification that the Interconnection Customer has complied with all applicable parallel operation requirements. Such authorization shall not be unreasonably withheld, conditioned, or delayed.

2.3 Right of Access

2.3.1 Upon reasonable notice, the Utility may send a qualified person to the premises of the Interconnection Customer at or ~~immediately~~ before the time the Generating Facility first produces energy to inspect the interconnection~~, and observe the commission of the Generating Facility (including required testing), startup, and operation for a period of up to three (3) Business Days after initial start-up of the unit. In addition, the Interconnection Customer shall notify the Utility at least (5) Business Days prior to conducting any on-site verification testing of the Generating Facility.~~ and those Interconnection Customer facilities which can impact the integrity or safety of the Utility's System or otherwise cause adverse operating effects, as described in Section 3.4.4, and observe the commissioning of the Generating Facility (including any required testing), startup, and operation for a period of up to three (3) Business Days after initial start-up of the unit. In addition, the Interconnection Customer shall notify the Utility at least five (5) Business Days prior to conducting any on-site verification testing of the Generating Facility.

2.3.2 Following the initial inspection process described above, at reasonable hours, and upon reasonable notice, or at any time without notice in the event of an emergency or hazardous condition, the Utility shall have access to the Interconnection Customer's premises for any reasonable purpose in connection with the performance of the obligations imposed on it by this Agreement or if necessary to meet its legal obligation to provide service to its customers.

2.3.3 Each Party shall be responsible for its own costs associated with following this Article, with the exception of Utility-required inspection and testing described in Section 2.1.3, the costs for which shall be the responsibility of the Interconnection Customer.

Article 3. Effective Date, Term, Termination, and Disconnection

3.1 Effective Date

This Agreement shall become effective upon execution by the Parties.

3.2 Term of Agreement

This Agreement shall become effective on the Effective Date and shall remain in effect for a period of ten (10) years from the Effective Date or such other longer period as the Interconnection Customer may request and shall be automatically renewed for each successive one-year period thereafter, unless terminated earlier in accordance with Article 3.3 of this Agreement.

3.3 Termination

No termination shall become effective until the Parties have complied with all Applicable Laws and Regulations applicable to such termination.

3.3.1 The Interconnection Customer may terminate this Agreement at any time by giving the Utility 20 Business Days written notice and physically and permanently disconnecting the Generating Facility from the Utility's System.

3.3.2 The Utility may terminate this <u>A</u>~~a~~greement ~~for~~ <u>upon the Interconnection Customer's</u> failure <u>to timely make the payment(s) required by Article 6.1.1 pursuant to the milestones specified in Appendix 4, or</u> to comply with the requirements of Article 7.1.2 or Article 7.1.3.

3.3.3 Either Party may terminate this Agreement after Default pursuant to Article 7.6.

3.3.4 Upon termination of this Agreement, the Generating Facility will be disconnected from the Utility's System. All costs required to effectuate such disconnection shall be borne by the terminating Party, unless such termination resulted from the non-terminating Party's Default of this Agreement or such non-terminating Party otherwise is responsible for these costs under this Agreement.

3.3.5 The termination of this Agreement shall not relieve either Party of its liabilities and obligations, owed or continuing at the time of the termination, including any remaining term requirements for payment of Charges that are billed under a monthly payment option as prescribed in Article 6.

3.3.6 The provisions of this article shall survive termination or expiration of this Agreement.

3.4 <u>Temporary Disconnection</u>

Temporary disconnection shall continue only for so long as reasonably necessary under Good Utility Practice.

3.4.1 <u>Emergency Conditions</u>

"Emergency Condition" shall mean a condition or situation: (1) that in the judgment of the Party making the claim is imminently likely to endanger life or property; or (2) that, in the case of the Utility, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to the Utility's System, the Utility's Interconnection Facilities or the systems of others to which the Utility's System is directly connected; or (3) that, in the case of the Interconnection

Customer, is imminently likely (as determined in a non- discriminatory manner) to cause a material adverse effect on the security

of, or damage to, the Generating Facility or the Interconnection Customer's Interconnection Facilities.

Under Emergency Conditions, the Utility may immediately suspend interconnection service and temporarily disconnect the Generating Facility. The Utility shall notify the Interconnection Customer promptly when it becomes aware of an Emergency Condition that may reasonably be expected to affect the Interconnection Customer's operation of the Generating Facility. The Interconnection Customer shall notify the Utility promptly when it becomes aware of an Emergency Condition that may reasonably be expected to affect the Utility's System or any Affected Systems. To the extent information is known, the notification shall describe the Emergency Condition, the extent of the damage or deficiency, the expected effect on the operation of both Parties' facilities and operations, its anticipated duration, and the necessary corrective action.

3.4.2 Routine Maintenance, Construction, and Repair

The Utility may interrupt interconnection service or curtail the output of the Generating Facility and temporarily disconnect the Generating Facility from the Utility's System when necessary for routine maintenance, construction, and repairs on the Utility's System. The Utility shall provide the Interconnection Customer with two (2) Business Days notice prior to such interruption. The Utility shall use Reasonable Efforts to coordinate such reduction or temporary disconnection with the Interconnection Customer.

3.4.3 Forced Outages

During any forced outage, the Utility may suspend interconnection service to effect immediate repairs on the Utility's System. The Utility shall use Reasonable Efforts to provide the Interconnection Customer with prior notice. If prior notice is not given, the Utility shall, upon request, provide the Interconnection Customer written documentation after the fact explaining the circumstances of the disconnection.

3.4.4 Adverse Operating Effects

The Utility shall notify the Interconnection Customer as soon as practicable if, based on Good Utility Practice, operation of the Generating Facility may cause disruption or deterioration of service to other customers served from the same electric Ssystem, or if operating the Generating Facility could cause damage to the Utility's System or Affected Systems. Supporting documentation used to reach the decision to disconnect shall be provided to the Interconnection Customer upon request. If, after notice, the Interconnection Customer fails to remedy the adverse operating effect within a reasonable time, the Utility may disconnect the Generating Facility. The Utility shall provide the Interconnection Customer with five (5) Business Day notice of such disconnection, unless the provisions of Article 3.4.1 apply.

3.4.5 Modification of the Generating Facility

The Interconnection Customer must receive written authorization from the Utility before making a Material Modification or any other change to the Generating Facility that may have a material impact on the safety or reliability of the Utility's System. Such authorization shall not be unreasonably withheld. Modifications shall be done in accordance with Good Utility Practice. If the Interconnection Customer makes such modification without the Utility's prior written authorization, the latter shall have the right to temporarily disconnect the Generating Facility.

3.4.6 Reconnection

The Parties shall cooperate with each other to restore the Generating Facility, Interconnection Facilities, and the Utility's System to their normal operating state as soon as reasonably practicable following a temporary or emergency disconnection.

Article 4. Cost Responsibility for Interconnection Facilities and Distribution Upgrades

4.1 Interconnection Facilities

4.1.1 The Interconnection Customer shall pay for the cost of the Interconnection Facilities itemized in Appendix 2 of this Agreement. The Utility shall provide a best estimate cost, including overheads, for the purchase and construction of its Interconnection Facilities and provide a detailed itemization of such costs. Costs associated with Interconnection Facilities may be shared with other entities that may benefit from such facilities by agreement of the Interconnection Customer, such other entities, and the Utility.

4.1.2 The Interconnection Customer shall be responsible for its share of all reasonable expenses, including overheads, associated with (1) owning, operating, maintaining, repairing, and replacing its own Interconnection Facilities, and (2) operating, maintaining, repairing, and replacing the Utility's Interconnection Facilities.

4.2 Distribution Upgrades

The Utility shall design, procure, construct, install, and own the Distribution Upgrades described in Appendix 6 of this Agreement. If the Utility and the Interconnection Customer agree, the Interconnection Customer may construct Distribution Upgrades that are located on land owned by the Interconnection Customer. The actual cost of the Distribution Upgrades, including overheads, on-going operations, maintenance, repair, and replacement, shall be directly assigned to the Interconnection Customer.

Article 5. Cost Responsibility for Network Upgrades

5.1 Applicability

No portion of this Article 5 shall apply unless the interconnection of the Generating Facility requires Network Upgrades.

5.2 Network Upgrades

The Utility shall design, procure, construct, install, and own the Network Upgrades described in Appendix 6 of this Agreement. If the Utility and the Interconnection Customer agree, the Interconnection Customer may construct Network Upgrades that are located on land owned by the Interconnection Customer. Unless the Utility elects to pay for Network Upgrades, the actual cost of the Network Upgrades, including overheads, on-going operations, maintenance, repair, and replacement shall be borne by the Interconnection Customer.

Article 6. Billing, Payment, Milestones, and Financial Security

6.1 Billing and Payment Procedures and Final Accounting

6.1.1 The Interconnection Customer shall pay 100% of required Interconnection Facilities and any other charges as required in Appendix 2 pursuant to the milestones specified in Appendix 4.

The Interconnection Customer shall pay 100% of required Upgrades and any other charges as required in Appendix 6 pursuant to the milestones specified in Appendix 4.

Upon receipt of 100% of the foregoing pre-payment charges for Upgrades, the payment is not refundable due to cancellation of the Interconnection Request for any reason. However, if an Interconnection Customer terminates its Interconnection Agreement and cancels its facility, it shall be entitled to a refund of any unspent amounts that had been collected by the Utility for the Interconnection Customer's Interconnection Facilities.

6.1.2 If implemented by the Utility or requested by the Interconnection Customer in writing, within 15 Business Days of the Interconnection Facilities Delivery Date, the Utility shall provide the Interconnection Customer a final accounting report within 120 Business Days addressing any difference between (1) the Interconnection Customer's cost responsibility for the actual cost of such facilities or Upgrades, and (2) the Interconnection Customer's previous aggregate payments to the Utility for such facilities or Upgrades. If the Interconnection Customer's cost responsibility exceeds its previous aggregate payments, the Utility shall invoice the Interconnection Customer for the amount due and the Interconnection Customer shall make payment to the Utility within 20 Business Days. If the Interconnection Customer's previous aggregate payments exceed its cost responsibility under this Agreement, the Utility shall refund to the Interconnection Customer an amount equal to the difference within 20 Business Days of the final accounting report. If necessary and appropriate as a result of the final accounting, the Utility may also adjust the monthly charges set forth in Appendix 2 of the Interconnection Agreement.

6.1.3 The Utility shall also bill the Interconnection Customer for the costs associated with operating, maintaining, repairing and replacing the Utility's System Upgrades, as set forth in Appendix 6 of this Agreement. The Utility shall bill the Interconnection Customer for the costs of providing the Utility's Interconnection Facilities including the costs for on-going operations, maintenance, repair and replacement of the Utility's Interconnection Facilities under a Utility rate schedule, tariff, rider or service regulation providing for extra facilities or additional facilities charges, as set forth in Appendix 2 of this Agreement, such monthly charges to continue throughout the entire life of the interconnection.

6.2 Milestones

The Parties shall agree on milestones for which each Party is responsible and list them in Appendix 4 of this Agreement. A Party's obligations under this provision may be extended by agreement, except for timing for Payment or Financial Security-related requirements set forth in the milestones, which shall adhere to Section 5.2.4 of the Standards. If a Party anticipates that it will be unable to meet a milestone for any reason other than a Force Majeure Event, it shall immediately notify the other Party of the reason(s) for not meeting the milestone and (1) propose the earliest reasonable alternate date by which it can attain this and future milestones, and (2) request appropriate amendments to Appendix 4. The Party affected by the failure to meet a milestone shall not unreasonably withhold agreement to such an amendment unless (1) it will suffer significant uncompensated economic or operational harm from the delay, (2) the delay will materially affect the schedule of another Interconnection Customer with subordinate Queue Position, (3) attainment of the same milestone has previously been delayed, or (4) it has reason to believe that the delay in meeting the milestone is intentional or unwarranted notwithstanding the circumstances explained by the Party proposing the amendment.

6.3 Financial Security Arrangements

Pursuant to the Interconnection Agreement Milestones Appendix 4, the Interconnection Customer shall provide the Utility a letter of credit or other financial security arrangement that is reasonably acceptable to the Utility and is consistent with the Uniform Commercial Code of North Carolina. Such security for payment shall be in an amount sufficient to cover the costs for constructing, designing, procuring, and installing the applicable portion of the Utility's Interconnection Facilities and shall be reduced on a dollar-for-dollar basis for payments made to the Utility under this Agreement during its term. In addition:

6.3.1 The guarantee must be made by an entity that meets the creditworthiness requirements of the Utility, and contain terms and conditions that guarantee payment of any amount that may be due from the Interconnection Customer, up to an agreed-to maximum amount.

6.3.2 The letter of credit must be issued by a financial institution or insurer reasonably acceptable to the Utility and must specify a reasonable expiration date.

6.3.3 The Utility may waive the security requirements if its credit policies show that the financial risks involved are de minimus, or if the Utility's policies allow the acceptance of an alternative showing of credit- worthiness from the Interconnection Customer.

Article 7. Assignment, Liability, Indemnity, Force Majeure, Consequential Damages, and Default

7.1 Assignment

7.1.1 The Interconnection Customer shall notify the Utility of the pending sale of an existing Generati~~on~~ng Facility in writing. The Interconnection Customer shall provide the Utility with information regarding whether the sale is a change of ownership of the Generati~~on~~ng Facility to a new legal entity, or a change of control of the existing legal entity.

7.1.2 The Interconnection Customer shall promptly notify the Utility of the final date of sale and transfer date of ownership in writing. The purchaser of the Generati~~on~~ng Facility shall confirm to the Utility the final date of sale and transfer date of ownership in writing

7.1.3 This Agreement shall not survive the transfer of ownership of the Generating Facility to a new legal entity owner. The new owner must complete a new Interconnection Request and submit it to the Utility within 20 Business Days of the transfer of ownership or the Utility's Interconnection Facilities shall be removed or disabled and the Generating Facility disconnected from the Utility's System. The Utility shall not study or inspect the Generating Facility unless the new owner's Interconnection Request indicates that a Material Modification has occurred or is proposed.

7.1.4 This Agreement shall survive a change of control of the Generating Facility' legal entity owner, where only the contact information in the Interconnection Agreement must be modified. The new owner must complete a new Interconnection Request and submit it to the Utility within 20 Business Days of the change of control and provide the new contact information. The Utility shall not study or inspect the Generating Facility unless the new owner's Interconnection Request indicates that a Material Modification has occurred or is proposed.

7.1.5 The Interconnection Customer shall have the right to assign this Agreement, without the consent of the Utility, for collateral security purposes to aid in providing financing for the Generating Facility, provided that the Interconnection Customer will promptly notify the Utility of any such assignment. Assignment shall not relieve a Party of its obligations, nor shall a Party's obligations be enlarged, in whole or in part, by reason thereof.

7.1.6 Any attempted assignment that violates this article is void and ineffective.

7.2 Limitation of Liability

Each Party's liability to the other Party for any loss, cost, claim, injury, liability, or expense, including reasonable attorney's fees, relating to or arising from any act or omission in its performance of this Agreement, shall be limited to the amount of direct damage actually incurred. In no event shall either Party be liable to the other

Party for any indirect, special, incidental, consequential, or punitive damages of any kind, except as authorized by this Agreement.

7.3 Indemnity

7.3.1 This provision protects each Party from liability incurred to third parties as a result of carrying out the provisions of this Agreement. Liability under this provision is exempt from the general limitations on liability found in Article 7.2.

7.3.2 The Parties shall at all times indemnify, defend, and save the other Party harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the other Party's action or inaction of its obligations under this Agreement on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the indemnified Party.

7.3.3 If an indemnified Party is entitled to indemnification under this Article as a result of a claim by a third party, and the indemnifying Party fails, after notice and reasonable opportunity to proceed under this Article, to assume the defense of such claim, such indemnified Party may at the expense of the indemnifying Party contest, settle or consent to the entry of any judgment with respect to, or pay in full, such claim.

7.3.4 If an indemnifying Party is obligated to indemnify and hold any indemnified Party harmless under this Article, the amount owing to the indemnified Party shall be the amount of such indemnified Party's actual loss, net of any insurance or other recovery.

7.3.5 Promptly after receipt by an indemnified Party of any claim or notice of the commencement of any action or administrative or legal proceeding or investigation as to which the indemnity provided for in this Article may apply, the indemnified Party shall notify the indemnifying Party of such fact. Any failure of or delay in such notification shall not affect a Party's indemnification obligation unless such failure or delay is materially prejudicial to the indemnifying Party.

7.4 Consequential Damages

Other than as expressly provided for in this Agreement, neither Party shall be liable under any provision of this Agreement for any losses, damages, costs or expenses for any special, indirect, incidental, consequential, or punitive damages, including but not limited to loss of profit or revenue, loss of the use of equipment, cost of capital, cost of temporary equipment or services, whether based in whole or in part in contract, in tort, including negligence, strict liability, or any other theory of liability; provided, however, that damages for which a Party may be liable to the other Party under another agreement will not be considered to be special, indirect, incidental, or consequential damages hereunder.

7.5 Force Majeure

7.5.1 As used in this article, a Force Majeure Event shall mean any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, or any other cause beyond a Party's control. A Force Majeure Event does not include an act of negligence or intentional wrongdoing.

7.5.2 If a Force Majeure Event prevents a Party from fulfilling any obligations under this Agreement, the Party affected by the Force Majeure Event (Affected Party) shall promptly notify the other Party, either in writing or via the telephone, of the existence of the Force Majeure Event. The notification must specify in reasonable detail the circumstances of the Force Majeure Event, its expected duration, and the steps that the Affected Party is taking to mitigate the effects of the event on its performance. The Affected Party shall keep the other Party informed on a continuing basis of developments relating to the Force Majeure Event until the event ends. The Affected Party will be entitled to suspend or modify its performance of obligations under this Agreement (other than the obligation to make payments) only to the extent that the effect of the Force Majeure Event cannot be mitigated by the use of Reasonable Efforts. The Affected Party will use Reasonable Efforts to resume its performance as soon as possible.

7.6 Default

7.6.1 No Default shall exist where such failure to discharge an obligation (other than the payment of money or provision of Financial Security) is the result of a Force Majeure Event as defined in this Agreement or the result of an act or omission of the other Party. Upon a Default, the non-defaulting Party shall give written notice of such Default to the defaulting Party. Except as provided in Article 7.6.2, the defaulting Party shall have five (5) Business Days from receipt of the Default notice within which to cure such Default.

7.6.2 If a Default is not cured as provided in this Article, the non-defaulting Party shall have the right to terminate this Agreement by written notice at any time until cure occurs, and be relieved of any further obligation hereunder and, whether or not that Party terminates this Agreement, to recover from the defaulting Party all amounts due hereunder, plus all other damages and remedies to which it is entitled at law or in equity. The provisions of this article will survive termination of this Agreement.

Article 8. Insurance

8.1 The Interconnection Customer shall obtain and retain, for as long as the Generating Facility is interconnected with the Utility's System, liability insurance which protects the Interconnection Customer from claims for bodily injury and/or property damage. The amount of such insurance shall be sufficient to insure against all reasonably foreseeable direct liabilities given the size and nature of the generating equipment being interconnected, the interconnection itself, and the characteristics of the system to which the interconnection is made. This insurance shall be primary for all purposes. The Interconnection Customer shall provide certificates evidencing this coverage as required by the Utility. Such insurance shall be obtained from an insurance provider authorized to do business in North Carolina. The Utility reserves the right to refuse to establish or continue the interconnection of the Generating Facility with the Utility's System, if such insurance is not in effect.

8.1.1 For an Interconnection Customer that is a residential customer of the Utility proposing to interconnect a Generating Facility no larger than 250 kW, the required coverage shall be a standard homeowner's insurance policy with liability coverage in the amount of at least $100,000 per occurrence.

8.1.2 For an Interconnection Customer that is a non-residential customer of the Utility proposing to interconnect a Generating Facility no larger than 250 kW, the required coverage shall be comprehensive general liability insurance with coverage in the amount of at least $300,000 per occurrence.

8.1.3 For an Interconnection Customer that is a non-residential customer of the Utility proposing to interconnect a Generating Facility greater than 250 kW, the required coverage shall be comprehensive general liability insurance with coverage in the amount of at least $1,000,000 per occurrence.

8.1.4 An Interconnection Customer of sufficient credit-worthiness may propose to provide this insurance via a self-insurance program if it has a self-insurance program established in accordance with commercially acceptable risk management practices, and such a proposal shall not be unreasonably rejected.

8.2 The Utility agrees to maintain general liability insurance or self-insurance consistent with the Utility's commercial practice. Such insurance or self-insurance shall not exclude coverage for the Utility's liabilities undertaken pursuant to this Agreement.

8.3 The Parties further agree to notify each other whenever an accident or incident occurs resulting in any injuries or damages that are included within the scope of coverage of such insurance, whether or not such coverage is sought.

Article 9. Confidentiality

9.1 Confidential Information shall mean any confidential and/or proprietary information provided by one Party to the other Party that is clearly marked or otherwise designated "Confidential." For purposes of this Agreement all design, operating specifications, and metering data provided by the Interconnection Customer shall be deemed Confidential Information regardless of whether it is clearly marked or otherwise designated as such.

9.2 Confidential Information does not include information previously in the public domain, required to be publicly submitted or divulged by Governmental Authorities (after notice to the other Party and after exhausting any opportunity to oppose such publication or release), or necessary to be divulged in an action to enforce this Agreement. Each Party receiving Confidential Information shall hold such information in confidence and shall not disclose it to any third party nor to the public without the prior written authorization from the Party providing that information, except to fulfill obligations under this Agreement, or to fulfill legal or regulatory requirements.

9.2.1 Each Party shall employ at least the same standard of care to protect Confidential Information obtained from the other Party as it employs to protect its own Confidential Information.

9.2.2 Each Party is entitled to equitable relief, by injunction or otherwise, to enforce its rights under this provision to prevent the release of Confidential Information without bond or proof of damages, and may seek other remedies available at law or in equity for breach of this provision.

9.2.3 All information pertaining to a project will be provided to the new owner in the case of a change of control of the existing legal entity or a change of ownership to a new legal entity.

9.3 If information is requested by the Commission from one of the Parties that is otherwise required to be maintained in confidence pursuant to this Agreement, the Party shall provide the requested information to the Commission within the time provided for in the request for information. In providing the information to the Commission, the Party may request that the information be treated as confidential and non-public in accordance with North Carolina law and that the information be withheld from public disclosure.

Article 10. Disputes

10.1 The Parties agree to attempt to resolve all disputes arising out of the interconnection process according to the provisions of this Article.

10.2 In the event of a dispute, either Party shall provide the other Party with a written notice of dispute. Such notice shall describe in detail the nature of the dispute.

10.3 If the dispute has not been resolved within 20 Business Days after receipt of the notice, either Party may contact the Public Staff for assistance in informally resolving the dispute., or the Parties may mutually agree to continue negotiations for up to an additional 20 Business Days. In the alternative, the Parties may, upon mutual agreement, seek the assistance of a dispute resolution service to resolve the dispute within 20 Business Days, with the opportunity to extend this timeline upon mutual agreement. If the Parties are unable to informally resolve the dispute, either Party may then file a formal complaint with the Commission.

10.4 Each Party agrees to conduct all negotiations in good faith.

Article 11. Taxes

11.1 The Parties agree to follow all applicable tax laws and regulations, consistent with North Carolina and federal policy and revenue requirements.

11.2 Each Party shall cooperate with the other to maintain the other Party's tax status. Nothing in this Agreement is intended to adversely affect the Utility's tax exempt status with respect to the issuance of bonds including, but not limited to, local furnishing bonds.

Article 12. Miscellaneous

12.1 Governing Law, Regulatory Authority, and Rules

The validity, interpretation and enforcement of this Agreement and each of its provisions shall be governed by the laws of the State of North Carolina, without regard to its conflicts of law principles. This Agreement is subject to all Applicable Laws and Regulations. Each Party expressly reserves the right to seek changes in, appeal, or otherwise contest any laws, orders, or regulations of a Governmental Authority.

12.2 Amendment

The Parties may amend this Agreement by a written instrument duly executed by both Parties, or under Article 12.12 of this Agreement.

12.3 No Third-Party Beneficiaries

This Agreement is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest and where permitted, their assigns.

12.4 Waiver

12.4.1 The failure of a Party to this Agreement to insist, on any occasion, upon strict performance of any provision of this Agreement will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party.

12.4.2.1 Any waiver at any time by either Party of its rights with respect to this Agreement shall not be deemed a continuing waiver or a waiver with respect to any other failure to comply with any other obligation, right, or duty of this Agreement. Termination or default of this Agreement for any reason by Interconnection Customer shall not constitute a waiver of the Interconnection Customer's legal rights to obtain an interconnection from the Utility. Any waiver of this Agreement shall, if requested, be provided in writing.

12.5 Entire Agreement

This Agreement, including all Appendices, constitutes the entire agreement between the Parties with reference to the subject matter hereof, and supersedes all prior and contemporaneous understandings or agreements, oral or written, between the Parties with respect to the subject matter of this Agreement. There are no other agreements, representations, warranties, or covenants which constitute any part of the consideration for, or any condition to, either Party's compliance with its obligations under this Agreement.

12.6 Multiple Counterparts

This Agreement may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

12.7 No Partnership

This Agreement shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation or partnership liability upon either Party. Neither Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Party.

12.8 Severability

If any provision or portion of this Agreement shall for any reason be held or adjudged to be invalid or illegal or unenforceable by any court of competent jurisdiction or other Governmental Authority, (1) such portion or provision shall be deemed separate and independent, (2) the Parties shall negotiate in good faith to restore insofar as practicable the benefits to each Party that were affected by such ruling, and (3) the remainder of this Agreement shall remain in full force and effect.

12.9 Security Arrangements

Infrastructure security of electric system equipment and operations and control hardware and software is essential to ensure day-to-day reliability and operational

security. All Utilities are expected to meet basic standards for electric system infrastructure and operational security, including physical, operational, and cyber-security practices.

12.10 Environmental Releases

Each Party shall notify the other Party, first orally and then in writing, of the release of any hazardous substances, any asbestos or lead abatement activities, or any type of remediation activities related to the Generating Facility or the Interconnection Facilities, each of which may reasonably be expected to affect the other Party. The notifying Party shall (1) provide the notice as soon as practicable, provided such Party makes a good faith effort to provide the notice no later than 24 hours after such Party becomes aware of the occurrence, and (2) promptly furnish to the other Party copies of any publicly available reports filed with any Governmental Authorities addressing such events.

12.11 Subcontractors

Nothing in this Agreement shall prevent a Party from utilizing the services of any subcontractor as it deems appropriate to perform its obligations under this Agreement; provided, however, that each Party shall require its subcontractors to comply with all applicable terms and conditions of this Agreement in providing such services and each Party shall remain primarily liable to the other Party for the performance of such subcontractor.

12.11.2 The creation of any subcontract relationship shall not relieve the hiring Party of any of its obligations under this Agreement. The hiring Party shall be fully responsible to the other Party for the acts or omissions of any subcontractor the hiring Party hires as if no subcontract had been made; provided, however, that in no event shall the Utility be liable for the actions or inactions of the Interconnection Customer or its subcontractors with respect to obligations of the Interconnection Customer under this Agreement. Any applicable obligation imposed by this Agreement upon the hiring Party shall be equally binding upon, and shall be construed as having application to, any subcontractor of such Party.

12.11.3 The obligations under this article will not be limited in any way by any limitation of subcontractor's insurance.

12.12 Reservation of Rights

The Utility shall have the right to make a unilateral filing with the Commission to modify this Agreement with respect to any rates, terms and conditions, charges, or classifications of service, and the Interconnection Customer shall have the right to make a unilateral filing with the Commission to modify this Agreement; provided that each Party shall have the right to protest any such filing by the other Party and to participate fully in any proceeding before the Commission in which such modifications may be considered. Nothing in this Agreement shall

limit the rights of the Parties except to the extent that the Parties otherwise agree as provided herein.

Article 13. Notices

13.1 General

Unless otherwise provided in this Agreement, any written notice, demand, or request required or authorized in connection with this Agreement (Notice) shall be deemed properly given if delivered in person, delivered by recognized national courier service, sent by first class mail, postage prepaid, or sent electronically to the person specified below:

If to the Interconnection Customer:

Interconnection Customer: ______________________________

Attention: ______________________________

Address: ______________________________

City: ____________________ State: ________ Zip: ________

E-Mail Address: ______________________________

Phone: ____________________ Fax: ____________________

If to the Utility:

Utility: ______________________________

Attention: ______________________________

Address: ______________________________

City: ____________________ State: ________ Zip: __________

E-Mail Address: ______________________________

Phone: ____________________ Fax: ____________________

13.2 Billing and Payment

Billings and payments shall be sent to the addresses set out below: If to the Interconnection Customer:

Interconnection Customer: ______________________________

Attention: ______________________________

Address: ______________________________

City: ____________________ State: ________ Zip: __________

E-Mail Address: ______________________________

If to the Utility:

Utility: ______________________________

Attention: ______________________________

Address: ______________________________

City: ____________________ State: ________ Zip: __________

E-Mail Address: ______________________________

13.3 Alternative Forms of Notice

Any notice or request required or permitted to be given by either Party to the other and not required by this Agreement to be given in writing may be so given by telephone, facsimile or e-mail to the telephone numbers and e-mail addresses set out below:

If to the Interconnection Customer:

Interconnection Customer: ______________________________

Attention: ______________________________

Address: ______________________________

City: ____________________ State: __________ Zip: ______

Phone: ____________________ Fax: ____________________

E-Mail Address: ______________________________

If to the Utility: ______________________________

Utility: ______________________________

Attention: ______________________________

Address: ______________________________

City: ____________________ State: __________ Zip: ______

Phone: ____________________ Fax: ____________________

E-Mail Address: ______________________________

13.4 Designated Operating Representative

The Parties may also designate operating representatives to conduct the communications which may be necessary or convenient for the administration of this Agreement. This person will also serve as the point of contact with respect to operations and maintenance of the Party's facilities.

Interconnection Customer's Operating Representative:

Interconnection Customer: ______________________________

Attention: ______________________________

Address: ______________________________

City: ______________ State: ____________ Zip: ________

Phone: ______________ Fax: ______________

E-Mail Address: ______________________________

Utility's Operating Representative:

Utility: ______________________________

Attention: ______________________________

Address: ______________________________

City: ______________ State: ____________ Zip: ________

Phone: ______________ Fax: ______________

E-Mail Address: ______________________________

13.5 Changes to the Notice Information

Either Party may change this information by giving five Business Days written notice prior to the effective date of the change.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed by their respective duly authorized representatives.

For the Utility

Name: ______________________________

Print Name: ______________________________

Title: ______________________________

Date: ______________

For the Interconnection Customer

Name:____

Print Name: _____________________________________

Title: ____

Date: ___________________

Glossary of Terms

See Glossary of Terms, Attachment 1 to the North Carolina Interconnection Procedures.

Description and Costs of the Generating Facility, Interconnection Facilities, and Metering Equipment

Equipment, including the Generating Facility, Interconnection Facilities, and metering equipment shall be itemized and identified as being owned by the Interconnection Customer, or the Utility. The Utility will provide a best estimate itemized cost, including overheads, of its Interconnection Facilities and metering equipment, and a best estimate itemized cost of the annual operation and maintenance expenses associated with its Interconnection Facilities and metering equipment.

**One-line Diagram Depicting the Generating Facility,
Interconnection Facilities, Metering Equipment, and Upgrades**

This agreement will incorporate by reference the one-line diagram submitted by the Customer on ______________________________________, dated __________________, with file name "________________________________" as part of the Interconnection Request, or as subsequently updated and provided to the Company.

Milestones

Requested Upgrade In-Service Date: _________________

Requested Interconnection Facilities In-Service Date _____

~~For an Interim Interconnection Agreement, this Appendix 4 is null and void.~~

Critical milestones and responsibility as agreed to by the Parties:

The build-out schedule does not include contingencies for deployment of Utility personnel to assist in outage restoration efforts on the Utility's ~~S~~system or the systems of other utilities with whom the Utility has a mutual assistance agreement. Consequently, the Requested In-~~S~~service ~~D~~date may be delayed to the extent outage restoration work interrupts the design, procurement and construction of the requested facilities.

	Milestone	Completion Date	Responsible Party
1)			
2)			
3)			
4)			
5)			
6)			
7)			
8)			

9)			
10)	Expand as needed		

Signatures on next page

Agreed to for the Utility:

Name: ______________________________

Print Name: ______________________________

Date: ____________________

Agreed to for the Interconnection Customer:

Name: ______________________________

Print Name: ______________________________

Date: ____________________

Additional Operating Requirements for the Utility's System and Affected Systems Needed to Support the Interconnection Customer's Needs

The Utility shall also provide requirements that must be met by the Interconnection Customer prior to initiating parallel operation with the Utility's System.

**Utility's Description of its Upgrades and
Best Estimate of Upgrade Costs**

The Utility shall describe Upgrades and provide an itemized best estimate of the cost, including overheads, of the Upgrades and annual operation and maintenance expenses associated with such Upgrades. The Utility shall functionalize Upgrade costs and annual expenses as either transmission or distribution related.

DOCKET NO. E-100, SUB 101

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Petition for Approval of Revisions to Generator Interconnection Standards	))))))	ORDER ALLOWING COMMENTS AND REPLY COMMENTS REGARDING PROPOSED EXPEDITED STUDY PROCESS FOR ADDING STORAGE TO GENERATION SITES

BY THE COMMISSION: On June 14, 2019, the Commission issued an Order Approving Revised Interconnection Standard and Requiring Reports and Testimony. Among other things, the Commission required Duke Energy Carolinas, LLC (DEC), and Duke Energy Progress, LLC (DEP and together with DEC, the Companies or Duke), to file a report setting forth:

(1) A streamlined process for efficiently studying the addition of storage at existing generation sites and that builds upon the grouping study approach that is already under development as required by the Stipulation; and

(2) Details of how the addition of storage to the direct current side of an existing generator would impact the facility's original System Impact Study results.

The Commission also directed the Companies to host stakeholder meetings and Technical Standards Review Group meetings regarding these issues.

On September 30, 2019, Duke filed the required report. Duke stated that it had hosted two stakeholder meetings to discuss these issues and to identify and address concerns identified by the stakeholders. Duke stated that implementing a proposal to streamline the interconnection process for adding storage at an existing site could result in allegations of discrimination "to the extent that this process is deemed to allocate system capacity in a manner contrary to the [current] serial process." Nevertheless, the Companies provided a proposal in response to the Commission's directive.

The Commission has reviewed Duke's Energy Storage System (ESS) Retrofit Study Process submittal and finds good cause to request comments from parties regarding that proposal, including the issue of potential discrimination allegations.

IT IS, THEREFORE, ORDERED as follows:

1. That parties may file comments on Duke's September 30, 2019 ESS Retrofit Study Process proposal and submit comments on or before November 8, 2019.

2. That Duke may file reply comments on or before December 6, 2019.

ISSUED BY ORDER OF THE COMMISSION.
This the 15th day of October, 2019.

NORTH CAROLINA UTILITIES COMMISSION
Kimberley A. Campbell, Chief Clerk

DOCKET NO. E-100, SUB 113

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Rulemaking to Implement Session Law 2007-397	))))	ORDER ESTABLISHING 2019, 2020, AND 2021 POULTRY WASTE SET-ASIDE REQUIREMENT ALLOCATION

BY THE COMMISSION: On April 18, 2016, the Commission issued an Order Establishing Method of Allocating the Aggregate Poultry Waste Resource Set-Aside Requirement. Among other things, that Order established that starting with compliance year 2016, the aggregate poultry waste set-aside requirement of G.S. 62-133.8(f) shall be allocated among the electric power suppliers by averaging three years of historic retail sales (2013, 2014, and 2015), with the resulting allocation being held constant for three years (2016, 2017, and 2018). That Order further stated that this process would be repeated in 2019 for the next 3 year period.

The 2016, 2017, and 2018 retail sales data that have been reported to NC-RETS by electric power suppliers and utility compliance aggregators as required by Rule R8-67(h)(11) and the resulting load ratio shares calculated based upon that data are shown on Appendix A to this Order. Appendix A details the following data for each electric power supplier: retail electricity sales for 2016, 2017, and 2018; the average of those three years of retail sales; the load ratio share of the State's aggregate retail sales for those three years; and the corresponding 2019 poultry waste set-aside compliance requirement based upon an aggregate 2019 poultry waste set-aside requirement of 500,000 MWh as established by the Commission's Order Modifying the Swine and Poultry Waste Set-Aside Requirements and Providing Other Relief issued contemporaneous with this Order in this docket. That Order also established the annual aggregate poultry waste set-aside requirement for calendar years 2020 and thereafter as 700,000 MWh

Based upon the foregoing, the Commission finds good cause to require that the three years of retail sales data and the load ratio shares based upon that data shall be used to allocate the aggregate poultry waste set-aside requirement for 2019, 2020, and 2021. Consistent with the 2019 Order, in this docket, this decision does not alter the annual reporting requirement of Commission Rule R8-67(h)(11), nor does it preclude an electric power supplier from requesting a waiver to correct its 2019 retail sales data. Such waiver, if granted, and correction would adjust an electric power supplier's general REPS obligation, but its load share ratio calculation and the resulting allocated share of the aggregate poultry waste set-aside requirement for 2019, 2020, and 2021 shall remain unchanged.

IT IS, THEREFORE, ORDERED as follows:

1. That the aggregate poultry waste set-aside requirement for 2019, 2020 and 2021 shall be allocated among the electric power suppliers and utility compliance aggregators based on the load ratio share calculations shown in the spreadsheet attached as Appendix A to this Order;

2. That the NC-RETS Administrator shall allocate the aggregate poultry waste set-aside requirement for REPS compliance reporting within NC-RETS consistent with this Order; and

3. That this allocation process shall be repeated in 2022 for the next 3-year period.

ISSUED BY ORDER OF THE COMMISSION.
This the 16th day of December, 2019.

NORTH CAROLINA UTILITIES COMMISSION
Kimberley A. Campbell, Chief Clerk

Commissioner Jeffrey A. Hughes did not participate in this decision.

APPENDIX A
PAGE 1 of 2

Account Holder	Electric Power Supplier	2018	2017	2016	3-Year Total	Ratio	2019 Requirement: 500,000 MWhs
NCMPA1	Albemarle	304,953.00	278,239.00	291,506.00	874,698.00	0.002167537	1,083.77
North Carolina Electric Membership Corporation	Albemarle EMC	231,807.38	213,330.29	214,203.60	659,041.27	0.001633131	816.57
North Carolina Eastern Municipal Power Agency	Apex	351,657.00	303,798.00	302,769.00	958,124.00	0.00237427	1,187.14
North Carolina Eastern Municipal Power Agency	Ayden	105,736.00	101,787.00	102,125.00	309,648.00	0.00076732	383.66
North Carolina Eastern Municipal Power Agency	Belhaven	16,895.00	16,211.00	16,413.00	49,519.00	0.00012271	61.36
North Carolina Eastern Municipal Power Agency	Benson	36,875.00	33,048.00	33,979.00	103,902.00	0.000257473	128.74
Duke Energy Corporation	Blue Ridge Electric Membership	1,136,139.00	1,047,634.82	1,056,978.55	3,240,752.37	0.008030717	4,015.36
Tennessee Valley Authority	Blue Ridge Mtn EMC	208,615.31	189,370.84	198,635.00	596,421.15	0.001477958	738.98
NCMPA1	Bostic	3,462.00	3,242.00	3,474.00	10,178.00	2.52215E-05	12.61
North Carolina Electric Membership Corporation	Broad River EC	6,985.89	5,401.11	5,655.49	17,042.49	4.2232E-05	21.12
North Carolina Electric Membership Corporation	Brunswick EMC	1,428,670.36	1,328,154.55	1,335,612.07	4,092,236.98	0.010140978	5,070.49
North Carolina Electric Membership Corporation	Cape Hatteras EC	141,734.90	128,003.14	135,499.69	405,237.73	0.001004198	502.10
North Carolina Electric Membership Corporation	Carteret-Craven EC	617,871.74	574,406.33	580,732.45	1,773,010.52	0.004393593	2,196.80
North Carolina Electric Membership Corporation	Central EMC	442,134.52	410,500.03	417,146.22	1,269,780.77	0.003146569	1,573.28
NCMPA1	Cherryville	63,061.00	48,447.00	50,457.00	151,965.00	0.000378551	189.28
Duke Energy Corporation	City of Concord	955,679.00	890,388.37	911,763.13	2,757,830.50	0.006834017	3,417.01
Duke Energy Corporation	City of Kings Mountain	144,153.00	144,760.20	142,935.22	431,848.42	0.001070138	535.07
North Carolina Eastern Municipal Power Agency	Clayton	119,952.00	103,500.00	102,182.00	325,634.00	0.000806934	403.47
NCMPA1	Cornelius	58,110.00	53,639.00	59,952.00	171,701.00	0.000425482	212.74
Dominion/NC Power	Dominion/NC Power	4,400,784.00	4,167,444.00	4,294,053.00	12,862,281.00	0.031873256	15,936.63
NCMPA1	Drexel	18,398.00	16,684.00	17,421.00	52,503.00	0.000130105	65.05
Duke Energy Corporation	Duke Energy Carolinas	59,480,703.00	56,012,298.69	57,542,362.27	173,035,363.96	0.428788708	214,394.35
Progress Energy Electric Supplier	Duke Energy Progress	38,887,268.00	36,629,898.57	37,272,480.00	112,789,646.57	0.279497355	139,748.68
North Carolina Eastern Municipal Power Agency	Edenton	106,710.00	95,370.00	93,968.00	296,047.00	0.000733617	366.81
North Carolina Electric Membership Corporation	Edgecombe-Martin Co EMC	238,684.49	224,158.85	223,856.84	686,700.18	0.001701671	850.84
North Carolina Eastern Municipal Power Agency	Elizabeth City	336,648.00	295,048.00	305,419.00	937,115.00	0.002322209	1,161.10
EnergyUnited	EnergyUnited	2,723,294.00	2,517,130.00	2,582,511.00	7,822,935.00	0.019385553	9,692.78
North Carolina Eastern Municipal Power Agency	Farmville	46,510.00	48,266.00	46,604.00	141,580.00	0.000350841	175.42
Fayetteville PWC	Fayetteville PWC	2,082,629.00	1,967,324.00	2,054,941.00	6,104,894.00	0.015128177	7,564.09
North Carolina Electric Membership Corporation	Four County EMC	959,993.51	891,997.53	899,756.74	2,751,747.78	0.006818944	3,409.47
North Carolina Eastern Municipal Power Agency	Fremont	12,410.00	12,624.00	11,590.00	36,624.00	9.07568E-05	45.38
North Carolina Electric Membership Corporation	French Broad EMC	533,225.01	502,644.73	502,011.44	1,537,881.18	0.003810932	1,905.47
NCMPA1	Gastonia	762,016.00	659,866.00	675,378.00	2,097,260.00	0.005197146	2,598.57
NCMPA1	Granite Falls	68,120.00	64,113.00	65,680.00	167,913.00	0.000416095	208.05
North Carolina Eastern Municipal Power Agency	Greenville	1,849,279.00	1,700,477.00	1,721,702.00	5,271,458.00	0.013062888	6,531.44
Halifax Electric Membership Corporation	Halifax EMC	187,942.46	160,613.00	164,084.99	492,640.45	0.001220783	610.39
North Carolina Eastern Municipal Power Agency	Hamilton	2,912.00	2,756.00	2,726.00	8,394.00	2.08007E-05	10.40
North Carolina Electric Membership Corporation	Haywood EMC	302,864.30	274,234.13	282,385.83	859,484.26	0.002129837	1,064.92
North Carolina Eastern Municipal Power Agency	Hertford	22,320.00	21,767.00	22,330.00	66,417.00	0.000164584	82.29
NCMPA1	High Point	1,201,233.00	1,120,508.00	1,161,138.00	3,482,879.00	0.008630717	4,315.36
North Carolina Eastern Municipal Power Agency	Hobgood	2,830.00	2,781.00	2,830.00	8,441.00	2.09171E-05	10.46
North Carolina Eastern Municipal Power Agency	Hookerton	5,744.00	5,638.00	5,755.00	17,137.00	4.24662E-05	21.23
NCMPA1	Huntersville	247,279.00	229,989.00	231,302.00	708,567.00	0.001755858	877.93
North Carolina Electric Membership Corporation	Jones-Onslow EMC	1,258,695.30	1,161,385.64	1,178,062.18	3,598,143.10	0.008916348	4,458.17
North Carolina Eastern Municipal Power Agency	Kinston	489,697.00	445,208.00	448,366.00	1,383,271.00	0.003378241	1,689.12
North Carolina Eastern Municipal Power Agency	La Grange	20,029.00	24,272.00	24,215.00	74,516.00	0.000184654	92.33
NCMPA1	Landis	47,709.00	43,864.00	46,276.00	137,849.00	0.000341595	170.80
North Carolina Eastern Municipal Power Agency	Laurinburg	145,766.00	131,294.00	134,159.00	411,209.00	0.001018993	509.50

NCMPA1	Lexington	435,839.00	378,808.00	391,732.00	1,196,879.00	0.002963437	1,481.72
NCMPA1	Lincolnton	69,294.00	46,791.00	58,498.00	173,883.00	0.000430146	216.07
North Carolina Eastern Municipal Power Agency	Louisburg	64,880.00	51,641.00	63,831.00	180,352.00	0.000397359	198.68
North Carolina Electric Membership Corporation	Lumbee River EMC	1,342,401.48	1,249,976.57	1,231,099.56	3,823,836.59	0.00947488	4,737.44
North Carolina Eastern Municipal Power Agency	Lumberton	291,470.00	239,383.00	270,856.00	801,709.00	0.001985885	993.33
North Carolina Eastern Municipal Power Agency	Macclesfield	2,856.00	2,885.00	2,866.00	8,607.00	2.10807E-05	10.54
NCMPA1	Maiden	85,309.00	82,776.00	85,910.00	253,994.00	0.000629409	314.70
North Carolina Electric Membership Corporation	Mecklenburg EC	1,824.65	1,642.67	1,712.08	5,179.40	1.28346E-05	6.42
NCMPA1	Monroe	734,807.00	707,395.00	717,263.00	2,159,465.00	0.005351243	2,675.62
NCMPA1	Morganton	348,469.00	325,405.00	336,776.00	1,010,650.00	0.002504432	1,252.22
Tennessee Valley Authority	Mountain Electric Cooperative	270,822.73	248,999.78	260,817.00	780,338.51	0.001933711	966.86
Tennessee Valley Authority	Murphy Power Board	258,086.76	131,693.28	142,955.00	602,734.03	0.001394475	697.24
North Carolina Eastern Municipal Power Agency	New Bern	458,287.00	441,875.00	448,542.00	1,308,904.00	0.003365428	1,683.21
NCMPA1	Newton	150,428.00	137,938.00	147,861.00	446,226.00	0.001103286	551.64
North Carolina Electric Membership Corporation	Pee Dee EMC	401,140.30	372,922.47	376,497.48	1,150,560.23	0.002851135	1,425.57
North Carolina Electric Membership Corporation	Piedmont EMC	507,457.64	466,004.44	480,916.36	1,449,878.44	0.003592856	1,796.43
North Carolina Eastern Municipal Power Agency	Pikeville	8,272.00	8,102.00	8,828.00	25,001.00	6.19535E-05	30.98
North Carolina Eastern Municipal Power Agency	Pinetops	18,671.00	18,054.00	18,121.00	54,846.00	0.000135911	67.96
NCMPA1	Pineville	116,853.00	103,681.00	109,808.00	329,942.00	0.00081761	408.80
North Carolina Electric Membership Corporation	Pitt & Greene EMC	199,190.84	182,477.56	189,284.32	580,952.42	0.001439624	719.81
North Carolina Electric Membership Corporation	Randolph EMC	631,903.84	492,852.72	512,939.63	1,637,696.89	0.003616473	1,808.24
North Carolina Eastern Municipal Power Agency	Red Springs	33,423.00	33,324.00	33,580.00	100,327.00	0.000248614	124.31
North Carolina Electric Membership Corporation	Roanoke EMC	280,834.08	267,391.73	279,953.68	833,179.44	0.002064653	1,032.33
North Carolina Eastern Municipal Power Agency	Robersonville	22,919.00	22,862.00	21,004.00	66,785.00	0.000165496	82.75
North Carolina Eastern Municipal Power Agency	Rocky Mount	742,771.00	690,826.00	707,390.00	2,140,987.00	0.00530471	2,652.36
Duke Energy Corporation	Rutherford Electric Membership	1,338,609.00	1,205,839.27	1,251,792.52	3,796,990.79	0.00940662	4,703.31
North Carolina Eastern Municipal Power Agency	Scotland Neck	28,264.00	26,068.00	24,918.00	79,250.00	0.000196429	98.21
North Carolina Eastern Municipal Power Agency	Selma	72,768.00	65,068.00	67,318.00	205,158.00	0.000508392	254.20
NCMPA1	Shelby	207,457.00	187,798.00	192,951.00	588,206.00	0.001457599	728.80
North Carolina Eastern Municipal Power Agency	Smithfield	178,611.00	168,346.00	172,874.00	520,831.00	0.001290641	645.32
North Carolina Electric Membership Corporation	South River EMC	838,447.91	789,728.06	805,729.59	2,433,905.56	0.006031317	3,015.66
North Carolina Eastern Municipal Power Agency	Southport	56,241.00	54,864.00	54,099.00	167,204.00	0.000414336	207.17
NCMPA1	Statesville	495,125.00	455,129.00	452,830.00	1,403,084.00	0.00347691	1,738.46
North Carolina Electric Membership Corporation	Surry-Yadkin EMC	383,928.11	363,253.97	366,770.28	1,103,952.04	0.002735636	1,367.82
North Carolina Eastern Municipal Power Agency	Tarboro	239,412.00	220,317.00	236,813.00	698,842.00	0.001731616	865.81
North Carolina Electric Membership Corporation	Tideland EMC	361,765.74	344,022.64	348,354.13	1,054,167.51	0.002612256	1,306.13
Progress Energy Electric Supplier	Town of Black Creek	12,033.00		11,453.00	23,486.00	5.81727E-05	29.10
Duke Energy Corporation	Town of Dallas	71,098.00	66,949.91	69,642.82	207,690.73	0.000514666	257.33
Halifax Electric Membership Corporation	Town of Enfield		17,990.00	32,068.00	50,058.00	0.000124046	62.07
Duke Energy Corporation	Town of Forest City	109,438.00	110,125.77	105,819.82	325,381.59	0.000806309	403.15
Duke Energy Corporation	TOWN OF FOUNTAIN		-	-	-	0	-
Progress Energy Electric Supplier	Town of Highlands	40,898.00	40,654.02	40,998.33	122,548.34	0.000303678	151.84
Progress Energy Electric Supplier	Town of Lucama	18,809.00		17,348.00	36,957.00	8.81029E-05	44.55
Progress Energy Electric Supplier	Town of Sharpsburg	17,328.00		16,194.00	33,522.00	8.30669E-05	41.53
Dominion/NC Power	Town of Stantonsburg	19,820.00		19,721.00	39,541.00	9.79842E-05	48.99
Progress Energy Electric Supplier	Town of Windsor	50,482.00	46,928.00	48,958.00	146,368.00	0.000362681	181.34
North Carolina Electric Membership Corporation	Town of Winterville	53,397.00		48,874.00	102,271.00	0.000253432	126.72
Tennessee Valley Authority	Tri-County EMC	609,421.27	529,302.88	541,759.36	1,630,483.51	0.004040405	2,020.20
North Carolina Electric Membership Corporation	Tri-State EMC	14,585.96	12,737.44	13,322.00	40,645.40	0.000100721	50.36
North Carolina Electric Membership Corporation	Union Power Cooperative	1,392,456.27	1,278,005.44	1,335,691.98	4,006,158.60	0.009927416	4,963.71
North Carolina Eastern Municipal Power Agency	Wake EMC	604,564.97	747,689.88	732,471.00	2,285,225.83	0.005662582	2,831.44
North Carolina Eastern Municipal Power Agency	Wake Forest	172,502.00	152,640.00	152,567.00	477,029.00	0.001184326	592.16
North Carolina Eastern Municipal Power Agency	Walstonburg	1,077.00	1,863.00	1,812.00	5,162.00	1.27859E-05	6.36
Town of Waynesville	Washington	296,763.00	271,551.00	276,527.00	846,841.00	0.002098507	1,049.25
North Carolina Eastern Municipal Power Agency	Waynesville	82,630.50	65,837.50	90,743.00	265,911.00	0.000658935	329.47
Wilson	Wilson	1,338,872.00	1,201,775.00	1,282,527.00	3,819,874.00	0.009466052	4,733.03
Totals					403,544,893	1.0000	500,000

DOCKET NO. E-100, SUB 126
DOCKET NO. E-100, SUB 157

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-100, SUB 126 In the Matter of Investigation of Integrated Resource Planning in North Carolina – Smart Grid Technology Plans DOCKET NO. E-100, SUB 157 In the Matter of 2018 Integrated Resource Plans and Related 2018 REPS Compliance Plans	)	ORDER AMENDING COMMISSION RULE R8-60, ELIMINATING RULE R8-60.1, AND REQUIRING COMPLIANCE FILING

BY THE COMMISSION: On August 13, 2019, in Docket No. E-100, Sub 126, the Commission issued an Order requesting comments on its proposed amendment to Commission Rule R8-60, and the proposed elimination of Commission Rule R8-60.1 (SGTP Rule). Further, the Order suspended the filing of the 2019 updated Smart Grid Technology Plans (SGTPs) that were due to be filed by the electric utilities on October 1, 2019, pending further orders of the Commission.

Summary of Comments

Comments were filed by Duke Energy Carolinas, LLC (DEC), Duke Energy Progress, LLC (DEP, collectively Duke), Dominion Energy North Carolina (DENC), the Public Staff, Southern Alliance for Clean Energy (SACE), jointly by Sierra Club and Environmental Defense Fund (Sierra Club/EDF), and North Carolina Sustainable Energy Association (NCSEA).

Duke stated that its SGTPs have grown significantly in size and complexity, and require considerable time. Duke also stated that its effort in producing SGTPs and responding to discovery requests is often duplicative of efforts in other dockets. In addition, Duke stated that it agrees with the Commission that there are a number of alternative means that the Commission can employ to learn about new technologies, and it cited as an example its Grid Improvement Plans (GIPs) and the activities surrounding the GIPs. Finally, Duke stated that it supports the proposed amendment to Rule R8-60, and the elimination of the SGTP Rule.

DENC stated that it does not oppose the proposed amendment to Rule R8-60, and the elimination of the SGTP Rule.

The Public Staff stated that the SGTPs have been valuable tools for initiating the conversation about evolving issues, but that much of the information contained in the SGTPs is duplicative of information reviewed in electric rate cases. However, the Public Staff stated that some of the information elicited in the SGTP process was helpful, and suggested that the Commission consider requiring the electric utilities to provide additional information on distribution planning, particularly with regard to integrating distributed energy resources (DERs). The Public Staff discussed some of the challenges arising due to the proliferation of DERs, and stated that a framework for distribution planning can work toward meeting some of the challenges. The Public Staff listed several topics on which it believes the Commission should consider requiring information from the electric utilities, including: (1) plans to modernize the grid, (2) an assessment of the current state of the distribution system, and (3) an assessment of metering technology and services. Finally, the Public Staff suggested that if DEC or DEP includes a proposal on GIP in their next rate cases that it would be appropriate to bifurcate the proposal from the rate cases.

Sierra Club/EDF opined that technology has outpaced the SGTP Rule, and stated that they do not oppose the proposed amendment to Rule R8-60, and the elimination of the SGTP Rule. Further, they recommended that the Commission simultaneously move forward to establish a more effective substitute to integrate grid planning into the Integrated Resource Planning (IRP) process. Sierra Club/EDF stated that general rate cases do not serve this purpose, and suggested that Integrated Systems and Operations Planning (ISOP) is a better alternative. They stated that the Commission should open a generic docket to investigate the electric utilities' grid modernization plans, and to update the IRP rules to include ISOP.

SACE stated that it concurs in the comments filed by Sierra Club/EDF.

NCSEA noted that it was an early and consistent proponent of SGTPs, but opined that the SGTP process has not been effective. NCSEA stated that it does not oppose the proposed amendment to Rule R8-60, and the elimination of the SGTP Rule. However, it stated that the electric utilities' grid modernization plans and proposed investments should be investigated by the Commission, and that the Commission should open a generic docket to investigate such plans and investments.

Discussion and Conclusions

The Commission appreciates the comments by the parties, and finds their observations and suggestions helpful. The Commission concludes that the SGTPs have served their intended purpose since their inception in 2014, but that their utility has become outweighed by the substantial amount of resources required to annually produce and review them, and the fast pace of renewables development and other technology changes. As a result, the Commission determines that Rule R8-60(i)(10) should be deleted, and that Rule R8-60.1 should be eliminated. These changes are shown in Appendix A attached to this Order.

With respect to the recommendations of the Public Staff and Sierra Club/EDF, the Commission is keenly interested in further exploring the challenges presented by DERs and the potential benefits of ISOP, as indicated by the ISOP technical conference held by the Commission on August 28, 2019. In addition, in Docket No. E-100, Sub 164, the Commission held a presentation on energy storage on October 7, 2019, and has planned a series of such presentations over the next several months. The Commission will take the parties' comments and recommendations under advisement, and intends to continue its consideration of all viable alternatives to gaining information that will help inform its decisions on new technologies and innovative systems to better serve electric utility customers in North Carolina.

Compliance Filings in Docket No. E-100, Sub 157

On July 22, 2019, the Commission issued an Order Accepting Smart Grid Technology Plans and Requiring Filing of Additional Information (SGTP Order) in Docket No. E-100, Sub 157 (Sub 157). The SGTP Order, among other things, accepted the 2018 SGTPs filed by DENC, DEC, and DEP (collectively utilities) in Sub 157 in October 2018. In addition, the SGTP Order required that

> [e]ach of the utilities shall include a discussion of "Grid Integrated Water Heater" technology in their next SGTP Updates. In addition, the Commission orders that DEC, DEP and DENC shall update their responses to the questions posed in the Commission's August 23, 2013 Order and include those responses in future SGTP filings. [compliance filings].

SGTP Order, at 23.

As previously noted, on August 13, 2019, in Docket No. E-100, Sub 126, the Commission issued an Order that, among other things, requested comments on eliminating the filing of SGTPs, and suspended the requirement that the utilities file SGTP Updates on October 1, 2019, pending further orders by the Commission.

Based on the foregoing and the record, the Commission finds good cause to clarify that the above compliance filings required in the SGTP Order shall be made by the electric utilities in Sub 157 on or before December 13, 2019.

IT IS, THEREFORE, ORDERED as follows:

1 That Commission Rule R8-60(i)(10) shall be deleted, and Commission Rule R8-60.1 shall be eliminated, as shown in Appendix A attached to this Order.

2. That DENC, DEC and DEP are relieved of their obligation to file 2019 updated Smart Grid Technology Plans.

3. That on or before December 13, 2019, DENC, DEC and DEP shall make the compliance filing required by the July 22, 2019 SGTP Order in Docket No. E-100, Sub 157.

ISSUED BY ORDER OF THE COMMISSION.
This the 13th day of November, 2019.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

Commissioner Kimberly W. Duffley did not participate in this decision.

APPENDIX A

Rule R8-60 INTEGRATED RESOURCE PLANNING AND FILINGS.

(i) Contents of Biennial Reports. — Each utility shall include in each biennial report the following:

~~(10) Smart Grid Impacts. Each utility shall provide information regarding the impacts of its smart grid deployment plan on the overall IRP.~~

~~(i) For purposes of this requirement, the term "smart" in smart grid means a system having the ability to receive, process, and send information and/or data—essentially establishing a two-way communication protocol.~~

~~(ii) For purposes of this requirement, smart grid technologies that are implemented in a smart grid deployment plan may include those that:~~

~~a. utilize digital information and controls technology to improve the reliability, security and efficiency of an electric utility's distribution or transmission system;~~

~~b. optimize grid operations dynamically;~~

~~c. improve the operational integration of distributed and/or intermittent generation sources, energy storage, demand response, demand-side resources and energy efficiency;~~

~~d. provide utility operators with data concerning the operations and status of the distribution and/or transmission system, as well as automating some operations; or~~

~~e. provide customers with usage information or retail energy pricing information in order to allow them to interpret and adjust their energy consumption.~~

~~(iii) The information provided shall include:~~

~~a. A description of the technology installed and for which installation is scheduled to begin in the next five years and the resulting and projected net impacts from installation of that technology, including, if applicable, the potential demand (MW) and energy (MWh) savings resulting from the described technology.~~

~~b. A comparison to "gross" MW and MWh without installation of the described smart grid technology.~~

~~c. A description of MW and MWh impacts on a system, North Carolina retail jurisdictional, and North Carolina retail customer class basis, including proposed plans for measurement and verification of customer impacts or actual measurement and verification of customer impacts.~~

GENERAL ORDERS – ELECTRIC

Rule R8-60.1 [DELETE] SMART GRID TECHNOLOGY PLANS AND FILINGS.

(a) Purpose. – The purpose of this rule is to establish guidelines for the reporting of information regarding a utility's smart grid technology plan in addition to that required in Rule R8-60(i)(10). The information included should describe the conceptual structure and overall organization and impact of the utility's smart grid plans and provide details about the smart grid technologies being evaluated, designed, or implemented.

(b) Smart Grid Technology Plan. – By October 1, 2014, and every two years thereafter, each utility subject to Commission Rule R8-60(i)(10) shall file with the Commission its biennial smart grid technology plan. By October 1 of each year in which the biennial smart grid technology plan is not required to be filed, each utility shall file with the Commission a smart grid technology update report that includes significant amendments or revisions to its biennial smart grid technology plan.

(c) Biennial Smart Grid Technology Plan Contents – For purposes of this Rule, smart grid technologies are as set forth in Rule R8-60(i)(10) and shall also include those that provide real-time, automated, interactive technologies that enable the optimization and/or operation of consumer devices and appliances, including metering of customer usage and providing customers with options to control their energy consumption.

The plan shall include all of the following:

(1) A summary of the utility's strategy for evaluating and developing smart grid technologies.

(2) A description of how the proposed smart grid technology plan will improve reliability and security of the grid.

(3) For all smart grid technologies currently being deployed or scheduled for implementation within the next five years:

    (i) A description of the technologies including the goals and objectives of each technology, options for ensuring interoperability of the technology with the legacy system, and the expected life of the technology.

    (ii) The status and timeframe for completion.

    (iii) A description of any existing equipment to be rendered obsolete by the new technology, its anticipated book value at time of retirement, alternative uses of the existing equipment, and the expected salvage value of the existing equipment.

    (iv) A description of how the utility intends the technology to transfer information between it and the customer while maintaining the security of that information.

    (v) A description of how third parties will implement or utilize any portion of the technology, including transfers of customer-specific information from the utility to third parties, and how customers will authorize that information for release by the utility to third parties.

    (vi) Approximate timing and amount of capital expenditures, including those already incurred.

    (vii) Analyses relied upon by the utility for installations, including an explanation of the methodology and inputs used to perform the analyses.

(4) For all smart grid technologies actively under consideration for implementation within the next five years, the smart grid technology plan shall include a description of the technologies, including the goals and objectives of the technologies, as well as a descriptive summary of any completed analysis used by the utility in assessing the smart grid technology.

(5) For each pilot project or initiative currently underway or planned within the next two years to evaluate smart grid technologies:

(i) A description, including its objective and an explanation of how it will improve grid performance or provide improved or additional utility goods and services.

(ii) The status and timeframe for completion.

(iii) The total cost incurred to date by the utility to conduct and investigate each pilot project or initiative, including whether and to what extent these projects are or will be funded by government grants.

(iv) A summary of the results of any pilot project or initiative that is completed if the final results of the pilot project or initiative have not yet been included in previous plans.

(v) An explanation of how the results of the pilot project or initiative will be used by the utility if the explanation has not yet been included in previous plans.

(6) A description of each project or initiative described in a previous plan that is no longer under consideration by the utility, and the basis for the decision to end consideration of each project or initiative.

(7) For automated metering infrastructure (AMI), in addition to the information required in subsections (3) or (4) of this section, as appropriate, the utility shall also provide:

(i) A table indicating the extent to which AMI meters have been installed in the utility's service territory and specifically in North Carolina, the North Carolina jurisdictional customer classes and/or tariffs of customers with AMI, and the predicted lifespans of these installations. This table should indicate the number of AMI meters that has been installed both cumulatively and since the filing of the last smart grid technology plan.

(ii) The number of meters in North Carolina that use traditional metering technology and/or automated meter reading (AMR) technology, and the predicted lifespans for these installations.

(iii) Any adjustment made by the utility to its capital accounting due to AMI, including the dollar amount of write-downs of its meter inventories.

(iv) A discussion of what AMI services or functions are currently being utilized, as well as any plans for implementing other AMI services or functions within the next two years.

(d) Review of Plans and Update Reports.

(1) Within 30 days after the filing of each utility's biennial smart grid technology plan, the Public Staff or any other intervenor may file comments on any or all of the plans. Within 14 days after the filing of initial comments, the parties may file reply comments addressing any substantive or procedural issues raised by any other

party. The Commission may schedule smart grid technology plan presentations by the utilities. A hearing to address issues raised by the Public Staff or any other intervenors may be scheduled at the discretion of the Commission. The scope of the hearing shall be limited to issues as identified by the Commission.

(2) Within 30 days of the filing of each utility's smart grid technology update report, the Public Staff shall report to the Commission whether each utility's update report meets the filing requirements of this rule. The Commission may schedule smart grid technology plan update presentations by the utilities.

(3) Any acceptance of a smart grid technology plan or update report shall not constitute an approval of the recovery of costs or of any specific technology or program associated with the plan.

(NCUC Docket No. E-100, Sub 126, 4/11/2012; NCUC Docket No. E-100, Sub 126, 5/06/2013; NCUC Docket No. E-100, Sub 126, 6/13/2016.)

DOCKET NO. E-100, SUB 153

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Commission Rules Related to Electric	)	ORDER REVISING RULES AND
Metering	)	REQUIRING ANNUAL REPORTS

BY THE COMMISSION: On August 21, 2017, the Commission issued an Order Initiating Rulemaking Proceeding in the above-captioned docket in which it found that there is good reason to believe that the Commission's rules related to the testing of electric meters require revision. In that Order the Commission made Duke Energy Carolinas, LLC (DEC), and Duke Energy Progress, LLC (DEP) (jointly Duke), and Dominion Energy North Carolina (DENC) parties to the proceeding and established a procedural schedule that included an intervention deadline of November 8, 2017, and subsequent deadlines for comments and reply comments. The Commission invited parties and interested persons to file proposed rules, rule revisions, or any comments or suggestions to assist the Commission in drafting rules to update and replace Commission Rules R8-7 through R8-14, and Rule R8-21.

On October 12, 2017, the Public Staff filed a Motion to Hold Proceeding in Abeyance, which Motion was granted on October 24, 2017.

On June 22, 2018, the Commission issued an Order Approving Manually Read Meter Rider with Modifications and Requesting Meter-Related Information (MRM Order). Among other things, that Order required DEC to submit verified responses to questions regarding meter testing by September 4, 2018. In that Order, the Commission also required DEC to include in its annual Smart Grid Technology Plan filing "details of smart meter malfunctions or problems, data on the number of customers on Rider MRM, and a verified statement about its meter data privacy procedures. . . ." MRM Order, at 15.

On August 29, 2018, DEC filed some of the information that the Commission sought.

On November 19, 2018, the Commission issued an Order Scheduling Staff Technical Conference and Tour of Meter Testing Facilities in which it required the electric public utilities to file additional information about their meter testing programs. In addition, the Commission scheduled a Staff Technical Conference, which was held December 18, 2018, for the purpose of obtaining additional information from DEC's meter testing experts and the Public Staff. The Commission also directed members of its staff to tour DEC's meter testing facilities by January 1, 2019, and provided that the Public Staff should be invited to attend the tour. The Commission also required all three electric public utilities to file reports explaining: (1) the tests performed by their meter manufacturers; (2) the tests performed by the utility upon acceptance of new meters; (3) their periodic tests during meter use; and (4) their meter tests conducted pursuant to customer complaints.

On December 5, 2018, DEC and DEP filed the required information, and DENC filed the required information on December 13, 2018. On December 18, 2018, the Staff Technical Conference was held, and on December 20, 2018, staff from the Commission and the Public Staff toured the meter testing facilities at DEC's Little Rock operations center in Charlotte. A copy of the tour presentation materials was filed in this docket on December 21, 2018.

On January 23, 2019, the Commission issued an Order Modifying Program in Docket No. E-2, Sub 834 in which it required DEP, among other things, to include in its annual Smart Grid Technology Plan filing details of smart meter malfunctions or problems, and the number of customers enrolled in each option of Rider MROP (Meter-Related Optional Programs).

On February 4, 2019, the Commission issued an Order Requiring Information, Requesting Comments, and Initiating Rulemaking. That Order provided that parties could file comments, suggestions, and/or draft meter testing rules by April 15, 2019. Subsequently the Commission granted two extensions of time in order to allow the Public Staff, DEC, DEP, and DENC to collaborate on the drafting of revised meter testing rules. On June 14, 2019, those four entities jointly filed comments and proposed rule revisions.

On February 21, 2019, the Commission received a consumer statement from a consumer who opposed DEC's fee for opting out of having an automated metering infrastructure (AMI) meter installed and also advocated for the right to be served via an analog meter. The Commission concludes that these issues are out of the scope of this rulemaking docket, and, therefore, the Commission will not address them here.

On July 10, 2019, the Commission issued an Order Requesting Comments on Proposed Rules and Requiring Additional Revisions in which it required DEC, DEP, DENC, and the Public Staff to file additional rule revisions that would include key provisions from the cited American National Standards Institute (ANSI) standards that are most likely to be of interest to customers. The Order also required parties to address the following questions:

1) How the rules could be amended to address the need to test the two-way communications aspects of AMI.

2) How the rules could be amended to assure the utilities take steps to protect their AMI communications networks from cyber-related vulnerabilities.

3) Whether the Commission should repeal Rule R8-16 (Standard Frequency) in its entirety.

4) Whether it would be more efficient for some or all of the requirements from the Commission's June 22, 2018 MRM Order to be transitioned from the Smart Grid Technology Plan filing into the proposed annual meter testing report.

The July 10, 2019 Order established a schedule for these filings and reply comments and also stated that parties could provide draft revisions to Commission Rule R8-7 (Information for Consumers) and R8-8 (Meter Readings and Bill Forms) in Docket No. E-100, Sub 161, in comments that were due in that docket on July 29, 2019.

On September 16, 2019, the Commission issued an Order Granting Further Extensions of Time in which it granted the Public Staff's motion requesting an extension of time to September 23, 2019, to file additional proposed revisions to the meter testing rules, and an extension of time to October 25, 2019, for parties to file reply comments. In its motion, the Public Staff stated that it had been discussing the proposed rule revisions with the electric utilities, but that the parties needed additional time for further discussions.

On September 23, 2019, joint partial comments and rule revisions were filed by the Public Staff, Duke and DENC. In addition, separate supplemental comments were filed on the same date by the Public Staff, Duke, and DENC.

On October 25, 2019, Duke filed reply comments.

In reviewing the proposed meter testing rules that the parties filed June 14, 2019, the Commission noted that the draft rules referred multiple times to various industry standards,[1] specifically:

- ANSI Standard C12.1 (Code for Electricity Metering)
- ANSI Standard Z1.4 (Sampling Procedures and Tables for Inspection by Attributes)
- ANSI Standard Z1.9 (Sampling Procedures and Tables for Inspection by Variables for Percent Nonconforming)

As to ANSI Standard C12.1, the parties stated that this industry standard was revised in 2016 and reflects "electric meter testing best practices." The parties recommended that the Commission's revised meter testing rules rely heavily on this ANSI standard, as well as on ANSI Standard Z1.4 and ANSI Standard Z1.9.

[1] The National Electrical Manufacturers Association published the cited standards with the approval of ANSI.

While not requested by the Commission, the parties also offered revisions to Commission Rule R8-16 (Standard Frequency) and R8-17 (Standard Voltage). The proposed revisions to R8-17 would rely heavily on yet another industry standard, ANSI Standard C84.1 (Electric Power Systems and Equipment – Voltage Ratings (60 Hz)).

The Commission's July 10, 2019 Order found that the proposed rules were grounded in the cited ANSI standards, which would ensure that they remained current over time. However, since ANSI standards are not in the public domain, such a construct would frustrate members of the public who seek clear, convenient information about North Carolina's electric meter standards. Therefore, in its July 10, 2019 Order, the Commission concluded that it was necessary to require the utilities and the Public Staff to submit additional revisions to their June 14, 2019 proposal, revisions that would recite key provisions from the ANSI standards so as to make the new rules transparent and accessible to consumers.

The revisions filed in the joint partial comments on September 23, 2019, address the Commission's concern. Specifically, proposed revisions to Rule R8-12 (Meter Accuracy), R8-13 (Periodic Tests of Meters), and R8-14 (Meter Testing at Request of Consumers) now state that a watt hour meter must have an "average percent registration not less than 98% or more than 102%." In the proposed rule changes, R8-11 (Method of Determining Average Error of Meters) now lists the four acceptable methods for calculating the average error of a meter, and R8-13 now lists the corrective action options for meters that don't meet the applicable performance criteria. The parties added similar additional details to other portions of the revised rule so that readers can understand their intent without securing a copy of the cited ANSI standards.

As to the communications infrastructure and software used to relay information to and from AMI meters, the Commission sought comments on how to ensure that these systems are performing accurately and are protected against cyberattacks. In particular, the Commission requested comments on the option of requiring the utilities to periodically engage a third party to audit their AMI communications for cyber-related vulnerabilities.

In its September 23, 2019 comments, DENC stated that it does not believe that any additional testing is needed because any AMI communications issues are automatically identified and addressed when DENC does not receive expected data from a meter. DENC stated further that data being transmitted between DENC's smart meters and its "head end" is encrypted using the highest industry cybersecurity standards set by the National Institute of Standards and Technology. DENC stated that each meter has a unique security key that is embedded at the time of manufacturing such that the key is never transmitted over the air. DENC stated further:

> Accordingly, compromising one meter will not allow access to any other meter because of the unique security keys in each device. In addition, each meter holds minimal data – limited to its configuration and the usage data being recorded – and at no time is any customer-identifying information held in or transmitted to a meter.
>
> The access points to which the meters connect are located on a private cellular network, and the connectivity from the cellular carrier to the data center is over dedicated encrypted links. The head end servers are housed in a high[ly] secure data center and protected by firewalls to limit access .... [T]he Company does not

believe it is necessary for the Commission to require periodic third party audits of its AMI communications.

DENC Comments, at 1.

The Public Staff stated that it understands that no standards are in place in the industry to evaluate/test AMI communications networks, and that electric utilities have procedures in place to accurately read the meters if the two-way communication is not functioning properly. The Public Staff stated that to the extent disconnect/reconnection functionality of AMI meters is not working properly, the electric utilities should include those instances in the discussion of smart meter malfunctions in their annual meter testing reports.

As to the Commission's concerns about cyber-related vulnerabilities, the Public Staff stated that it shares these concerns but suggested that the Commission request information on an ongoing basis directly from the electric utilities so that the information could be provided in a confidential fashion, as appropriate. Also, the Public Staff understands that the electric utilities already engage third parties to audit and perform penetration testing on grid components.

In their comments, Duke stated that the Companies believe it is "unnecessary to include communication testing in the meter testing rules," explaining that prior to the deployment of AMI, they used communicating AMR meters, and no such testing was required for them. Duke stated that the Companies have procedures in place to deal with a situation in which the AMI meters do not communicate, and that they are not aware of standards in the industry for evaluating or testing an AMI communications network. Duke committed to providing in-person cybersecurity briefings to the Commission, including information on the schedule and scope of audits to their AMI systems. In its reply comments, Duke stated that, "the schedule and scope of audits on the AMI system would be more appropriately discussed" in one of those in-person briefings "due to the sensitivity of such critical energy infrastructure information." Duke Comments, at 1. The Commission finds Duke's proposal to be reasonable, and will, therefore, adopt it.

In its July 10, 2019 Order, the Commission sought comments on whether it would be more efficient for DEC to fulfill its smart meter reporting obligations via its new annual meter testing report, rather than in its Smart Grid Technology Plan (SGTP) filing. (DEP is subject to similar, but not identical filing requirements.)[1] In its September 23, 2019 comments, Duke stated that

> [t]he meter testing report already addresses the accuracy and function of the Companies' meters and would include malfunctions or problems, should any exist. Regarding the number of customers on Rider MRM (or MROP), DEC and DEP are tracking the number of customers enrolled and would provide that to the Commission upon request but do not believe it should be part of the meter testing rule as utilities have not historically reported on the number of customers on other tariffs. The verified statement of an officer is currently only a requirement of DEC,

[1] Subsequently, on November 13, 2019, the Commission issued an order in Docket No. E-100, Sub 126, in which it eliminated the rules requiring the annual SGTP filings in their entirety.

> and it references privacy policies and standards [that are] publicly available on the Company's website.... [T]he Companies are unsure of what value the current reporting requirements ... would have if the SGTP rule is eliminated. Finally, the Companies believe that, if addressed at all, the meter data privacy procedures would be more properly reviewed in the data access docket, Docket No. E-100, Sub 161.

Duke Comments, at 2.

The filing requirements to which Duke objects have been in place only a short time. Given the negative reaction some customers have had to the DEC and DEP smart meter deployments, the Commission finds that it is premature to rescind the filing requirements. Instead the Commission will sunset them such that Duke is to include the required smart meter information with its annual metering reports for five years. As to the data privacy requirement that applies only to DEC, the Commission will consider this requirement in Docket No. E-100, Sub 161, as Duke suggests.

As requested by the Commission, the parties' proposed Rule R8-13(f) now requires each electric public utility to report annually on its in-service meter testing program, including providing both the results of the previous year's tests as well as an outline of the current year's testing plan. In addition, Proposed Rule R8-13(f) specifies that these annual reports and plans are to be filed by April 1 each year. (DEC and DEP will be required to include in their annual meter testing reports information about their smart meter programs, as discussed above.) The Commission concludes that this is an improvement over the current rules wherein each utility must maintain an approved sampling program on file with the Commission. Under the new rule, finding a utility's current meter testing plan and results will be more straightforward.

The Commission's initial Order establishing this proceeding did not contemplate revisions to R8-16 (Standard Frequency) or R8-17 (Standard Voltage). However, the parties submitted proposals relative to these two rules, and since no party has objected, the Commission will consider them.

The parties initially proposed to rewrite Rule R8-16 (Standard Frequency). Currently this rule states that each utility shall adopt a standard frequency and then operate within plus or minus two percent of that standard frequency. In its July 10, 2019 Order the Commission sought comments on whether it should eliminate Rule R8-16 in its entirety because the Federal Energy Regulatory Commission (FERC) has established a robust reliability standard relative to standard frequency (NERC standard BAL-003-1.1, Frequency Response and Frequency Bias Setting). In their comments, all parties agreed that Rule R8-16 should be repealed. Based on those comments and FERC's jurisdiction over bulk electric system reliability standards, the Commission finds it appropriate to repeal Rule R8-16.

As to R8-17 (Standard Voltage), the parties initially proposed to eliminate the table that currently summarizes the standard nominal voltages that utilities must offer, and instead proposed to incorporate a reference to ANSI Standard C84.1 (Electric Power Systems and Equipment-Voltage Ratings (60 Hz)). In response to the Commission's July 10, 2019 Order, however, the parties now propose to reinsert a chart listing the nominal voltages from ANSI C84.1, which have changed slightly since R8-17 was last updated.

The Commission has reviewed the revised rules that were submitted by the parties on September 23, 2019. No party submitted comments in opposition to any of the proposed changes. In its initial Order Initiating Rulemaking Proceeding in this docket, the Commission noted that it has been more than 50 years since the Commission established the rules now found in Article 3 of Chapter 8 – Electric Light and Power. The Commission finds that the proposed changes are appropriate in light of changes in metering technology and industry standards for meter testing. The Commission finds that the revised rules proposed by the parties strike the appropriate balance by being both accessible to the public and grounded in national industry standards that are updated periodically via a rigorous standard-setting process. However, in several instances, the proposed revisions to Rule R8-17 (Standard Voltage) would replace "electric supplier" with "electric utility." No party provided an explanation for this proposed change, which would have the effect of creating ambiguity as to whether all portions of Rule R8-17 continue to apply to all electric suppliers. The Commission will therefore amend the proposed revisions by replacing "utility" with "electric supplier," so that Rule R8-17 is internally consistent as to its application to all electric suppliers. Therefore, the Commission will adopt the proposed rule changes, including the repeal of Rule R8-16 (Standard Frequency), as reflected in Appendix A of this Order, effective the date of this Order.

IT IS, THEREFORE, ORDERED as follows:

1. That the Commission hereby adopts the revised rules as shown in Appendix A (redlined) and Appendix B (clean), effective the date of this Order.

2. That each electric public utility shall file the meter testing annual report and testing plan as required by revised Rule R8-13(f), beginning April 1, 2020, and these reports shall be filed in Docket No. E-100, Sub 153A.

3. That DEC shall include in each meter testing annual report required by Rule R8-13(f) details of smart meter malfunctions or problems, and data on the number of customers on Rider MRM, annually for five years, ending with the report due on April 1, 2024, unless this requirement is re-instituted by the Commission. (This filing requirement was initially established in the Commission's June 22, 2018 MRM Order.) As to the requirement for DEC to annually provide a verified statement about its smart meter data privacy procedures, the Commission will address that issue in Docket No. E-100, Sub 161.

4. That DEP shall include in each meter testing annual report required by Rule R8-13(f) details of smart meter malfunctions or problems, and the number of customers enrolled in each option of Rider MROP annually for five years, ending with the report due on April 1, 2024, unless this requirement is re-instituted by the Commission. (This filing requirement was initially established in the Commission's January 23, 2019 Order Modifying Program in Docket No. E-2, Sub 834.)

5. That the electric public utilities shall periodically provide in-person briefings to the Commission regarding the schedule, scope, and results of cyber-security audits of their AMI communication systems.

ISSUED BY ORDER OF THE COMMISSION.
This the 27th day of November, 2019.

NORTH CAROLINA UTILITIES COMMISSION
Kimberley A. Campbell, Chief Clerk

APPENDIX A
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ARTICLE 3

METERS, METER TESTS, AND RECORDS

Note: Throughout this Article 3, cited standards of the American National Standards Institute (ANSI) means the most recent approved ANSI standard as amended from time to time.

Rule R8-9. LOCATION AND CONTROL OF METERS.

(a) No consumer's meter shall be installed in any location where it may be unreasonably exposed to heat, cold, dampness or other cause of damage, or in any unduly dirty or inaccessible location.

(b) ~~Meters should not be placed in coal or wood bins or on partitions forming such bins, or on any unstable supports subject to vibration.~~ Unless otherwise authorized by the Commission, each electric utility shall provide, install, and continue to own and maintain all meters necessary for the measurement of electric energy consumed by its customers.

(c) ~~Meters should be easily accessible for reading, testing, and making necessary adjustments and repairs. When several meters are placed on one meter board the distance between centers should not, where practicable, be less than 15 inches, and each "house" loop should be tagged or marked to indicate the circuit metered.~~ All meters shall be of a standard type that meets applicable industry standards for the type and application of electric utility service.

(d) Meters shall be placed on stable and unobstructed supports sufficient for the purpose of maintaining the integrity of the meter, meter base, and any other appurtenant equipment necessary for metered utility service.

(e) Meters shall be easily accessible and acceptable clearances shall be maintained on all sides of enclosures for installing, removing, reading, testing, communicating, and making necessary adjustments and repairs. Such clearances must allow for any hinged doors or panels to be opened a minimum of 90 degrees. When two or more meter enclosures are placed on one meter board, each meter enclosure shall be tagged to indicate the circuit metered.

(~~d~~f) Each customer shall provide and maintain a suitable and convenient place for the location of meters, where they will be readily accessible at any reasonable hour for the purpose of reading, testing, repairing, removing etc., and such other appliances owned by the utility and placed on the premises of the ~~consumer~~ customer shall be so placed as to be readily accessible at such times as are necessary, and the authorized agent of the utility shall have authority to visit such meters and appurtenances at such times as are necessary in the conduct of the business of the utility.

Rule R8-10. TESTING FACILITIES.

(a) Each utility furnishing metered electric service shall, unless specifically excused by the Commission, provide and have available such meter laboratory, standard meters, instruments, and facilities as may be necessary to make the tests required by these rules, together with such portable indicating electrical testing instruments, watt hour meters, and facilities of suitable type and range for testing service watt hour meters, voltmeters and other electrical equipment, used in its operations, as may be deemed necessary and satisfactory to the Commission.

(b) All portable indicating electrical testing instruments ~~such as voltmeters, ammeters and watt hour meters~~, when in regular use for testing purposes, shall be checked against suitable reference standards periodically, and with such frequency as to insure their accuracy whenever used in testing service meters of the utility.

Rule R8-11. METHOD OF DETERMINING AVERAGE ERROR OF METERS.

(a) ~~In determining the average error of a watt hour meter, the following procedure is recommended:~~ The average percent registration of a watt hour meter shall be determined using one of the following methods prescribed by the American National Standards Institute (ANSI) Standard C12.1 – Code for Electricity Metering, where "FL" means the percent registration at full load test amps and unity power factor, "LL" means the percent registration at light load test amps and unity power factor; and "PF" means the percent registration at full load test amps and 50% power factor:

(1) ~~All meters whenever possible, shall be tested at the following three loads: one tenth of the current rating of the meter, normal load and at rating.~~ Method 1: Average percent registration = (4FL + LL)/5

(2) ~~The average of these tests obtained by multiplying the results of the test at normal load by three (3), adding the results of the tests at one tenth rating and at the current~~

~~rating, and dividing the total by five, shall be deemed the condition of the meter.~~
Method 2: Average percent registration = (FL + LL)/2

(3) ~~In an installation where it is impossible to obtain a load of ten percent (10%) of the rating, or one hundred percent (100%) of the rating of the meter tests shall be made at the nearest obtainable loads to ten percent (10%) and one hundred percent (100%) of the rating of the meter and the values given in the ratios as stated above.~~
Method 3: Average percent registration = registration at a single load point when this single load point represents the registration within the range.

(4) Method 4: Average percent registration = (4FL + 2LL + PF)/7

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~~(b) To determine normal load, use the percentage of connected load indicated below for the class of service metered.~~

~~*Class of Service Metered*~~	~~*Percentage of Connected Load*~~
~~Residence and Apartment Lighting~~	~~40%~~
~~Elevator Service~~	~~40%~~
~~Factories (Individual Drive), Churches and Offices~~	~~45%~~
~~Factories (Shaft Drive), Theatres, Clubs, Entrances, Hallways, and General Store Lighting~~	~~60%~~
~~Restaurants, Pumps, Air Compressors, Ice Machines and Moving Picture Theatres~~	~~70%~~
~~Signs and Window Lighting and Blowers~~	~~100%~~

~~(c) When a meter is connected to an installation consisting of two or more of the above classes of load, the normal load would be the sum of the normal loads for each class.~~

Rule R8-12. METER ACCURACY.

(a) ~~Creeping.~~ — No watt hour meter ~~which~~ that registers on "no load" as defined by ANSI C12.1 (voltage circuits energized and zero current), ~~when the applied voltage is less than one hundred and ten percent (110%) of standard service voltage~~ shall be placed in service or allowed to remain in service.

(b) ~~Initial Accuracy Requirements.~~ — No watt hour meter shall be placed in service ~~which~~ that is in any way ~~mechanically~~ defective~~,~~ or ~~which~~ has incorrect constants, nor shall any watt hour meter be maintained in service ~~which~~ that does ~~is~~ not ~~adjusted to~~ meet the following performance requirements: Average percent registration not less than 98% or more than 102%.

~~Average error not over 2% plus or minus;~~
~~Error at heavy load not over 2% plus or minus;~~
~~Error at light load not over 4% plus or minus.~~

(c) ~~Adjustment after Test. -- Whenever a test made by the utility or by the Commission on a service watt hour meter connected in its permanent position in place of service shows that the average error is greater than that specified above, the meter shall be adjusted to bring the average error within the specified limits.~~ All meters shall be accuracy tested by the manufacturer. Test results shall be provided to the utility and stored by the utility for the life of the meter and at least three years after the retirement of the meter.

(d) ~~Allowable Error. -- A service watt hour meter having an average error of not more than 2% plus or minus, may be considered as correct, and no adjustment of charges shall be entailed by such an error.~~ Acceptance testing shall be performed on a statistically valid sample of each shipment of new meters. The statistical sampling plan used shall conform to the accepted principles of statistical sampling as set forth in ANSI Z1.4 – Sampling Procedures and Tables for Inspection by Attributes, ANSI Z1.9 – Sampling

Procedures and Tables for Inspection by Variables for Percent Nonconforming, or other generally accepted statistical methodology. If the total number of failures exceeds the level allowed under the sample plan, the entire shipment will be rejected and returned to the manufacturer or corrected on site.

(e) Whenever a test made by the utility or Commission on a service watt hour meter connected in its permanent position in place of service shows an average percent registration less than 98% or more than 102%, the meter shall be replaced.

(f) A service watt hour meter having an average percent registration not less than 98% or more than 102% may be considered as correct, and no adjustment of charges shall be entailed by such an error.

Rule R8-13. ~~PERIODIC TESTS OF METERS~~ IN-SERVICE METER TESTING.

(a) Meter Testing Required -- Each in-service watt hour billing meter shall be included in either a periodic or sampling testeding plan as prescribed by ANSI C12.1 – Code for Electricity Metering. Average meter registration accuracy that is less than 98% or more than 102% will be counted as a failure.~~according to the following schedule, while connected, if practical, in its permanent position in place of service:~~

~~(1) Two and three wire commutating type and mercury type meters, up to and including 50 amperes rated capacity of meter element, shall be tested at least once every 18 months.~~

~~(2) Two and three wire commutating type and mercury type meters of over 50 amperes rated capacity of meter element shall be tested at least once every 12 months.~~

~~(3) Two and three wire single phase induction type meters, up to and including 25 amperes rated capacity of meter element, shall be tested at least once every 96 months.~~

~~(4) Two and three wire single phase induction type meters of over 25 amperes rated capacity of meter element shall be tested at least every 96 months.~~

~~(5) Self contained polyphase meters, up to and including 50 kW rated capacity, shall be tested at least once every 72 months.~~

~~(6) Self contained polyphase meters of over 50 kW rated capacity shall be tested at least once every 72 months.~~

~~(7) Polyphase meters, connected through current transformers or current and potential transformers, to circuits up to and including 50 kW rated capacity, shall be tested at least once every 48 months.~~

~~(8) Polyphase meters, connected through current transformers or current and potential transformers, to circuits of over 50 kW rated capacity, shall be tested at least once every 48 months.~~

~~(9) A statistical sampling program for self contained single phase watt hour meters may be used by any utility in lieu of the periodic testing program specified under subdivisions (3) and (4) above provided the utility files with~~

~~the Commission a statistical sampling plan which is approved by the Commission and which conforms to the following criteria:~~

~~a. The plan submitted shall conform to accepted principles of statistical sampling and should be evaluated by qualified independent mathematical statisticians.~~

~~b. The plan shall include an adequate policy for testing meters on request and a consumer protection procedure for high bills due to fast meters to compensate for the fact that an individual meter may not be tested for a period longer than the present eight year schedule.~~

~~c. Meters shall be divided into homogeneous groups such as manufacturer's types and, if necessary, into homogeneous groups on the basis of location or other environmental factors which may affect the performance of the meters.~~

~~d. A sample shall be taken each year, from each homogeneous group, of a sufficient size to demonstrate with reasonable assurance the condition of the group from which the sample is drawn.~~

~~e. It is extremely important that each meter in each group be drawn with known probability, and the sample must be selected at random. (In most probability sampling systems involved in meter registration control, it is expected that every meter in the group will have an equal chance to be~~

~~drawn; however, the criteria are written to allow a wider choice of probability sampling systems.) In order to accomplish random sampling, it is necessary to use a table of random numbers, or some equivalent mechanical or numerical procedure.~~

~~f. The sampling plan shall be designed to provide information on which the utility may base a program to maintain its meters in an acceptable degree of accuracy throughout their service life in accordance with the requirements of the Commission and in keeping with proper standards for good customer relations. The plan shall contain a table of mathematically calculated sample sizes and related values in accordance with g below for determining the characteristics of the homogeneous groups, accompanied by curves for determining the risk of making an incorrect decision which may be detrimental to the customer or to the utility.~~

~~g. An acceptable sampling program is one having the property that, when applied to a meter group in which the proportion of meters with registrations greater than 102% is as high as 0.03, then the probability that the group will be judged to be satisfactory (and no corrective action taken) shall be no greater than 0.05. A sample size at least 400 meters for a plan based on the attributes method is recommended. If a variable plan is used, select a minimum sample size so that the variable plan under minimum sample size will have roughly the same operating characteristics curve as the attributes plan for the minimum sample size stated above. If a group of meters~~

~~does not meet the performance criteria, then an established program of corrective action shall be followed.~~

~~h. The corrective action shall consist of an accelerated test and maintenance program to raise the accuracy performance of the group to acceptable standards or it may consist of retirement of the meters in the group from service in an accelerated rate. The accelerated test program should provide for testing at rates which vary in accordance with the calculated percentage of meters in the group outside the acceptable limits of accuracy but not less than 20% of the group tested per year. When any group of meters is so placed on an accelerated test program the meters, selected each year for test, shall be selected on the basis of the longest time since last test. Meters so tested and placed into service shall be sampled as a separate group from the remainder of the original group not tested. When the sample results of the remainder of the original group indicate that the group has come up to acceptable limits the two components of the group may be consolidated for sampling.~~

~~i. Reports shall be made to the Commission annually to indicate the number of meters in each homogeneous group in service at the beginning of each year, the number of meters making up the sample for each such group, the test results for each group and any corrective action taken.~~

(b) Statistical Sampling Plan – The statistical sampling plan provides for the division of meters into homogenous groups such as manufacturer and manufacturer type and may be further subdivided based on other factors such as age or vintage of meter. The selection process is random where each meter within each group has an equal chance of being selected. Selected meters in each group are tested for energy registration accuracy. The statistical sampling plan used shall conform to the accepted principles of statistical sampling as found in ANSI Z1.4 – Sampling Procedures and Tables for Inspection by Attributes, ANSI Z1.9 – Sampling Procedures and Tables for Inspection by Variables for Percent Nonconforming, or other statistically valid programs that have been evaluated by qualified independent mathematical statisticians.

(c) Periodic Interval Plan – Every meter included in a periodic interval plan shall be tested for energy registration accuracy at a minimum of once every sixteen years. The utility may elect to test more frequently based on factors such as complexity of the metering system, class of customer, or size of service.

(d) Corrective Action -- If testing pursuant to subsection (a) or (b) shows that a meter or group of meters does not meet the performance criteria, then an established program of corrective action shall be followed. Corrective action shall consist of one or more of the following methods listed in ANSI C12.1 section 5.0.3.4.4: a) an accelerated test program, b) splitting a group into two or more subgroups, c) a time-specific retirement program, or d) a sample-driven retirement program. The accelerated test program should provide for testing at rates that vary in accordance with the calculated percentage of meters in the

group outside the acceptable limits of accuracy but not less than 20% of the group tested per year. Meters so tested and placed into service shall be sampled as a separate group from the remainder of the original group not tested. When the sample results of the remainder of the original group indicate that the group has come up to acceptable limits the two components of the group may be consolidated for sampling.

(e) Utility to Retain Test Results -- Accuracy test results shall be stored by the utility for the life of the meter and at least three years after the retirement of the meter.

(f) Utility Reporting -- No later than April 1 of each year, a utility shall report to the Commission on its in-service meter program. For tests performed pursuant to subsection (b), the report shall indicate the number of meters in each homogeneous group in service at the beginning of each year, the number of meters making up the sample for each such group, the test results for each group, and any corrective action taken. In addition, the report shall describe the results from meters tested under a periodic interval plan pursuant to subsection (c), including the number of meters in each homogeneous group in service at the beginning of each year, the number of meters tested, the test results, and any corrective action taken. The report shall also identify any classes of meters for which the utility tests on a more frequent basis than prescribed in ANSI C12.1, and the basis for the more frequent testing. The report shall also outline the current year's testing plan.

(g) Inspections -- When metering installations are tested or inspected, instrument transformers and wiring associated with the installation shall be visually inspected for correctness of connections and evidence of damage. Nameplate or stenciled ratios shall be verified against ratios used by the utility for billing. These inspections are not required if performing them cannot be done safely.

Rule R8-14. METER TESTING AT REQUEST OF ~~CONSUMERS~~CUSTOMERS.

(a) Upon reasonable notice, when requested in writing by the ~~consumer~~ customer, each utility shall test the accuracy of the meter in use by the ~~consumer~~ customer.

(b) No deposit or payment shall be required from the ~~consumer~~ customer for a meter test, except when the ~~consumer~~ customer has requested, within the previous twelve months, that the same meter be tested, in which case the ~~consumer~~ customer shall be required by the utility to deposit with it an amount as determined by the Commission to cover the reasonable cost of such test.

(c) A schedule of deposits or fees for testing various classifications of meters shall be filed with, and approved by, the Commission.

(d) The amount so deposited with the utility shall be refunded or credited to the ~~consumer~~ customer (as a part of the settlement in the case of a disputed account) if the meter is found, when tested, to register more than two percent (2%) fast; otherwise the deposit shall be retained by the utility.

(e) The ~~consumer~~ customer may, if ~~he~~ customer so requests, be present when the utility conducts the test on ~~his~~ customer's meter, or if ~~he~~ the customer desires, may

provide (at ~~his~~ customer's expense) an expert, or other representative appointed by ~~him~~ customer, to be present at the time of the meter test.

(f) A report of the results of the meter test shall be made within a reasonable time after the completion of the test. This report shall give the name of the ~~consumer~~ customer requesting the test, the date of the request, the location of the premises where the meter is installed, the type, make, size, and serial number of the meter, the date of removal, the date tested, and the results of the test, a copy of which shall be supplied to the ~~consumer~~ customer upon request. The utility shall inform the ~~consumer~~ customer that ~~he~~ the customer has a right to request such written copy of the report of the meter test.

(g) Any meter tested pursuant to this rule that fails the following performance requirements shall be removed from service and remain out of service until it is determined to be in compliance: Average percent registration not less than 98% or more than 102%.

ARTICLE 4

OPERATION

Note: Throughout this Article 4, cited standards of the American National Standards Institute (ANSI) means the most recent approved ANSI standard as amended from time to time.

Rule R8-16. STANDARD FREQUENCY.

~~Each utility supplying alternating current shall adopt a standard frequency, the suitability of which may be determined by the Commission, and shall maintain this frequency within 2% plus or minus of standard at all times during which service is supplied; provided, however, the momentary variations of frequency of more than 5%, which are clearly due to no lack of proper equipment or reasonable care on the part of the utility, shall not be construed as a violation of this rule.~~ [Repealed.]

Rule R8-17. STANDARD VOLTAGE.

(a) Each electric supplier shall adopt and file with the Commission standard average service voltages available from its distribution class facilities. The filing shall contain the nominal voltage, base voltage, lower limit, and upper limit. The voltage maintained at the point of delivery shall be reasonably constant and variations therein should not normally exceed the limits set forth in this rule.

(1) The standard nominal voltage adopted by the electric supplier shall be a voltage indicated by the version of ANSI Standard C84.1, Electric Power Systems and Equipment-Voltage Ratings (60 Hz), or equivalent ANSI standard as later amended, in effect at the time of adoption of nominal voltages. ~~In order to promote standardization of service voltages,~~ Tthe

following standard nominal service voltages are hereby adopted by the Commission as the preferred standard nominal service voltages:

NOMINAL SYSTEM VOLTAGE******		
Two-wire	Three-wire	Four-wire
	Single-Phase Systems	
120*	**120/240***	
	Three-Phase Systems	
		208Y/120***
		240/120
	240	
		480Y/277
	480	
	600**	
	2400	
	4160	4160Y/2400
	4800	
	6900	
		8320Y/4800
		12000Y/6930
		12470Y/7200
		13200Y/7620
	~~138~~**13800**	**13800Y/7970**
		20780Y/12000
	23000	22860Y/13200
		24940Y/14400
	34500	**34500Y/19920**

*see (a)(2) below
** This classification covers the range of nominal voltages from 550 to 600 volts.
***A modification of this three-phase, four-wire system is available as a 120/208YV service for single-phase, three-wire, open-wye applications.
****Preferred system voltages are in bold-face type.

(2) ~~Each electric supplier operating within the State of North Carolina under the jurisdiction of the Commission shall offer 120/240 volt, single phase service. No electric supplier shall offer 115/230 volt single phase service or other such similar variant of 120/240 volt single-phase service except upon specific authorization of the Commission.~~ An electric supplier may adopt different nominal voltages to serve specific customers if such action does not compromise prudent transmission and distribution system operation.

(b) In order to promote harmony between the service of electric suppliers and the utilization of voltage requirements of presently manufactured equipment, the following service voltage variations are permitted:

(1) For service rendered for individual residential use or specifically for lighting purposes, the voltage variations shall not exceed five percent (5%) above or below the standard base voltage.

(2) For other service the voltage variations shall not exceed ten percent (10%) above or below the standard base voltage.

(c) An electric supplier may elect to deliver service at a nominal voltage ~~which~~ that is not standard on its system. The variation in the nonstandard voltage shall not exceed the limits set forth above for the type of service being rendered.

(d) Upon approval of the Commission and proper notification to its customers a utility may cease to deliver a particular voltage.

(e) Variations in voltage in excess of those specified that are caused by the following ~~addition of customer equipment without proper notification to the electric supplier, by the operation of customer's equipment, by the action of the elements, by infrequent and unavoidable fluctuations of short duration due to system operations, by conditions which are part of practical operations and are of limited extent, frequency, and duration, or by emergency operations~~ shall not be construed a violation of this rule~~.~~:

(1) Addition of customer equipment without proper notification to the electric supplier.

(2) Operation of customer's equipment.

(3) The action of the elements.

(4) Infrequent and unavoidable fluctuations of short duration due to system operations.

(5) Conditions that are part of practical operations and are of limited extent, frequency, and duration.

(6) Emergency operations.

(f) ~~Consumers~~ Customers shall select, install, maintain and operate their electrical equipment so as to cause the least interference with the regulation of the electric supply system. Three phase motors in excess of 20 horsepower, single phase motors in excess of five horsepower and other apparatus with high starting or fluctuating currents must be installed in accordance with the supplier's filed tariffs and rules and regulations.

(g) Greater variations in voltage for service to installations ~~which~~ that permit greater variations than those required above may be allowed upon specific authorization by ~~this~~ the Commission.

GENERAL ORDERS – ELECTRIC

Rule R8-21. INSTALLATION OR REPLACEMENT OF METERS AND CHANGES IN LOCATION OF SERVICE.

(a) A customer's request for electric utility service grants the utility permission to install any metering device that meets the requirements of Rules R8-8, -9, -11, and -12, as deemed appropriate by the utility and in compliance with Commission orders.

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(b) Whenever a ~~consumer~~ customer requests the replacement of the service meter on the customer's ~~his~~ premises, such request shall be treated as a request for the test of such meter, and as such, shall fall under the provisions of Rule R8-14.

(~~b~~c) Whenever a ~~consumer~~ customer moves from the location where ~~current~~ electric service is used by ~~him~~ the customer, and thereby requires the disconnecting and/or connecting at a new location of the electric ~~supply~~ supplier, or information is required from the metering infrastructure to complete the transfer of service, and the same work has been done for ~~him~~ the customer within one year preceding, the utility may make a charge, subject to such charge having been approved by the Commission.

APPENDIX B
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ARTICLE 3

METERS, METER TESTS, AND RECORDS

Note: Throughout this Article 3, cited standards of the American National Standards Institute (ANSI) means the most recent approved ANSI standard as amended from time to time.

Rule R8-9. LOCATION AND CONTROL OF METERS.

(a) No consumer's meter shall be installed in any location where it may be unreasonably exposed to heat, cold, dampness or other cause of damage, or in any unduly dirty or inaccessible location.

(b) Unless otherwise authorized by the Commission, each electric utility shall provide, install, and continue to own and maintain all meters necessary for the measurement of electric energy consumed by its customers.

(c) All meters shall be of a standard type that meets applicable industry standards for the type and application of electric utility service.

(d) Meters shall be placed on stable and unobstructed supports sufficient for the purpose of maintaining the integrity of the meter, meter base, and any other appurtenant equipment necessary for metered utility service.

(e) Meters shall be easily accessible and acceptable clearances shall be maintained on all sides of enclosures for installing, removing, reading, testing, communicating, and making necessary adjustments and repairs. Such clearances must allow for any hinged doors or panels to be opened a minimum of 90 degrees. When two or more meter enclosures are placed on one meter board, each meter enclosure shall be tagged to indicate the circuit metered.

(f) Each customer shall provide and maintain a suitable and convenient place for the location of meters, where they will be readily accessible at any reasonable hour for the purpose of reading, testing, repairing, removing etc., and such other appliances owned by the utility and placed on the premises of the customer shall be so placed as to be readily accessible at such times as are necessary, and the authorized agent of the utility shall have authority to visit such meters and appurtenances at such times as are necessary in the conduct of the business of the utility.

APPENDIX B
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Rule R8-10. TESTING FACILITIES.

(a) Each utility furnishing metered electric service shall, unless specifically excused by the Commission, provide and have available such meter laboratory, standard meters, instruments, and facilities as may be necessary to make the tests required by these rules, together with such portable indicating electrical testing instruments, watt hour meters, and facilities of suitable type and range for testing service watt hour meters, voltmeters and other electrical equipment, used in its operations, as may be deemed necessary and satisfactory to the Commission.

(b) All portable indicating electrical testing instruments, when in regular use for testing purposes, shall be checked against suitable reference standards periodically, and with such frequency as to insure their accuracy whenever used in testing service meters of the utility.

Rule R8-11. METHOD OF DETERMINING AVERAGE ERROR OF METERS.

(a) The average percent registration of a watt hour meter shall be determined using one of the following methods prescribed by the American National Standards Institute (ANSI) Standard C12.1 – Code for Electricity Metering, where "FL" means the percent registration at full load test amps and unity power factor, "LL" means the percent registration at light load test amps and unity power factor, and "PF" means the percent registration at full load test amps and 50% power factor.

(1) Method 1: Average percent registration = (4FL + LL)/5

(2) Method 2: Average percent registration = (FL + LL)/2

(3) Method 3: Average percent registration = registration at a single load point when this single load point represents the registration within the range

(4) Method 4: Average percent registration = (4FL + 2LL + PF)/7

Rule R8-12. METER ACCURACY.

(a) No watt hour meter that registers on "no load" as defined by ANSI C12.1 (voltage circuits energized and zero current), shall be placed in service or allowed to remain in service.

(b) No watt hour meter shall be placed in service that is in any way defective or has incorrect constants, nor shall any watt hour meter be maintained in service that does not meet the following performance requirements: Average percent registration not less than 98% or more than 102%.

(c) All meters shall be accuracy tested by the manufacturer. Test results shall be provided to the utility and stored by the utility for the life of the meter and at least three years after the retirement of the meter.

(d) Acceptance testing shall be performed on a statistically valid sample of each shipment of new meters. The statistical sampling plan used shall conform to the accepted principles of statistical sampling as set forth in ANSI Z1.4 – Sampling Procedures and Tables for Inspection by Attributes, ANSI Z1.9 – Sampling Procedures and Tables for Inspection by Variables for Percent Nonconforming, or other generally accepted statistical methodology. If the total number of failures exceeds the level allowed under the sample plan, the entire shipment will be rejected and returned to the manufacturer or corrected on site.

(e) Whenever a test made by the utility or Commission on a service watt hour meter connected in its permanent position in place of service shows an average percent registration less than 98% or more than 102%, the meter shall be replaced.

(f) A service watt hour meter having an average percent registration not less than 98% or more than 102% may be considered as correct, and no adjustment of charges shall be entailed by such an error.

Rule R8-13. IN-SERVICE METER TESTING.

(a) Meter Testing Required -- Each in-service watt hour billing meter shall be included in either a periodic or sampling testing plan as prescribed by ANSI C12.1 – Code for Electricity Metering. Average meter registration accuracy that is less than 98% or more than 102% will be counted as a failure.

(b) Statistical Sampling Plan – The statistical sampling plan provides for the division of meters into homogenous groups such as manufacturer and manufacturer type and may be further subdivided based on other factors such as age or vintage of meter. The selection process is random where each meter within each group has an equal chance of being selected. Selected meters in each group are tested for energy registration accuracy. The statistical sampling plan used shall conform to the accepted principles of statistical sampling as found in ANSI Z1.4 – Sampling Procedures and Tables for Inspection by Attributes, ANSI Z1.9 – Sampling Procedures and Tables for Inspection by Variables for Percent Nonconforming, or other statistically valid programs that have been evaluated by qualified independent mathematical statisticians.

(c) Periodic Interval Plan – Every meter included in a periodic interval plan shall be tested for energy registration accuracy at a minimum of once every sixteen years. The utility may elect to test more frequently based on factors such as complexity of the metering system, class of customer, or size of service.

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(d) Corrective Action -- If testing pursuant to subsection (a) or (b) shows that a meter or group of meters does not meet the performance criteria, then an established program of corrective action shall be followed. Corrective action shall consist of one or more of the following methods listed in ANSI C12.1 section 5.0.3.4.4: a) an accelerated test program, b) splitting a group into two or more subgroups, c) a time-specific retirement program, or d) a sample-driven retirement program. The accelerated test program should provide for testing at rates that vary in accordance with the calculated percentage of meters in the group outside the acceptable limits of accuracy but not less than 20% of the group tested per year. Meters so tested and placed into service shall be sampled as a separate group from the remainder of the original group not tested. When the sample results of the remainder of the original group indicate that the group has come up to acceptable limits the two components of the group may be consolidated for sampling.

(e) Utility to Retain Test Results -- Accuracy test results shall be stored by the utility for the life of the meter and at least three years after the retirement of the meter.

(f) Utility Reporting -- No later than April 1 of each year, a utility shall report to the Commission on its in-service meter program. For tests performed pursuant to subsection (b), the report shall indicate the number of meters in each homogeneous group in service at the beginning of each year, the number of meters making up the sample for each such group, the test results for each group, and any corrective action taken. In addition, the report shall describe the results from meters tested under a periodic interval plan pursuant to subsection (c), including the number of meters in each homogeneous group in service at the beginning of each year, the number of meters tested, the test results, and any corrective action taken. The report shall also identify any classes of meters for which the utility tests on a more frequent basis than prescribed in ANSI C12.1, and the basis for the more frequent testing. The report shall also outline the current year's testing plan.

(g) Inspections -- When metering installations are tested or inspected, instrument transformers and wiring associated with the installation shall be visually inspected for correctness of connections and evidence of damage. Nameplate or stenciled ratios shall be verified against ratios used by the utility for billing. These inspections are not required if performing them cannot be done safely.

Rule R8-14. METER TESTING AT REQUEST OF CUSTOMERS.

(a) Upon reasonable notice, when requested in writing by the customer, each utility shall test the accuracy of the meter in use by the customer.

(b) No deposit or payment shall be required from the customer for a meter test, except when the customer has requested, within the previous twelve months, that the same meter be tested, in which case the customer shall be required by the utility to deposit with it an amount as determined by the Commission to cover the reasonable cost of such test.

(c) A schedule of deposits or fees for testing various classifications of meters shall be filed with, and approved by, the Commission.

(d) The amount so deposited with the utility shall be refunded or credited to the customer (as a part of the settlement in the case of a disputed account) if the meter is found, when tested, to register more than two percent (2%) fast; otherwise the deposit shall be retained by the utility.

(e) The customer may, if customer so requests, be present when the utility conducts the test on customer's meter, or if the customer desires, may provide (at customer's expense) an expert, or other representative appointed by customer, to be present at the time of the meter test.

(f) A report of the results of the meter test shall be made within a reasonable time after the completion of the test. This report shall give the name of the customer requesting the test, the date of the request, the location of the premises where the meter is installed, the type, make, size, and serial number of the meter, the date of removal, the date tested, and the results of the test, a copy of which shall be supplied to the customer upon request. The utility shall inform the customer that the customer has a right to request such written copy of the report of the meter test.

(g) Any meter tested pursuant to this rule that fails the following performance requirements shall be removed from service and remain out of service until it is determined to be in compliance: Average percent registration not less than 98% or more than 102%.

ARTICLE 4

OPERATION

Note: Throughout this Article 4, cited standards of the American National Standards Institute (ANSI) means the most recent approved ANSI standard as amended from time to time.

Rule R8-16. STANDARD FREQUENCY.

[Repealed.]

Rule R8-17. STANDARD VOLTAGE.

(a) Each electric supplier shall adopt and file with the Commission standard average service voltages available from its distribution class facilities. The filing shall contain the nominal voltage, base voltage, lower limit, and upper limit. The voltage maintained at the point of delivery shall be reasonably constant and variations therein should not normally exceed the limits set forth in this rule.

(1) The standard nominal voltage adopted by the electric supplier shall be a voltage indicated by the version of ANSI Standard C84.1, Electric Power Systems and Equipment-Voltage Ratings (60 Hz), or equivalent ANSI

standard as later amended, in effect at the time of adoption of nominal voltages. The following standard nominal service voltages are hereby adopted by the Commission as the preferred standard nominal service voltages:

NOMINAL SYSTEM VOLTAGE****		
Two-wire	Three-wire	Four-wire
	Single-Phase Systems	
120*	**120/240***	
	Three-Phase Systems	
		208Y/120* **
		240/120
	240	
		480Y/277
	480	
	600**	
	2400	
	4160	4160Y/2400
	4800	
	6900	
		8320Y/4800
		12000Y/6930
		12470Y/7200
		13200Y/7620
	13800	**13800Y/7970**
		20780Y/12000
	23000	22860Y/13200
		24940Y/14400
	34500	**34500Y/19920**

*see (a)(2) below

** This classification covers the range of nominal voltages from 550 to 600 volts.

***A modification of this three-phase, four-wire system is available as a 120/208YV service for single-phase, three-wire, open-wye applications.

****Preferred system voltages are in bold-face type.

(2) An electric supplier may adopt different nominal voltages to serve specific customers if such action does not compromise prudent transmission and distribution system operation.

(b) In order to promote harmony between the service of electric suppliers and the utilization of voltage requirements of presently manufactured equipment, the following service voltage variations are permitted:

(1) For service rendered for individual residential use or specifically for lighting purposes, the voltage variations shall not exceed five percent (5%) above or below the standard base voltage.

(2) For other service the voltage variations shall not exceed ten percent (10%) above or below the standard base voltage.

(c) An electric supplier may elect to deliver service at a nominal voltage that is not standard on its system. The variation in the nonstandard voltage shall not exceed the limits set forth above for the type of service being rendered.

(d) Upon approval of the Commission and proper notification to its customers a utility may cease to deliver a particular voltage.

(e) Variations in voltage in excess of those specified that are caused by the following shall not be construed a violation of this rule:

(1) Addition of customer equipment without proper notification to the electric supplier.

(2) Operation of customer's equipment.

(3) The action of the elements.

(4) Infrequent and unavoidable fluctuations of short duration due to system operations.

(5) Conditions that are part of practical operations and are of limited extent, frequency, and duration.

(6) Emergency operations.

(f) Customers shall select, install, maintain and operate their electrical equipment so as to cause the least interference with the regulation of the electric supply system. Three phase motors in excess of 20 horsepower, single phase motors in excess of five horsepower and other apparatus with high starting or fluctuating currents must be installed in accordance with the supplier's filed tariffs and rules and regulations.

(g) Greater variations in voltage for service to installations that permit greater variations than those required above may be allowed upon specific authorization by the Commission.

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Rule R8-21. INSTALLATION OR REPLACEMENT OF METERS AND CHANGES IN LOCATION OF SERVICE.

(a) A customer's request for electric utility service grants the utility permission to install any metering device that meets the requirements of Rules R8-8, -9, -11, and -12, as deemed appropriate by the utility and in compliance with Commission orders.

(b) Whenever a customer requests the replacement of the service meter on the customer's premises, such request shall be treated as a request for the test of such meter, and as such, shall fall under the provisions of Rule R8-14.

(c) Whenever a customer moves from the location where electric service is used by the customer, and thereby requires the disconnecting and/or connecting at a new location of the electric supplier, or information is required from the metering infrastructure to complete the transfer of service, and the same work has been done for the customer within one year preceding, the utility may make a charge, subject to such charge having been approved by the Commission.

DOCKET NO. E-100, SUB 157

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of 2018 Biennial Integrated Resource Plans and Related 2018 REPS Compliance Plans	)))))	ORDER ACCEPTING INTEGRATED RESOURCE PLANS AND REPS COMPLIANCE PLANS, SCHEDULING ORAL ARGUMENT, AND REQUIRING ADDITIONAL ANALYSES

HEARD: Monday, February 4, 2019, at 7:00 p.m. in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Chairman Edward S. Finley, Jr., Presiding, and Commissioners ToNola D. Brown-Bland, Jerry C. Dockham, James G. Patterson,[1] Lyons Gray, Daniel G. Clodfelter, and Charlotte A. Mitchell.

[1] Chairman Edward S. Finley, Jr., resigned from the Commission effective June 1, 2019, and Commissioners Jerry C. Dockham and James G. Patterson resigned from the Commission effective June 30, 2019.

APPEARANCES:

For Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC (Duke):

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For Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina:

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For the Using and Consuming Public:

Teresa Townsend, Special Deputy Attorney General, Department of Justice, 114 West Edenton Street, Raleigh, North Carolina 27603

Dianna Downey, Heather Fennell, and Bob Gillam, Staff Attorneys, Public Staff - North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

BY THE COMMISSION: Integrated Resource Planning (IRP) is intended to identify those electric resource options that can be obtained at least cost to the utility and its ratepayers consistent with the provision of adequate, reliable electric service. IRP considers demand-side alternatives, including conservation, efficiency, and load management, as well as supply-side alternatives in the selection of resource options. Commission Rule R8-60 defines an overall framework within which the IRP process takes place in North Carolina. Analysis of the long-range need for future electric generating capacity pursuant to N.C. Gen. Stat. § 62-110.1 is included in the Rule as a part of the IRP process.

North Carolina General Statute § 62-110.1(c) requires the Commission to "develop, publicize, and keep current an analysis of the long-range needs" for electricity in this State. The Commission's analysis should include: (1) its estimate of the probable future growth of the use of electricity; (2) the probable needed generating reserves; (3) the extent, size, mix, and general location of generating plants; and (4) arrangements for pooling power to the extent not regulated by the Federal Energy Regulatory Commission (FERC). Further, N.C.G.S. § 62-110.1 requires the Commission to consider this analysis in acting upon any petition for the issuance of a certificate for public convenience and necessity for construction of a generating facility. In addition, the statute requires the Commission to submit annually to the Governor and to the appropriate committees of the General Assembly a report of its: (1) analysis and plan; (2) progress to date in carrying out such plan; and (3) program for the ensuing year in connection with such plan. N.C. Gen. Stat. § 62-15(d) requires the Public Staff to assist the Commission in making its analysis and plan pursuant to N.C.G.S. § 62-110.1.

North Carolina General Statute § 62-2(a)(3a) declares it a policy of the State to:

> assure that resources necessary to meet future growth through the provision of adequate, reliable utility service include use of the entire spectrum of demand-side options, including but not limited to conservation, load management and efficiency programs, as additional sources of energy supply and/or energy demand reductions. To that end, to require energy planning and fixing of rates in a manner to result in the least cost mix of generation and demand-reduction measures which is achievable, including consideration of appropriate rewards to utilities for efficiency and conservation which decrease utility bills....

Session Law (S.L.) 2007-397 (Senate Bill 3), signed into law on August 20, 2007, amended N.C. Gen. Stat. § 62-2(a) to add subsection (a)(10) that provides that it is the policy of North Carolina "to promote the development of renewable energy and energy efficiency through the implementation of a Renewable Energy and Energy Efficiency Portfolio Standard (REPS)" that will: (1) diversify the resources used to reliably meet the energy needs of North Carolina's consumers, (2) provide greater energy security through the use of indigenous energy resources available in North Carolina, (3) encourage private investment in renewable energy and energy efficiency, and (4) provide improved air quality and other benefits to the citizens of North Carolina. To that end, Senate Bill 3 further provides that "[e]ach electric power supplier to which N.C. Gen. Stat. § 62-110.1 applies shall include an assessment of demand-side management and energy efficiency in its resource plans submitted to the Commission and shall submit cost-effective demand-side management and energy efficiency options that require incentives to the Commission for approval."[1]

Senate Bill 3 also defines demand-side management (DSM) as "activities, programs, or initiatives undertaken by an electric power supplier or its customers to shift the timing of electric use from peak to nonpeak demand periods" and defines an energy efficiency (EE) measure as "an equipment, physical or program change implemented after 1 January 2007 that results in less energy being used to perform the same function."[2] Energy Efficiency measures do not include DSM.

To meet the requirements of N.C.G.S. § 62-110.1 and N.C.G.S. § 62-2(a)(3a), the Commission conducts an annual investigation into the electric utilities' IRPs. Commission Rule R8-60 requires that each utility, to the extent that it is responsible for procurement of any or all of

[1] N.C. Gen. Stat. § 62-133.9(c).

[2] N.C. Gen. Stat. §§ 62-133.8(a)(2) and (4).

its individual power supply resources,[1] furnish the Commission with a biennial report in even-numbered years that contains the specific information set out in Rule R8-60. In odd-numbered years, each of the electric utilities must file an annual report updating its most recently filed biennial report.

Further, Commission Rule R8-67(b) requires any electric power supplier subject to Rule R8-60 to file a REPS compliance plan as part of each biennial and annual report. In addition, each biennial and annual report should (1) be accompanied by a short-term action plan that discusses those specific actions currently being taken by the utility to implement the activities chosen as appropriate per the applicable biennial and annual reports, and (2) incorporate information concerning the construction of transmission lines pursuant to Commission Rule R8-62(p).

Within 150 days after the filing of each utility's biennial report and within 60 days after the filing of each utility's annual report, the Public Staff or any other intervenor may file its own plan or an evaluation of, or comments on, the utilities' biennial and annual reports. Furthermore, the Public Staff or any other intervenor may identify any issue that it believes should be the subject of an evidentiary hearing. The Commission must schedule one or more hearings to receive public testimony.

2018 BIENNIAL REPORTS

This Order addresses the 2018 biennial reports (2018 IRPs) filed in Docket No. E-100, Sub 157, by Duke Energy Progress, LLC (DEP); Duke Energy Carolinas, LLC (DEC); and Dominion Energy North Carolina (DENC) (collectively, the investor-owned utilities, utilities or IOUs). In addition, this Order also addresses the REPS compliance plans filed by the IOUs.

The following parties have been allowed to intervene in this docket: North Carolina Sustainable Energy Association (NCSEA); Carolina Industrial Group for Fair Utility Rates I, II, and III (CIGFUR); North Carolina Waste Awareness and Reduction Network (NC WARN); North Carolina Clean Energy Business Alliance (NCCEBA); Carolina Utility Customers Association, Inc. (CUCA); Environmental Defense Fund (EDF); jointly, Southern Alliance for Clean Energy, the Sierra Club, and the Natural Resources Defense Council (SACE, the Sierra Club, and NRDC); Ecoplexus, Inc. (Ecoplexus); and Broad River Energy, LLC (Broad River). The Public Staff's intervention is recognized pursuant to N.C. Gen. Stat. § 62-15(d) and Commission Rule R1-19(e). The Attorney General's intervention is recognized pursuant to N.C. Gen. Stat. § 62-20.

[1] During the 2013 Session, the General Assembly enacted S.L. 2013-187 (House Bill 223), which exempted the EMCs from the requirements of N.C. Gen. Stat. § 62-110.1(c) and N.C. Gen. Stat. § 62-42, effective July 1, 2013. As a result, EMCs are no longer subject to the requirements of Rule R8-60 and are no longer required to submit IRPs to the Commission for review.

PROCEDURAL HISTORY

On May 1, 2018, DENC filed its 2018 biennial IRP report and REPS compliance plan. DEC and DEP (collectively, Duke) filed their 2018 biennial IRP reports and REPS compliance plans on September 5, 2018.

On September 27, 2018, the Commission issued an Order Scheduling Public Hearing on 2018 IRP Reports and Related 2018 REPS Compliance Plans. That Order set the public witness hearing for 7:00 p.m. on February 4, 2019, in Raleigh.

On November 8, 2018, NC WARN filed a motion for an expert witness hearing.

On November 15, 2018, DEC and DEP filed a response in opposition to NC WARN's motion for an expert witness hearing, as did DENC on November 27, 2018.

On December 14, 2018, NC WARN filed initial comments on the utilities' 2018 IRPs.

On December 19, 2018, Duke filed notification of the retirement of its 99 Islands hydroelectric units 5 and 6 located near Gaffney, South Carolina.

On January 17, 2019, NCSEA filed a motion for extension of time to file initial comments and reply comments, which the Commission granted on January 24, 2019.

On January 22, 2019, the Public Staff and DENC filed a joint motion for an additional sixty (60) days after DENC files its corrected 2018 IRP in early March 2019 for the filing of initial comments and 60 days after the initial comments for the filing of reply comments. On January 24, 2019, the Commission granted the joint motion of the Public Staff and DENC.

On February 4, 2019, the public hearing was held in Raleigh, as scheduled, with forty-nine (49) public witnesses in attendance. In summary, the public witnesses focused on the need to encourage energy efficiency and clean renewable resources, such as solar and wind. A few witnesses commented on the value of integrating batteries, and other storage technologies, with the utilities' distributed resources. In addition, the witnesses encouraged the Commission to promote an economy and energy future focused on renewables and distributed energy systems. Other witnesses contended that coal and gas perpetuate climate issues because of greenhouse gas emissions, and further, that the utilities should stop investing in hydraulic fracked gas infrastructure, including the Atlantic Coast Pipeline.

On February 7, 2019, the Public Staff filed a motion for extension of time for all parties to file comments on Duke's 2018 IRPs, which the Commission granted on February 8, 2019.

On February 15, 2019, EDF filed initial comments on the utilities' 2018 IRPs.

On February 21, 2019, the City of Charlotte and Mecklenburg County Local Government Officials requested an additional public hearing and an expert witness hearing on the 2018 IRPs, as did members of the General Assembly from Western North Carolina on March 11, 2019 and Representative Verla Insko from Orange County on March 22, 2019.

On March 7, 2019, initial comments were filed by the Public Staff, the Attorney General's Office, NCSEA, and jointly by SACE, NRDC and the Sierra Club. On March 12, 2019 and May 24, 2019, the Public Staff filed corrections to its initial comments.

On March 7, 2019, DENC filed corrections to its 2018 IRP and REPS Compliance Plan.

On April 29, 2019, Duke filed a motion for extension of time to file reply comments, which the Commission granted on May 1, 2019.

On May 6, 2019, the Public Staff filed initial comments on DENC's 2018 IRP.

On May 20, 2019, Duke filed reply comments, as did the Attorney General and NC WARN.

On June 16, 2019, the Commission issued an order requiring the filing of proposed orders.

On July 5, 2019, DENC filed reply comments.

On July 23, 2019, the Commission issued an order scheduling a technical conference on Integrated Systems and Operations Planning for August 28, 2019. The Order also included several Commission questions to be answered by Duke on or before August 21, 2019.

On July 26, 2019, proposed orders were filed by Duke, DENC, the Public Staff, AGO, NCSEA, and jointly by SACE, NRDC and Sierra Club.

PUBLIC HEARING

Pursuant to N.C.G.S. § 62-110.1(c) the Commission held a public hearing in Raleigh on Monday, February 4, 2019, at 7:00 p.m., where 49 public witnesses provided testimony. In summary, the testimonies of the public witnesses focused on the need to encourage energy efficiency and clean renewable resources, such as solar and wind. A few of the witnesses commented on the value of integrating batteries, and other storage technologies, with the utilities' distributed resources. In addition, the witnesses encouraged the Commission to promote an economy and energy future focused on renewables and distributed energy systems. Many of the witnesses discussed the imminent danger that climate change presents and the failure of the IOUs' IRPs to address the need for aggressive action. Other witnesses contended that coal and gas perpetuate climate issues because of greenhouse gas emissions, and further, that the utilities should stop investing in hydraulic fracked gas infrastructure, including the Atlantic Coast Pipeline. Several owners of independent small hydroelectric plants testified in opposition to the assumption in Duke's IRPs that no existing PURPA small hydroelectric contracts would be renewed.

CONSUMER STATEMENTS OF POSITION

As of August 21, 2019, the Commission has received and filed in this docket approximately 1,789 consumer statements of position on a variety of topics from people all across the state. A sampling of 705 statements found 56 from Asheville, 21 from Winston-Salem, 35 from Chapel Hill, 17 from Wilmington, 3 from Sylva, 40 from Charlotte, 51 from Durham, 11 from Brevard, 8 from Black Mountain, 7 from Boone, 7 from High Point 4 from Waynesville, 3 from Murphy, 6 from Hendersonville, 18 from Greensboro, 5 from Salisbury, 3 from Pffaftown, and 3 from Concord.

SUMMARY CONCLUSION

The Commission has carefully considered the full record in this proceeding, including the public witness testimony, the consumer statements of position, the various consultants' reports, and the parties' comments. The Commission concludes that the record raises several issues that are worthy of more in-depth examination. Within an IRP that spans a 15-year planning horizon, there are a myriad of policy issues, technology choices, models and other components that could be examined. The Commission has identified several topics and sub-topics that it deems to merit additional analysis and examination. The Commission believes that a focused inquiry into these specific topics and sub-topics in the 2020 IRPs will yield a more useful outcome than could be achieved by holding further hearings in the present proceeding relating to the 2018 biennial IRPs. The Commission will accept DENC's 2018 IRP as adequate for planning purposes, subject to DENC's 2019 IRP Update. The Commission will accept DEC's and DEP's 2018 IRPs as adequate to be used for planning purposes during the remainder of 2019 and in 2020, subject to DEC's and DEP's 2019 IRP Updates. However, the Commission does not accept some of the underlying assumptions upon which DEC's and DEP's IRPs are based, the sufficiency or adequacy of the models employed, or the resource needs identified and scheduled in the IRPs beyond 2020. Instead, the Commission will use the 2018 IRPs and this Order as an opportunity to provide direction to the IOUs, the Public Staff and intervenors for an orderly presentation of answers to the specific topics and sub-topics identified herein by the Commission and for preparation of the 2020 biennial IRP reports by the utilities. The Commission commends the utilities, intervenors, public witnesses, and authors of position statements for the quality of presentation and analyses. The following sections summarize issues significant to the Integrated Resource Plans filed by the utilities and reflect the full record in the proceeding.

I. Peak and Energy Forecasts

Summary of Growth Rates

The following table summarizes the growth rates for the IOUs' system peak and energy sales forecasts in their IRP filings.

	Summer Peak	Winter Peak	Energy Sales	Annual MW Growth
DEP	0.8%	0.7%	1.0%	127
DEC	1.0%	1.0%	0.9%	186
DENC	0.7%	1.5%	0.7%	124

A. Public Staff Initial Comments – Peak and Energy Forecasts

The Public Staff reviewed the 15-year peak and energy forecasts (2019–33) of DEP, DEC, and DENC. The compound annual growth rates (CAGRs) for the forecasts are within the range of 0.7% to 1.0% for DEC and DEP and 0.7% to 1.5% for DENC. The Public Staff noted that all the utilities used accepted econometric and end-use analytical models to forecast their peak and energy needs. They commented that with any forecasting methodology, there is a degree of uncertainty associated with models that rely, in part, on assumptions that certain historical trends or relationships will continue in the future. The Public Staff noted that in its Compliance Filing, DENC revised the peak demand forecasts it filed in its May 1, 2018 IRP, modeling them using the PJM DOM Zone non-coincident peak forecast, which resulted in a significant reduction of peak demand over the forecast horizon.

In assessing the reasonableness of the forecasts, the Public Staff first compared the utilities' most recent weather-normalized peak loads to those forecasted in their 2017 IRP updates. The Public Staff then analyzed the accuracy of the utilities' peak demand and energy sales predictions in their 2012 IRPs by comparing them to their actual peak demands and energy sales. They commented that a review of past forecast errors can identify trends in the IOUs' forecasting and assist in assessing the reasonableness of the utilities' current and future forecasts. Finally, in reviewing DEC and DEP's IRPs, the Public Staff reviewed the forecasts of other adjoining utilities in the VACAR region and the SERC Reliability Corporation.

In regard to DEC and DEP, the Public Staff commented that except for a brief time in the 1980's, the dominant seasonal peak has occurred during summer afternoons. The Public Staff noted that the Companies' annual peak sporadically occurred in the winter season, but since 2013, all of DEP's annual peaks have been during January or February, while DEC's annual peaks have occurred during both the winter and the summer seasons. After DEC and DEP experienced their all-time system peaks in February 2015, they conducted a new reserve margin study, the results of which were incorporated in their 2016 and 2018 IRPs. The Public Staff stated that DEC's and DEP's 2018 IRPs forecast DEP to be a winter peaking system and DEC to be a summer peaking system; however, DEC's planning is based on the winter season. The Public Staff further noted that DEP's weather normalized winter peaks have grown at annual rates significantly greater than the growth rates in DEP's peak forecast. For DENC, the Public Staff commented that its 15-year forecast in the Compliance Filing is based on PJM's peak load and energy sales forecast, scaled down for the Dominion load serving entity, which predicts that DENC will become a winter peaking system in 2024.

1. **Public Staff Initial Comments – DEP's Peak and Energy Forecasts**

The Public Staff noted that since the 2016 IRP, DEP has projected that it will be a winter peaking system and winter planning utility. It stated that DEP's forecasted winter peak loads reflect a combined average growth rate (CAGR) of 0.7% over the forecast years of 2019 through 2033, which is significantly lower than the 1.2% CAGR in its 2016 IRP and the 1.2% CAGR in its 2014 IRP. The Public Staff pointed out that as with DEC's 2018 IRP and DEP's prior IRPs, relatively little demand reduction is forecasted as being available from EE and DSM programs during the winter seasons, a 0.2% reduction in the CAGR from EE through 2033 of DEP's system peaks and a reduction of the winter demands from DSM by approximately 4%. The Public Staff noted that DEP expects to have the ability to reduce its summer peak loads by 7% through DSM. According to the Public Staff, over the next 15 years, the average annual growth of DEP's winter peak is projected to be approximately 127 MW and the winter peaks are projected to be approximately 604 MW greater than the forecasted summer peaks.

The Public Staff noted that DEP's energy sales, including reductions associated with its EE programs, are predicted to grow at a CAGR of 0.5%, a significantly lower growth rate than the 0.9% in the 2016 IRP and the 1.0% in the 2014 IRP. Further, the Company's EE programs are predicted to reduce its energy sales by approximately 1% in 2019 to 3% in 2033 according to the Public Staff.

The Public Staff's review of DEP's actual and weather adjusted peak load forecasting accuracy for one year showed that DEP's 2017 IRP forecast underestimated the actual 2018 winter peak load by 17%, and by 11% using a weather-normalized peak. When the Public Staff compared the current forecast to the 2012 IRP forecasts for 2013 – 2018, DEP's forecasts indicate a mean average error (MAE) of 9%. Each of the six forecasts used to calculate the MAE was lower than the actual loads, reflecting forecast errors ranging from -18% in 2018 to -0.3% in 2014. The MAE fell to 6% when the forecasts were compared with weather-adjusted loads.

The Public Staff also reviewed DEP's 2012 energy sales forecast, based on the 2012 IRP forecasts for 2013 - 2018, calculating a 13% MAE, reflecting actual sales being significantly less than expected. The Public Staff noted that DEP predicts that over the next 15 years, its EE programs will reduce its annual energy sales by approximately 0.5% in 2019, increasing to 3% in 2033. In addition, the Public Staff found it noteworthy that DEP's predicted load factor is approximately 51% over the next 15 years, significantly lower than the average 55% load factor predicted in the 2016 IRP and the 56% load factor predicted in the 2014 IRP. According to the Public Staff, a decreasing load factor generally indicates a greater need for peaking plants.

The Public Staff found the economic, weather-related, and demographic assumptions underlying DEP's 2018 peak and energy forecasts to be reasonable, but stated that the excessive forecast errors associated with DEP's winter peak indicate that review and revision of DEP's statistical and econometric forecasting practices may be warranted. However, the Public Staff expressed concerns that DEP's actual winter peaks were significantly greater than predicted; such that the 9% MAE equates to an average forecast that is 1,456 MW lower than predicted.

2. Public Staff Initial Comments – DEC's Peak and Energy Forecasts

The Public Staff commented that DEC's forecasted winter peak loads reflect a significantly lower CAGR of 1.0% as compared to the 1.3% CAGR in its 2016 IRP and 1.4% CAGR in its 2014 IRP. The Public Staff pointed out that relatively little demand reduction is forecasted as being available from EE and DSM programs during the winter seasons: a forecasted 0.1% reduction in the CAGR of DEC's system peaks due to EE programs and a reduction in winter demand from DSM programs of approximately 2%. For summer peak loads, the Public Staff noted that DEC forecasts being able to reduce its summer peak loads by 6% through use of DSM. The Public Staff noted that the predicted average annual growth of DEC's winter peak is 186 MW over the next 15 years, as compared to 232 MW in the 2016 IRP and 286 MW in the 2014 IRP. The Public Staff stated that DEC's energy sales, including the effects of its EE programs, are expected to grow at a CAGR of 0.9%, as compared to a 1.0% growth rate in the 2016 IRP and 1.4% in the 2014 IRP. Further, the Company's EE programs are expected to reduce energy sales by approximately 1% in 2019 and 4% in 2033.

The Public Staff's review of DEC's actual and weather adjusted peak load forecasting accuracy for one year indicated that DEC's 2017 IRP forecast was under-predicted by 4% and that on a weather-normalized basis, the actual peak was 2% greater than predicted. When the accuracy of DEC's forecasts is reviewed since 2012, the Public Staff's analysis shows the 2012 IRP yielded a MAE of 5%. It further showed that of the six predicted load forecasts comprising the MAE, two were higher than expected and four were lower than expected, and that the MAE fell to 4% when the forecasts were compared with peaks that were adjusted for abnormal weather.

The Public Staff made a similar review of DEC's 2012 energy sales forecast, which had a 13% MAE. The Public Staff noted that DEC predicts that over the next 15 years, its EE programs will reduce its annual energy sales by approximately 0.8% in 2019, increasing to 4% in 2033. Further it commented that DEC's predicted load factor remains reasonably constant at 58% over the next 15 years, similar to the 59% load factor in the 2016 IRP and the 57% load factor from the 2014 IRP.

The Public Staff concluded that the economic, weather-related, and demographic assumptions underlying DEC's 2018 peak and energy forecasts were reasonable, but that DEC has overestimated its energy sales relative to the 2012, 2014, and 2016 IRPs. The Public Staff noted that DEC had maintained in discussion that its retail energy sales forecast is reasonably accurate when adjusted for abnormal weather. The Public Staff stated that since the Company continues to reduce the predicted growth rates for its projected energy sales and as the peak demand forecast has a direct influence on its capacity expansion plans, the Public Staff places more weight on its review of the Company's peak demands. Noting that the MAE based on actual versus forecasted loads was 5%, but fell to 4% when compared using weather-normalized loads, the Public Staff concluded that DEC's peak load and energy sales forecasts were reasonable for planning purposes. The Public Staff recommended that both DEC and DEP continue to review their winter peak equations in order to better quantify the response of customers to low temperatures. The Public Staff suggested that the Companies may wish to evaluate multiple approaches such as a single equation that relies on multiple observations that focus on customer's response to cold weather in January and February, in conjunction with a separate equation that examines responses during July and August. Given the different customer responses to extreme cold and winter temperatures, the use of separate equations for the summer peak and winter peak may allow for improved understanding of how customers respond to extreme temperatures, which is in contrast to Duke's current use of a single equation for all twelve months of the year.

3. Public Staff Initial Comments – DENC's Peak and Energy Forecasts

Noting that DENC will become a winter peaking system in 2024, the Public Staff pointed out the faster CAGR of 1.5% for DENC's winter peaks as compared to a 0.7% CAGR of its summer peaks. The Public Staff stated that the predicted winter peak CAGR is slightly higher than the 1.3% growth rate from the 2016 IRP, while the CAGR for the summer peak is significantly lower than the 1.5% CAGR from the 2016 IRP. It noted that while the DOM Zone is predicted to become a winter peaking system, PJM is a summer peaking system and thus the Company must procure adequate capacity for the summer peak demand forecast. To do so, the Company's IRP is modeled to procure both supply-side and demand-side resources with the annual forecast of summer peak demands. According to the Public Staff, on average over the 15-year forecast, the winter peaks are approximately 173 MW greater than the forecasted summer peaks, DENC's EE programs are predicted to provide approximately 1% to 2% reduction of the summer and winter peaks through 2033, and the activation of DSM programs is expected to reduce the peak demands by approximately 1% of MW load. The Public Staff commented that the average annual growth of DENC's winter peak is predicted to be 267 MW and 124 MW for the summer peak over the next 15 years, as compared to the 293 MW annual growth of its summer peaks from the 2016 IRP.

The Public Staff stated that DENC's Compliance Filing projected average annual energy sales growth of 0.7%, a significant decrease from the 1.5% growth rate of the 2016 IRP, and a decrease from the original IRP forecast of 1.4%. It noted DENC's estimate that its EE programs would reduce its energy sales by approximately 2% by 2033, as opposed to the 1% reduction in energy sales due to EE forecasted in its 2016 IRP.

The Public Staff's review of DENC's actual peak load forecasting accuracy for one year showed that DENC's 2017 IRP over-predicted the 2018 summer peak load by 7% and under-predicted the 2018 winter peak load by 15%. The Public Staff reviewed DENC's peak load forecasting accuracy based on the 2012 IRP forecasts for 2013 - 2018. Its review indicated that all of the predicted annual peak demands were greater than the actual peaks, with a MAE of 6%, while its energy sales from the 2012 IRP generated an 11% error rate, with four of the previous six annual peaks occurring during the winter season.

The Public Staff stated that based on its review of DENC's forecast accuracy and pattern of predicting loads greater than the actual loads, it supported DENC's use of the relatively lower PJM peak demand forecast as ordered by the VSCC. The Public Staff found DENC's revised peak load and energy sales forecasts to be reasonable for planning purposes, but noted the growing dominance of morning winter peaks, which appears to represent a shift in the use of electricity and warrants further examination of the Company's econometric and statistical forecast models.

4. Public Staff Areas of Concern and Recommendations – Peak and Energy Forecasts

In its comments on Duke's IRPs, the Public Staff identified several areas of concern, including peak load forecasts and use of smart meter data. In regard to peak load forecasts, the Public Staff expressed concern about DEP's forecast errors of its winter peaks. It noted a continuing pattern of under-forecasting, pointing out that DEP's weather-normalized winter peak of 15,165 MW for 2018 is over 1,000 MW greater than the predicted 2019 winter peak of 14,161 MW. The Public Staff also expressed concern regarding the predicted annual growth rate of DEP's winter peaks of 0.7%, which is a significant departure from the 3.0% CAGR of its actual winter peaks from 2013 through 2018, and 2.1% CAGR of its weather-normalized peaks. It noted the faster growth of DEP's winter peaks over its summer peaks, as opposed to the more balanced growth of DEC's summer and winter peaks.

A key area of concern for the Public Staff with DEP's winter forecasting accuracy was that all of the Company's peaks occurred in the winter season and all of the errors were due to forecasts being below the actual peak demands; as compared to DEC's errors being balanced between forecasts both too high and too low. The Public Staff posited that one reason for the growing dominance of DEP's winter peak may be the lack of heating alternatives to electric heat pumps in DEP's service area, pointing out that heat pumps rely on inefficient heat strips or resistance heating at certain operating conditions. It stated that a second reason may be that natural gas is relatively less available in DEP's service area than DEC's territory.

The Public Staff recommended that Duke evaluate alternative equations and modeling tools that would provide a check on forecasts based on monthly data, as it questioned whether the equation current used by Duke is accurately modeling customers' responsiveness to extreme weather, especially in relation to extreme cold temperatures in the DEP service territory. The Public Staff also noted that the data period used for the regression ended on December 31, 2017, excluding the extreme cold that occurred over several days in January 2018. The Public Staff stated that it may be appropriate to expand the data period to include the full winter season to better capture customers' response to extreme weather.

The Public Staff also noted that it had asked Duke how it used smart meter usage data in developing and informing the Companies' load forecasting models and developing improved rate designs, but neither of the utilities reported incorporating usage data obtained from smart meters in its load forecasting models. Additionally, the Public Staff stated that an Integrated Volt-Var Control (IVVC) program could be utilized to provide a variety of grid services to enhance the operability of the grid (e.g., peak reduction), as well as provide a cost savings aspect to ratepayers. IVVC is the process of optimally managing voltage levels and reactive power to achieve more efficient grid operation by reducing system losses, peak demand, energy consumption, or a combination of all three. The Public Staff indicated that while it had not fully reviewed the cost-benefit analysis and assumptions of an IVVC program installed on the DEC system, it recommended that DEC should continue to revise its estimates and cost benefit analysis for the IVVC program in future IRP filings, and consider scenarios that take into account the impact of multiple assumptions, including the installation of IVCC, on the capacity need. The Public Staff recommended that as smart meters are deployed and data from those meters becomes available, the utilities should include in their IRPs a discussion on how they are using that data to inform their load forecasting and improved rate designs.

The Public Staff also recommended that the Companies continue to review their winter peak equations in order to better quantify the response of customers to low temperatures. The Public Staff further recommended that DEC and DEP continue to review their load forecasting methodology to ensure that assumptions and inputs remain current and use appropriate models quantifying customers' response to weather, especially abnormally cold winter weather events.

In regard to DENC, the Public Staff recommended that the Company's 2020 IRP rely on the PJM coincident peak scaled down for the DENC load serving entity forecast for its baseline peak and energy forecasts and encouraged the Company to present its internal peak demand and energy forecasts as a comparison and to allow for a sensitivity analysis with an alternative expansion plan.

B. SACE, Sierra Club, and NRDC Initial Comments – Peak and Energy Forecasts

According to comments filed by SACE, NRDC and the Sierra Club (SACE et al.), the load forecast is a major factor determining a utility's need for new resources to meet system energy and demand. Overstating load growth will result in excess capacity on the system, and excess costs borne by ratepayers. In their comments, SACE et al. observed that over the 15-year planning horizon, DEC forecasts an annual average growth rate of 1.0% (summer) and 0.9% (winter) with energy growth of 0.8%. DEP forecasts an annual average growth rate of 0.8% (summer) and 0.7% (winter) with energy growth of 0.5%. SACE et al. retained James F. Wilson, an economist and independent consultant in the electric power and natural gas industries, to evaluate the peak load forecasts used in the 2018 IRPs.

Mr. Wilson concluded in his report that while the DEC and DEP load forecasts appear more reasonable than in the past, they should be carefully examined.[1] Moreover, it is too soon to draw a conclusion about the Companies' winter peak load forecasts because the instances of loads exceeding the forecasts have generally occurred under very unusual extreme cold events (such as "Polar Vortex" events). Mr. Wilson recommended that the Companies further research the drivers of sharp load spikes under extreme winter cold conditions, and develop demand response programs and other strategies for shifting load or shaving these spikes. In addition, DEC and DEP should develop a more sophisticated model of how extreme winter weather affects their loads. Mr. Wilson also recommended that the Companies further evaluate wholesale customers' contribution to system peak loads, which affect required reserve margins and capacity needs.

[1] James F. Wilson, Review and Evaluation of the Load Forecasts for the Duke Energy Carolinas and Duke Energy Progress 2018 Integrated Resource Plans (March 7, 2019), Attachment 3 to the Comments of SACE, NRDC and Sierra Club.

C. Environmental Defense Fund Initial Comments – Peak and Energy Forecasts

EDF points out that using load forecasts that are too high can lead to costly excess capacity. It recommends that the Commission carefully analyze the utilities' load growth assumptions, including a thorough backcast analysis, to determine whether the load growth assumptions are reasonable.

D. NCSEA Initial Comments – Peak and Energy Forecasts

NCSEA pointed out that while Duke continues to promote its grid improvement plans, the plans are not reflected in the IRPs. NCSEA noted that Duke's grid improvement plans include IVVC, which will allow Duke to manage distribution and allow the utilization of peak shaving and emergency modes of operation.

E. Attorney General's Office Initial Comments – Peak and Energy Forecasts

The AGO supported the Initial Comments of the Public Staff and other parties who recommended that the Integrated Volt-Var Control (IVVC) program be included in Duke's load forecasts developed in IRPs for future years of capacity planning.

F. Duke Reply Comments – Peak and Energy Forecasts

As noted above, the Public Staff generally found DEC and DEP's 2018 IRP load forecasts to be reasonable for planning purposes and compliant with Commission rules and requirements. The Public Staff, NCSEA, and the joint comments of SACE, NRDC and Sierra Club (SACE et al.) all made recommendations to the Commission regarding the load forecasts in the 2018 IRPs and future IRP load forecasting requirements, to which Duke replied as follows.

i. That DEC and DEP continue to review their winter peak equations in order to better quantify the response of customers to low temperatures.

Duke commented that it continues to review and improve the load forecast peak model specifications in accordance with the Commission's Order from the 2016 IRP proceeding (Docket No. E-100, Sub 147). Recently, Duke completed an extensive review of the entire peak load forecasting process, including load definition verification, peak weather methodology, and model specification. The results were summarized in the 2018 IRPs.

Duke stated that the peak forecast model objective is to provide a reasonable forecast of future peak demand under the assumption of normal peak conditions. Duke noted that extreme historical peak demand and weather conditions are captured both in the history used by the peak model, as well as in the weather normalization processes. Duke cautioned that any additional attempt to directly or intentionally model extreme peak conditions within the current IRP peak model process would increase the probability of over-forecasting peak demand.

ii. That DEC include in its forecasted load the projected impact of Integrated Volt-Var Control (IVVC) programs.

NCSEA alleged that Duke continues to promote its grid improvement plans, but does not reflect it in its IRPs.[1] NCSEA noted that Duke's grid improvement plans, which would prepare the grid for decentralized, distributed generation over a 10-year period, includes IVVC, a voltage management program, which will allow Duke to manage distribution circuits (to reduce impacts to customers with large motors sensitive to voltage control) and allow the utilization of peak shaving and emergency modes of operation. Duke commented that the original grid improvement plan proposed in DEC's last general rate case in Sub 1146 did not contain a DEC IVVC program. Duke noted that, based upon stakeholder feedback received through the subsequent grid improvement stakeholder workshops hosted by Duke, it has added a DEC IVVC program and plans to reflect the DEC IVVC program in future IRPs. The Commission expects to see the results of this program reflected in the 2020 biennial IRP filing.

iii. That DEC and DEP continue to review their load forecasting methodology to ensure that assumptions and inputs remain current and that appropriate models quantifying customers' response to weather, especially abnormally cold winter weather events, are employed.

Duke noted that, in response to the Commission's request in 2016, it completed a thorough review of the peak forecasting methodology in 2018, which led to raising the peak forecast significantly. Duke agreed with the Public Staff that the revised methodology provides a reasonable forecast of normal peak demand. Duke noted that the peak forecast process is also continuously adapting to changing weather and demand trends as it receives additional history. This process will result in higher forecasted peaks if extreme winter weather becomes more prevalent. The process will also prevent the models from over-reacting to one or two years where extreme winter weather was an outlying event. Duke explained that an example of this would be comparing the winter of 2017-18, which was a very extreme winter from a demand perspective, to the winter of 2018-19, which was very mild.

Finally, Duke cautioned against attempting to model extreme winter peaking conditions, noting that one of the key drivers of the Companies' 17% reserve margin is to cover such events. According to Duke, attempting to model customer responsiveness to extreme weather would force it to make broad assumptions about customers' actions during an extreme peak period that could lead to significant over-forecasting of peak demand.

iv. That DEC and DEP include in future IRPs and updates a discussion of their use of data from smart meters to inform their load forecasting, cost of service studies, and rate designs.

Duke noted its agreement that smart meter data has the potential to be very informative from a load forecasting perspective. Duke also noted that the Commission has initiated a rulemaking on certain data access issues in Docket No. E-100, Sub 161, which is pending and may help inform the load forecasting review. Duke further replied, however, that the Commission has

[1] NCSEA Comments, at p. 11.

existing Smart Grid Technology Plan dockets, which provide the Commission and parties with extensive information about smart meters and how DEC and DEP are utilizing this technology and data issues, so Duke does not believe that additional formal reporting should be required in the IRPs. Nonetheless Duke committed to update the Public Staff on their progress in incorporating smart meter data into the load forecasting process.

Duke stated that SACE et al. consultant, James F. Wilson of Wilson Energy Economics, generally found DEC and DEP's 2018 IRP load forecasts to be reasonable for planning purposes and compliant with Commission rules and requirements. On pages 21 to 23 of his Evaluation of Load Forecasts, Mr. Wilson summarized several recommendations to the Commission regarding the 2018 load forecasts, to which Duke responded to selected recommendations as set forth below:

> **v. Duke should research the drivers of the very high loads that have occurred in each service territory under very cold weather.**

Duke commented that it agrees with the Public Staff's assessment in its 2018 IRP comments that primary drivers of high peak demand during extreme temperatures are the predominance of electric heat pumps, and the lack of availability of natural gas as a heating source. According to Duke, these factors are more significant in DEP's than in DEC's service territory, which is indicative by how much more sensitive the DEP region is to extreme winter weather. Duke noted that it will continue to share information on this topic with the Public Staff and other intervenors as more information becomes available.

> **vi. Duke should develop a more sophisticated model of how extreme winter weather affects their loads, drawing upon the experience gained over the past five years. The focus should be on accurately modeling not just the usual (that is, long-term typical) peak-producing weather, but also more extreme conditions, which have occurred in recent years and can cause loads well above the usual annual peaks. Detailed analysis might show, for example, that an average of temperatures over an extended period leading up to the morning peak hour (perhaps 12 preceding hours) better predicts the peak than the single hourly or daily average temperature, and that other conditions, such as wind speeds and cloud cover, also have predictive value. A similar model for extreme summer weather could also be developed.**

Duke noted that its understanding is that the peak forecast should provide a reasonable forecast of system demand, under the assumption of peak normal weather. According to Duke, the model does account for any historical extreme weather and peak conditions within the past 7 years for model specification, and the past 30 years for the development of peak weather normal conditions. Duke disagrees with the suggestion to modify the current peak model to capture extreme conditions, as this would conflict with the NCUC's Order from the 2016 IRP proceeding, Docket No. E-100, Sub 147. More specifically, such a modification would increase the standard errors of the peak model coefficients, resulting in a peak forecast that will not satisfy the Commission's mandate of a peak forecast that predicts probable growth. Duke noted that although both jurisdictions have seen several extreme winters recently, these few data points are clearly outliers. Structuring the peak model to model historical outliers would result in peak forecasts that may drastically over- or under-forecast peaks, even under normal circumstances. Finally, Duke commented that it does not share Mr. Wilson's perception regarding the lack of sophistication of the peak models. Duke explained that it continuously evaluates the peak model specifications to improve peak forecast accuracy, in accordance with the Commission's Order from the 2016 IRP proceeding, Docket No. E-100, Sub 147.

> **vii. Duke should provide more comprehensive documentation of their peak load forecasting methodology. Duke should consider enhancing their approach to make use of a broader set of high load data (not just monthly peaks), and an enhanced relationship between weather conditions and load as described above. Duke should also consider providing sensitivity analysis of the peak forecasts to key drivers and assumptions, to demonstrate whether the forecasts are likely to be stable over time, or instead may change substantially due to new data.**

Duke noted that it is committed to transparency regarding all aspects of the load forecast methodology. Duke explained that it cannot endorse Mr. Wilson's recommendations suggested above, which would conflict with producing a reasonable peak forecast, as mandated by N.C. Gen. Stat. § 62-110.1(c). Finally, Duke questioned how Mr. Wilson defines "stability over time." Duke explained that its peak models use actual monthly peaks and the average daily weather on the day of peak as inputs. In recent years, some of these historical data points reflect extreme or mild peak conditions. According to Duke, while Mr. Wilson may perceive these extreme historical data points as instability, Duke views each historical data point as vital information that will provide guidance in identifying vital information that leads to improving load forecast accuracy.

> **viii. Duke should develop a more effective method for estimating historical weather-normalized peak loads. Weather-normalized values are very useful for understanding load trends, and Duke's new approach appears to have shortcomings (the approach used in the 2016 IRPs accounted for weather variation more completely). The more sophisticated model of how weather affects loads, recommended above, should contribute to a more accurate weather-normalization methodology.**

Duke noted that it agrees with Mr. Wilson about the importance of the peak weather-normalization process in understanding peak history and evaluating peak forecasts. Duke also agreed that its methodology is "imperfect," as are all its processes (and those of every load forecaster who attempts to predict the future), due to the dynamic nature of load forecasting. However, Duke disagrees with Mr. Wilson's following assertions regarding their weather-normalization process:

- Mr. Wilson's comments inaccurately describe Duke's weather-normalization process via simplification, compared to the summary description provided in the 2018 IRPs.

- Mr. Wilson asserts that Duke recognizes that the weather normalization process is "imperfect" and does not fully remove the impact of actual weather. Duke agrees that the methodology is imperfect, primarily due to the natural chaotic behavior of weather. Specifically, the more extreme (normal) peak conditions are, the less (more) likely the peak normalization process will be to capture weather impacts accurately.

- Mr. Wilson refers to the previous weather-normalization process (2016 IRP) as being superior to the current methodology. According to Duke, Mr. Wilson mistakenly describes Duke's process as focusing solely on the peak day. Part of Duke's revised peak weather normalization process implicitly includes a "build-up" effect from the previous day(s) of the peak. This enhancement has proven to be more effective in generating peak weather normal than the previous methodology, which focused solely on the coldest day, which may or may not have aligned with the day of peak. Duke explained that it is important to note that Mr. Wilson's comments appear to be directed more at extreme peak events, which are outliers in history, versus the normal peak demand history that typically occurs.

- Duke disputes Mr. Wilson's assertions that the weather-normalization process does not produce a clear historical trend. Tables C-5 and C-6 of the 2018 IRPs provide annual historical trends of DEC and DEP actual and weather normal peak trends. In comparison, Mr. Wilson's charts (JFW-5 to JFW-8) provide an "alternate" view of this data by narrowing the magnitude of the Y-Axis, which gives the perception of nonlinearity. Finally, Mr. Wilson asserts that the Companies' peak weather normal history should be a steady linear trend. In his comments, he assumes that the underlying drivers of the peak weather-normalization history were relatively stable. However, according to Duke, from 2011 to 2018, both DEC and DEP saw various economic, weather, industrial, and jurisdictional load definition disruptions that impacted the weather normalization process.

ix. With respect to wholesale loads, Duke should provide historical aggregate wholesale firm commitments. Weather-normalized historical peaks should be estimated for the wholesale customer loads separately (and such estimates should exclude quantities associated with any short-term wholesale transactions that may have been in place at the time of the peak). The Companies should further evaluate wholesale customers' contribution to system peak loads, which affect required reserve margins and capacity needs.

Duke currently incorporates an energy and demand forecast methodology like the retail energy and peak forecasts, with the following exceptions:

- All forecasts are econometric models; and
- Duke does not forecast North Carolina Electric Membership Corporation (NCEMC) and North Carolina Eastern Municipal Power Agency (NCEMPA) contracts per agreement, and incorporate those forecasts into the system forecast as given.

G. DENC Reply Comments – Peak and Energy Forecasts

Chapter 2 of DENC's 2018 IRP describes DENC's methodology for forecasting its peak demand and energy sales needs. DENC presented its 15-year peak and energy forecasts (2019-2033) and compound annual growth rates (CAGRs) for the relevant years. In its Compliance Filing, DENC revised its peak demand forecast using the PJM Interconnection, L.L.C. (PJM) DOM Zone non-coincident peak forecast (the PJM load forecast), which resulted in a reduction of the 2018 IRP's peak demand forecast. This revision is addressed at Section 3.d of the Compliance Filing. DENC's 2018 IRP is modeled to procure both supply-side and demand-side resources with the annual forecast of summer peak demands. While PJM predicts that the DOM Zone will become a winter peaking system in 2024because DENC is part of PJM and the Compliance Filing uses the PJM load forecast, DENC continued to model its 2018 IRP based on summer peak demand. DENC predicted its energy sales to grow at an average annual rate of 0.7%, which is a decrease from the 1.5% growth rate predicted in DENC's 2016 IRP. Relatedly, DENC's 2018 IRP predicted that the savings from EE programs is anticipated to reduce energy sales by 2% by 2033, which is a greater reduction compared to the 1% reduction in energy sales predicted in DENC's 2016 IRP.

DENC stated in its reply comments that it is not opposed to showing both the PJM and Company load forecasts for the 2020 IRP. In addition, consistent with the Public Staff's recommendation, DENC stated that it is committed to studying the effects of the winter peak on its econometric and statistical forecast models either through its own analysis or that of an outside consultant. DENC noted that in its final order on its 2018 IRP and Compliance Filing,[1] the VSCC directed DENC to continue to use the PJM load forecast, reduced by the energy efficiency spending requirement of Virginia Senate Bill 966, both as an energy reduction and a supply resource, and separately identify the load associated with data centers in its 2020 IRP. Therefore, DENC noted, the PJM load forecast is now required to be used in DENC's future full IRP filings.

With regard to smart meter data, DENC noted that Virginia now requires it to evaluate "[l]ong-term electric distribution grid planning and proposed electric distribution grid transformation projects" in preparing its full IRPs beginning with the 2020 IRP, and that information about the use of smart meters will also be part of DENC's Grid Transformation Plan, which it intends to refile with the VSCC in 2019. DENC also noted that its ability to use smart meter data to inform load forecasting, cost of service studies, and rate designs will be limited until it can fully deploy smart meters throughout its service territory. Nevertheless, DENC stated that it intends to use data from its smart meters to inform these matters when sufficient data is available.

II. RESERVE MARGINS

A. Public Staff Initial Comments – Reserve Margins

1. DEP and DEC

The Public Staff explained that based upon the 2016 Resource Adequacy Study performed by Astrapé (Resource Adequacy Study), both Companies used a combined 17% reserve margin for planning purposes. The Public Staff noted that the study was warranted due to extreme weather experienced in the Companies' service territories and was first presented during the 2017 IRP update in Docket E-100, Sub 147. The Public Staff pointed out that the use of peak system load for system planning is relevant in the context of the capacity value of solar resources. Both DEP and DEC have target reserves of 17%, with DEP having a 17% minimum reserve over the planning horizon and DEC at 16.8%, and DEP having a maximum reserve over the planning horizon of 33.8% in the summer of 2025 and DEC at 22.4% in the summer of 2023. For the planning period 2019 to 2033, the Public Staff stated that the range of reserve margins reported by the electric

[1] In re: Virginia Electric and Power Company's Integrated Resource Plan filing pursuant to Va. Code § 56-597 et seq., Case No. PUR-2018-00065 (June 27, 2019) (VSCC Compliance Order).

utilities continues to be similar to those seen in previous IRPs, i.e., a loss of load expectation (LOLE) of 0.1 days/year of 16.7% for DEC, 17.5% for DEP, and an average of 17.1% for the combined Companies.

The Public Staff noted that in its April 2, 2018, Joint Report with Duke discussing the Resource Adequacy Study, the Public Staff raised several concerns with the Astrapé study, including the use of forced outrage rates, load regression during extreme events, economic load growth error, load multiplier values, and joint utility operations. The Public Staff recommended a 16% reserve margin. On the other hand, Duke argued it was more appropriate to take a holistic view of the study's reasonableness as opposed to focusing on specific individual factors that could potentially result in a lower reserve margin. The Public Staff noted that the Commission's April 16, 2018 Order Accepting Filing of 2017 Update Reports and Accepting 2017 REPS Compliance Plans, concluded DEC and DEP could continue to use the minimum 17% winter reserve margin for planning purposes, but should present a sensitivity analysis in their resource plan discussion illustrating the impact of a 16% winter reserve margin for planning, including the risk impacts. Duke was also required to address how to model economic load forecast uncertainties in its 2018 IRPs.

The Public Staff explained that the Companies' 2018 IRPs examined the impact of a 16% reserve margin on the timing of future resource additions as well as on system LOLE. DEC found that a 16% reserve margin would not have any effect on future resource additions, and that LOLE would increase to 0.116 days/year, or one expected firm load shed event every 8.6 years. DEP found that the 16% reserve margin would reduce its short-term market purchases and defer a portion of the combustion turbine (CT) blocks in 2029 and 2032 by two years each. The Public Staff also noted that DEP calculated a LOLE of approximately 0.13 days/year based upon these changes, which is equivalent to one expected load shed event every 7.7 years.

In addition to the effects of a 16% reserve margin, the Public Staff noted that Duke's IRPs addressed load forecast error (LFE) assumptions involving uncertainty and probability distribution. With respect to LFE uncertainty, the Public Staff explained that the Companies presented additional Resource Adequacy Study results with no LFE that indicated that the required reserve margin is only 0.28% less than the Public Staff's recommendation of 16%. The Public Staff further noted the Companies' belief that there is meaningful load growth uncertainty over a two to four-year period, requiring reserves greater than 0.28%

With respect to LFE probability distribution, the Public Staff pointed out that the Companies predict a symmetrical probability distribution, where there is equal likelihood of a significant under or over-forecast. However, the Public Staff's LFE probability distribution used a log-normal distribution so that the probability of a lower-than-expected economic growth rate is greater than a higher-than-expected economic growth rate. The Public Staff noted that Duke indicated that it found it inappropriate to use the over-forecast bias recommended by the Public Staff.

The Public Staff stated that it continues to believe that use of a 2-year LFE is appropriate, given that IRPs are required to be filed every two years and that the effects of cold weather outages should be removed. The Public Staff noted that it agreed with Duke that several modeling and market assistance assumptions should be revisited in the next resource adequacy study. As such, the Public Staff continued to recommend a 16% reserve margin, but indicated its willingness to work with the Companies to reach consensus within the constructs of the next resource adequacy study.

2. DENC

The Public Staff noted that DENC, as a member of PJM, is a summer planning and summer peaking utility, and generally considers summer peak load as the load upon which the reserve margin is based. The Public Staff pointed out that in its original filing, DENC used PJM's reserve margin of 15.9%, adjusted based on the coincident factor between the DOM Zone coincidental and non-coincidental peak load, resulting in a reserve margin target of 11.7%. This reserve margin calculation is the same in both the original IRP and the Compliance Filing, but the Public Staff noted that the load forecast is reduced to comply with the VSCC Order in DENC's Compliance Filing. The Public Staff pointed out that the original IRP projected a deficit under Alternative Plan E of 5,275 MW, while the Compliance Filing projects a deficit of 3,028 MW – a 43% reduction in capacity need by 2033.

B. SACE, Sierra Club, and NRDC Initial Comments – Reserve Margins

According to comments filed by SACE et al., the planning reserve margin is a key element of an IRP because it determines how much extra capacity the utility maintains on its system to meet demand in the event of an outage or other unanticipated capacity gap. Both of the Duke 2018 IRPs use a 17% winter planning reserve margin, an increase relative to the 16% reserve margins used before the 2016 IRPs. These planning reserve margins used in developing the IRPs were, in turn, based on resource adequacy studies conducted by Astrapé Consulting in 2016 (2016 RA Studies). SACE et al. retained James F. Wilson, an economist and independent consultant in the electric power and natural gas industries, to evaluate reserve margins used in the 2018 IRPs. Mr. Wilson concluded that due to a number of flaws in the 2016 RA Studies, the DEC and DEP planning reserve margins are improperly inflated, and the 17% planning reserve margins should be rejected.

According to the SACE et al.'s summary of Mr. Wilson's findings, the 2016 RA Studies exaggerated the risk and magnitude of extreme winter peak loads, calling into question the shift by DEC and DEP to planning for "winter-peaking" systems. The RA Studies also substantially overstated the risk of very high loads under extreme cold, mainly due to a faulty approach to extrapolating the increase in load due to very low temperatures. In addition, due to the RA Studies' assumptions about demand response capacity and operating reserves applicable to winter peak conditions, the resource adequacy risk in winter was substantially overstated relative to the risk in summer and other periods of the year. Mr. Wilson also suggested that including multi-year economic load forecast uncertainty in the resource adequacy studies is not appropriate because many short lead-time actions could and very likely would be taken if load grows faster than expected. These findings, along with corresponding recommendations for improvement, are discussed in detail in the Wilson Energy Economics report.[1] Based on Mr. Wilson's analysis, SACE et al. commented that the use of overly high reserve margins in the IRPs means that DEC and DEP are planning to add too much new capacity on the system, which would add unnecessary costs for ratepayers.

C. NCSEA Initial Comments – Reserve Margins

NCSEA commissioned the Synapse Study in order to perform "a rigorous, scenario-based analysis to evaluate an alternative clean energy future compared to the more traditional portfolio of fossil-fueled resource additions included in Duke Energy Carolinas and Duke Energy Progress's (collectively Duke Energy) IRPs". Synapse Study, p. 1. The study found that the energy portfolio in Duke's 2018 IRPs is not the least cost mix of energy resources, and that the Synapse Study's Clean Energy Scenario was a more economical energy portfolio for the state. Id. As part of its least-cost analysis, Synapse evaluated the reserve margin that would achieve its Clean Energy Scenario.

> The Clean Energy Scenario maintains the required 15 percent reserve margin and EnCompass projects no loss-of-load hours and sees zero hours with unserved energy, proving that the retirement of fossil fuels and build-out of renewables leads to no new system reliability issues.

NCSEA Initial Comments, p. 8. As indicated above, according to Synapse's analysis, a 15% reserve margin achieves both aspects of an adequate reserve margin as defined by Duke: it is high enough to ensure reliable energy for Duke customers without burdening ratepayers.

D. DEC and DEP Reply Comments – Reserve Margins

DEC and DEP noted that they used a 17% minimum winter reserve margin target in development of their 2018 IRPs, consistent with results from the 2016 resource adequacy studies. DEC and DEP stated that since completion of the 2016 studies, they have worked extensively with the Public Staff and other intervenors to explain study results and methodology and respond to discovery in efforts to address intervenor questions and concerns.

As an initial matter, DEC and DEP stated that they have complied with all Commission orders regarding the 2016 resource adequacy studies. The NCUC's 2016 IRP Order in Docket No. E-100, Sub 147 concluded that the reserve margins included in the DEP and DEC 2016 IRPs are reasonable for planning purposes. They pointed out, however, that the Commission also directed DEP and DEC to work with the Public Staff to address outstanding concerns raised by the Public Staff and SACE consultant Wilson. The Commission further directed the DEC, DEP, and the Public Staff to file a Joint Report summarizing their review and conclusions within 150 days of the filing of Duke's 2017 IRP updates. The Joint Report was filed on April 2, 2018 and noted that although the discussions between the Public Staff, DEC and DEP were helpful, the parties did not reach agreement regarding the methodology used to incorporate economic load forecast

[1] James F. Wilson, Review and Evaluation of Resource Adequacy and Solar Capacity Value Issues with Regard to the Duke Energy Carolinas and Duke Energy Progress 2018 Integrated Resource Plans and Avoided Cost Filing (February 12, 2019).

uncertainty. Ultimately, the Public Staff recommended that DEC and DEP utilize a 16% reserve margin in their IRPs, and DEC and DEP recommended a minimum 17% winter reserve margin in their IRPs. The Commission's April 16, 2018 Order Accepting Filing of 2017 Update Reports and Accepting 2017 REPS Compliance Plans, in Docket No. E-100, Sub 147 (Sub 147), accepted the parties' Joint Report and concluded that DEC and DEP may continue to utilize the minimum 17% winter reserve margin for planning purposes in their 2018 IRPs. In addition, the Commission ordered DEC and DEP to further address the economic load forecast uncertainty issue in their 2018 IRPs. The Commission also required the Companies to present a sensitivity analysis in their 2018 IRPs that illustrates the impact of a 16% winter reserve margin, including the specific risk impact (LOLE) of using a 16% minimum reserve margin versus a 17% minimum reserve margin. DEC and DEP assert that they complied with the Commission orders in developing their 2018 IRPs.

1. Economic Load Forecast Uncertainty

In this docket, the Public Staff continues to support a 16% reserve margin target based on their PS-S2 scenario proposed in Sub 147 which reflects the removal of short duration cold weather-related outages primarily experienced during the winter of 2014, and also incorporates different economic load forecast uncertainty assumptions as compared to assumptions used in the 2016 studies. As a result of these differences, the PS-S2 scenario results in a reserve margin target of 16%, though DEC and DEP continue to support a reserve margin target of 17%.

DEC and DEP stated that they had previously demonstrated that removal of the cold weather outages, as requested by the Public Staff, is insignificant to the 2016 Resource Adequacy study results and impacts the average reserve margin by less than 0.1%. DEC and DEP explained that, as documented extensively in the Joint Report and the Companies' 2018 IRPs, the Companies believe that the Public Staff's load forecast uncertainty assumptions overstate the probability that actual load will be at or below the Companies' forecast levels. DEC and DEP commented that they are not comfortable with the over forecast bias that is assumed in the Public Staff's load forecast error assumptions, which reflect a probability of over forecasting load approximately 48% of the time and under forecasting load approximately 17% of the time.

Instead, DEC and DEP believe that because the load forecast represents a 50/50 forecast, the load forecast uncertainty should reflect possible loads that are equally likely to fall either above or below the forecast. That is, 50% of the time load growth is expected to be higher than projected, and 50% of the time it is expected to be lower than projected. This load forecast uncertainty distribution more reasonably captures expected fluctuations in load growth as compared to the PS-S2 scenario, which reflects an over-forecast of load the majority of the time.

Further, DEC and DEP commented that, as demonstrated in the Companies' 2018 IRPs, assuming perfect knowledge of its 50/50 weather normal forecast, the Public Staff's recommended 16% reserve margin is only 0.28% greater than the reserve margin needed with perfect forecasting knowledge. DEC and DEP believe that there is meaningful load growth uncertainty over a two to four-year period and that reserves of greater than 0.28% of load are required to manage that risk.

DEC and DEP explained that, given the disagreement in methodology and assumptions for incorporating load uncertainty in the resource adequacy studies, it is notable that the Public Staff expressed concerns in their IRP comments regarding DEP's projected annual peak demand growth rate reflecting a significant departure as compared to higher growth of actual winter peaks.[1] Through discovery[2] DEC and DEP asked the Public Staff to reconcile that concern with their position regarding the economic load forecast uncertainty included in the resource adequacy studies which reflects a significantly greater probability of over-forecasting load growth compared to under-forecasting load growth. The Public Staff explained that their concerns about the forecasting accuracy of DEP's winter peak demands relate to the inability of the forecasting process to adequately capture how customers' use of energy changes in response to extreme weather events. The Public Staff further noted that this issue is unrelated to the economic load uncertainty referred to in the Public Staff's scenario PS-S2. DEC and DEP noted that they appreciate and recognize this difference but also noted that this issue further illustrates the uncertainty in the non-weather-related load forecast, and that DEC and DEP believe that the uncertainty included in the resource adequacy studies is not unreasonable.

2. Multi-Year Economic Load Forecast Uncertainty

SACE et al. consultant Wilson suggests that including multi-year economic load forecast uncertainty in the resource adequacy studies is not appropriate and suggests that many short lead-time actions could and very likely would be taken if load grows faster than expected.[3] Mr. Wilson suggests that if the rate of load growth raised concerns about resource adequacy, utilities would have time adjust their plans and take actions such as accelerating the development of new resources, increasing demand response or energy efficiency programs, delaying a planned retirement, adjusting firm purchases or allowing wholesale contracts to expire. DEC and DEP commented that while these are all worthy ideas and actions that they would likely consider in the event of a significant increase in the load forecast due to economic or other uncertainty, such alternatives are not always sufficiently available or practical to satisfy a resource deficit. In particular, large quantities of demand response and energy efficiency programs are typically not achievable within a short timeframe.

According to DEC and DEP, the 2018 DEP IRP saw a 600 MW increase in winter peak demand from the 2017 IRP Update, which contributed to an approximate 2,000 MW near-term need for capacity and energy resources in DEP. As a result of that increase, and as identified in the IRP, DEP conducted a capacity and energy market solicitation that sought to extend existing purchase power contracts and identify new capacity proposals from similar operationally capable existing generation facilities or systems with firm transmission deliverability into DEP. While the response to the market solicitation was robust, the capacity need in DEP is significant, and additional steps may be needed to ensure that DEP can continue to meet its 17% minimum reserve margin requirement. DEC and DEP noted that options, including deferring unit retirements, are limited, however. Additionally, due to the influx of solar in the Carolinas, which has limited

[1] Reference page 78 of Public Staff's Comments which states: "The Public Staff is also concerned with the predicted annual growth rate of DEP's winter peaks of 0.7%, reflecting a significant departure from the historical growth of its actual winter peaks that have grown at a 3.0% CAGR from 2013 through 2018, while the weather-normalized peaks have grown at 2.1%."

[2] Public Staff response to DEC/DEP data request No. 1-1.

[3] SACE et al. Comments, Attachment 4, at 15.

contribution to meeting winter peak capacity needs, the transmission interconnection queue is operating with a significant delay, which makes building new generation that requires transmission interconnection studies, very challenging to execute in an expedited manner. As the timing required to site new generation increases, and older generating units are asked to operate longer to meet capacity requirements, the need to include multi-year economic load forecast uncertainty in the resource adequacy studies only increases. The reality of these circumstances suggests that including only one year of load forecast uncertainty, as suggested by Mr. Wilson, to establish a long-term reliability planning target, is inadequate.

3. Relationship between Winter Load and Cold Temperatures

DEC and DEP noted that SACE et al. consultant Wilson echoes many of the same arguments he presented in the 2016 IRP proceeding concerning the Companies' 2016 Resource Adequacy studies. In particular, they stated that he again argues against the methodology used to capture the relationship between winter load and cold temperatures.[1] DEC and DEP asserted that they have complied with all Commission orders regarding the 2016 Resource Adequacy studies, including working with the Public Staff to address Mr. Wilson's concerns.

Mr. Wilson notes that including "more rather than less historical weather data is preferred" but also suggests that the 15-year period from 1982-1996 should be excluded because it results in flawed regressions and overstates winter resource adequacy risk.[2] This is also apparent from his statement "...the 2016 RA Studies results are very sensitive to the choice of 20 or 30 historical weather years..."[3] DEC and DEP commented that the purpose of a reserve margin is to cover uncertainties such as extreme load and generator outages and it would be irresponsible to ignore the potential for these extreme cold weather events when assessing resource adequacy. They argued that excluding 15 years of the 36-year weather history used in the study just because it reflects colder temperatures compared to other historical years is irresponsible. These are precisely the periods that the reserve margin is designed to cover. DEC and DEP explained that, in fact, as noted in the Joint Report, NCUC Rule R8-61 (CPCN) requires utilities to provide "a verified statement as to whether the facility will be capable of operating during the lowest temperature that has been recorded in the area..."[4] DED and DEP noted that the Commission is concerned and expects utilities to provide reliable service to customers even during extreme weather events.

DEC and DEP explained that, pursuant to the Commission's June 27, 2017 Order accepting the Companies' 2016 IRPs, the Public Staff, DEC and DEP reviewed the cold weather load modeling in the 2016 studies and performed a sensitivity analysis that reduced the regression equations significantly for temperatures below the levels seen in recent years.[5] This sensitivity

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[1] Id., at 6-13.

[2] Id., at 12.

[3] Id., at 25.

[4] Joint Report filed in Docket No. E-100, Sub 147, April 2, 2018, at slide 10.

[5] Id., at slide 20.

analysis showed a relatively small decrease in reserve margin (0.3%) given that the sensitivity reduced the cold weather impact by half of that assumed in the base case. According to DEC and DEP, the reason that the impact is not larger is because the sensitivity only impacts 7 occurrences in the 36-year weather history. As stated by the Public Staff in the Joint Report, after having further discussions with DEC and DEP, the Public Staff was satisfied that the approach taken in the 2016 studies by the Companies is reasonable.[1]

DEC and DEP further noted that the 2016 resource adequacy studies reflected a maximum summer peak that was 7.5% above the expected summer peak for both DEC and DEP. In comparison, the 2018 PJM Reserve Requirement Study reflects a maximum summer peak that is 24% higher than the expected summer peak.[2] For winter, the 2016 study for DEC reflected a maximum winter peak that was 18.3% greater than the expected winter peak while the DEP study reflected a winter peak that was 21.5% greater than the expected winter peak. In comparison, the 2018 PJM study reflected a maximum winter peak that was 21% higher than the expected winter peak. DEC and DEP explained that the variability in load due to temperature extremes that was modeled in the 2016 resource adequacy studies for DEC and DEP were at or below the peak load variability included in the 2018 PJM study.

DEC and DEP noted that they and Astrapé recognize that appropriately capturing the relationship between extreme cold weather and load are key drivers of the resource adequacy study results. Although there is limited data at extreme cold temperatures, DEC, DEP, and Astrapé believe that the modeling included in the 2016 studies was reasonable. DEC and DEP therefore asserted that Mr. Wilson's comments on this topic are not persuasive.

4. Operating Reserve Assumptions

DEC and DEP argued that Mr. Wilson initiated a new unfounded claim in SACE et al.'s comments by claiming that the 2016 Resource Adequacy studies exaggerate winter risk through the operating reserve assumptions. They asserted that Mr. Wilson's claim that over 1,000 MW for DEC, and about 750 MW for DEP, of operating reserves are held back in the SERVM model resulting in firm load curtailments is grossly inaccurate.[3] In fact, DEC and DEP noted that SERVM allows operating reserves to drop to the regulation requirement which was 216 MW in DEC and 134 MW in DEP for the resource adequacy and solar capacity value studies. DEC and DEP commented that it is interesting to note that they responded in detail to this exact question in response to DEC-DEP SACE DR 2-19 in Sub 147, yet Mr. Wilson still makes these unsubstantiated claims regarding the operating reserves policy used in the studies. DEC and DEP argued that Mr. Wilson's arguments have no basis in fact and should be rejected.

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[1] Id., at 2.

[2] 2018 PJM Reserve Requirement Study: https://www.pjm.com/-/media/planning/res-adeq/2018-pjm-reserve-requirement-study.ashx?la=en

[3] SACE et al. Comments, Attachment 4, at 20.

5. **Demand Response Assumptions**

SACE et al. consultant Wilson concludes that the DEC's and DEP's demand response winter assumptions should be "brought up to the summer level."[1] Although DEC and DEP agree that winter demand response programs are a reasonable tool for reducing winter peak demand and winter LOLE, when available, they note that the levels of reduction proposed by Mr. Wilson are extremely optimistic and not reasonably achievable in the near term, if at all. DEC and DEP commented that, as an example, the residential DEP EnergyWise Home program currently offers winter measures (Hot Water Heaters & Heat Pump Heat Strips) in its Western region in and around Asheville. These measures have been in place for 10 years and have been marketed aggressively with direct mail, email, outbound calling, and door-to-door canvassing. Over that 10-year period, the program has achieved 15 MW for a residential customer base of approximately 150,000. According to DEC and DEP, assuming the same level of achievable potential in the rest of DEP and DEC, a more reasonable estimate of residential winter DSM would be 150 MW in each jurisdiction in 10 years, which would only be true if those measures remained cost-effective into the future.

DEC and DEP stated that, moreover, actual program experience from DEP EnergyWise Home has shown that winter residential program potential is actually more difficult to achieve than summer potential for several reasons. First, not all residential customers have electric resistance hot water heaters or heat pumps with electric resistance strip heat. Instead, almost all have compressorized cooling in the form of straight air conditioning or heat pumps. Second, residential winter measure installations require appointments to enter the customer's home that are often rescheduled and more costly than a summer air conditioning installation, which does not require an in-home installation.

DEC and DEP also noted their plans to implement new winter DSM programs as proposed in the 2018 IRPs, and to continue their work toward implementation of those programs. According to DEC and DEP, however, the extreme amounts of winter demand response programs anticipated to be cost-effective and reasonably achievable as cited by Mr. Wilson cannot prudently be included in the IRP forecast. They explained that Mr. Wilson attempts to support his claim by stating that the most recent Market Potential Study for DEC and DEP identified additional winter demand response technical and economic potential up to 2,300 MW;[2] however, the amount of potential that is reasonably achievable must be based on DEC's and DEP's experience with DSM program adoption and, in DEC and DEP's experience, adoption of high levels of DSM programs has been challenging despite significant effort by the Companies. According to DEC and DEP, therefore, Mr. Wilson's claim that winter demand response can be magically brought up to the summer level to reduce winter resource adequacy risk should be rejected.

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[1] Id., at pp. 19-20.

[2] Id., at 20.

6. Load Net of Solar Resources

Mr. Wilson makes the following assertion on page 22 of Attachment 4 to SACE et al.'s Comments:

> A more balanced seasonal weighting is also suggested by the simple fact that the vast majority of high load hours are in summer on both systems. According to DEC's load forecast, 83% of the highest load hours (top 1%) are in summer; for DEP's load forecast, 74% of the top 1% load hours are in summer.

DEC and DEP commented that, as Mr. Wilson points out, DEC and DEP do experience significant summer loads; however, summer peaks occur in late afternoon hours when solar has significantly greater energy contributions as compared to dark winter mornings where very little – if any – solar is available at the time of peak. Thus, the summer peak loads net of solar output are reduced relative to winter peak loads net of solar. DEC and DEP explain that this load net of solar has a significant impact on summer versus winter LOLE values and represents the net load that the remainder of the Companies' resources must satisfy. They noted, however, that when asked whether Mr. Wilson's analysis of seasonal weighting reflected consideration of load net of solar resources, SACE et al. responded, "...that comment referred to load, not load net of any particular resources."[1] Further, when asked to provide a detailed explanation of why Mr. Wilson believes it is appropriate to exclude the impact of solar generation when evaluating seasonal loss of load risk, SACE et al. responded; "Not applicable."

DEC and DEP stated that they appreciate constructive feedback regarding their planning processes and studies. They argued, however, that misleading (winter load and temperature relationship); unachievable (demand response potential) and false (operating reserves policy) claims regarding the 2016 resource adequacy studies largely do not add value and are counter-productive. DEC and DEP also noted that their review of Mr. Wilson's comments was also limited by insufficient information and late responses to the Companies' data requests (SACE et al.'s responses to DEC/DEP Data Requests Nos. 4-2 and 4-5).

[1] SACE et al. response to Duke Data Request 4-5.

7. **Resource Adequacy Summary Comments**

DEC and DEP noted that, as stated in the 150 Day Joint Report and 2018 IRPs, they believe that a holistic review and consideration of resource adequacy study inputs and assumptions is appropriate when judging the reasonableness of the study results. DEC and DEP stated that while some parties may believe that certain study inputs and assumptions may have overstated the required reserve margin (i.e., resulting in a reserve margin that is too high), they believe that certain assumptions in the 2016 studies, including outage rate modeling and market assistance assumptions, may have been aggressive and understated the required reserve margin (resulted in a reserve margin that is too low). DEC and DEP agree with Mr. Wilson's comment that resource adequacy and reserve margin requirements can change over time and they note that this is precisely why DEC and DEP conduct periodic resource adequacy assessments in order to capture significant changes in inputs and assumptions that may impact study results. DEC and DEP expressed their plans to work with the Public Staff to refresh inputs and assumptions and complete new resource adequacy studies in support of their 2020 IRPs. According to DEC and DEP, it is prudent to maintain a minimum 17% winter reserve margin to provide adequate reliability and satisfy the target of less than one firm load shed event every 10 years. As a result, DEC and DEP recommend use of a 17% winter reserve margin until such time as a new study is completed.

E. **DENC Reply Comments – Reserve Margins**

Chapter 4 of DENC's 2018 IRP discusses its Planning Assumptions, and states that DENC participates in the PJM capacity planning process for short- and long-term capacity planning. As a PJM member, DENC is a signatory to PJM's Reliability Assurance Agreement, which obligates it to own or procure sufficient capacity to maintain overall system reliability. PJM determines these obligations for each zone through its annual load forecast and reserve margin guidelines, and then conducts a capacity auction through its Short-Term Capacity Planning Process for meeting these requirements three years into the future. This auction process determines the reserve margin and the capacity price for each zone for the third year. DENC is obligated to obtain enough capacity to cover its PJM-determined capacity requirements either from the auction or through bilateral trades.

DENC uses PJM's reserve margin guidelines in conjunction with its own load forecast to determine its long-term capacity requirement. PJM's 2017 Reserve Requirement Study recommended using a reserve margin of 15.9%. DENC uses a coincidence factor to account for the historically different peak periods between DENC and PJM and determine the reserve margin needed to meet reliability targets. The coincidence factor reduces DENC's reserve margin requirement to 11.7%. The same 11.7% requirement was utilized in the Compliance Filing.

In its reply comments, DENC stated that it does not oppose the Public Staff's recommendation that, in future IRPs, DENC should provide information regarding PJM's capacity value for renewable resources as well as a justification for any difference between DENC's and PJM's calculated capacity values or methodology. Accordingly, DENC stated that it would provide such information in its 2019 IRP update. In addition, DENC noted that the VSCC has directed DENC to, in future full IRPs, model future solar PV tracking resources using two alternative capacity factor values: (a) the actual capacity performance of Company-owned solar tracking fleet in Virginia using an average of the most recent three-year period; and (b) 25%. Finally, DENC stated that it will evaluate incorporating a sub-hourly analysis into the 2020 IRP. DENC noted that because it uses internal information to establish the adjusted reserve margin and coincidence factor and the use of advanced analytical techniques requires a level of detail not provided in the PJM forecast, it will therefore use available internal data and forecasts when evaluating the feasibility and benefits of advanced analytical techniques in the 2020 IRP.

III. SYSTEM PEAKS, DEMAND-SIDE MANAGEMENT (DSM) AND ENERGY EFFICIENCY (EE)

A. System Peaks

1. Public Staff Initial Comments – System Peaks (DEP)

The Public Staff noted that DEP's 2018 annual system peak demand of 16,191 MW occurred on January 7, 2018, at the hour ending 7:00 a.m., at a system-wide temperature of 11 degrees Fahrenheit (°F). DEP activated its DSM resources and reduced its winter peak hourly load by 225 MW. The Public Staff noted that during the Company's nine other highest hourly winter loads, DEP activated its DSM six more times when the average system temperature was between 15°F and 24°F.

Based on the Public Staff's comments, DEP's summer system peak of 13,403 MW occurred on June 19, 2018, at the hour ending 5:00 p.m., at a system-wide temperature of 94°F. DEP activated its DSM resources and reduced its summer peak hourly load by 22 MW. During the Company's nine other highest hourly summer loads, the Public Staff noted that DEP activated its DSM program five more times between 91°F and 93°F.

2. Public Staff Initial Comments – System Peaks (DEC)

The Public Staff noted that DEC's 2018 annual system peak demand of 19,436 MW, occurred on January 5, 2018, at the hour ending 8:00 a.m., at a system-wide temperature of 12°F. DEC's summer system peak was 18,008 MW occurred on June 19, 2018, at the hour ending 4:00 p.m., at a system-wide temperature of 94°F. According to the Public Staff, DEC did not activate any of its DSM resources during either the winter system peak or the summer peak. During the Company's nine other highest hourly winter peak loads, DEC activated its DSM program during five of those hours when the average temperature at the peak was 10°F and 13°F. In regard to the nine other highest hourly summer loads, the Public Staff noted that DEC activated its DSM once during its ninth highest hourly load, when the average temperature was 91°F.

In its recommendations regarding Duke's IRPs, the Public Staff recommended that the Companies maximize the use of their DSM to reduce fuel costs, especially when marginal costs of energy are high, as well as to ensure reliability. The Public Staff also recommended that the Companies' DSM resource forecast represent the reasonably expected load reductions that are available at the time the resource is called upon as capacity. Finally, the Public Staff proposed that DEC and DEP investigate the potential for new time-of-use rate designs that could encourage customers to shift usage from peak to off-peak periods, particularly during winter peaks.

3. Public Staff Initial Comments – System Peaks (DENC)

The Public Staff noted that DENC's 2018 annual system peak of 17,792 MW occurred on January 7, 2018, at the hour ending 8:00 a.m., at a system-wide temperature of 7°F. DENC's summer system peak of 16,528 MW occurred on July 2, 2018, at the hour ending 5:00 p.m., at a system-wide temperature of 91°F. The Public Staff indicated that DENC activated DSM during both of these peaks. During its 15 highest peak loads from July 2017 through August 2018, the Public Staff noted that DENC activated its Residential AC Cycling program nine times and its Distributed Generation program 13 times over the 15 highest peak demands.

4. Public Staff Conclusions – System Peaks

The Public Staff acknowledges that load conditions, energy prices, generation resource availability, and customer tolerance for the use of DSM are all important considerations in determining which DSM resources should be deployed. Use of DSM resources is largely dependent on the circumstances and cannot be prescribed in any definitive manner. Nevertheless, the Public Staff concluded that the utilities should maximize the use of their DSM to reduce fuel costs, especially when marginal costs of energy are high.

In its review of DENC's DSM activations at the time of its 15 highest hourly peaks, the Public Staff notes an ongoing concern regarding the difference in DSM resources available in the winter and the summer due, in part, to the fact that winter season programs are typically not cost effective. The Public Staff stated that DENC activated its Distributed Generation program during the Company's 2018 winter peak and most of the other near peaks during the winter season; however, the activations only led to 4 - 6 MW of load reduction. As with DEC and DEP, the Public Staff recommends that each IOU investigate and implement any cost-effective DSM that would be available to respond to the growth of the winter peak demands.

B. DSM/EE

1. Public Staff Initial Comments – DEC and DEP'S DSM/EE

The Public Staff stated that its review of DEC and DEP's DSM/EE forecasts and programs indicated that the Companies had complied with the requirements of Commission Rule R8-60 and previous Commission orders regarding the forecasting of DSM and EE program savings, as well as the presentation of data related to those savings. DEC and DEP included information about their DSM/EE portfolios similar to the information reported in their 2017 IRP updates. The Public Staff opined that DEC and DEP appropriately addressed the changes in their forecasts of DSM and EE resources and the peak demand and energy savings from those programs. The Public Staff noted that while DEC's forecast did not change by more than 10%, DEP's forecast did vary by more than 10%.

The Public Staff noted several factors that will continue to affect the utilities' ability to develop and implement cost-effective EE programs: changes to federal standards for future lighting measures to take effect January 1, 2020, changes in other appliance standards, and efforts to modify building and energy codes. The Public Staff also pointed to recent decreases in the utilities' avoided costs that have decreased the value of avoided energy and capacity benefits from an EE program, making it more difficult to design, implement, and maintain cost-effective programs. Further, the large contribution of EE savings to portfolios from lighting measures are unlikely to continue beyond one to two more years. Additionally, technologies such as space heating/cooling and building envelop measures will continue to face similar headwinds.

The Public Staff stated its belief that an increased nationwide emphasis on EE is producing EE savings outside of utility-sponsored programs; these EE savings are being incorporated into the IRP load forecasts. Factors influencing load forecasts include the "roll-off" of utility EE savings, savings from more stringent appliance and lighting standards, more efficient heating and cooling equipment, greater emphasis on incorporating efficiency standards into building and energy codes, self-installation of EE measures by large commercial and industrial customers, and consumer adoption of EE. While measuring the EE embedded in the load forecasts is challenging, the Public Staff states its belief that EE has contributed to the lower sales growth rates identified in the utilities' IRPs, which is likely to continue into the near future.

The Public Staff pointed out that DEC does not offer any residential DSM program that can be used during winter peaking events, while DEP's EnergyWise program offers a limited DSM program for controlling water heaters and strip heat on heat pumps in its western service area. The Public Staff also noted that DEC had received Commission approval to cancel a pre-Senate Bill 3 water heater load control program in its most recent general rate case because the costs of continuing the program exceeded the benefits.

The Public Staff stated that it has worked with utilities to find new cost-effective programs to reduce residential demands during winter peaking events, but no program design has proven to be cost effective. The Public Staff indicated that it would continue to encourage utilities to look for new residential DSM opportunities, including the potential for new rate designs that incorporate a more dynamic pricing structure. According to the Public Staff, new time-of-use schedules have the greatest potential to help residential customers curtail loads during winter peaking events. Further, as smart meter technologies are deployed and more customer data become available, customers should have the opportunity to better understand their usage patterns and how those patterns impact system peaks, offering residential customers opportunities to curtail load.

The Public Staff indicated that DEC's and DEP's portfolios of EE programs are not materially different from those in their 2016 IRPs and 2017 IRP updates, and that they continue to align their new and existing DSM and EE programs. The Public Staff also noted that as observed in the last few DSM/EE rider proceedings, both utilities' portfolios continue to shift the source of EE savings away from lighting measures toward behavioral programs such as the My Home Energy Report. The Public Staff pointed out that DEC's projections of portfolio energy savings decline by approximately 9% and DEP's by 20% from the energy savings identified in their 2017 IRP updates. Both DEC and DEP continue to treat DSM as a capacity resource and EE as a reduction to their load forecast.

The Public Staff explained that both utilities produce EE-related savings through their respective portfolios of EE programs over the measure lives of each program. At the end of the measure's life, the utilities assume that as customers replace EE measures with other as or more efficient measures, those savings will continue in the form of reductions to the load forecast, which is designated as historical savings ("roll-off" savings). New measures are separately identified and incorporated into the load forecast tables as new savings. The Public Staff noted that the assumption that EE measures will be replaced with other or new measures differs from the assumptions Duke uses regarding non-utility generator (NUG) contract renewals as discussed *infra*. The Public Staff indicated that the use of these different assumptions may affect the timing and type of resources in the IRP.

As discussed in regard to peak forecasts, the Public Staff recommended that DEC and DEP put a renewed emphasis on designing new DSM programs to meet winter peak demands, as well as summer peak demands. Additionally, the Public Staff recommended that DEC and DEP continue to identify any changes in EE-related technologies, regulatory standards, or other drivers that would impact future projections of EE savings regardless of the 10% threshold for which a discussion is required.

2. Public Staff Initial Comments – DENC's DSM/EE

The Public Staff commented that DENC's portfolio of EE programs has undergone significant changes since the 2017 IRP update and that changes to the portfolio are greatly influenced by the DSM/EE activities of Dominion Energy Virginia and the decisions of the VSCC. The Public Staff indicated that DENC's 2018 IRP reduced the energy savings by 30% over the planning horizon from the savings identified in the 2017 IRP update, primarily due to the cancellation of several programs in Virginia that had been offered on a system-wide basis. The Public Staff noted that DENC requested approval for a North Carolina-only program from the Commission for any program that was cost-effective on a North Carolina-only basis.

The Public Staff also noted that DENC completed a market potential study in late 2017 that identified 3,042 GWhs of achievable savings over a ten-year period, but the measures identified in the market potential study have not been incorporated into DENC's 2018 IRP. The study found that the greatest economic potential for residential and non-residential sectors was in lighting and space heating and cooling measures. However, the Public Staff noted that there were no recommendations for specific measures that would contribute toward the achievable potential for either customer class, and the achievable potential excluded the impact of customers eligible to opt-out of utility-sponsored EE portfolios.

The Public Staff explained that while the market potential study would likely have limited influence on DENC's EE portfolio, Virginia Senate Bill 966, the "Grid Transformation and Security Act of 2018"(GTSA)[1] would more likely drive the Company's future EE deployment. Under the GTSA, the Company is required to spend $870 million over the next ten years on EE, including existing and new EE programs. The Public Staff noted that the Company had filed 11 DSM/EE programs for approval before the VSCC, which the Commission notes were approved

[1] 2018 Virginia Acts of Assembly, Ch. 296 (effective July 1, 2018).

by the VSCC in April.[1] The proposed portfolio of 11 new programs has a spending projection of approximately $262 million over the next five years, and the Company has indicated that this will count toward the $870 million targeted by the GTSA. The Public Staff stated that DENC's 2018 IRP does not include impacts from these proposed programs. DENC filed eight of the programs for approval before this Commission on July 13, 2019.[2]

As it recommended for DEC and DEP, the Public Staff recommended that DENC put a renewed emphasis on designing new DSM programs to meet winter peak demands, as well as summer peak demands, and that it continue to identify any changes in EE-related technologies, regulatory standards, or other drivers that would impact future projections of EE savings regardless of the 10% threshold for which a discussion is required. The Public Staff also recommended that the IOUs continue to pursue all cost-effective EE and DSM. Finally, the Public Staff proposed that DENC should continue to evaluate the potential to cost-effectively implement an EE program on a North Carolina-only basis, should the program be denied approval by the VSCC to implement the program on a system-wide basis.

3. SACE, Sierra Club, and NRDC Initial Comments – DEC and DEP'S DSM/EE

SACE et al. commented that the 2018 IRP Plans underutilize cost-effective energy efficiency and demand-side management. They assert that Duke prematurely limited the amount of energy efficiency that its IRP model could select as an available resource. SACE et al. commented that screening out efficiency options prior to running the resource planning models biases the analysis in favor of supply-side options. They further commented that Duke's planning process does not allow energy efficiency to be easily compared with supply-side resources in a capacity expansion model. The underutilization of cost-effective energy efficiency results in a higher-cost "preferred" portfolio than necessary. SACE et al. recommended that EE and DSM be evaluated on a level playing field with supply-side resources by allowing the IRP planning models to "select" DSM or EE as a resource, or by modeling varying levels of efficiency without screening out a subset of efficiency potential based on flawed assumptions.

SACE et al. also commented that the 2018 IRP Plans assume declining savings from energy efficiency and demand-side management over the fifteen-year planning period. They stated that DEC assumes that no new demand-side management capacity will be added to help meet winter or summer peak demand or reserves after 2024, and projects decreasing reductions to peak from energy efficiency investments after 2027; And that DEC anticipates no additional growth in load impacts from its demand-side management programs on summer or winter peak after 2023. SACE et al. stated that DEP anticipates no growth in several of its demand response programs after 2024 and practically no growth in savings from its energy efficiency EnergyWise for Home program after 2022. They noted that Duke's EE and DSM projections are at odds with Duke's statement

[1] Petition of Virginia Electric and Power Company for approval to implement demand-side management programs and for approval of two updated rate adjustment clauses pursuant to § 56-585.1 A 5 of the Code of Virginia, Order Approving Programs and Rate Adjustment Clauses, Case No. PUR-2018-00168 (May 2, 2019).

[2] Docket Nos. E-22, Subs 567-574.

that it "is committed to continuing to grow the amount of EE and DSM resources utilized to meet customer growth."

4. **AGO Initial Comments – DEC and DEP'S DSM/EE**

The AGO recommended that Duke's plans be supplemented to include a more robust consideration of modern EE and DSM measures that reduce consumption or shift load to off-peak times -- including measures that are targeted to winter peaks. The AGO discussed three concerns.

First, the AGO, like the Public Staff, identified as a major shortcoming in Duke's plans that they offer little to no residential demand-side measures to lower winter peaks. The lack of emphasis on winter EE/DSM measures is particularly problematic given the importance Duke placed on planning to meet winter peaks in the analysis of its requirements for additional generating resources.

According to the AGO, Duke evaluated a direct load control program as a possible DSM measure, and found it to be too costly. However, that result is not cause to overlook other opportunities. The AGO's consultant Strategen Consulting, LLC, commented that there are numerous advanced demand-side management programs that have been found to be cost effective in other jurisdictions; these programs could be used to shave winter peaks. Strategen gave examples of two such programs that are being designed with reasonable costs for ratepayers by encouraging customers to use their own devices (called "Bring Your Own Device" or BYOD measures). One such measure is a smart thermostat program where, instead of directly installing smart thermostats, the utility recruits and acquires participants who bring their own devices. Another example is a utility BYOD program in which the utility shares access with the customer's battery storage system to lower peaks on cold winter nights. Customers purchase the batteries and are provided incentives that are based on the amount of energy transferred from the customer's battery to the grid.

Strategen noted that Duke currently integrates smart thermostats into three of its energy efficiency offerings, but observed that Duke's offerings are limited, Duke's offerings do not include other types of devices, and Duke's offerings do not appear to focus on obtaining flexible (i.e. dispatchable) HVAC measures that could help address winter peaks. For example, one of the Duke programs provides an incentive for using a smart thermostat, but does not appear to make use of the device for demand response or load shifting. Another Duke program incentivizes winter demand reduction, but at a lower level than in summer, and has a small amount of participating winter capacity. None of the Duke programs allow for customers to bring other devices, such as energy storage, to increase flexible capacity in both the winter and summer. As such, more emphasis is needed in Duke's plans on the design and development of measures that address winter resource requirements.

The AGO also agreed with the Public Staff that new time-of-use schedules have great potential for helping residential customers curb loads during winter peaking events.

The second concern addressed in the AGO comments is about how DSM programs are evaluated in Duke's planning process. The AGO agreed with NCSEA, and SACE et al. that it would be valuable to model energy efficiency measures and demand-side management on a level playing field with other resources. Strategen noted that modeling demand-side resources alongside supply-side resources is considered a best practice in the industry. Without that approach, demand-side measures cannot be fairly compared to supply-side alternatives, potentially limiting the amount of cost-effective energy efficiency and demand-side measures selected, resulting in a higher cost portfolio.

The third concern raised by the AGO is that Duke's plans appear to assume that additional energy efficiency savings will not be achieved in future planning years once current measures have been tapped out. That assumption overlooks advances in technology, including automation and load controls. Strategen predicts that such advances will most likely "unlock new forms of cost-effective energy efficiency and demand management."

5. DEC and DEP Reply Comments – DSM/EE

Several intervenors commented or made recommendations regarding Duke's DSM and EE plans. In response, Duke stated it disagreed with the statement made by SACE et al., at pages 12-13 of their IRP Comments, that the Companies' projections of DSM/EE peak savings in the later years of the IRP are "inconsistent with its declared commitment to continue to grow the amount of DSM/EE resources to meet customer demand." Duke explained that, specifically for the DSM projections, the amounts of DSM included in the IRP forecast are based on Duke's past experience with customer acceptance of these programs and the expectation that the amount of DSM capacity savings will reach a steady-state level beyond the first few years of the IRP forecast is consistent with this experience. As explained in detail in the response to comments of NCSEA in the 2018 Avoided Cost proceeding, Docket No. E-100, Sub 158, Duke believes that the forecast of DSM program savings are reasonable and accurately reflect a continued effort to add new customers; however, the forecast recognizes customer response to these programs has been limited, despite targeted and ongoing efforts to increase participation.[1] According to Duke, DEC and DEP's forecast of additional increases in DSM peak savings for the next few years followed by a period of steady-state peak savings is reasonable and prudent and accurately reflects the amount of "customer demand" for these programs.

Also, regarding the impact of EE programs on peak demand, Duke disagreed with the intervenors' conclusion that Utility Energy Efficiency (UEE) program disinvestment occurs in the outer years of the IRP forecast. Duke commented that incremental annual UEE savings projection levels are similar throughout the entire forecast period as shown in the tables in Appendix D of the IRPs. However, as shown in the LCR tables in the IRPs (Tables 12-E and 12-F), the outer year UEE projections are being offset by UEE programs initiated 8 to 10 years prior that have reached the end of their useful life. Once UEE savings reach this stage, they no longer contribute to future UEE cumulative savings and are therefore removed from the cumulative savings amounts. Failure to remove these savings from the cumulative amounts would result in over-stating, or "double-counting" the impact of the Companies' UEE programs on sales.

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[1] See Duke Energy Reply Comments, Docket No. E-100, Sub 158, at pp. 63-66 (Mar. 27, 2019).

6. DENC Reply Comments – DSM/EE

DENC stated that it will continue to identify and seek approval to implement DSM and EE programs that are cost effective or meet public policy goals. With respect to the design of DSM programs to meet winter as well as summer peak demands, DENC commented that its Distributed Generation program is currently available in Virginia during winter periods to non-residential customers who meet participation requirements based upon size. DENC further explained that it recently received approval for a demand response residential thermostat control program in Virginia and will be filing for approval of that program in North Carolina in July 2019. In addition, DENC commented that 10 new EE programs addressing both summer and winter peaks as well as energy requirements were approved by the VSCC in May 2019 and will be brought to the Commission for approval in July 2019. DENC explained that while demand response programs can be used to reduce peak periods explicitly, EE programs can also provide reductions during winter hours. Nevertheless, DENC noted that these reductions are not dispatchable and instead occur because a measure installed through the program is providing energy savings during a peak hour and thus providing a winter peak reduction. DENC underscored that since the actual system peak drives the need for additional resources to meet reliability requirements, it is difficult for programs that provide benefits in mainly non-peak hours to provide a meaningful amount of benefits. Finally, DENC noted that it is participating in a stakeholder process required by the GTSA to help it identify potential opportunities for EE and demand response and is hopeful this will lead to additional DSM resources in the future that will address both summer and winter peak hours.

IV. NATURAL GAS ISSUES

For purposes of calculating longer-term avoided energy rates, DEC and DEP propose to use forward natural gas prices through 2028; transition to Duke's fundamental forecast through 2033, which shows little growth over the ten year period; and then use an assumption that natural gas prices will grow at 2.5% through 2040. This approach is similar to the approach proposed by DEC and DEP in recent years,[1] and has been the subject of extensive testimony and discussion before the Commission, most recently in the comments filed by parties in the 2018 avoided cost proceeding in Docket No. E-100, Sub 158.

DENC utilized natural gas prices derived from the forward market for natural gas for the first 18 months, and then it gradually (over the next 18 months) blends the monthly prices from the forward market with the monthly prices from the long-term price projection from ICF International, Inc. (ICF).

[1] This issue was also addressed in Phase Two of the Sub 140 proceeding, but the focus during that time was primarily consistency between the methodologies used for avoided cost and IRP purposes. In its December 17, 2015, Order Establishing Standard Rates and Contract Terms for Qualifying Facilities in Docket No. E-100, Sub 140 (Phase Two Order), the Commission directed DEC and DEP to recalculate their avoided energy rates using natural gas and coal price forecasts that were developed in a manner consistent with those utilized in their 2014 IRPs, which at the time relied on market data for the first five years before switching to their fundamental forecast.

A. Public Staff Initial Comments – Natural Gas Issues

The Public Staff commented that it appreciates the difficulty in forecasting long-term prices of natural gas as well as other fuel prices, and found reasonable DENC's reliance on forecasts from ICF. However, the Public Staff expressed concerns with the natural gas price forecasts utilized by DEP and DEC in their 2018 IRPs. As discussed in its Initial Statement filed in Docket No. E-100, Sub 158, which were incorporated by reference, the Public Staff believes that the proposed use of forward natural gas prices for ten years by DEP and DEC leads to natural gas prices that are overly conservative and inappropriate for planning purposes. On page 22 of the Initial Statement, the Public Staff noted that Duke Energy Florida, Duke Energy Kentucky, and Duke Energy Indiana each rely wholly on market prices for the first five years and blend market and fundamental prices for the next five years, before switching to the fundamental forecast for the remainder of the planning period in their IRPs. As in previous IRPs and avoided cost proceedings,[1] the Public Staff indicated its preference for DENC's approach with its use of three years of forward price data before transitioning to its long-term fundamental natural gas price forecast.

The Public Staff noted in its comments that the use of an excessively conservative natural gas price forecast is unlikely to alter DEP and DEC's generation expansion plans, however, the use of a low gas price forecast will depress the avoided energy costs that are paid to qualifying facilities, and also reduce the avoided energy costs that are used to evaluate the cost-effectiveness of DSM and EE programs. Duke's conservative natural gas price forecast is graphically displayed on page 27 of the Public Staff's Initial Statement relative to DENC's natural gas price forecast. Therefore, the Public Staff recommended that DEP and DEC, in future expansion models, reflect the use of no more than five years of forward natural gas prices before transitioning to their fundamental forecast.

B. AGO Comments – Natural Gas Issues

The AGO expressed concern that Duke's reliance on natural gas raises a risk that ratepayers will face unanticipated, unmodeled costs from natural gas price volatility.

C. DEC and DEP Reply Comments – Natural Gas Issues

In its reply comments, Duke responded to the comments and recommendations of the parties related to natural gas price issues as follows:

> **1. Duke disagrees with Public Staff's recommendation to revise the natural gas fuel price forecast used in developing the generation expansion plans to use no more than five years of forward market data before transitioning to the fundamental forecast.**

[1] Docket No. E-100, Sub 147, and Docket No. E-100, Sub 148.

As the Public Staff references in their comments, the duration that DEC and DEP use for forecasting market-based natural gas prices prior to transitioning to fundamental natural gas forecasts has been the subject of extensive testimony and discussion before the Commission, most recently in the initial comments filed by parties in the 2018 avoided cost proceeding in Docket No. E-100, Sub 158. The Public Staff references the "same arguments and perspectives it raised on pages 21-28 of its February 12, 2019, initial comments in Docket No. E-100, Sub 158"[1] where they argued that Duke should use five years of market data before switching to the fundamental forecast.

Duke similarly incorporated by reference their Reply Comments, filed on March 27, 2019 in Docket No. E-100, Sub 158 on pages 10-19, as evidence for continuing to rely on 10 years of forward market data in the Duke filed IRPs. Specifically, the Commission directed Duke to maintain consistency between the fuel forecasts presented in their IRPs and those used in their avoided cost filings and that "to the extent the Utilities wish to propose changes in the way they utilize forward prices and long-term forecasts...these changes should be made in the Utilities' biennial [IRPs], and the same approach should be used in their biennial avoided cost filings for that same year."[2] Generally, Duke made the following arguments as part of a broader discussion of natural gas prices in the referenced reply comments:

- Duke's customers are facing a $4.5 billion long-term financial obligation and an approximately $2 billion overpayment risk as a consequence of an unprecedented number of Qualifying Facilities (QFs) obligating Duke to purchase their output, coupled with the use of lagging and inaccurate fundamental forecasts to calculate avoided cost rates.
- As demonstrated by the continued, regular purchase of 10 years of forward market natural gas, the market for purchasing 10 years of forward market natural gas is liquid.
- In these regular purchases of 10 years of forward market natural gas, Duke obtained multiple price quotes, each with similar prices, evidencing that there are multiple sellers in the current 10-year natural gas market, and there is a lack of price volatility in the 10-year forward natural gas market.
- Duke is not alone in North Carolina in its ability to purchase 10-year forward natural gas, as another market participant in North Carolina (name filed under seal in Docket No. E-100, Sub 158) purchased significant quantities of 10-year forward natural gas.

Duke commented that using 10 years of forward market natural gas prices in their IRPs is appropriate for evaluating future generation needs and allows for an appropriate head-to-head comparison of long-term purchase power obligations from QFs required under PURPA.

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[1] Public Staff Comments, at p. 71.

[2] Order Establishing Standard Rates and Contract Terms for Qualifying Facilities, Docket No. E-100, Sub 140, at 27 (Dec. 17, 2015).

2. Contrary to the AGO's suggestion, Duke already considers the impacts and future costs from natural gas price volatility in their filed IRPs.

On page 10 of its comments, the AGO asserts as a concern that, "Duke's reliance on natural gas raises a risk that ratepayers will face unanticipated, unmodeled costs from natural gas price volatility." Duke noted that this concern, however, is precisely why Duke considers a range of future fuel price scenarios, including high and low natural gas prices, in the development of their IRPs. As described in Chapter 13 of the 2018 DEP IRP and Chapter 12 of the 2018 DEC IRP, and in greater detail in Appendix A of both IRPs, Duke considers natural gas prices that are both significantly lower and significantly higher than base assumptions in both the short- and long-term. The impacts of these sensitivities on each of the seven portfolios are detailed in the above referenced sections in the IRP. Duke noted that the AGO's suggestion that Duke does not "thoroughly evaluate...potential future costs from natural gas price volatility" is inconsistent with the analysis that is actually filed in the DEC and DEP IRPs. Duke stated that it should be noted the AGO does not mention the risk of falling gas prices that has contributed to the current projection of an approximately $2 billion customer overpayment for solar QF generation that was based on natural gas price forecasts significantly above the current market prices for natural gas.

V. Capacity Value of SOLAR

A. Public Staff Initial Comments – Capacity Value of Solar

The Public Staff commented that the assumption of both DEP and DEC regarding the contribution of solar energy to peak capacity has a significant impact on future capacity requirements. According to the Public Staff, even a small adjustment in the percent of nameplate capacity available at peak demand has the potential to delay or even eliminate the need for additional capacity. As such, the Public Staff recommended that the issue of aggregate solar generation coincidence at peak for both winter and summer be evaluated further, given the growing importance of solar generation in North Carolina.

The Public Staff noted that in prior IRPs, DEC and DEP calculated the capacity value for solar facilities by averaging actual solar output at the typical peak load hour, using several years of historical load data. The Public Staff indicated that this methodology provided a reasonable estimate for how much intermittent, non-dispatchable capacity would be available during the system peak. For their 2018 IRPs, Duke retained Astrapé Consulting (Astrapé) to perform a reliability-based analysis using techniques similar to those used in resource adequacy planning. The Capacity Value of Solar study (CVS Study) modeled each Company's system at varying levels of solar capacity to identify the timing of projected firm load shed events for each level of solar penetration, and the contribution of solar during those hours. This analysis establishes the capacity value of solar resources, as well as the seasonal allocation of LOLE.

The CVS Study results are presented in the form of a seasonal capacity value for each level of solar penetration in DEC and DEP, with different values for fixed and tracking solar photovoltaic (PV) because tracking results in a higher capacity value. Using these findings, Duke then discounts the amount of installed solar capacity, both utility and third party-owned, by this capacity value in each utilities' Load, Capacity, and Reserves Tables (LCR Tables),[1] thereby reducing the amount of available capacity and increasing the need for traditional thermal resources to meet peak system load. Using the values from the CVS Study, as opposed to its previously used coincident peak method, the need for traditional resources in 2033 increases by 138 MW in DEC and 168 MW in DEP.

The Public Staff expressed concern regarding the difference between how Duke plans to meet its peak system load and how it values the capacity contribution of solar resources. In past IRPs, the Companies discounted the available solar capacity to match the estimated solar output during the hour of peak system load, and thus planned future resource additions to meet the peak system load, and also considered the availability of solar resources during that same peak system load.

The Public Staff contended that use of the CVS Study results effectively bifurcates the treatment of solar resources and the treatment of traditional utility-owned thermal resources. By discounting the solar contribution based on its output during projected firm load shed events (High Risk Hours), yet planning future resource additions to meet the output needed during the hour of peak system load (Peak Load Hours), the actual contribution of solar resources during the Peak Load Hours is ignored. The Public Staff also pointed to the disparate treatment of solar resources versus dispatchable thermal resources, which receive a capacity value of 100%, despite their not having guaranteed availability at the time of all High Risk Hours due to planned and forced outages.

The Public Staff proposed that DEC and DEP either plan future capacity resource additions based upon the estimated load during High Risk Hours or discount the capacity value of solar resources by their output during the Peak Load Hours, rather than their output during High Risk Hours. The Public Staff proposed a coincident peak methodology that relies upon utility data and statistical analysis to determine the capacity value, and can be applied to any intermittent resource with a history of hourly generation data. According to the Public Staff, this methodology addresses the perceived disconnect between Peak Load Hours and High Risk Hour, and considers both the operational history of intermittent resources in each utility's service territory and forecasted system operational models that employ numerous assumptions related to load forecasting, solar output, and generation performance characteristics. The Public Staff stated that while it did not have access to the models used by Duke in determining the future resource need, it estimates that using the capacity values produced using its methodology would delay the need for future resource additions.

The Public Staff also noted that the CVS Study considers such factors as load uncertainty and unit outages when it calculates LOLE and capacity value, and that these factors may lower solar capacity value and increase the required minimum reserve margin. The Public Staff contends that these factors should cause either an increased reserve margin or a decreased solar capacity value, but not both. Thus, the Public Staff is concerned that the need for future resource additions may be overstated.

[1] DEC IRP, Tables 12-E and 12-F; DEP IRP, Tables 13-E and 13-F.

The Public Staff recommended that DEC and DEP utilize the coincident peak methodology for establishing the capacity value of solar, rather than the Astrapé Solar Capacity Value Study. For planning purposes in this IRP, the Public Staff recommended that DEC and DEP use a Capacity Value for solar of 3% in winter and 55% in summer. Finally, the Public Staff recommended that the Commission require DEC and DEP to file a report discussing the impact of this change, and if the first year of capacity need changes, in the 2018 avoided cost proceeding.

In regard to DENC, the Public Staff recommended that DENC continue to discuss mitigation strategies to address high levels of solar penetration and system operations, including revising and improving its estimates of both fixed and variable integration costs. Further, to the extent that the Company identifies required mitigation strategies to address the aggregate effect of distributed solar PV, such as the addition of a supplemental CT to address generation volatility or ramp rates, the Public Staff stated that those applicable costs should be assigned to the overall installed cost of solar.

The Public Staff pointed out that PJM publishes a methodology for calculating capacity values for non-dispatchable resources and recommends using a three-year average of historical wind and solar facility output during the summer peak hours to determine the applicable capacity value for use in reserve margin planning. For facilities less than three years old, PJM publishes "class average capacity factors" for use in the determination of capacity values. The Public Staff indicated that DENC's proposed capacity values for solar are significantly lower than the PJM class average, and recommended that DENC continue to evaluate renewable resources' contribution to coincident peak and update its models to reflect the additional research. The Public Staff also recommended that in future IRPs and updates, the Commission require DENC to provide PJM's capacity value for renewable resources as comparison benchmark, and to the extent that DENC's calculated capacity values or methodology differ from PJM's, provide a justification for the difference.

The Public Staff also noted that it had recommended in the avoided cost docket that DENC's proposed re-dispatch cost be reduced based on the Public Staff's proposed modifications. The Public Staff agreed that a re-dispatch or solar integration charge are important concepts as increasing levels of intermittent and non-dependable generation are added into the electrical grid. The Public Staff recommended that to the extent possible, the modeling programs used by the utilities within the IRP process for selection of future projects evaluate and use appropriate price signals to reasonably demonstrate the costs to ratepayers as new generation units are selected.

B. SACE, Sierra Club, and NRDC Initial Comments – Capacity Value of Solar

Like the Public Staff, SACE et.al. commented that Duke undervalued the capacity that solar resources provide to the DEC's and DEP's systems. They also commented that the 2018 IRPs under-project future solar and solar-plus-storage resources.

SACE et.al. commented that Duke has grossly undervalued the capacity value that solar provides by relying on the Astrapé study that relies on flawed data and methodology. SACE et.al. retained expert consulting firm Wilson Energy Economics to evaluate Duke's calculation of the capacity value of solar resources. The Wilson report concluded that Astrapé had overstated the winter resource adequacy risk, and that the winter/summer capacity values of solar resources on which the 2018 IRP Plans were based should be rejected.

SACE et.al. also commented that Duke's projections fail to account for likely improvements in solar technology and are on the low end of what has been observed from projects that have been put in service in recent years. For example, DEP projects summer solar PV capacity values of 8.2 to 12.4 percent, far lower than the weighted average of 27.6 percent observed in projects installed nationally over the last ten years.

SACE et.al. recommended that Duke reevaluate its projections for addition of new solar resources. DEP's 2018 IRP Plan projects the addition of 1,441 MW of solar over the next 15 years, with approximately 1,000 MW occurring in the next five years (a 36% increase), but with only an 11.6% increase between 2023 and 2033. DEC's 2018 IRP Plan projects the addition of 1,314 MW of solar between 2019 and 2023, but additions of only about 90 MW per year between 2023 and 2033. Duke assumes in its IRPs that it effectively stops adding significant solar resources after it has satisfied the procurement obligations in House Bill 589. The groups noted that these projections do not reflect the recent trends in accelerated solar installations in the Carolinas nor the continuing and steep cost declines for solar. SACE et.al. recommended that Duke reevaluate its projections for future solar installations using more realistic assessments of current and likely future cost declines and improved panel efficiencies.

In addition, SACE et.al. commented that the 2018 IRP Plans include only token amounts of solar-plus-storage resources and do not fairly evaluate the addition of these resources. Greater additions of grid-connected battery storage will support addition of solar and other clean energy resources on the DEC and DEP systems, as well as providing a new resource for balancing grid supply and demand, a new tool for peak shaving, and other benefits. SACE et.al. identified examples from across the country of the steadily declining costs of solar-plus-storage projects, including prices for battery energy storage that are less costly than fossil fuel-fired generation. They recommended that Duke incorporate higher levels of solar-plus-storage in its long-term plans, especially given North Carolina's position as a national leader in solar development.

C. AGO – Capacity Value of Solar

The AGO agreed with concerns expressed by the other intervenors about Duke's assessment of the capacity value of solar energy. To the extent that solar capacity is undervalued, that causes Duke's plans to include more traditional thermal capacity resources than are necessary, leading to increased costs to Duke's customers.

AGO consultant Strategen reviewed the Astrape analysis prepared for Duke and detailed multiple aspects of Astrape's capacity value calculation that could potentially undervalue solar resources. Strategen described the following flaws:

1. Underlying load and non-solar resources within each solar tranche

Duke's analysis shows declining capacity value as solar penetration increases in subsequent MW tranche additions. While this general trend is to be expected, it is not clear if each subsequent solar tranche also included changes to the underlying load and non-solar resources on Duke's system. In reality, higher MW solar scenarios would coincide with other changes. For example, a) load growth may occur predominately in the summer, thus shifting the share of loss of load expectation (LOLE) towards summer months, or b) the mix of non-solar generators may change towards those with fewer outages. Both of these could affect the calculated solar capacity value and potentially increase it relative to what has been portrayed.

2. Demand response availability in winter

In Duke's analysis, it is assumed that there are significantly less demand response resources available in winter versus summer (625 MW less for DEC, and 503 MW less for DEP). This has the effect of increasing LOLE during winter hours, and in turn could decrease solar capacity value. If in fact Duke's system is increasingly a winter peaking system, it is not clear why existing/new demand response resources couldn't be targeted more towards winter peak load hours instead and modeled accordingly.

3. Share of tracking PV resources

Duke's analysis assumes a 25% share of single-axis tracking systems versus 75% fixed tilt. While this appears consistent with historical deployment in NC, other jurisdictions have shown a greater trend towards tracking systems. It's possible this broader trend could also occur in NC going forward and would lead to a higher overall capacity value for the solar fleet.

4. Assistance from neighboring Balancing Areas

A critical underlying assumption in Duke's analysis is the availability of resources from neighboring balancing areas. The reported occurrence of a greater share of LOLE hours during winter signifies a greater unavailability of neighboring resources during this season. However, several of the balancing areas neighboring Duke not only have significant excess capacity exceeding their reserve margins but they are also summer peaking systems. Thus, it appears that there should be substantial winter resources available from neighboring systems. If the availability of neighboring resources in winter is modeled at too low a level it could have the effect of increasing LOLE at these times, and in turn reducing solar capacity value.

5. Outage rates for combustion turbines

Public Staff points out that in Duke's analysis, "Solar resources are also treated differently than dispatchable thermal resources in that those thermal resources receive a capacity value of 100%, despite the fact that even dispatchable thermal resources are not guaranteed to be available 100% of the time in High Risk Hours due to planned and forced outages." Strategen agrees with Public Staff's assessment that this reflects inconsistent treatment between resource types that should be remedied. Either capacity value of non-solar resources should be de-rated according to their outage rates, or a different methodology should be adopted.

6. Adjustment of combustion turbine versus load

As the Public Staff points out in their comments, Duke's approach of adjusting the combustion turbine value to determine capacity value "varies slightly from a traditional (effective load carrying capacity) study, where load is adjusted to achieve a (loss of load expectation) of 0.1 events/year." Strategen agrees with Public Staff's observation. Furthermore, since DEP is modeled as two load centers (east and west), Duke's approach could also lead to a lower solar capacity value than the traditional method, depending on where the combustion turbine is located in the model and what transmission constraints are assumed.

Strategen believes that, conceptually, an effective load carrying capability (ELCC) framework, such as that used by Duke can be a sound approach to determining the capacity value of solar for resource planning. However, before such a framework can be adopted, more information is needed regarding certain underlying assumptions in Duke's analysis. Thus, for the purposes of the 2018 IRP, the method proposed by Public Staff seems acceptable and would be consistent with past practice in North Carolina. An ELCC approach could be explored for future IRPs but stakeholders should have additional opportunities to review the evaluation framework proposed by Duke and the Commission should provide guidance on it as well. For these reasons, Strategen believes Public Staff's recommendations regarding solar capacity value are reasonable."[1]

D. DEC and DEP Reply Comments – Capacity Value of Solar

On page 85 of its Comments, the Public Staff states its concern that "there is a disconnect between how Duke plans to meet its peak system load and how it values the capacity contribution of solar resources." A remedy is proposed by the Public Staff to calculate the Capacity Value of Solar utilizing a Coincident Peak methodology which would address the perceived disconnect between Peak Load Hours and High Risk Hours.

Duke noted that, although it had not yet reviewed the models used by the Public Staff in determining the Coincident Peak methodology, it was trying to ascertain why the Public Staff's proposed capacity values in Table 1-1 remain static despite the fact that possibly over 10,000 MW of solar capacity could be installed in the Carolinas over the next 15 years. In Tables S5 and S6 of the Capacity Value of Solar (CVS) study completed by Astrapé Consulting, each additional tranche of solar capacity provides diminishing marginal capacity value to the system

Duke explained that Astrapé calculated its results in the CVS study by modeling thousands of iterations in its proprietary Strategic Energy Risk Valuation Model (SERVM) using 36 different weather years developed from a National Renewable Energy Laboratory (NREL) dataset dating back to 1980. Both the seasonal and hourly pattern changes were captured across different solar

[1] Strategen Attachment to the AGO Reply Comments, at 10-11.

penetration levels. As solar increases across the system resulting in optimal performance on sunny days, system Loss of Load Expectation (LOLE) shifts to the winter; firm load shed events no longer occur during solar hours and become more prominent during hours of little to no daylight. According to Duke, it cannot ascertain from Figure 7, Table 10, or Table 11 in the Public Staff's comments that any research into the shift in LOLE has been performed, which therefore does not support fixed winter/summer capacity values that do not adapt to the level of solar installed on the DEC and DEP systems.

As further support for Duke's probabilistic approach to valuing solar capacity, Duke referred the Commission to the direct testimony of Brian Horii[1] on behalf of the South Carolina Office of Regulatory Staff in Public Service Commission of South Carolina (PSCSC) Docket No. 2019-2-E. On page 8 and beginning on line 17 of his testimony, Mr. Horii states as follows:

> E3 has been at the forefront of evaluating the impact of renewable resources on utility planning and operations. Through our work it is clear that resources such as wind and solar generation must be evaluated using probabilistic methods that evaluate all hours of a given period, not just a single peak hour. Moreover, the importance of probabilistic models is generally recognized across the industry, as noted by the North American Electric Reliability Corporation's (NERC) Probabilistic Adequacy and Measures Technical Reference Report (April, 2018):
>
> There is a recognized need to support probability-based resource adequacy assessment resulting from the changing resource mix with significant increases in variable and energy-limited resources (intermittent in nature); changes in net demand profiles resulting in the shifting of the hour of the peak demand, and other factors can have an effect on resource adequacy. NERC, p. 6.

In his testimony, Mr. Horii disputes the appropriateness of using a coincident peak hour approach to valuing the capacity contribution of solar generation and notes that such an approach fails to recognize the capacity value provided not just by output at the time of the peak hour but also by the output during the myriad of other peak hours for which there is a non-zero risk of the utility being unable to meet all customer demand.[2] Mr. Horii further referenced the detailed hourly solar capacity value studies performed by Astrapé Consulting for DEC and DEP to infer a capacity value contribution for incremental solar for another utility's system.[3]

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[1] Mr. Horii is a Senior Partner with Energy and Environmental Economics, Inc. (E3) and was retained by the South Carolina Office of Regulatory Staff (ORS) to assist in the analysis of South Carolina Electric & Gas Company's avoided cost calculations, and review the Value of Distributed Energy Resource (DER) methodology, in PSCSC Docket No. 2019-2-E.

[2] Brian Horii Direct Testimony in PSCSC Docket No. 2019-2-E, at 8.

[3] Id., at 10-11.

1. Duke disagrees with the AGO's assessment that the Companies may be undervaluing the peak load contribution of solar technologies.

The AGO disputes Duke's assertion that additional solar resources beyond those shown in the 2018 IRPs have limited value because additional solar capacity only provides negligible contribution to meeting peak load needs (AG) IRP Comments, pp. 3-4). The AGO cites a "study performed by the National Renewable Energy Lab [NREL] in California, where solar resources have a higher penetration rate" as the basis for the argument that solar resources may have more capacity value than that attributed by the Companies. Id. Duke notes that while North Carolina is number 2 in the U.S. in installed solar behind only California, the AGO's argument is flawed for two reasons: (1) California has significantly higher solar irradiance than North Carolina, and (2) California's electricity demand profile is significantly different than North Carolina's electricity demand profile simply based on the range of temperatures seen in California versus North Carolina, as well as different sources of heating and cooling in the two jurisdictions. Duke points out that consumers in North Carolina and South Carolina have significantly higher energy needs due to much greater electrical heating and cooling demand than California. Simply put, regional differences in solar output, as well as customer usage profiles make such a comparison meaningless. Duke noted its disappointment that the AGO used a study that is based on California electricity demand and solar conditions to criticize Duke for not placing enough value on solar in North Carolina -- when North Carolina is second only to California in installed solar capacity.

2. Duke acknowledges that inclusion of additional storage and solar plus storage resources in the IRPs may be warranted, as suggested by the AGO; however, Duke is committed to studying the true value of energy storage on the DEP and DEC systems before arbitrarily assigning value in the IRPs.

For the first time, Duke included battery storage as a resource in the 2018 IRPs. In total, DEC and DEP included nearly 300 MW (nameplate) of lithium-ion battery storage as capacity resource placeholders which were assumed to provide 80% of their nameplate capacity towards meeting the Companies' winter peak capacity needs per the Electric Power Research Institute (EPRI) study cited in the 2018 IRPs. Additionally, Duke acknowledged in the IRPs that "Battery storage costs are expected to continue to decline, which may make this resource a viable option for grid support services, including frequency regulation, solar smoothing during periods with high incidences of intermittency, as well as, the potential to provide overall energy and capacity value."[1] Furthermore, despite the AGO's assertion that Duke "does not thoroughly evaluate [the downward trend of storage technology costs],"[2] to the contrary, the Duke IRPs assume that battery storage costs drop by nearly 40% by year 2025 in the IRP Base Case.[3] Additionally, Duke noted that its IRPs include an aggressive capital cost sensitivity that would further the decline in battery storage

[1] DEC IRP, p. 33; DEP IRP, p. 33.

[2] AGO's Comments, p. 5.

[3] DEC IRP, p. 101; DEP IRP, p. 102.

costs to 60% by 2025. Finally, Duke included a sensitivity of replacing a future undesignated CT with a grid-tied battery storage option in both the DEC and DEP IRPs.[1]

Even though Duke acknowledged the potential benefits of storage, included steep cost declines for battery storage technologies, evaluated a sensitivity of replacing a future CT with battery technology, and went as far as to include upwards of 300 MW of battery storage as capacity assets in the DEC and DEP IRPs, the AGO argues the Companies did not go far enough by not evaluating multiple storage plus solar technologies. Duke commented that there is the potential for battery storage technologies to provide value to the DEP and DEC systems, but pairing storage with solar to allow "the storage component to benefit from federal investment tax credits"[2] as suggested by the AGO may not always be in the best interest of the Companies' customers. According to Duke because North Carolina's peak conditions occur in both summer afternoons and winter mornings and afternoons, and can be at least several hours in duration, there may be limitations to the capacity value of batteries, particularly batteries charged solely from solar resources. Furthermore, on May 10, 2019, the Commission issued its Order Granting Certificate of Public Convenience and Necessity with Conditions for the DEP Hot Springs Microgrid Project, which is a combination 3 MW (DC) solar and 4 MW lithium-ion based battery energy storage system. The Commission held that although it is not clear that the Hot Springs Microgrid is the most cost-effective way to address reliability and service quality issues at Hot Springs, the overall public convenience and necessity would be served by granting the certificate (CPCN) for the solar generation components of the microgrid because the system benefits of the microgrid are difficult to quantify and DEP will gain valuable experience by operating the Hot Springs Microgrid as a pilot project. The Commission further stated that it supports "cost-effective development of solar and battery storage by DEP . . . and encourages DEP to continue to pursue such projects on behalf of its customers."[3]

Duke noted that it is committed to further studying the capacity value of incremental battery storage (both grid-tied storage and solar plus storage systems) in the Carolinas at increasing penetration levels. Like the Capacity Value of Solar Study Duke completed in 2018, a similar study is required to study the capacity value of storage. Duke explained that a study of this type is both time and data intensive; however, Duke expects to include the results of a capacity value of storage study as early as the 2020 biennial IRP filings. The Commission expects the 2020 filings to include such results, absent a showing as to why the necessary study could not be completed.

E. Duke's NREL Study

In NCSEA's initial comments, NCSEA noted that Duke has recently retained the National Renewable Energy Laboratory (NREL), to study how Duke's grid can accommodate a renewable energy penetration of 50% of peak demand. NCSEA stated that the fact that Duke is undertaking such a study "undermines the credibility of their own IRPs, and calls into question how Duke has

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[1] Portfolio #7 (CT Centric / High Renewables with Battery Storage) is assessed in a variety of CO_2, fuel price, and capital cost scenarios.

[2] AGO's Comments, p. 4.

[3] Hot Springs Order, at p. 17.

modeled clean energy resources."[1] NCSEA further alleged that its Synapse study shows that Duke has "unfairly marginalized clean energy resources." Id. NCSEA also cited the Virginia State Corporation Commission's rejection of Dominion's IRP because of failure to adequately model clean energy resources.

In its reply comments, Duke *explained* that it plans to study a number of scenarios. The entire study including Phase II will take as much as two years and possibly longer to complete, which would not be timely for the current IRPs. According to Duke, when Duke's General Manager, Distributed Energy Technologies Renewable Integration & Operations, Ken Jennings, recently spoke at the University of North Carolina at Chapel Hill, he acknowledged that Duke will be examining a number of scenarios but did not state that the system would definitely be able to accommodate that much intermittent solar. He also mentioned that the study would be similar to the TECO Study which states that:

> Must-Take solar becomes infeasible once solar penetration exceeds 14% of annual energy supply due to unavoidable oversupply during low demand periods, necessitating a shift to the Curtailable mode of solar operations. As the penetration continues to grow, the operating reserves needed to accommodate solar uncertainty become a significant cost driver, leading to more conservative thermal plant operations and increasingly large amounts of solar curtailment.

The TECO Study further states:

> The energy value on the TECO system of additional solar energy in Curtailable operating mode decays rapidly above about 14% solar energy penetration. The energy value (or, equivalently, the production cost savings) is calculated as the change in annual production costs as solar penetration increases, excluding the capital cost of additional solar resources. Solar provides very little marginal energy value at penetration levels above 19%. In the extreme – above 23% solar energy production potential – solar has a negative marginal energy value.

According to Duke, at that time, it did not know exactly what the scenarios would be. Currently, Duke projects for Phase I a penetration level as high as 35% solar as a component of energy rather than summer peak demand, which is about 28,000 MW of solar and actually closer to 70% of summer peak demand. Duke argues that, absent results from both the Phase I and Phase II versions of the study, it would be imprudent to make assumptions about the utility's ability to manage such levels of intermittent solar, and if the results of the NREL study are similar to the results of the TECO study, such levels of intermittent solar may actually require more thermal generation than is currently called for in the IRPs.

F. DENC Reply Comments – Capacity Value of Solar

In response to the Public Staff's comments, DENC indicated that it is committed to continuing and improving its efforts to analyze solar integration costs, the results of which will be

[1] NCSEA Comments, p. 14.

provided in the 2020 IRP. DENC also stated that it intends to further refine its integration costs analysis in future IRPs and updates based on the methodology used in the 2017 and 2018 IRPs. As part of that analysis, the Company committed to consider the costs associated with any identified strategies to mitigate the aggregate effect of distributed solar PV on the Company's system. As previously discussed, DENC also agrees to include in future filings the PJM class average capacity value for solar as a comparison to its proposed capacity value, and provide justification for any difference.[1]

VI. BATTERY STORAGE

In Docket No. E-100, Sub. 147, the Commission noted that the evaluations of battery storage technology in the 2016 IRPs have "not been fully developed to a level sufficient to provide guidance as to the role this technology should play going forward."[2] As such, it required utilities to "provide in future IRPs or IRP updates a more complete and thorough assessment of battery storage technologies including the 'full value' as discussed in the NCSEA comments. If the standard technical and economic analyses of generation resources somehow preclude the complete and thorough assessment of battery storage technologies, then a separate discussion of this point should be included in the IRPs."[3]

A. DEC and DEP Integrated Resource Plans – Battery Storage

According to DEC and DEP, they are assessing the integration of battery storage technology into their portfolio of assets. DEC and DEP note that battery storage costs are expected to continue to decline, which may make it a viable option for grid support services, including frequency regulation, solar smoothing during periods with high incidences of intermittency, as well as, the potential to provide overall energy and capacity value.

DEC and DEP further note that energy storage can also provide value to the transmission and distribution (T&D) system by deferring or eliminating traditional upgrades and can be used to improve reliability and power quality to locations on the Company's distribution system. This approach results in stacked benefits which couples value streams from the Transmission, Distribution, and Generation systems. This evaluation process falls outside of the Company's traditional IRP process which focuses primarily on meeting future generation needs reliably and at the lowest possible cost. This new approach to evaluating technologies that have generation, transmission and distribution value is being addressed through the Integrated System and Operations Planning (ISOP) process as discussed later in this Order.

DEC and DEP state that they will begin investing in multiple grid-connected storage systems dispersed throughout their North and South Carolina service territories that will be located

[1] DENC Reply Comments, at 9.

[2] Docket No. E-100, Sub 147, Order Accepting Integrated Resource Plans and Accepting REPS Compliance Plans (2016 IRP Order), at 60 (June 27, 2017).

[3] Id. at 60.

on property owned by the Companies or leased from their customers. These deployments will allow for a more complete evaluation of potential benefits to the distribution, transmission and generation system while also providing actual operations and maintenance cost impacts of batteries deployed at a significant scale.

DEC and DEP included battery storage in its screening analysis for the 2018 IRP: a 5 MW / 5 MWh Li-ion Battery, a 20 MW / 80 MWh Li-ion Battery, and 2 MW Solar PV plus 2 MW / 8 MWh Li-ion Battery. In their IRPs, DEC and DEP have included 150 MW and 140 MW of lithium-based battery storage "placeholders" in their Portfolio 1, respectively. This is reflected in their short-term action plans, in which DEC begins with four MW deployed in 2020, growing to 60 MW by 2023, and DEP begins with 12 MW deployed in 2019, reaching 64 MW by 2023. Both utilities plan to begin investing in grid-connected storage systems dispersed throughout their service territories, with specific investments identified in DEP's discussion of the Western Carolinas Modernization Project (WCMP).[1]

Both DEC and DEP refer to the planned lithium-based battery storage devices as "placeholders" largely due to the way in which energy storage was modeled in the IRP. First, they performed a technical screening of various energy storage technologies. While they identify many types of energy storage, only lithium-ion batteries are actually modeled in System Optimizer and Prosym; the remaining choices are screened out from quantitative analysis for various reasons, including technological feasibility and commercial availability.[2] Traditional generation technologies are made available to the System Optimizer for economic selection, based upon techno-economic characteristics, to meet load and reserve margin requirements over the planning horizon. However, energy storage provides a range of benefits, such as transmission investment deferral and ancillary services,[3] which are difficult, if not nearly impossible, to quantify over the long-term period of the capacity expansion model.

To address the difficulty in modeling energy storage, DEC and DEP specified the battery storage capacity to be included exogenously, effectively "forcing" storage into the capacity expansion plan. The cost impact of energy storage was evaluated in the production cost model Prosym, where battery resources were assumed to have the primary responsibility of providing generation, energy, and ancillary benefits, except in cases where the primary purpose was transmission or distribution benefits.[4] Pumped storage, such as the Bad Creek facility, is analyzed using a two-pass approach: First, Prosym runs without energy storage; then, energy storage inflows and outflows are scheduled to levelized marginal costs subject to physical and technical constraints; finally, Prosym is run a second time with the additional scheduled load or generation from pumped storage. This analysis captures the benefits of bulk energy time shifting, but does

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[1] DEP IRP, at 51.

[2] DEC and DEP screen out the following energy storage technologies from future capacity deployments: pumped storage, compressed air storage, liquid air storage, flow batteries, and high temperature batteries.

[3] See the Storage Applications and Services section of the NC State Energy Storage Team's Energy Storage Options for North Carolina, at 10-13, https://energy.ncsu.edu/storage/.

[4] DEC and DEP's response to PS DR 4-4.

not quantify additional energy storage benefits as defined in the recently published Energy Storage Options for North Carolina study (Storage Study).[1]

DEC and DEP discuss the limitations of the IRP in relation to energy storage in a discussion of the insights gained from an analysis of Portfolio 7, which is based on Portfolio 6, except the next planned CT resource is replaced with battery storage. In DEP, this change actually resulted in a lower PVRR than Portfolio 6 (in no sensitivity scenario was Portfolio 7 more cost effective than Portfolio 1 or 2). These projections depend upon the energy storage device being grid-tied and controlled by the utility in real-time. DEC and DEP both conclude that the difficulty in understanding the value of energy storage makes it "important for the Company to operate utility storage on its system to properly evaluate the abilities and value of battery storage."[2]

B. DENC Integrated Resource Plan – Battery Storage

DENC stated in its IRP that batteries serve a variety of purposes that make them attractive options to meet energy needs in both distributed and utility-scale applications, including providing energy for a power station blackstart, peak load shaving, frequency regulation services, or peak load shifting to off-peak periods. DENC noted that batteries have gained considerable attention due to their ability to integrate intermittent generation sources, such as wind and solar, onto the grid. DENC pointed out that the primary challenge facing battery systems is the cost, and that other factors such as recharge times, variance in temperature, energy efficiency, and capacity degradation are also important considerations for utility-scale battery systems. DENC did not consider batteries for further analysis in the Company's busbar curve. However, under the GTSA, DENC is required to propose a plan to deploy 30 MW of battery storage under a new pilot program. In its revisions to its IRP, the Company modeled 30 MW battery storage pilots as a proxy generation resource.

C. Public Staff Initial Comments – Battery Storage

1. DEC and DEP

The Public Staff recognized that modeling the various uses of energy storage presents challenges such as capturing and quantifying the various value streams. High capital costs of energy storage (even under assumptions of a 50% decline in capital costs by 2028), coupled with the aforementioned challenges, make it nearly impossible for DEC and DEP's existing modeling software to economically select energy storage in its System Optimizer. The Public Staff noted that DEC and DEP have identified the need for improved modeling capabilities in the Integrated System Operations Planning (ISOP) sections of their IRPs, which envision future IRPs that are capable of recognizing the benefits energy storage can provide on a sub-hourly and "stacked"

[1] The full study is available for download at https://energy.ncsu.edu/storage/.

[2] DEP IRP, at 107; DEC IRP, at 105.

basis.[1] In addition, the increasing cost of integrating solar energy identified in the Astrapé Ancillary Service Study[2] indicates the need for a more flexible system, which energy storage is well suited to provide. With improved modeling, energy storage could also be assessed for cost-effectiveness in different renewable energy penetration scenarios.[3] The Public Staff encouraged DEC and DEP to continue to enhance their modeling capabilities as described in the ISOP sections of their IRPs, with the eventual goal of accurately quantifying energy storage benefits and costs so that there would be no need to force storage into the IRP modeling.

2. DENC

The Public Staff noted that DENC discussed battery storage in extremely broad terms, while recognizing that energy storage could provide grid stability as more renewables are integrated into the grid and reduce the intermittency of wind and solar generation. As DENC states did not consider battery storage for further analysis in the Company's busbar curve, the Public Staff concluded that DENC failed to thoroughly assess battery storage technologies or include a separate discussion justifying their absence from the IRP.

The Public Staff stated its belief that DENC did not comply with the Commission's 2016 IRP Order to provide a more complete and thorough analysis of battery storage technologies, as opposed to DEC and DEP's 2018 IRPs where battery storage was included as a technology which their models could select and placeholders were input to the model and production cost runs reflected the effect of bulk energy shifting. The Public Staff noted that the Energy Information Administration (EIA) estimates that there were approximately 700 MW of installed battery storage projects at the end of 2017, with 40% of that capacity in PJM.[4] The Public Staff recommended that DENC be required to submit a supplemental filing to its 2018 IRP with a more detailed analysis showing why battery storage technologies were excluded from the Company's busbar curves, including a quantitative analysis of energy storage costs. The Public Staff also noted that DENC should address how its solar integration cost estimates are affected by battery storage, including a discussion of whether the legislatively mandated 5,000 MW of solar could be more cost-effectively integrated if coupled with energy storage technologies in future IRPs and IRP updates.

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[1] Value stacking refers to the ability of energy storage devices to provide benefits over a range of service categories, i.e., one energy storage facility providing frequency regulation, improved reliability, and transmission asset deferral. See Storage Study, p. 137, for a discussion of "value stacking".

[2] Referenced in DEC and DEP's Initial Statement, filed November 1, 2018, Docket No. E-100, Sub 158.

[3] Public Service of New Mexico's 2017-2036 IRP retained Astrapé Consulting to quantify the effect of energy storage on reliability and system flexibility at various levels of solar PV penetration, using similar methodologies to Duke's Ancillary Service Study.

[4] EIA, U.S. Battery Storage Market Trends, May 2018. Accessed at https://www.eia.gov/analysis/studies/electricity/batterystorage/pdf/battery_storage.pdf

D. SACE, Sierra Club, NRDC Initial Comments – Battery Storage

SACE, et al. noted that DEC and DEP had recognized the declining cost of battery storage and included battery storage in their resource plans, but contended that there should be greater additions of grid-connected battery storage. Additional battery storage would support additional solar and other clean energy resources, as well as provide balancing of grid supply and demand, peak shaving, and other benefits. These parties noted the steady fall of the costs of solar-plus-storage technologies, and contended that contracted and demonstrated prices for battery storage are already least-cost compared with traditional fossil fuels in some applications and are expected to continue to fall. Thus, SACE, et al. recommended that DEC and DEP incorporate higher levels of battery storage into their long-term plans.

E. AGO Comments – Battery Storage

The AGO commented that DEC's and DEP's plans, when modeling resource alternatives, do not adequately address solar-plus-storage resources as options to meet peak hours of demand. The AGO believes that this issue is important to the development of reasonable resource plans because, as was pointed out in NCSEA comments, battery storage technologies provide flexibility that enables a larger part of DEC's and DEP's energy and capacity requirements to be satisfied at lower economic and environmental costs. Given the current broad array of storage technologies with different sizes, configurations, and operating characteristics, modeling should include an array of storage alternatives consistent with industry best practice.

According to the AGO, DEC and DEP considered only one solar-plus-storage technology configuration in the initial screen of the model used to evaluate resource options: a 2-MW battery with 8 MWh of duration paired with a 2-MW solar facility. In contrast, DEC's and DEP's initial modeling screen included nine natural gas-burning technologies, two coal technologies, two nuclear technologies, and two stand-alone storage technologies. Further, the ratio of PV to storage in DEC's and DEP's one option does not necessarily align with recent trends in the industry. Strategen noted that batteries recently procured by utilities in other states (Hawaii, Arizona, Nevada, and Colorado) have been much larger in order to benefit from economies of scale and lower siting and interconnection costs (e.g., installing one 100 MW battery is cheaper than fifty 2 MW batteries).

The AGO asserted that battery storage offers several advantages as described in Strategen's memorandum that are not sufficiently evaluated in Duke's plans:

- Storage is a valuable tool to address peak demand.
- Storage has a modular design and can be added in small increments that fit growth. Whereas larger traditional power plants often add more capacity than is needed, at least until load growth catches up to the installed capacity, storage can be added relatively quickly as needed or avoided altogether if load growth does not materialize.

- Storage enhances the resilience of the grid during catastrophic events like hurricanes. The effectiveness of storage was demonstrated during Hurricane Irma, when two large battery storage projects in the Dominican Republic helped stabilize grid frequency and alleviate fluctuations caused when 40% of the generation fleet had suffered an outage.

- The importance of creating a resilient electric grid that integrates clean energy resources is a factor discussed in Executive Order No. 80, the North Carolina policy addressing climate change.

- Recent studies have shown that inverter-based resources (like batteries) have actually responded faster and more accurately than traditional generators in the face of a disturbance.

The AGO recommended two improvements to DEC's and DEP's analyses of storage. First, multiple storage alternatives should be modeled alongside other resource alternatives. That way, DEC's and DEP's models would select the sizes and ratios of solar plus storage that fit a system need (rather than pre-selecting more limited options). Second, the model should use publicly-available cost estimates wherever possible to make the assumptions underlying the model results more transparent. The model used by intervenor NCSEA relied on publicly-available cost estimates from the National Renewable Energy Laboratory and Lazard that are considered to be industry standards.

F. NC WARN Comments – Battery Storage

NC WARN provided a number of examples of the decline in costs of battery storage and breakthroughs in battery technology. It also highlighted plans of utilities and governmental entities that include substantial amounts of solar coupled with battery storage. NC WARN recommended that DEC and DEP redirect their reliance upon gas turbine generation to reliance upon battery storage, especially solar combined with battery storage.

G. DEC and DEP Reply Comments – Battery Storage

DEC and DEP noted that for the first time, they included battery storage as a resource in the 2018 IRPs; in total, nearly 300 MW (nameplate) of lithium-ion battery storage as capacity resource placeholders were assumed to provide 80% of their nameplate capacity towards meeting the Companies' winter peak capacity needs. The Companies also noted their agreement as indicated in their filed IRPs that battery storage costs are expected to continue to decline, making batteries an option for grid support services, including frequency regulation, solar smoothing during periods with high incidences of intermittency, as well as, the potential to provide overall energy and capacity value. DEC and DEP dispute the AGO's contention that they did not thoroughly evaluate the downward trend of storage technology costs, noting that its IRPs assume that battery storage costs drop by nearly 40% by year 2025 in the IRP Base Case. DEC and DEP also indicated that the Companies' IRPs include an aggressive capital cost sensitivity that would further the decline in battery storage costs to 60% by 2025. Additionally, the Companies include a sensitivity of replacing a future undesignated CT with a grid-tied battery storage option in both the DEC and DEP IRPs. DEC and DEP also argued that pairing storage with solar to allow "the storage component to benefit from federal investment tax credits as suggested by the AGO may not always be in the best interests of ratepayers." They pointed out that because North Carolina's peak conditions occur in both summer afternoon and winter morning and afternoon, and can be at least several hours in duration, there may be limitations to the capacity value of batteries, particularly batteries charged solely from solar resources. DEC and DEP noted the Commission's recent approval of a Certificate of Public Convenience and Necessity for DEP's Hot Springs Microgrid Project, a combination 3 MW (DC) solar and 4 MW lithium-based battery energy storage system. They indicated that they are committed to further studying the capacity value of incremental battery storage (both grid-tied storage and solar plus storage systems) in the Carolinas at increasing penetration levels. They stated that a study of the capacity value of storage is needed, and that the Companies expect to include the results of a capacity value of storage study as early as the Companies' 2020 biennial IRP filings.

H. DENC Reply Comments – Battery Storage

DENC addressed battery storage at Section 5.1.2 of the 2018 IRP and Section 3.c.iv of the Compliance Filing. As referenced in the Compliance Filing and by the Public Staff, in addition, the GTSA requires DENC to submit a proposal to deploy a battery storage pilot of up to 30 MW.

The Public Staff acknowledged DENC's recognition that energy storage could have value to provide grid stability as more renewable energy sources are integrated into the grid and could reduce the intermittency of wind and solar generation. The Public Staff contended, however, that DENC did not comply with the Commission's directive to assess battery storage technology. The Public Staff noted that DENC did not consider battery storage technologies for further analysis in its busbar curve, and asserted that DENC did not appear to thoroughly assess battery storage technologies and did not otherwise justify their absence from the IRP. The Public Staff therefore recommended that DENC be required to submit a supplemental filing to its 2018 IRP with a more detailed analysis of why battery storage technologies were excluded from its busbar curves, including a quantitative analysis of energy storage costs. The Public Staff also encouraged DENC to address how its solar integration cost estimates are affected by battery storage, including a discussion of whether the legislatively mandated 5,000 MW of solar could be more cost effectively integrated if coupled with energy storage techniques. The Public Staff suggested that DENC should also be required to file this information in future IRPs and IRP updates.

In its reply comments, DENC noted that many types of technologies can store energy, including electrical, thermal, mechanical, and electrochemical technologies. DENC explained that hydroelectric pumped storage, a form of mechanical energy storage, accounts for the greatest share of large-scale energy storage power capacity in the United States. DENC explained further, however, that large-scale energy storage capacity additions since 2003 have been almost exclusively electrochemical (or battery) storage. According to DENC, as of May 2019, there has been limited operating experience in utility scale applications of batteries with 901 MW for the entire United States (298 MW in PJM).

DENC further explained that it is in the early stages of battery research and has relied on publicly available industry guidance regarding battery storage projects to help evaluate the technology's merits as compared to traditional generation sources. DENC acknowledged that battery storage can be a viable future option for peak shifting at a stand-alone storage facility or while co-located at a solar farm and may also improve overall energy production at a solar facility via capturing energy that may be clipped by the inverters.

Because battery storage is still in its early stages of development, DENC stated that the estimates for a battery storage facility in the 2018 IRP were more reflective of a pilot program versus a larger utility scale facility. In addition, DENC explained that CTs can provide backup for periods of lower production from solar facilities, such as prolonged weather patterns or projected variations in capacity factors over the course of a year. DENC stated that CTs in the 2018 IRP short-term action plan were slated for deployment in 2022 and 2023, at approximately 458 MW nominal capacity per facility and an overnight installed cost of $476 per kilowatt (kW). According to DENC, pricing of an equivalent battery storage facility was not cost competitive based on those 2018 estimates. As a result, based on the 2018 economics and technology, DENC stated that it does not expect battery storage facilities to significantly displace CT facilities supplementing the solar generation profile within the next several years.

DENC stated that in the 2018 IRP, it screened out battery storage resources as part of its future resource analysis because of (1) limited utility scale operating experiences, (2) PJM being in the process of revising its tariffs for energy storage resources due to FERC Order 841, and (3) high costs. In the Compliance Filing, a 30 MW battery storage pilot program was available as an option in the "final" PLEXOS IRP modeling based on the directive in the VSCC 2018 IRP Order. DENC stated that the 30 MW battery storage pilot was not chosen by the model as a least-cost option in Plan A. According to DENC, this validates its decision in the 2018 IRP to screen out battery storage resources in its 2018 IRP future resource process because of their then (i.e., 2018) high cost relative to their benefits as a generating resource. Nevertheless, DENC acknowledged that the battery storage pilot was forced into all other Plans (Alternative Plans B through F) as required by the VSCC 2018 IRP Order. Notwithstanding their treatment in the 2018 IRP, DENC stated that it will include battery storage and other energy storage options such as pumped storage facilities in the busbar analysis and provide the results of that revised analysis in its 2019 IRP update.

Finally, DENC stated that it disagrees with the recommendation from Public Staff that the Commission require DENC to submit a supplemental filing to specifically address how its solar integration cost estimates are affected by battery storage. According to DENC, it will not have sufficient information to analyze the effect on solar integration for the 2020 IRP because DENC's experience with battery storage technologies is still in its early stages of development. Nevertheless, DENC stated that it will continue to assess battery storage technologies in future IRPs and IRP updates as required by prior Commission orders, and will report and incorporate the results of any relevant experience with battery storage. As part of that effort, DENC will, as directed by the VSCC Compliance Order, model battery storage using the most updated cost estimates available in its future full IRP filings.

VII. Integrated Systems and Operations Planning (ISOP)

Duke stated in its IRPs that it is examining ways of enhancing the traditional methods of utility resource planning in order to keep pace with changes occurring in the industry. As an example, Duke stated that it has not been able to identify the locational value of distributed generation sources, and is now developing models to do so. Duke indicated that it is addressing this and other issues through an Integrated Systems and Operations Planning (ISOP) effort. Further, Duke indicated that the future enhancements in planning are expected to be addressed over the next several years, as soon as the modeling tools, processes, and data development will allow.

The Commission has carefully considered the importance of the evolving nature of integrated resource planning. The Commission recognizes that some of the most promising emerging resource solutions, such as battery storage and leading-edge intelligent grid controls, are still in the early stages and will require enhanced capabilities, such as those promoted through ISOP. As a result, the Commission concluded that it would be helpful for the Commission to receive additional information from Duke about ISOP and ordered that a Technical Conference be held on August 28, 2019 for that reason. (See Commission Order dated July 23, 2019 in Docket No. E-100, Sub 157)

A. Public Staff Initial Comments – ISOP

The Public Staff recognizes the complexity of fully valuing battery storage, and encourages the development of improved modeling capabilities envisioned by ISOP.[1] The Public Staff also recommended that in future IRPs, the Companies continue to evaluate the feasibility and benefits of advanced analytic techniques that incorporate sub-hourly modeling and more granular system performance data, and to the extent these advanced analytics are available at reasonable cost, utilize these resources to provide better information and understanding on optimizing reserve margin needs, as well as overall system operations.

B. EDF Comments – ISOP

EDF commends Duke for using this innovative planning approach, which it maintains can save customers money through deferring or avoiding costly investments. However, EDF recognizes that there are not many details in Duke's IRP, and encourages the Commission to open a rulemaking or separate docket to explore the most effective and systematic way to implement ISOP.[2]

C. NCSEA Comments – ISOP

In its initial comments, NCSEA stated that it is encouraged by the statements made regarding Duke's ISOP process, and compares it to Integrated Distribution Planning (IDP), stating that the proposed ISOP description is similar but for its exclusion of a hosting capacity map.[3] NCSEA criticizes Duke for not including more detail or a timeline associated with ISOP, and calls upon the Commission to create a rulemaking proceeding to implement ISOP in order to establish

[1] Initial Comments of the Public Staff, at 76.

[2] Initial Comments of EDF, at 5.

[3] Initial Comments of NCSEA, at 19.

a set of rules by which the ISOP process is governed. NCSEA believes such a rulemaking procedure would guarantee that the process has sufficient oversight and transparency so as to allow ratepayers real opportunities to see if the investment decisions are in their best interests.

D. AGO Comments – ISOP

The AGO supported the recommendation made by intervenor NCSEA that a holistic approach should be adopted for the evaluation of the improvements and investments that will be needed to modernize Duke's distribution and transmission grid to better enable use of energy resources such as storage or demand-side measures. Planning and modeling for the future grid – including the integration of distributed resources into distribution and transmission systems – are important pieces of developing integrated resource plans. Strategen noted that some forecasts indicate that distributed resources will almost double by 2023, and North Carolina has witnessed tremendous growth in solar installations and projects. These forecasts need to be considered when formulating integrated resource plans. Accordingly, the AGO recommended that the Commission review and take a proactive role in the planning of integrated distribution planning, either by opening a rulemaking for that purpose or by other appropriate procedures.

E. DEC and DEP Reply Comments – ISOP

In their comments, EDF and NCSEA asked the Commission to initiate a rulemaking proceeding to adopt procedures related to ISOP and Integrated Distribution Planning (IDP), respectively. Duke commented that it does not oppose a rulemaking, but recommended that the Commission allow interested parties to participate in a pre-rulemaking stakeholder process to facilitate common understanding of ISOP issues, and attempt to reach consensus on as many areas as possible to make the formal rulemaking process more collaborative and efficient. Duke indicated it has discussed this stakeholder proposal informally with the Public Staff, and believes that such a process could be beneficial to the Commission and interested stakeholders.

VIII. QUANTIFICATION OF THE VALUE OF FUEL DIVERSITY AND RISK ANALYSIS

A. Public Staff Initial Comments – Fuel Diversity and Risk Analysis

The Public Staff noted that the Comprehensive Risk Analysis used by DENC provides valuable information in trying to identify which least cost portfolio is best in an uncertain world. The Public Staff found that the approach taken by DENC to analyze the various scenarios with regard to exposure to fuel price volatility scenarios, consideration of rate impacts to customers, and utilizing a probabilistic risk assessment framework provides insightful information to its customers and the Commission. The Public Staff recommended that DEC and DEP develop similar analytical tools to those utilized by DENC, such as the Comprehensive Risk Analysis, to determine the least cost plan that provides the lowest risk to its customers, while also providing operational and compliance flexibility to each utility.

B. SACE, Sierra Club, and NRDC Initial Comments – Fuel Diversity and Risk Analysis

SACE, et al. commented that Duke's 2018 IRP Plans rely excessively on new gas-fired generating capacity. Gas-fired generation is subject to numerous uncertainties, including fuel cost volatility, and carbon regulation. The groups noted that as more energy efficiency programs, renewable energy resources, and battery storage are added to Duke's resource mix, the need for additional gas-fired capacity is diminished.

NRDC commissioned energy consulting firm ICF to perform a power sector analysis using ICF's Integrated Planning Model (IPM®), a power sector dispatch model. SACE, et al. commented that ICF's IPM analysis shows that greater reliance on cleaner energy sources, rather than fossil fuel generation, delivers cost savings and pollution reductions for North Carolina compared to the "business-as-usual" approach in the Duke IRPs. With respect to gas-fired generation, ICF's "economically optimized" case, which allowed the model to optimize for a least-cost outcome, coal-fired capacity was reduced and replaced primarily with new solar; no new gas capacity was selected by the model based on economics. If North Carolina were to follow this economically optimized path, electric sector carbon emissions would fall to 41% below 2005 levels by 2025. The business-as-usual case would have a total system cost of $5.6 billion more that the economically optimized case—or, 3% higher bills for the average residential customer by 2030 and 5% higher by 2035.

C. NCSEA Initial Comments – Fuel Diversity and Risk Analysis

It is NCSEA's position that, with a heavy reliance on natural gas and other traditional generating resources, the IRP plans fail to account for cost-effective clean energy alternatives to the increasingly uneconomic operations of Duke's existing coal plants. NCSEA argues that the Synapse Study details a realistic clean energy future that provides both the energy and capacity to meet the needs of Duke's customers, while effectively meeting future reliability requirements as traditional generating resources are retired.

D. AGO Initial Comments – Fuel Diversity and Risk Analysis

The AGO commented that Duke's continued reliance on natural gas plants as the primary way to meet future resource needs is not justified because Duke's plans have not adequately considered the economic and environmental risks of that option.

The AGO stated that one concern about Duke's heavy reliance on natural gas generation for planning purposes is that natural gas production and consumption are associated with significant carbon dioxide and methane emissions, greenhouse gases that contribute to climate change, whereas alternatives that use renewables paired with storage are not. Climate change has real costs affecting ratepayers. The economic costs associated with frequent and intense hurricanes, such as those experienced in North Carolina in the past year, were cited as key factors motivating Executive Order No. 80. That order highlights a State commitment to fight climate change and transition to a clean economy, setting a goal of reducing statewide greenhouse gas emissions to 40% below 2005 levels by 2025. The AGO advocated that the Commission broaden its consideration of environmental factors in light of the policy goals announced in Executive Order 80.

Another concern about Duke's increased reliance on natural gas power production is the economic risk of that option. The AGO and Strategen agreed with the recommendation made by the Public Staff that Duke should be directed to use an analytical tool similar to the Comprehensive Risk Analysis that was employed in the initial IRP report of DENC in order to address the relative riskiness of alternative resources. That tool considers tradeoffs between the costs and riskiness of the resources that make up the portfolio. The risk assessment may take into account not only the potential volatility of prices but also risks associated with climate change impacts and mitigation efforts. If Duke is directed to perform a Comprehensive Risk Analysis, Strategen notes that there should be transparency about the assumptions used in the analysis and recommends that Duke should either supply a working copy of the model so that assumptions may be evaluated by other parties in detail or should run alternative specifications and scenarios for others.

According to the AGO, Duke's increased reliance on natural gas power production also poses a longer-term risk that the investment may become stranded before the end of the useful life of such plants. Conventional gas-fired plants are built to last for decades, and new emission standards or technological change may cause the plants to become uneconomic. This concern was identified by the Indiana Utility Regulatory Commission when it rejected an 850 MW natural gas plant proposal. The Indiana Commission directed Vectren to evaluate alternatives to the large, centralized generation approach, given the potential that the plant could become a stranded asset as the cost of renewable energy declines.

E. NC WARN Initial Comments – Fuel Diversity and Risk Analysis

NC WARN noted in its initial comments that public utility commissions, such as in Arizona and Virginia, have rejected proposed IRPs and required utilities to consider opportunities for renewable energy before considering new natural gas infrastructure. NC WARN recommended that the Commission direct Duke to consider battery storage options as opposed to new natural gas infrastructure. NC WARN filed an updated version of its North Carolina Clean Path 2025 Plan, which provides for replacement of 50% of all coal and gas used for electricity with clean energy by 2025, and 100% by 2030. NC WARN's plan indicates that solar combined with battery storage is now more reliable and cost effective than new natural gas power plants. The Plan indicates that gas turbine manufacturing is declining due to this shift to renewables with storage. The Plan states that Duke's contention that it must build gas turbines to back up solar is "unsubstantiated."

In its reply comments, NC WARN encouraged the Commission to carefully review Duke's plan to meet demand mostly from resources using fracked gas. It contended that the demand for fracked gas would likely decline as renewable energy technologies grew and battery costs fell. NC WARN also recommended that the Commission reject Duke's proposal to add over 9,000 MW of natural gas infrastructure and direct Duke to seek renewable generation instead. NC WARN contends that Duke's proposal to build natural gas plants and pipelines is not the least-cost option and exposes customers to significant risk.

F. DEC and DEP Reply Comments – Fuel Diversity and Risk Analysis

The Public Staff suggests that DEC and DEP adopt a fuel diversity analysis similar to the analysis provided by DENC in its IRP filings. DEC and DEP commented that their high-level understanding of DENC's approach is the deployment of a long-term stochastic modeling approach. Under such an approach, long-term fuel prices are statistically simulated over hundreds or even thousands of scenarios to examine a distribution of potential outcomes dependent on the mean forecast of various fuels such as coal, natural gas and fuel oil. In addition, statistical parameters such as long-term commodity volatility curves and long-term cross commodity correlations would be required in such an approach. While such an approach provides a comprehensive distribution of potential production cost outcomes, it is dependent upon these forward-looking statistical assumptions that are difficult to ascertain and verify. Currently, parties to the IRP docket have varying opinions on the long-term fuel price forecasts used by DEC and DEP. DEC and DEP noted that moving to a long-term statistical approach greatly expands the debate given the dependence on long-term forecasts of fuel volatility, mean reversion parameters and correlation variables. They continue to assert that the use of discrete fuel price sensitivity and scenario analysis provides a more transparent view of fuel diversity benefits. Furthermore, DEC and DEP commented that their discrete sensitivity and scenario approach is consistent with Rule R8-60 that outlines variables such as fuel prices should be varied so portfolio results can be viewed under these varying assumptions.

IX. OTHER ISSUES

A. UTILITY STATEMENT OF NEED

The Public Staff noted the fundamental link between each IOU's IRP and avoided costs, formalized with the passage of HB 589, which provided that a "future capacity need shall only be avoided in a year where the utility's most recent biennial [IRP] filed with the Commission ... has identified a projected capacity need to serve system load..." The Public Staff pointed out that a number of assumptions used by the IOUs in the avoided cost proceeding have not been clearly specified by each utility. To remedy this issue and mitigate the potential for paying for more capacity than what is needed, the Public Staff recommended that the utilities, in their IRP Update to be filed in 2019 and all future IRPs and updates, include a new Utility Statement of Need section. The Public Staff explained that the Utility Statement of Need section will specifically address the link between the first year of capacity need and avoided cost proceeding and specifically address:

1. The year in which the utility would fall below its planning reserve margin without commitment(s) to procure additional resources.

2. Whether QF contracts expiring within the avoided cost term are renewed / replaced in kind, or excluded.

3. Whether utility uprates are solely installed for additional capacity and if they could be considered avoidable.

4. Whether new EE measures are included in the determination of capacity need.

5. The quantity of MW needed in the first year, and a discussion of whether avoided capacity payments will be made to QF contracts executed in excess of that capacity.

6. The year in which the utility's first avoidable capacity need becomes unavoidable.

7. Whether it is appropriate to create a separate "Avoided Cost Portfolio" in the IRP's portfolio analysis section, which might present a more objective determination of capacity need that could ensure QFs providing capacity are not treated as captive.

The Public Staff explained that this section would then be directly referenced by each utility in its avoided cost proceeding, establishing a clear and well-understood methodology to establish the first year of capacity need for the calculation of avoided capacity payments. The Public Staff contended that the utilities should continue to conduct the foundational analysis of the IRP, with incorporation of the Public Staff's recommendations.

In its reply comments, Duke agreed with the Public Staff's recommendations and stated that it will include a Statement of Need section to more clearly identify the undesignated capacity needs for each utility in DEC's and DEP's 2019 IRP Updates and in future biennial IRP filings.

B. RETAIL RATE IMPACT OF PORTFOLIOS

In Docket No. E-100, Sub 147, the Public Staff previously recommended that DEC and DEP "file a residential rate analysis of the proposed expansion plans, along with a comprehensive risk analysis that addresses similar key risk factors employed by DNCP" in future IRPs. The Commission did not rule on the issue of including a residential rate analysis of the proposed expansion plans in its June 27, 2017 Order Accepting Integrated Resource Plans and Accepting REPS Compliance Plans in Docket No. E-100, Sub 147 (2016 IRP Order).

In the current docket, the Public Staff noted that an analysis of the rate impacts of each portfolio would inform the comments of intervenors, as well as testimony and comments from the using and consuming public, how changes in generation plans and costs would impact a retail customer, particularly residential customers as to an estimate of the short and long-term costs of the various portfolios. The Public Staff indicated that while there is not currently a statutory or regulatory requirement for Duke to include rate impacts in future IRPs as there is in Virginia,[1] such information could also be useful in other forums, such as the North Carolina Climate Change Interagency Council and the stakeholder workshops formed to facilitate the implementation of Executive Order 80. Therefore, the Public Staff recommended that the Commission require DEC and DEP in future IRPs to evaluate the residential rate impacts of each portfolio evaluated against a no CO_2 scenario and present this information in a manner similar to that used by DENC.

The Public Staff noted that DENC presents the incremental cost of compliance of each of the Alternative Plans compared to the least cost plan, but due to the significant changes in

[1] Va. Code § 56-599 B 9 requires DENC to evaluate "[t]he most cost effective means of complying with current and pending state and federal environmental regulations, including compliance options to minimize effects on customer rates of such regulations." Accordingly, DENC evaluates the residential rate impact of each Alternative Plan against its Plan A: No CO_2 Tax. This analysis may be found in Section 6.6 of DENC's 2018 IRP filed May 1, 2018.

investment decisions between the filings of the original IRP and its revisions, these estimates are no longer valid. Thus, the Public Staff recommended that DENC submit as a supplemental filing with a recalculated rate impact analysis of the modified Alternative Plans found in its Compliance Filing. DENC requested instead that it be permitted to provide an updated rate impact analysis of the Alternative Plans in its 2019 IRP Update due to be filed by September 1, 2019.

The AGO supported the recommendations of the Public Staff and other parties that Duke should be required to provide an analysis of the residential annual rate impacts of each of its portfolios similar to that presented in Dominion's 2016 and 2018 IRPs. The AGO recommended that the analysis should show the impacts of the portfolios on ratepayer bills, and the analysis should not be limited to residential ratepayers, but rather, should be applied generally to all customer classes. Further the bill impact analysis should include a breakout of the portion of rates that are fuel-related and thus bear the price risk borne by ratepayers.

C. DENC NUGs

The Public Staff noted that some facilities DENC listed as NUGs in Appendix 3B to its IRP are not included in the NUG capacity in Figure 3.1.1.3, while some utility-scale solar facilities are considered as NUG capacity in Figure 3.1.1.3 and others not. The Public Staff also noted that DENC considers all utility-scale solar facilities to be behind the meter, but these facilities typically separate the metering of electricity sales from electricity purchases. The Public Staff recommended that in future IRPs, DENC clarify its definition of a NUG facility; use that definition consistently through the IRP; re-evaluate which generating facilities sell energy directly to DENC and identify them separately from facilities that do not; separately identify facilities that sell energy/capacity directly to DENC from facilities that sell directly into PJM; and be consist in references to nameplate rating or equivalent firm capacity rating.

In its reply comments, DENC indicated that it had discussed these recommendations with Public Staff and had agreed to make changes to Appendix 3B and Figure 3.1.1.3 in future full IRPs and to provide an updated version of Appendix 3B as part of the 2019 IRP Update filing to the extent the information is available.

D. QF CONTRACT EXPIRATION IN THE IRP

In its Initial Comments, NCSEA takes exception with the method used by Duke in the treatment of QF contract expirations in the IRPs. NCSEA states that, "despite the fact the PPAs with QFs will eventually expire, Duke assumes that the PPAs will 'be either renewed or replaced in kind.' However, there is no guarantee, or requirement, that a QF will continue to provide the utility with capacity past the end of its initial PPA, even if the QF has remaining operational life." [1] This statement was made in reference to a data request response provided by the Companies to the Public Staff in this docket.[2]

[1] NCSEA Comments, p. 25, Paragraph 1.

[2] Duke Energy Carolinas, LLC's Response to Public Staff Data Request No. 6-4 and Duke Energy Progress, LLC's Response to Public Staff Data Request No. 4-12, included in NCSEA's Comments as Attachment 2.

Duke commented that this data request response refers only to solar QF contracts, as existing contracts of any other technology are assumed to expire at the end of the purchased power agreement ("PPA") term. Solar capacity, however, will continue to grow in the future, increasing the Companies' planned solar capacity. As such, the capacity of existing solar QFs will either be procured by the renewal of existing contracts or replaced with other solar PPAs. Whether the capacity is from an existing QF or another QF does not matter in the context of the IRP, only that the capacity comes from a solar resource.

NCSEA goes on to allege that "Duke assumes for planning purposes that a QF's PPA will be renewed despite the fact that it has made numerous efforts in other proceedings to make it more difficult for a QF to renew a PPA,"[1] going on to cite Docket No. E-100, Sub 101 and Docket No. E-100, Sub 158, as examples. Duke argued that both dockets cited by NCSEA relate to the upgrade of QF equipment, which is in no way impactful to the 2018 IRPs.

NCSEA continues its argument by stating that "other wholesale PPAs are removed from DEC and DEP's respective generation stacks when they expire and create capacity needs. However, Duke treats PPAs with QFs differently in its planning process."[2] Duke noted that it is true that DEC and DEP have consistently assumed across multiple planning cycles that all wholesale purchase contract capacity, including QFs, is removed in the year after a wholesale contract expires and that QFs are not presumptively assumed to establish a new PPA to deliver capacity and energy to the Companies over a new fixed term in the future. According to Duke, if, however, the QFs have already executed a contract extension or renewal with Duke, the specific contract capacity will be included past the original contract expiration year to the year of expiration of the extended/new contract. Thus, the existing QF contracts may either be renewed or replaced with other new solar facilities so that, in the aggregate solar penetration reaches levels projected in the IRP. The IRP is agnostic as to which choice is made but rather focuses on an expected level of solar penetration. Furthermore, Duke commented that the IRPs present scenarios with both higher and lower levels of solar penetration that are also agnostic to the decision of renewal versus replacement with new solar facilities. Duke noted that this is consistent with the approach for all contracted generation. For example, at the time DEP's 2018 IRP was filed, several natural gas PPAs were expiring. The IRP did not explicitly assume these contracts were renewed but rather put in a generic undesignated PPA that was deemed avoidable by QFs for the purpose of establishing avoided cost rates. Therefore, NCSEA's argument that the Companies are treating existing QF contracts differently and unfairly in the IRPs is untrue.

Duke noted that, based upon the foregoing circumstances, it continues to find its IRP planning approach of assuming a capacity reduction after expiring QF contracts reasonable and consistent with the objectives of their IRPs to determine the long-range generation needs to reliably serve their customers' energy needs in North Carolina. Thus, Duke argues that DEC and DEP are justified in removing from their respective IRPs the third-party wholesale contract capacity (both QF and non-QF) in the year when the contract expires.

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[1] NCSEA Comments, p. 25, Paragraph 2.

[2] Id. p. 26, Paragraph 1.

According to Duke, DEC and DEP have taken a reasonable and consistent approach to recognizing expiring wholesale purchase contracts, including QF contracts, in their 2018 IRPs. Duke's IRPs actually assume that, upon expiration of any third-party wholesale purchase contract (both QF and non-QF), DEC and DEP recognize a reduction in capacity by the amount of the capacity provided in the expiring wholesale purchase contract in the year following contract expiration. Duke noted that this approach to capacity planning is not new. Since the Duke Energy/Progress Energy merger, Duke's 2012, 2014, 2016, and 2018 biennial IRPs have all consistently assumed the expiration of wholesale purchase PPAs, including QF PPAs, that result in a need for replacement capacity to be procured through each utility's resource planning process to meet the targeted reserve margin during a given year. Thus, the expiration of each PPA has the potential to impact the timing of DEC and DEP's first capacity need, particularly when viewed in aggregate with other contract expirations or retirements. Fundamentally, it is prudent resource planning not to rely upon assumed future third-party owned capacity in years where no contract or other legally enforceable commitment guaranteeing delivery exists.

E. CLIMATE CHANGE

Duke responded to intervenor comments on climate change issues as follows.

1. Duke agrees with the AGO that incorporating environmental considerations into resource planning is critical even if specific standards are not yet defined in environmental regulations, which is why Duke models the potential costs of future carbon dioxide (CO_2) legislation as part of their comprehensive scenario analysis described in the IRP.

Duke noted that, as described in Chapter 13 of the DEP IRP and Chapter 12 of the DEC IRP, and in more granular detail in Appendix A of both IRPs, Duke analyzed the potential costs associated with multiple government-imposed limitations on greenhouse gas emissions. These CO_2 sensitivities are placeholders for future legislations, and the IRPs reflect the costs associated with the implementation of those potential regulations. Any benefits to Duke's customers associated with those potential regulations are largely driven by state and federal rules and standards that are also evolving and will influence how technologies are deployed. Duke asserted that, to be clear, the IRP does not set policy, but it responds to regulations and can provide a view of the impacts of potential regulations, as Duke has shown with potential greenhouse gas emission regulations.

2. Duke supports lowering carbon emissions, and the IRPs are consistent with Duke Energy's Sustainability Report. Furthermore, the DEC and DEP systems are projected to exceed Executive Order No. 80 which set a goal of reducing statewide greenhouse gas emissions to 40% below 2005 levels by 2025.

Duke noted that it has been aggressive with its pace of retiring coal plants (having retired more than half of its Carolinas coal plants over the last decade), adding renewables to the resource mix, increasing EE/DSM offerings to its customers, and operating a reliable nuclear fleet that provides half of its customers' energy demand with zero CO_2 emissions. These actions, along with operating efficient natural gas generation with low cost fuel, will allow the DEC and DEP systems to meet and exceed the goals of Executive Order No. 80, signed in the Fall of 2018, as well as the Companies' own sustainability targets, all while meeting the Commission's Rule R8-60 requirement to "provide reliable electric utility service at least cost over the planning period."[1] Duke explained that it is participating in the Executive Order No. 80 stakeholder meetings and, although the State's specific plans to implement the order are currently unknown, with the final report not expected until October 2019, Duke will address any additional requirements in future IRPs once any additional requirements are known.

In the introduction to its reply comments, Duke noted that the IRP is a "snapshot in time" view of DEC's and DEP's proposed mix of diverse resources to reliably meet customers' needs over the fifteen (15) year planning horizon. The IRP process is lengthy and dynamic. Duke commented that a consistent theme reflected in numerous consumer statements of position filed with the Commission is a call for accelerated retirement of the Companies' remaining coal plants, less reliance on natural gas or other fossil fuels, and greater reliance upon renewable resources, energy storage, DSM and EE. These same general themes are expressed in the comments filed by many of the intervenors to this docket. Duke explained that the 2018 Duke IRPs reflect a diverse mix of least-cost generation, storage, DSM and EE resources: in 2019, 46% of DEC's capacity is expected to come from carbon-free resources, and 39% of DEP's capacity is expected to come from carbon-free resources. Using the assumptions embedded in the 2018 IRPs, 60% of the combined DEC and DEP energy would come from carbon-free resources in 2019. Of the proposed resource additions over the 2018 IRP planning horizon, 46% of the DEC additions and 23% of the DEP additions would come from renewables, storage, DSM and EE.

However, change is constant in the energy industry, and Duke noted that successful companies are those that recognize and adapt to the changing landscape. Duke stated that it shares its stakeholders' desire to provide increasingly clean energy for the benefit of its North Carolina and South Carolina customers. A lower carbon future requires a delicate balancing act with no one-size-fits-all solution, as Duke must continue to provide all of its customers with safe, reliable and affordable energy. In its 2017 Climate Report to Shareholders and its 2018 Sustainability Report, Duke Energy Corporation reiterated its voluntary goal to reduce carbon emissions 40% across its six state generation fleets by 2030, and noted that its long-term strategy is to continue to drive carbon out of its system. The specific potential path forward and timing to a low-carbon energy future, however, will depend on a number of challenging and uncertain factors, including market forces, public policy, technology innovation/ commercialization and customer demand. Duke routinely evaluates retirement of its generation assets, but as Duke considers a course specific to the Carolinas, DEC and DEP will evaluate accelerated retirement of their remaining North Carolina coal units, coupled with other necessary supply and demand-side investments to reliably meet customer needs. Because such plans would not only impact Duke's future generation mix, but would also impact customer rates, any such accelerated coal unit retirement plans would also need to be considered in ratemaking dockets. Duke noted its commitment to make appropriate filings with the Commission in future dockets after it has completed its analysis and reached any conclusions.

[1] Commission Rule R8-60 – Integrated Resource Plans and Filings.

F. ALTERNATIVE FILED RESOURCE PLANS

NCSEA, SACE et al., and NC WARN filed what might be styled as alternative resource plans as part of their comments on the 2018 IRPs. Duke responded to these alternative plans as follows.

1. The Synapse Report filed by NCSEA is the product of a special interest group that appears to make assumptions in their model with a predetermined outcome in mind. The Synapse Report would not conform to the regulated utilities' requirement to provide reliable electric utility service at least cost over the planning period and should be dismissed.

Duke noted that the Synapse report filed by NCSEA as Attachment 1 to its comments claims to detail "a realistic clean energy future that provides both the energy and capacity to meet the needs of Duke's customers, while effectively meeting future reliability requirements as traditional generating resources are retired"[1]; however, the report's cost savings are based on multiple assumptions that, if implemented, would cripple the reliability of the DEC and DEP systems.

Duke argues that, first, the Synapse report, which purports to gain an immediate cost savings of 28% through "removal of [coal generation] must-run designations"[2] does not consider "transmission implications that may or may not be associated with must-run designations."[3] The must-run designations that Synapse removes are not required at all energy demand levels on the DEP and DEC systems, and Duke is not seeking "to find a use for the costly must-run coal generation"[4] as Synapse suggests. Duke instead notes that, in fact, in Synapse's attempt to match the DEC and DEP IRP base cases (with must-run designations included), "one-third of the coal generation shown in 2019 is exported to neighboring utility service territories rather than being used to meet Duke's own load requirements."[5] Duke states that it does not model sales to neighboring utilities unless those are firm sales with co-owners that are part of nuclear generation contracts or the new Lee CC, and DEC and DEP generally do not sell energy to external markets unless there are economic incentives for consumers to do so. Generally, must-run requirements increase as system energy demand levels increase or other generating units near the must-run units are not available. This level of detail was not considered relevant to Synapse as they relied on Horizons Energy's National Database for their EnCompass model[6] which greatly oversimplifies must-run requirements on the DEC and DEP systems. Must-run requirements are in place to

[1] NCSEA Comments, pp. 5-6

[2] North Carolina's Clean Energy Future: An Alternative to Duke's Integrated Resource Plan, Prepared for the North Carolina Sustainable Energy Association by Synapse Energy Economics, Inc. (Synapse Report), p. 6

[3] NCSEA Response to Duke Data Request No. 1, Item No. 1-3 part c.

[4] Synapse Report, p. 6.

[5] Id., p. 5.

[6] NCSEA Response to Duke Data Request No. 1, Item No. 1-3 part b.

maintain stability on the transmission system by providing voltage support or other services. According to Duke, without these must-run requirements, the transmission system would be in jeopardy of not being able to serve load, which is a risk that Synapse and NCSEA have ignored.

Another source of cost savings in the Synapse report is the reduction of the required minimum reserve margins in DEC and DEP from 17% to 15% based on the NERC 2018 Long Term Reliability Assessment.[1] As noted in footnote 4 on page 53 of the NERC report, SERC Reliability Corporation (SERC) members perform individual reliability assessments, and SERC does not provide reference margin levels for its sub-regions. Further, page 151 of the NERC report states that NERC applies a 15% margin for predominately thermal systems if a reference margin is not provided by a given assessment area. In short, the SERC and NERC reports cited by NCSEA as a basis for a lower reserve margin do not reflect the level of solar penetration that exists in the Carolinas or the need for a winter reserve margin target as determined by the Companies' resource adequacy studies. The minimum reserve margin requirement in DEC and DEP has been a point of extensive comment since the 17% reserve margin was introduced in the 2016 IRP Reports. The minimum reserve margin requirement is based on comprehensive resource adequacy studies that the Companies conducted with Astrapé Consulting in 2016. Duke explained that, although some of the intervening parties apparently still chose to stubbornly debate the findings of the study, the Commission found the 17% reserve margin requirement reasonable for planning purposes, with the requirement that the Companies and the Public Staff file a joint report summarizing their review after filing the 2017 IRP Update.[2] Synapse took it upon themselves to ignore the 17% requirement that was developed through a study that focused on the issues facing the DEC and DEP systems, and instead used the NERC study that did not consider the level of solar penetration facing the Carolinas, which was a major driver of the increased reserve margin requirement. Duke argued that, again, Synapse and NCSEA are relying on a reduction in system reliability to drive the results of their biased resource report.

Duke commented that the third source of cost savings that is inconsistent with maintaining a reliable energy system in the Carolinas is Synapse's reliance on energy imports into the Carolinas. The Synapse "Clean Energy scenario" relies on 14% energy imports from neighboring utilities to meet demand by 2033.[3] According to Duke, this reliance on neighboring utilities to meet the Carolinas' energy and capacity needs is inconsistent with the reality that there is not enough firm transmission available to reliably import this level of energy, and the Synapse study makes no mention of the costs required to obtain firm transmission into the region. Duke argued that NCSEA and Synapse are either ignorant of the realities of transmission constraints into DEC and DEP, or they have intentionally ignored them.

Duke further pointed out that it is not clear that increasing energy imports from neighboring utilities, as NCSEA proposes to do, would result in fewer CO_2 emissions for the Carolinas. In fact, relying on other states' generation, including those states that may still rely mainly on coal

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[1] Id., Item No. 1-2 part b.

[2] Order Accepting Integrated Resource Plans and Accepting REPS Compliance Plans, Docket No. E-100, Sub 147.

[3] Synapse Report, p. 5.

generation, would be contrary to the spirit of Executive Order No. 80's goal to reduce CO_2 emissions in the state to 40% of 2005 emission levels by 2025. As stated above, Duke's plan already exceeds Executive Order No. 80's directive by using resources located in the Carolinas.

Duke argued that perhaps the comment that most clearly shows the lack of understanding by NCSEA and Synapse as to what constitutes a reliable system is the following statement:

> The Clean Energy Scenario maintains the required 15 percent reserve margin and EnCompass projects no loss-of-load hours and sees zero hours with unserved energy, proving that the retirement of fossil fuels and build-out of renewables leads to no new system reliability issues.[1]

As Duke explained, one does not simply use Duke's weather-normalized peak demand forecast, along with an hourly load shape from the EnCompass National Database as Synapse did, and claim no reliability concerns when the model converges without unserved energy hours. According to Duke, that is equivalent to someone guaranteeing that because they did not run out of gas when they drove from Chapel Hill to Raleigh at 7:00 a.m. on a Sunday morning with their low fuel light on, then they could successfully complete that drive at any time with little gas in the tank. How would they fare at 5:00 pm on a Friday in rush hour? Duke noted that when asked to explain their understanding of why the Companies carry a reserve margin, NCSEA's consultant, Ric O'Connell responded:

> NCSEA understands the reserve margin used in the IRP is a "planning reserve margin" which is defined by NERC as: Planning reserve margin is designed to measure the amount of generation capacity available to meet expected demand in [the] planning horizon.

Duke commented that such a definition may be accurate for the NERC study, but the Companies carry a reserve margin to be able to meet unexpected demand due to extreme temperatures, economic load forecast uncertainty, and unexpected outages of its operating units. The reserve margin that Duke requires is there not just to meet expected demand, but to be able to reliably serve customers under extreme and unexpected circumstances.

In summary, Duke noted that any party can claim that their plan is lower cost than the Companies' plans, but to achieve those costs savings in the manner that NCSEA and Synapse did, while still claiming to meet the reliability standards that the NCUC, Duke, and its customers demand, is unrealistic and lacks regulatory rigor. Duke, as the regulated utility in North Carolina, has the sole obligation to meet its customers' energy needs at all times throughout the year, and the Companies are steadfast in their belief that the DEC and DEP IRPs achieve that standard by doing so at the lowest reasonable cost while meeting and exceeding environmental regulations at the state and federal levels. Duke noted that, simply put, other parties to this docket do not have the obligation to serve, nor do they have an obligation to maintain a reliable electric system. Their use of overly simplistic modeling approaches to reach a predetermined ideological outcome would not be compliant with reliability standards and as such should be rejected.

[1] NCSEA Comments, p.8.

2. SACE et al.'s consultant Applied Economics Clinic's (AEC) Report, "Review of Duke Energy's North Carolina Coal Fleet in the 2018 Integrated Resource Plans" includes misleading and false accusations regarding the Companies' business practices.

Duke commented that the assertion of the Applied Economics Clinic in Attachment 2 of the SACE et al. comments that "the Companies have hard-wired the useful lives for their existing coal units, preventing a fair comparison of the economics of these units relative to replacement resources"[1] is misleading. The retirement dates for existing coal units are projections for planning purposes in the IRPs, and are based on retirement dates in depreciation studies approved in the most recent general rate cases by the Commission (and PSCSC).

Additionally, Duke argued that AEC's assertion that "...the Companies make major decisions about their resources behind closed doors"[2] is disingenuous. Multiple analyses are performed regarding the retirement options of the Companies' coal units, as confirmed in data requests received and cited by AEC in the SACE et al. Attachment 2. The results of those analyses are utilized and represented in the next filed IRP. Furthermore, Duke's IRPs and depreciation studies are open to scrutiny in the public and transparent dockets this Commission oversees with the intervention and active participation of parties like SACE et al.

Duke commented that while SACE et al. and AEC attempt to discredit Duke and its commitment to meet customers' energy needs at the lowest reasonable costs, the full picture is not considered. Duke is regulated by this Commission and the PSCSC and is under an obligation to provide reliable and affordable service to their customers. Duke pointed out that the special interest group intervenors, on the other hand, may freely utilize whatever data sources and reports that support their intended purpose, while ignoring the realities of the obligation of serving customers. Statements made by the intervenors criticizing Duke's analysis techniques, assumptions, and generally, any decision that does not meet their agenda are presented as fact in their comments, without regard for realistic actualities. In reality, the statements and assertions aimed at discrediting Duke are incorrect. Duke noted that, notwithstanding its criticism of SACE et al.'s tactics, as noted above, Duke will continue to evaluate potential accelerated retirement of their remaining North Carolina coal units and advise the Commission in future dockets.

3. NRDC's commissioned ICF analysis is unable to be reviewed and should be considered inconsequential.

SACE et al.'s comments state that NRDC commissioned the energy consultant, ICF, to perform analyses to develop its own "optimum" resource plan based upon inputs developed by NRDC. ICF utilized their Integrated Planning Model ("IPM") to develop what they call an "economically optimized" case and an "IRP" case, which is intended to replicate the No Carbon Base Case presented by the Companies in its filed IRP.

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[1] Review of Duke Energy's North Carolina Coal Fleet in the 2018 Integrated Resource Plans, p. 18, Part A.

[2] Id.

In a data request to SACE et al.,[1] Duke requested a copy of the report developed by ICF in the study, to which SACE et al. responded that, "ICF did not develop a report. All written materials were developed by NRDC, based on data outputs provided by ICF using their IPM model with all assumptions and policy scenarios provided by NRDC."[2] According to Duke, in the data request response, NRDC provided a file including the inputs developed by them. Duke explained that there is no discussion or detailed information about the calculation and algorithm details of the models. Additionally, how the input data was actually utilized in the model is unclear. In the same response, NRDC provided a single page of outputs for each case developed by the IPM model.[3] While two cases were provided, an "economically optimized" case was not one of them. SACE et al.'s data request response provides outputs for a "reference case" (also titled as "BAU No CCS") and an "IRP case." It is unclear if the "reference case" and the "economically optimized" case are the same case. As such, Duke noted it is impossible for the Companies to adequately review and comment on the outputs at this time.

Duke further commented that, even so, NRDC presents ICF's "economically optimized" case as a least cost option as compared to the "IRP" scenario that was created. There are several issues in question from Duke's point of view. First, in the ICF results presented as Attachment 1 of NRDC's Comments, in the description of the "economically optimized" case, it is stated that, "the model was allowed to endogenously retire and add generating resources to determine a least-cost pathway for the state given existing federal and state regulations."[4] Once again, in the absence of information regarding the calculation methodology and rigor of the ICF study, it is not clear how the model does this, what units are retired or when they are retired.

Duke explained that, additionally, NRDC states in Attachment 1 that "the only additional natural gas capacity added is from units already under construction" in the "economically optimized" case.[5] However, the capital costs and fuel prices utilized by ICF for new natural gas units are based on publicly-available generic data that is proven to be higher than in-house new-build costs developed for Company-specific locations and that consider economies of scale/scope that make these resources economic options. The costs utilized to make this statement are inordinately high and likely give any natural gas resources an unfair disadvantage.

NRDC claims, also, that "this 'optimized' case only represents a possible future in which decisions are made by an infallible market operator, instead of a reality where regulators may have to base their decisions on imperfect or incomplete information, and utilities are driven by

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[1] Southern Alliance for Clean Energy, Natural Resources Defense Council and the Sierra Club Responses to Second Data Request of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC, Docket No. E-100, Sub 157, April 29, 2019.

[2] Id., Response to DEC/DEP Data Request No. 2-1.

[3] Id., Response to DEC/DEP Data Request No. 2-2 including Input and Output Excel Files.

[4] Economically Optimized Independent Power Sector Modeling Shows Multiple Benefits when Compared to Duke's IRP, p. 2, bullet one.

[5] Id., p. 1, bullet three.

incentives that do not always align with their customers' interests."[1] Duke argues that, first, there is no such thing as an "infallible market operator," which discredits the "optimized" case as being unrealistic. Second, Duke suggests that the inference that utilities make decisions based on "incentives" that do not "align with customers' interests" is outrageous. Duke also notes that the SACE et al. inference that the information utilized by the Companies is incomplete is absolutely false. Duke explains that its resource plans are based on best-available information that takes months to gather, vet, and include properly in modeling and analysis utilized to develop the resource plans.

Finally, NRDC claims that renewable generation (primarily solar) replaces any existing coal or future natural gas resources by stating, "renewable energy generation more than makes up for the generation reductions..."[2] Duke commented that it is impossible for intermittent solar to replace baseload resources required to reliably meet the Companies' customer demand, particularly during peak times when solar is only available to a small degree. The IPM model outputs provided in SACE et al.'s data request response mentioned above do not provide any discernable information about the operational reliability assumptions and load shapes of the solar generation or the impacts of even higher levels of intermittent solar to Duke's generating system. As determined by the Capacity Value of Solar study presented in the Companies' filed IRPs,[3] solar resources provide very little capacity value at the time of winter peak demand and capacity values decrease as the penetration of solar increases. Duke explains that infinitely high amounts of solar cannot be added to a generating system and still maintain the integrity and reliability of the system and meet required NERC reliability standards.

Duke argues that, once again, SACE et al. fail to consider the real world in which the Companies operate. DEC and DEP are regulated utilities that have real obligations to its customers. Duke noted it is DEC and DEP's highest commitment to serve their customers in the most reliable, dependable, environmentally-friendly and economical manner possible. There are real-world consequences to the theoretical exercises SACE et al. continue to present as fact. Duke argues that the misleading and incomplete information presented by the intervenors consistently supports their own agenda but is developed without full consideration of the best interest of all customers.

4. NC WARN Comments – Alternative Filed Resource Plans

In its comments and attached report, NC WARN alleged, among other things, that DEC and DEP can achieve 100% fossil-free energy by 2030, getting halfway there by 2025. In response, Duke noted that NC WARN has, yet again, argued that the Commission should adopt an energy plan for North Carolina that is unrealistic and would jeopardize the reliable and affordable energy system that this Commission has consistently required from Duke in fulfilling the Commission's mission under the Public Utilities Act. Duke noted that although NC WARN objected to 8 of the 13 data requests DEC and DEP sent to it seeking analytical and factual support for statements

[1] Id., p. 5, paragraph two.

[2] Id., p. 1, bullet 4.

[3] DEC 2018 IRP, Chapter 9, and DEP 2018 IRP, Chapter 9.

made in its filed IRP comments and report, the information NC WARN did provide in its responses reveals that its comments and report are not supported by competent analysis or facts. For example, in DEC and DEP Data Request 1-4, the Companies asked NC WARN to:

> Please provide all documents and analyses including inputs, assumptions, calculations, results, models, spreadsheets with working formulas, or other data or information supporting your position that sufficient and cost-effective battery storage can be online by 2025 to displace thousands of megawatts of natural gas generation.

In response, NC WARN simply referred the Companies to the reports filed by NC WARN in connection with its 2017 and 2018 IRP comments. Duke notes that, in other words, NC WARN asserted that the underlying analysis supporting its comments was simply its own comments. Likewise, in DEC and DEP Data Request 1-7, the Companies asked NC WARN:

> On page 9 of your initial comments, you state that, "In his report, Mr. Powers establishes that DEC and DEP can achieve one-hundred (100) percent fossil-free energy by 2030, getting halfway there by 2025." Please identify and produce all documents and analyses including inputs, assumptions, calculations, results, models, spreadsheets with working formulas, or other data or information upon which you and/or Mr. Powers rely upon in support of this statement.

In response, NC WARN simply stated, "This statement is explained in detail, with applicable citations, in Mr. Powers' N.C. Clean Path 2025 Report and the Update: N.C. Clean Path 2025." This lack of quantitative analysis and circular reasoning is found throughout NC WARN's data request responses. See DEC/DEP Exhibit 1. Duke explains that although NC WARN's simplistic and hyperbolic conclusions may advance its own interests, its arguments should not, and cannot, be credibly relied upon by the Commission or anyone who truly values a reliable and affordable supply of energy for the State of North Carolina.[1]

X. REQUESTS FOR EXPERT WITNESS HEARING

NC WARN, as well as many of the consumer statements of interest filed with the Commission, have asked for an expert witness hearing on the 2018 IRPs. The Commission concludes that an expert witness hearing with respect to the 2018 biennial plans is not necessary because the Commission has a voluminous record before it, including studies and reports from various technical witnesses, which is adequate to review and rule on the adequacy of the 2018 IRPs. All intervenors have had the opportunity to make legal, factual, and technical arguments to the Commission in their filed comments, and the Commission has received the testimony of public witnesses in a public hearing, as well as numerous statements of consumer position filed with the Commission. Finally, the comments of some consumers appear to reflect an incorrect assumption that Commission acceptance of an IRP constitutes Duke's request for, or Commission approval of, specific generation resources contained therein. As the Commission noted in its June 26, 2015

[1] The Commission notes that NC WARN's assertion that North Carolina can retire all coal and gas-fired power plants by 2030 is directly contradicted by even its own admission in response to DEC and DEP Data Request 1-10, that gas plants would be needed to serve in a backup role in 2030 even under its proposed energy plan.

Order Approving Integrated Resource Plans and REPS Compliance Plans, in Docket No. E-100, Sub 141, at pages 11-12:

> General Statute 62-110.1(c), in pertinent part, requires the Commission to "develop, publicize, and keep current an analysis of the long-range needs for expansion of facilities for the generation of electricity in North Carolina, including its estimate of the probable future growth of the use of electricity." In State ex rel. Utils. Comm'n v. North Carolina Electric Membership Corporation, 105 N.C. App 136, 141, 412 S.E.2d 166, 170 (1992), the Court of Appeals discussed the nature and scope of the Commission's IRP proceedings. The Court affirmed the Commission's conclusion that
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> > [t]he Duke and CP&L plans were "reasonable for the purposes of [the] proceeding" before it. That is to say, the plans submitted by Duke and CP&L were reasonable for the purpose of "analy[zing]...the long-range needs for expansion of facilities for the generation of electricity in North Carolina..." See N.C. Gen. Stat. § 62-110.1(c).
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> The Court further explained that the IRP proceeding is akin to a legislative hearing in which the Commission gathers facts and opinions that will assist the Commission and the utilities to make informed decisions on specific projects at a later time. On the other hand, it is not an appropriate proceeding for the Commission to use in issuing "directives which fundamentally alter a given utility's operations." With regard to the Commission's authority to issue specific directives, the Court cited the availability of the Commission's certificate of public convenience and necessity (CPCN) proceedings and complaint proceedings. Id., at 144, 412 S.E.2d at 173.

As such, by statute the Commission's decisions on the need, cost, and timing of a specific generation resource are made only after a CPCN application is filed and considered by the Commission in a public and transparent CPCN proceeding conducted pursuant to N.C.G.S. §§ 62-110.1 and 62-82.

The Commission finds and concludes that for the purposes of N.C.G.S. § 62-110(c) and Rule R8-60 the record in this docket is sufficient, and that NC WARN and the other interested persons requesting an expert witness hearing have not shown good cause for such a hearing. Accordingly, the requests for an expert witness hearing on the 2018 IRPs are denied. As will be noted later in this Order, however, and based on the record compiled in connection with the 2018 filings, the Commission will require certain supplemental filings and proceedings and will direct that certain specific matters be addressed in the utilities' 2020 biennial IRPs.

XI. REPS COMPLIANCE PLANS

North Carolina General Statute § 62-133.8 requires all electric power suppliers in North Carolina to meet specified percentages of their retail sales using renewable energy and energy efficiency. One megawatt-hour (MWh) of renewable energy, or its thermal equivalent, equates to one renewable energy certificate (REC), which is used to demonstrate compliance. An electric power supplier may comply with the REPS by generating renewable energy at its own facilities, by purchasing bundled renewable energy from a renewable energy facility, or by buying RECs. Alternatively, a supplier may comply by reducing energy consumption through implementation of EE measures or electricity demand reduction.[1] The electric public utilities (DEP, DEC, and DENC) may use EE measures to meet up to 25% of their overall requirements in N.C. Gen. Stat. § 62-133.8(b). One MWh of savings from DSM/EE or demand reduction is equivalent to one energy efficiency certificate (EEC), which is a type of REC. All electric power suppliers may obtain RECs from out-of-state sources to satisfy up to 25% of the requirements of N.C. Gen. Stat. §§ 62-133.8(b) and (c), with the exception of DENC, which can use out-of-state RECs to meet its entire requirement. The total amount of renewable energy or EECs that must be provided by an electric power supplier for 2018, 2019, and 2020 is equal to 10% of its North Carolina retail sales for the preceding year.

Commission Rule R8-67(b) provides the requirements for REPS Compliance Plans. Electric public utilities must file their plans on or before September 1 of each year, as part of their IRPs, and explain how they will meet the requirements of N.C. Gen. Stat. §§ 62-133.8(b), (c), (d), (e), and (f). The plans must cover the current year and the next two calendar years, or in this case 2018, 2019, and 2020 (the planning period). An electric power supplier may have its REPS requirements met by a utility compliance aggregator as defined in R8-67(a)(5).

A. Public Staff Initial Comments – REPS Compliance Plans

The Public Staff commented on DEP, DEC, and DENC's plans to comply with N.C. Gen. Stat. §§ 62-133.8(b), (c), and (d), the general[2] and solar energy requirements. The Public Staff also provided consolidated comments on the IOUs' plans to comply with N.C. Gen. Stat. §§ 62-133.8(e) and (f), the swine and poultry waste set-asides.

According to the Public Staff, DEP has contracted for and banked sufficient resources to meet the REPS requirements of N.C. Gen. Stat. §§ 62-133.8(b), (c), and (d). As of December 31, 2017, DEP's compliance services contracts with the Towns of Sharpsburg, Stantonsburg, Black Creek, Lucama, and Winterville terminated, and DEP no longer provides REPS compliance services for any other electric suppliers.

DEP intends to use EE programs to meet 25% of its REPS requirements. A substantial portion of the general requirement will be met by executed purchased power agreements and REC-only purchases from biomass power providers, some of which are combined heat and power (CHP) facilities. Hydroelectric facilities of 10 MW or less, and power generated from landfill gas, will also provide RECs for DEP's retail customers. In addition, DEP plans to continue using solar energy to help it meet the general requirement. It may also use wind energy, either

[1] "Electricity demand reduction," as used herein, is defined in N.C. Gen. Stat. §62-133.8(a)(3a).

[2] The overall REPS requirement of N.C. Gen. Stat. §62-133.8(b), less the requirements of the three set-asides established by N.C. Gen. Stat. §§ 62-133.8(d)-(f), is frequently referred to as the "general requirement."

through REC-only purchases or through energy delivered to its customers in North Carolina, to satisfy this requirement.

To meet the solar set-aside, DEP will obtain RECs from its own solar facilities, its residential solar V program, and REC-purchase contracts with other solar PV and solar thermal facilities. DEP is the owner of 140.7 MW of solar facilities that are now operational and available for use to meet a portion of its REPS compliance obligations.[1]

DEP plans to evaluate additional projects through the competitive procurement process established in HB 589. HB 589 allows for competitive procurement of 2,660 MW of additional renewable energy capacity in the Carolinas, with proposals issued over a 45-month period. DEP may develop up to 30% of its required competitive procurement capacity using self-owned facilities.

DEP anticipates that its incremental REPS compliance costs will remain below the cost caps in N.C. Gen. Stat. §§ 62-133.8(h)(3) and (4), but it expects them to rise by approximately 20% over the planning period, reaching approximately 85% of the cost cap in 2020.

DEP files evaluation, measurement, and verification (EM&V) plans for each EE program in the respective program approval docket.

According to the Public Staff, DEC has contracted for or procured sufficient resources to meet the REPS requirements of N.C. Gen. Stat. §§ 62-133.8(b), (c), and (d) for the planning period, both for itself and for the electric power suppliers for which it is providing REPS compliance services. These suppliers are Rutherford EMC, Blue Ridge EMC, the Town of Dallas, the Town of Forest City, the City of Concord, the Town of Highlands, and the City of Kings Mountain (collectively, DEC's Wholesale Customers). DEC's contractual obligation to provide REPS compliance for the City of Concord and the City of Kings Mountain ended effective December 31, 2018; therefore, these comments reflect REPS compliance services for the City of Concord and the City of Kings Mountain only through 2018.

DEC intends to use EE programs to meet 25% of its REPS requirements. Hydroelectric facilities with a capacity of 10 MW or less and energy allocations from the Southeastern Power Administration (SEPA) will be used to meet up to 30% of the general requirement of DEC's Wholesale Customers.

Hydroelectric facilities of 10 MW or less, together with incremental capacity from the 2012 modifications to DEC's Bridgewater hydroelectric plant, will provide RECs for DEC's retail as well as its wholesale customers. DEC has entered into a contract to sell five of its hydroelectric

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[1] See DD Fayetteville Solar, Inc., Docket No. E-2, Subs 1054, 1055, and 1056, Order Transferring Certificate of Public Convenience and Necessity (Dec. 16, 2014); Duke Energy Progress, Inc., Docket No. E-2, Sub 1063, Order Issuing Certificate of Public Convenience and Necessity (Apr. 14, 2015).

facilities. All of these facilities intend to register as new renewable energy facilities, so as to retain the option of selling the RECs produced to DEC for REPS compliance purposes.[1]

A substantial portion of DEC's general requirement will be met by purchased power agreements and REC-only purchases from biomass power providers, some of which are CHP facilities. In addition, DEC will continue to use solar energy and power generated from landfill gas to comply with the general requirement. It may also use wind energy, through either REC-only purchases or energy delivered onto its system.

To meet the solar set-aside, DEC will obtain RECs from its self-owned solar PV facilities and from other solar PV and solar thermal facilities. DEC's solar resources include 75 MW of capacity at the Monroe and Mocksville solar facilities, approximately 20 MW from the small distributed solar facilities approved in Docket No. E-7, Sub 856, and 6 MW of anticipated capacity from the Woodleaf facility, which became fully operational in January 2019.

DEC anticipates that its REPS compliance costs will increase, but will be below the cost caps in N.C. Gen. Stat. §§ 62-133.8(h)(3) and (4), for the planning period.

According to the Public Staff, DENC has contracted for and banked sufficient resources to meet the REPS requirements of N.C. Gen. Stat. §§ 62-133.8(b) and (c) through 2019 for itself and for the Town of Windsor (Windsor), for which it provides REPS compliance services. DENC has contracted for and banked sufficient resources to meet the REPS requirement of N.C. Gen. Stat. § 62-133.8(d) as well. DENC plans to use EE and purchased RECs to meet the general REPS requirements of N.C. Gen. Stat. §§ 62-133.8(b) and (c) for itself and indicated that it may also use Company generated RECs. For Windsor's general REPS requirement, DENC will use out-of-state wind RECs, in-state biomass and solar RECs, and Windsor's SEPA allocation. For the solar set-aside, DENC plans to purchase in-state and out-of-state solar RECs for itself and Windsor. DENC will rely on out-of-state RECs to meet its compliance requirements, as allowed by N.C. Gen. Stat § 62-133.8(b)(2)(e), but will obtain in-state RECs to meet Windsor's 75% in-state requirement. Its total costs are the same as its incremental costs because, unlike DEC and DEP, it currently plans to purchase only unbundled RECs, rather than RECs that are bundled with renewable electric energy, to meet its REPS requirements.

DENC anticipates that during the planning period, it will incur annual research costs of $50,000 for the continued development of its Microgrid Project. The Microgrid Project consists of wind, solar and fuel cell energy generation and battery storage at DENC's Kitty Hawk District Office.

DENC expects that the REPS compliance costs for itself and Windsor will be well below the cost caps in N.C. Gen. Stat. §§ 62-133.8(h)(3) and (4) for the planning period.

[1] See Joint Notice of Transfer, Request for Approval of Certificates of Public Convenience and Necessity, Request for Accounting Order and Request for Declaratory Ruling, filed on July 5, 2018, by DEC, Northbrook Carolina Hydro II, LLC, and Northbrook Tuxedo, LLC, in Docket Nos. E-7, Sub 1181, SP-12478, Sub 0, and SP-12479, Sub 0.

DENC files EM&V plans for each EE program in the respective program approval docket.

B. REPS Compliance Summary Tables

The following tables are compiled from data submitted in DEP, DEC, and DENC's Plans. Table 1 shows the projected annual MWh sales on which the utilities' REPS obligations are based. It is important to note that the figures shown for each year are the utilities' MWh sales for the preceding year; for instance, the sales for 2018 are MWh sales for calendar year 2017. The totals are presented in this manner because each utility's REPS obligation is determined as a percentage of its MWh sales for the preceding year. The sales amounts include retail sales of wholesale customers for which the utility is providing REPS compliance reporting and services. Table 2 presents a comparison of the projected annual incremental REPS compliance costs with the utilities' annual cost caps.

TABLE 1: MWh Sales for Preceding Year

	Compliance Year		
Electric Power Supplier	**2018**	**2019**	**2020**
DEP	36,829,899	37,521,080	37,685,819
DEC	59,518,351	60,104,379	60,285,246
DENC	4,203,708	4,217,958	4,239,131
TOTAL	100,551,958	101,843,417	102,210,196

TABLE 2: Comparison of Incremental Costs to the Cost Cap

		DEP	**DEC**	**DENC**
2018	Incremental Costs	$41,294,711	$27,120,881	$1,052,998
	Cost Cap	$63,874,278	$94,975,829	$5,632,261
	Percent of Cap	65%	29%	19%
2019	Incremental Costs	$47,421,825	$36,738,176	$1,224,857
	Cost Cap	$64,583,052	$93,929,320	$5,288,797
	Percent of Cap	73%	39%	23%
2020	Incremental Costs	$55,445,392	$48,524,154	$1,419,320
	Cost Cap	$65,271,008	$94,623,837	$5,304,517
	Percent of Cap	85%	51%	27%

C. Swine Waste and Poultry Waste Set-Asides

North Carolina General Statute § 62-133.8(a) provides that in 2012 at least 0.02% of the electric power sold to customers should be produced from swine waste, and this percentage increases to 0.14% by 2015 and 0.20% by 2018. Subsection (f) provides that in 2012 at least 170,000 MWh of power sold to retail customers will be generated from poultry waste, and that this requirement will increase to 700,000 MWh in 2013 and 900,000 MWh in 2014.

In every year from 2012 through 2017, the electric suppliers moved that the swine waste requirement be delayed until the following year, and the Commission granted their requests. In 2018, they moved that the requirement be set at 0.02% for the electric public utilities and zero for the EMCs and municipalities, and this request likewise was granted.

With respect to poultry waste, the electric suppliers moved in 2012 and again in 2013 to delay the 170,000-MWh annual requirement for a year, and the Commission granted their motions. The Commission's 2013 order set the requirement at 170,000 MWh for 2014 and 700,000 MWh for 2015. The electric suppliers were able to meet the 170,000-MWh requirement in 2014, but they could not comply with the increase to 700,000 MWh for 2015. In that year, and again in 2016 and 2017, they moved that the poultry waste requirement be kept at 170,000 MWh, and their motions were granted. In their 2018 motion, the electric suppliers proposed that the poultry waste requirement be set at 300,000 MWh, and the Commission approved their proposal.

In its annual orders granting delays or reductions in the swine and poultry waste requirements, the Commission has also required the electric power suppliers to file reports describing the state of their compliance with the set-asides and their negotiations with the developers of swine and poultry waste-to-energy projects, initially on a tri-annual basis and now semiannually. These reports are filed confidentially in Docket No. E-100, Sub 113A. The Commission has further required the electric power suppliers to provide internet-available information to assist the developers of swine and poultry waste-to-energy projects in getting contract approval and interconnecting facilities. Additionally, the Commission has directed the Public Staff to hold periodic stakeholder meetings to facilitate compliance with the swine and poultry waste set-asides. In response, the Public Staff organized a stakeholder meeting held on June 23, 2014, and eight subsequent occasions. The attendees have included farmers, the North Carolina Pork Council, the North Carolina Poultry Federation, waste-to-energy developers, bankers, state environmental regulators, and the electric power suppliers. The meetings allow the stakeholders to network and voice their concerns to the other parties. Due to advancements in compliance, all parties agreed that semiannual meetings were no longer necessary and requested that they only be held yearly. The Commission granted this request in its 2017 order.

Up to now, the State's electric power suppliers have been able to comply only to a limited extent with the poultry waste set-aside requirement, and to an even lesser extent with the swine waste requirement. Nevertheless, the REPS statute has served as a stimulus for several important advances in waste-to-energy technology.

First, several swine farms have installed anaerobic digesters at their swine waste lagoons and have produced biogas that has been used as fuel to operate small electric generators at these farms. Electric power suppliers have purchased the electricity produced by these generators -- or, alternatively, have purchased the RECs when the electricity was used on the farm where it was generated – and this represented the initial step toward compliance with the swine waste set-aside.

Second, poultry waste has been transported by truck to existing and new generation facilities, where it has been co-fired with wood or other fuels.

Third, there has been progress in the development of large centralized anaerobic digestion plants in areas where numerous swine farms are located. These plants receive swine waste from numerous sources, produce biogas from the waste by the digestion process, and eliminate impurities from the biogas so that it meets quality standards and is eligible to be injected into the natural gas pipeline system. A specified amount of this biogas, which is referred to as "directed biogas" or "renewable natural gas," is injected into a pipeline, and an equivalent amount of natural gas is delivered by the pipeline operator to a gas-fired electric generating plant. These directed biogas facilities were first built in Midwestern states with extensive swine farming activity, but on December 2, 2016, Carbon Cycle Energy, LLC, began construction of a directed biogas facility in Warsaw, North Carolina.[1]

Four days after the start of construction at the Carbon Cycle facility, Piedmont Natural Gas Company, Inc., petitioned the Commission for approval of a new Appendix F to its service regulations, authorizing the company to accept "Alternative Gas" (which includes, subject to various restrictions, biogas, biomethane, and landfill gas) onto its system and deliver it to purchasers. In an order issued on June 19, 2018, the Commission approved Piedmont's proposed Appendix F and established a three-year pilot program to implement it. The Commission has authorized six firms – C2E Renewables NC, Optima KV, LLC, Optima TH, LLC, GESS International North Carolina, Inc., Foothills Renewables LLC and Catawba Biogas, LLC – to participate in the pilot program.

In March of 2018, Optima KV completed its interconnection to the Piedmont Natural Gas system and began delivering biogas to DEP's Smith Energy Complex in Hamlet, North Carolina. The Optima KV facility thus became the first operational directed biogas facility in North Carolina.

The Public Staff stated that the electric power suppliers will likely continue to have difficulty meeting the swine and poultry waste set-asides. However, they have made substantial progress toward complying with these difficult obligations, and as advances in waste processing technology are made, they may be able to achieve full compliance with the statutory requirements in the not too distant future. The supplier best positioned to reach full compliance is DENC, since it can obtain all of its RECs from out-of-state. Indeed, DENC's compliance plan indicates that already "both DENC and the Town of Windsor have sufficient RECs in [NC-RETS] to meet the 2018-2020 requirements" for swine waste. DENC does not express quite as high a degree of certainty about its compliance with the poultry waste set-aside, given the possibility that between now and 2020 some of its suppliers may default on their contracts; however, it does state that its efforts have "yielded multiple poultry waste REC contracts and

[1] See Order Accepting Registration of New Renewable Energy Facilities, Docket No. E-7, Subs 1086 and 1087 (Mar. 11, 2016). In this docket, DEC stated that it had entered into contracts to purchase directed biogas from High Plains Bioenergy, LLC, in Oklahoma, and Roeslein Alternative Energy of Missouri, LLC. On March 18, 2016, DEC supplemented its registration statement to indicate that it also entered into contracts to purchase directed biogas from Carbon Cycle Energy for nomination to its Buck Combined Cycl Station.

sufficient delivered volume to comply with both the Company's and Town of Windsor's out-of-state requirements for years 2018, 2019 and 2020."

D. Public Staff Conclusions – REPS Compliance Plans

In summary, the Public Staff concluded that:

1. Overall, the electric public utilities believe they are in a better position to comply with all of the requirements of the REPS, including the set-asides, than in previous years.
2. DEC, DEP, and DENC should be able to meet their REPS obligations during the planning period, with the exception of the swine and poultry waste set-asides, without nearing or exceeding their cost caps; however, DEP may approach the caps in 2020.
3. All three utilities should be able to meet the swine and poultry waste requirements in 2018, after the issuance of the Commission's order of October 8, 2018, reducing the requirements.
4. DEC and DEP indicated in their REPS compliance plans that they could comply with the poultry waste set-aside in 2018, and DEC stated that it could meet the swine waste requirement as well; but both companies indicated that compliance would deplete their supply of swine and poultry RECs so severely that they could not comply in 2019 and 2020. Both subsequently joined in the electric suppliers' motion to reduce the swine and poultry requirements for 2018, and their motion was granted. However, the fact that DEC and DEP were even able to consider the possibility of compliance in 2018 represents progress in comparison with previous years.
5. DENC expects to meet the swine waste requirements for 2018 through 2020, both for itself and the Town of Windsor, and it is confident, although not certain, that it will also meet the poultry waste requirement for all three years of the planning period.
6. DEC and DEP are actively seeking energy and RECs to meet the set-aside requirements for the years in which they expect to fall short of compliance. DENC is also seeking to acquire RECs and thus strengthen its position for compliance with the swine and poultry requirements in future years.
7. The Commission should approve the 2018 REPS Compliance Plans filed by DEC, DEP, and DENC.

Commission Conclusions – REPS Compliance Plans

The Commission concludes that the REPS Compliance Plans filed by the utilities contain the information required by Commission Rule R8-67(b). As such, and based on the recommendation of the Public Staff, the Commission accepts the REPS Compliance Plans filed in this docket.

CONCLUSION

Integrated Resource Planning is intended to identify those electric resource options that can be obtained at least cost to the utility and its ratepayers consistent with the provision of adequate, reliable, and safe electric service. Potential significant regulatory changes, particularly at the federal level, and evolving marketplace conditions create additional challenges for already detailed, technical, and data-driven IRP processes. The Commission finds the IRP processes employed by the utilities to be both compliant with State law and reasonable for planning purposes in the present docket. However, the Commission recognizes that the IRP process continues to evolve.

The Commission carefully considered the full record in this proceeding with respect to the 2018 IRPs and concludes that the record is sufficient to enable the Commission to assess whether the 2018 IRPs comply with the requirements of N.C.G.S. § 62-110.1 and Commission Rule R8-60. The Commission finds and concludes that DENC's 2018 IRP is adequate for planning purposes, and should be accepted, subject to DENC's 2019 IRP Update. The Commission finds and concludes that DEC's and DEP's 2018 IRPs are adequate to be used for planning purposes during the remainder of 2019 and in 2020, subject to DEC's and DEP's 2019 IRP Updates. However, the Commission declines to accept all of the underlying assumptions upon which DEC's and DEP's IRPs are based, the sufficiency or adequacy of the models employed, or the resource needs identified and scheduled in them beyond 2020.

The parties raised many issues that are worthy of more in-depth examination, along with additional issues that the Commission itself finds pertinent. Some of the issues will require the parties to conduct a considerable amount of research in order to fully address them. In addition, some of the issues may be more effectively addressed by means other than typical IRP hearings. At this point, the Commission's judgment is that the most productive course is to focus the utilities, Public Staff, and other interested parties on the parameters and contents of the IRPs due to be filed in 2020. The Commission will do so by using several different procedures. The first will be the technical conference on ISOP that has been scheduled by the Commission for August 28, 2019. The additional steps are described as part of the following summary of four of the issues that were not fully resolved by the 2018 IRPs.

<u>Load Forecasts and Reserve Margins</u>

On June 27, 2017, in Docket No. E-100, Sub 147, the Commission issued an Order Accepting Integrated Resource Plans and Accepting REPS Compliance Plans (2016 IRP Order). In the 2016 IRP Order, the Commission concluded that the electric utilities' peak load and energy sales forecasts were reasonable for planning purposes. However, the Commission expressed concern about DEC's forecast:

> The Commission further concludes that the DEC load forecast may be high. In reaching this conclusion, the Commission recognizes the Wilson Report.[1] To quote from Mr. Wilson's report, "Overall, the DEC winter peak forecast seems somewhat high compared to the trend in the weather-adjusted peaks . . ." Mr. Wilson notes in his report on page 9 that for DEC, there has been a steady differential between the weather-adjusted summer and winter peaks during recent years, averaging 750 MW over 2009 to 2016, and averaging 683 MW over 2014 to 2016. The report states that DEC's current forecast breaks from this pattern, again suggesting that the winter peak forecast is high (see Figure JFW-6: DEC Summer and Winter Peaks, Historical and Forecast).
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> Continuing to address the DEC winter forecast, Mr. Wilson states in his report on page 7 that changes in end-use technologies may be affecting these brief, extreme winter peak loads under extreme cold conditions. The report points out that DEC stated it has not performed any formal analysis to determine which end uses are contributing to these load spikes on extremely cold winter mornings (response to Data Request SACE 2-11).

2016 IRP Order, at 15.

As a result, the Commission directed DEC to address in its 2017 IRP Update any refinements in its load forecasting methodology. Id.

With respect to reserve margins, in the 2016 IRP Order the Commission concluded that the electric utilities' reserve margins in their IRPs were reasonable for planning purposes. However, the Commission noted concerns identified by the Public Staff and the Wilson Report regarding Duke's proposed 17% winter reserve margin target. Consequently, the Commission directed that

> [D]EC and DEP should work with the Public Staff to address the Public Staff's and Mr. Wilson's reserve margin concerns and to implement changes as necessary to help ensure that the reserve margin target(s) are fully supported in future IRPs. Further, the Commission requests that Duke and the Public Staff file a joint report summarizing their review and conclusions within 150 days of the filing of Duke's 2017 IRP Updates. In addition to addressing the reserve margin concerns identified by the Public Staff and Mr. Wilson, the report should clearly define the support and basis for the targeted reserve margins incorporated into the IRPs. If the parties cannot reach consensus, then the report should outline their differences and recommend a procedure for the Commission to pursue in reaching a conclusion about the reserve margins recommended by DEC and DEP in their IRPs.

Id. at 22-23.

[1] On behalf of Southern Alliance for Clean Energy, Sierra Club, and Natural Resources Defense Council (hereinafter, SACE), James F. Wilson of Wilson Energy Economics prepared a report entitled "Review and Evaluation of the Peak Load Forecasts for the Duke Energy Carolinas and Duke Energy Progress 2016 Integrated Resource Plans" (Wilson Report).

On April 2, 2018, Duke and the Public Staff submitted their joint report on their discussions and conclusions (Joint Report). The Commission accepted the Joint Report in its April 16, 2018 Order Accepting Filing of 2017 Update Reports and Accepting 2017 REPS Compliance Plans, in Docket No. E-100, Sub 147 (2017 IRP Order). The Commission noted that Duke and the Public Staff had engaged in discussions, Duke responded to multiple requests for information and evaluated multiple inputs and scenarios that were suggested by the Public Staff, and Duke and its consultant, Astrapé Consulting, met with the Public Staff to present results of the additional analyses and to work toward a consensus. The Commission stated that the Public Staff and Duke did not reach consensus on all of the issues, one such unresolved issue being how to model economic load forecast uncertainties. In the Joint Report, the Public Staff recommended that DEC and DEP utilize a 16% reserve margin for planning purposes in their 2018 IRPs, and until such time that a new resource adequacy study is conducted. On the other hand, Duke stayed with its position that DEC and DEP utilize a minimum 17% winter reserve margin for planning purposes until such time that a new resource adequacy study is conducted. Both recommended that DEC and DEP update their reserve margins no later than the 2020 biennial IRP filings to reflect updated peak load and forecast data, weather, and other relevant inputs. In the 2017 IRP Order, the Commission directed that Duke further address the reserve margin issue in its 2018 IRPs, including additional review and assessment of the Public Staff's proposed approach versus that employed by Astrapé in its 2016 Resource Adequacy Study. 2017 IRP Order, at 8-9.

In its 2018 IRPs, DEC stated that the use of a 16% reserve margin versus 17% reserve margin would not impact DEC's 2018 IRP. However, DEP acknowledged that DEP's resource plan would be impacted if the lower reserve margin were used for planning. DEP noted that a 16% reserve margin would result in lesser short-term purchase quantities, as well as deferral of some of the undesignated future resources.

Both DEC and DEP discussed the impact of 16% reserves on loss of load expectation (LOLE). DEC stated that allowing the reserve margin to decline to 16% for a given year would increase the LOLE to approximately 0.116 days/year, which equates to one expected firm load shed event approximately every 8.6 years. According to DEP, a comparable increase in LOLE for it is approximately 0.13 days/year, or one expected firm load shed event approximately every 7.7 years.

The Public Staff stated in its comments that it continues to recommend a 16% reserve margin, but will work with Duke "to reach consensus within the constructs of the next resource adequacy study." Comments of the Public Staff, at 46-47.

SACE, et al. included with its comments an updated report by James Wilson. Mr. Wilson again raises concerns about Duke's load forecasts and reserve margins being too high.

To address the above issues surrounding Duke's reserve margin and load forecasts, the Commission will hold an oral argument on Wednesday, January 8, 2020, at 10:00 a.m. The parties who submitted comments on Duke's load forecasts and reserve margins – the Public Staff, SACE et al., and NCSEA – will be given 30 minutes each to present their positions, and Duke will be given 30 minutes to respond. In order to facilitate this hearing, on or before November 4, 2019, Duke and the Public Staff shall file written responses to the questions and information requested in item numbers 1 and 2 of Appendix A, which is attached to this Order. The Commission expects that the hearing will focus on the topics in these two items in Appendix A.

Carbon Dioxide Reductions and Coal Plant Retirements

On October 29, 2018, North Carolina Governor Roy Cooper issued Executive Order No. 80 that, among other things, sets a goal of by 2025 reducing statewide greenhouse gas emissions to 40% below 2005 levels. This goal being well within the IRPs' 15-year planning horizons, the Commission concludes that DEC and DEP should be required to model their IRPs to show the efforts that will be required by each of them to contribute to the attainment of the goal. In particular, the two utilities should model plans that result, on a combined basis, in at least a 40% reduction in CO_2 emissions in 2030 compared to their combined 2005 CO_2 emission levels.

To address the issues surrounding carbon dioxide reductions, on or before November 4, 2019, Duke shall file written responses to the information requested in item number 3 of Appendix A. Based on these responses, the Commission may issue further orders related to the preparation of the utilities' 2020 IRPs.

In their 2018 IRPs DEC and DEP contemplate that their remaining coal-fired generating plants will continue in use until they have been fully depreciated. However, today's capacity factors for these plants are substantially lower than the historical capacity factors of the plants. It does not appear from the information in the IRPs that DEC and DEP have fully considered early retirement of any of these coal plants by replacing their contributions with other alternative generation resources or with energy efficiency (EE) and demand-side management (DSM) resources. As a result, the Commission determines that it should require Duke to provide an analysis showing whether continuing to operate each of its existing coal-fired units is the least cost alternative compared to other supply-side and demand-side resource options, or fulfills some other purpose that cannot be achieved in a different manner.

To address the issue of economic retirement of aging coal plants, in the 2020 IRPs DEC and DEP shall include an analysis that removes any assumption that their coal-fired generating units will remain in the resource portfolio until they are fully depreciated. Instead, the utilities shall model the continued operation of these plants under least cost principles, including by way of competition with alternative new resources. In this exercise the full costs of disposal of coal combustion wastes shall be included in making any comparison with alternative resources. If such analysis concludes that continued operation of the utilities' existing coal-fired units until they are fully depreciated is the least cost resource alternative, then the utilities 2020 IRPs shall separately model an alternative scenario premised on advanced retirement of one or more of such units and shall include in that alternative scenario an analysis of the difference in cost from the base case and preferred case scenarios.

Storage Resources

In the 2016 IRP Order, the Commission noted the potential that battery storage could play in the electric utilities' resource planning. The Commission stated:

> [T]he Commission is of the opinion that evaluations of this technology, as documented in the IRPs, have not been fully developed to a level sufficient to provide guidance as to the role this technology should play going forward. As such, the utilities should provide in future IRPs or IRP updates a more complete and thorough assessment of battery storage technologies including the "full value" as discussed in the NCSEA comments.[1] If the standard technical and economic analyses of generation resources somehow preclude the complete and thorough assessment of battery storage technologies, then a separate discussion of this point should be included in the IRPs.

2016 IRP Order, at 60.

In DEC's and DEP's 2018 IRPs, they provided some discussion of the potential for battery storage, as well as information about its present and planned projects that utilize battery storage. However, DEC and DEP did not model the incorporation of storage facilities as a part of its supply side resources. On the other hand, public witnesses and intervenors have asserted that energy storage is rapidly becoming more cost effective. The Commission concludes that DEC and DEP should be required to provide additional analysis of battery storage in Portfolio 7 of their 2018 IRPs, as described more fully below.

To address the issues surrounding energy storage, on or before November 4, 2019, DEC, DEP, and the Public Staff shall file written responses to the information requested in item number 4 of Appendix A,

<u>Consideration of All Resources</u>

Commission Rule R8-60 (d), (e), (f) and (g) requires the electric utilities to assess the benefits of purchased power solicitations, other alternative supply side resources, potential DSM/EE programs, and a comprehensive set of potential resource options and combinations of resource options. Although Duke's IRPs include some discussion and general information about its consideration of these alternatives, the Commission determines that Duke should be required to explicitly describe all analyses that it has undertaken in developing the IRPs. For example, Duke simply accepts its presently established levels of EE and DSM for planning purposes, and plugs those amounts into its IRP. However, Rule R8-60(f) requires the electric utilities to "assess on an on-going basis programs to promote demand-side management," which under the rule includes EE and conservation programs. The Commission acknowledges that in Portfolio 5 Duke modeled a high EE case, in conjunction with a high renewables scenario. However, the Commission concludes that the IRP information, and the spirit of the rule, will be better served by requiring Duke to separately assess the potential for increased EE and DSM, and model the increase in those resources without combining that modeling with additional renewables, as described more fully below.

[1] NCSEA's Comments, Docket No. E-100, Sub 147 (February 17, 2017), Storage in the Integrated Resource Plans at 5-15.

To address the requirement that DEC and DEP consider all resource options in developing its IRPs, each utility shall in its 2020 IRPs provide the information and modeling specified in item number 5 of Appendix A.

Finally, after the utilities file their 2019 IRP Updates, the Commission may identify additional issues to be addressed or information to be provided by the utilities and parties.

IT IS, THEREFORE, ORDERED as follows:

1. That the IRP filed herein by Dominion Energy North Carolina is adequate for planning purposes, subject to DENC's 2019 IRP Update, and the Commission hereby accepts DENC's IRP.

2. That the IRPs filed herein by Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC, are adequate for planning purposes during the remainder of 2019 and for 2020, subject to DEC's and DEP's 2019 IRP Updates, and the Commission hereby accepts the IRPs, subject to the questions raised in this Order concerning the underlying assumptions upon which the IRPs are based, the sufficiency or adequacy of the models employed, or the resource needs identified and scheduled in the IRPs beyond 2020.

3. That the 2018 REPS compliance plans filed by the IOUs are hereby accepted.

4. That pursuant to the Regulatory Conditions imposed in the Merger Order, DEC and DEP shall continue to pursue least-cost Integrated Resource Planning and file separate IRPs until otherwise required or allowed to do so by Commission order, or until a combination of the utilities is approved by the Commission.

5. That NC WARN's motion for an expert witness hearing, and the other requests for expert witness and additional public witness hearings on the 2018 IRPs, are denied.

6. That on Wednesday, January 8, 2020, at 10:00 a.m., the Commission will hold an oral argument to address reserve margin and load forecasting issues in DEC's and DEP's IRPs, as specified in the body of this Order. The oral argument will be held in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina.

7. That on or before November 4, 2019, DEC, DEP, and the Public Staff shall file responses to the information requested in Appendix A, as specified in the body of this Order.

8. That in their 2020 IRPs DEC and DEP shall include the information, analyses, and modeling regarding economic retirement of coal-fired units and consideration of all resource options, as specified in the body of this Order.

ISSUED BY ORDER OF THE COMMISSION.
This the 27th day of August, 2019.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

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1. DEC and DEP's basis for using a 17% winter reserve margin target, including:

(a) Additional details for the contention that a holistic view of the Astrapé study's reasonableness is more appropriate than focusing on specific individual factors (such as those raised by the Public Staff) that could potentially result in a lower reserve margin. [See Page 18 of the Joint Report]

(b) An explanation and/or additional support for the following statement: "The 2016 resource adequacy studies also demonstrated the economic benefits of minimizing total reliability costs to customers and showed economic reserve margin ranges of up to about 19% for DEC and 20% for DEP (95th percentile confidence level) to minimize substantial firm load shed and high cost risk. On a probabilistic weighted average basis, the net cost to customers of going from 15% to 17% is small compared to the potential risk of expensive market purchases and customer outage costs that can be avoided in extreme years." [See Page 38 of slide deck attached to the Joint Report] Produce all analyses supporting this cost-benefit claim.

(c) A discussion detailing the "sensitivity analysis items noted in the Wilson report" referred to on Page 34 of the slide deck attached to the Joint Report.

(d) An explanation of "Firm Load Shed Event" and discussion of significance in Astrapé's Resource Adequacy Studies. [See Page 43 of Duke Energy Carolinas and Duke Energy Progress Solar Ancillary Service Study]

(e) An explanation and additional characterization of the potential impact of increasing the loss of load expectation for DEP to approximately 0.13 days/year (one firm load shed event every 7.7 years) and for DEC to approximately 0.116 days/year (one firm load shed event every 8.6 years). [See Page 42 in DEP's IRP and Page 42 in DEC's IRP]

(f) A discussion of the following statement included in Astrapé's 2016 Resource Adequacy Studies: "Across the industry, the traditional 1 day in 10 year standard is defined as 0.1 LOLE. Additional reliability metrics calculated are Loss of Load Hours (LOLH) in hours per year, and Expected Unserved Energy (EUE) in MWh." [See Page 30 of both DEP's and DEC's 2016 Resource Adequacy Studies]

Include a discussion and assessment of the following statement: "One event in ten years translates to 0.1 loss of load events (LOLE) per year, regardless of the magnitude or duration of the anticipated individual involuntary load shed events. Alternatively, one day in ten years translates to 2.4 loss of load hours (LOLH) per year, regardless of the magnitude or number of such outages. As we show, the difference between these interpretations of the 1-in-10 standard translates to differences in planning reserve margins that may exceed five percentage points, with planning reserve margins of possibly less than 10% based on the 2.4 LOLH standard and more than 15% based on the 0.1 LOLE standard." [Brattle Group and Astrapé Consulting for FERC, Resource Adequacy Requirements: Reliability and Economic Implications, by J. Pfeifenberger and K. Carden (2013), Executive Summary Page iii, www.ferc.gov/legal/staff-reports/2014/02-07-14-consultant-report.pdf]

(g) An analysis and conclusion as to what DEC's and DEP's reserve margins would be using an economically-optimal analysis, as discussed in the Brattle and Astrapé report noted in (f) above. Address the following statement: "Utilities, system operators, and regulators across North America have relied on variations of the 1-in-10 standard for many decades, and typically enforce the standard without evaluating its economic implications." [See reference in (f) above]

(h) A detailed work plan for developing the update to Astrapé's Resource Adequacy Studies proposed for 2020. [See Page 32 of the Joint Report]

(i) A characterization and discussion of the impact and risks of potentially delaying the awarding of contracts associated with DEP's capacity and energy market solicitation until an updated Resource Adequacy Study is completed and effectively vetted. [See Page 81 of DEP IRP]

(j) A listing of the reserve margins included in DEC's and DEP's IRPs from 2003 through 2018;

(k) An explanation of why DEC's and DEP's reserve margins have increased over the last 15 years;

(l) DENC's reserve margin is 11.87% and PJM's reserve margin is 15.9%. DENC's and PJM's resource mix is comparable to Duke's. Explain why DEC's and DEP's reserve margins are higher than DENC's and PJM's.

(m) NERC's 2018 SERC-Southeast reference reserve margin level is 15%. Explain why DEC's and DEP's reserve margins are higher than NERC's.

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2. Duke's basis for its load forecasts, including:

(a) Tables that show DEC's and DEP's summer and winter load forecasts prepared in each of the years 2003 through 2018 and the corresponding actual summer and winter peak loads for each year;

(b) Analyses performed by Duke to determine which end uses are contributing to load spikes on extremely cold winter mornings.

(c) As a part of DEP's Blue Horizons Project (BHP), DEP has had success in employing DSM in the Western Region to shave winter peaks. Discuss whether DEP's success in using DSM could be replicated by DEC in its North Carolina service territory. If that success can be replicated, explain why DEC has not done so. If not, explain why not.

3. DEC's and DEP's most current strategic plans to reduce carbon dioxide (CO_2) emissions, including:

(a) The implementation plan (including CO_2 glide path) that results in the attainment of DEC's and DEP's most current goals for reductions in CO_2 emissions.

(b) Modelling of the carbon reduction goals in the draft Clean Energy Plan released for public comment on August 16, 2019, by the North Carolina Department of Environmental Quality and Duke's current carbon reduction plan. The modelling should not only show the resource portfolio needed to achieve these goals but should also show any cost differentials (increases or savings) from the base case and the preferred case. In modelling cost differentials, the plans should include anticipated costs attributable to disposal of coal wastes from ongoing and continued operation of coal-fired plants and anticipated cost savings attributable to earlier retirement of such plants.

(c) A comparison of DEC's and DEP's most current plans for CO2 emission reductions to the Governor's Executive Order No. 80 which states that "The State of North Carolina will strive to accomplish the following by 2025: a. Reduce statewide greenhouse gas emissions to 40% below 2005 levels."

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4. With regard to Portfolio 7 in DEC's and DEP's 2018 IRPs (CT Centric with Battery Storage and High Renewables):

(a) A discussion of the differences of executing this portfolio compared to the base case (including the differences in Present Value of Revenue Requirement as well as specific changes to resource plans). [See Page 60 of DEP's IRP and Page 56 of DEC's IRP]

(b) An examination of the cost of battery storage at existing distributed resource sites compared to the expected cost of DEP's capacity and energy market solicitation.

(c) Do the modeling and results in Portfolio 7 provide a statistically representative sample that can be extrapolated into a broader analysis and result by assuming the use of individual battery storage on existing and planned solar facilities, specifically including distribution interconnected QFs and the solar capacity to be brought on line pursuant to HB 589, on Duke's system? If not, explain how the modeling of battery storage added to or included in these solar facilities would differ from that employed in Portfolio 7.

5. 2020 biennial IRPs prepared by DEC and DEP that explicitly include and demonstrate assessments of the benefits of purchased power solicitations, alternative supply side resources, potential DSM/EE programs, and a comprehensive set of potential resource options and combinations of resource options, as required by Commission Rule R8-60(d), (e), (f) and (g), including:

(a) A detailed discussion and work plan for how Duke plans to address the 1,200 MW of expiring purchased power contracts at DEP and 124 MW at DEC. [See Page 80 of DEP 2018 IRP and Page 78 of DEC 2018 IRP]

(b) A discussion of the following statement: "The Companies' analysis of their capacity and energy needs focuses on new resource selection while failing to evaluate other possible futures for existing resources. As part of the development of the IRPs, the Companies conducted a quantitative analysis of the resource options available to meet customers' future energy needs. This analysis intended to produce a base case through a least cost analysis where each company's system was optimized independently. However, the modeling exercise fails to consider whether existing resources can

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(c) be cost effectively replaced with new resources. Therefore, Duke has not performed a least-cost analysis to design its recommended plans." [See Page 2 of the Report for the Natural resources Defense Council, the Sierra Club and the Southern Alliance for Clean Energy entitled Review of Duke Energy's North Carolina Coal Fleet in the 2018 Integrated Resource Plans (March 7, 2019)]

(d) A stand-alone analysis of the cost effectiveness of a substantial increase in EE and DSM, rather than the combined modeling of EE and high renewables included in DEC's and DEP's Portfolio 5 in their 2018 IRPs.

(e) In 2009, in Docket No. E-100, Sub 122, the Commission examined the benefits to be derived if the electric utilities fully utilized the wholesale market to meet their resource needs. Although in the end the Commission did not adopt new IRP requirements, it reiterated the importance of Rule R8-60(d), which requires that the utilities "assess on an ongoing basis the potential benefits of soliciting proposals from wholesale power suppliers and power marketers." Provide a discussion of the advantages and disadvantages of periodically issuing "all resources" RFPs in order to evaluate least-cost resources (both existing and new) needed to serve load.

DOCKET NO. E-100, SUB 159

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
2018 REPS Compliance Plans and	)	ORDER APPROVING 2017 REPS
2017 REPS Compliance Reports	)	COMPLIANCE REPORTS
	)	AND ACCEPTING 2018 REPS
	)	COMPLIANCE PLANS

BY THE COMMISSION: North Carolina's Renewable Energy and Energy Efficiency Portfolio Standard (REPS), codified at N.C. Gen. Stat. § 62-133.8, requires all electric power suppliers in North Carolina to meet specific percentages of their retail sales using renewable energy and energy efficiency. Sub-section 62-133.8(c) sets out the percentage requirements that apply to electric membership corporations (EMCs) and municipalities that sell electric power to retail electric power customers in North Carolina, and provides the options available to these EMCs and municipalities for meeting the REPS requirements. These options include generating electric power at a new renewable energy facility, reducing energy consumption through the implementation of demand side management (DSM) and energy efficiency (EE) measures, and purchasing renewable energy certificates (RECs) derived from in-state and out-of-state renewable energy facilities. Pursuant to N.C.G.S. § 62-133.8(k), the Commission has developed, implemented, and maintains the North Carolina Renewable Energy Tracking System (NC-RETS) to verify REPS compliance and to facilitate the establishment of a market for the purchase and sale of RECs.

Pursuant to N.C.G.S. § 62-133.8(i), the Commission adopted Commission Rule R8-67 to implement the provisions of the REPS. Commission Rule R8-67(c) requires each EMC and municipal electricity supplier, or its utility compliance aggregator, to file a verified REPS compliance report on or before September 1 of each year describing its compliance with the REPS during the previous calendar year. Commission Rule R8-67(c)(1) provides a list of the supporting documentation required to be included in the compliance report, including, the results of each EE and DSM program's measurement and verification (M&V) plan, or other documentation supporting an estimate of the program's energy reductions achieved in the previous year, pending implementation of a M&V plan. Commission Rule R8-67(b) requires each electric power supplier, or its utility compliance aggregator, to file a REPS compliance plan on or before September 1 of each year setting forth its plan for future compliance with the REPS during the three-year period beginning with the current calendar year. Commission Rule R8-67(b)(1) provides a list of the minimal information required to be included in each electric power supplier's compliance plan. Commission Rule R8-67(h) requires each electric power supplier to participate in NC-RETS and to provide data to NC-RETS to calculate its REPS obligation and demonstrate its compliance with the REPS requirements.

Between August 20 and October 1, 2018, the following municipal electric power suppliers, electric membership corporations, and utility compliance aggregators filed their 2017 REPS compliance reports and 2018 REPS compliance plans: EnergyUnited Electric Membership Corporation (EnergyUnited); North Carolina Eastern Municipal Power Agency (NCEMPA), on behalf of its 32 municipal members; North Carolina Municipal Power Agency Number 1 (NCMPA1), on behalf of its 19 municipal members; the Town of Waynesville (Waynesville); the Public Works Commission of the City of Fayetteville (FPWC); the Tennessee Valley Authority (TVA), on behalf of itself, Blue Ridge Mountain EMC, Mountain Electric Cooperative, Murphy Electric Power Board, and Tri-State EMC; Halifax Electric Membership Corporation (Halifax), on behalf of itself and the Town of Enfield; and the North Carolina Electric Membership Corporation (NCEMC), on behalf of its member cooperatives and four other electric power suppliers.[1] In addition, NTE Carolinas, LLC (NTE) filed 2018 REPS compliance plans on behalf of the several municipalities to whom it is now supplying wholesale power.[2]

On February 6, 2019, the Public Staff filed comments (February 6 comments) addressing the following: the 2017 REPS compliance reports filed in this docket, including specific comments on the individual reports; issues related to earning energy efficiency credits (EECs) from lighting measures; the 2018 REPS compliance plans filed in this docket, including specific comments on the individual plans; compliance with the swine and poultry waste set-aside requirements; and compliance with the REPS spending limits. The Public Staff's comments provide details about each of the 2017 REPS compliance reports that were filed by the electric power suppliers. Based upon its review of the REPS compliance reports, the Public Staff recommends that the Commission approve the 2017 REPS compliance reports filed by Halifax, NCEMC, NCEMPA, NCMPA1, TVA, and Waynesville. The Public Staff further recommends that the Commission find that the REPS compliance plans filed in this docket indicate that the municipalities and EMCs should be able to meet their REPS obligations during the planning period without nearing or exceeding the REPS spending limits. Finally, the Public Staff recommends that the Commission not approve the REPS compliance reports filed by EnergyUnited or by FPWC for reasons discussed below.

On March 13, 2019, EnergyUnited filed an updated 2017 REPS compliance report.

On April 2, 2019, the Commission issued an Order amending a protective order previously issued related to the handling of potentially confidential information related to FPWC's REPS compliance report.

On May 9, 2019, the Public Staff filed supplemental comments (May 9 comments) addressing the 2017 REPS compliance report and 2018 REPS compliance plan filed by FPWC. The Public Staff recommends that the Commission approve FPWC's 2017 REPS compliance report filed by FPWC.

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[1] In its 2017 REPS compliance report, NCEMC identifies the following EMCs as member cooperatives: Albemarle EMC, Brunswick EMC, Cape Hatteras EMC, d/b/a Cape Hatteras Electric Cooperative, Carteret-Craven EMC, d/b/a Carteret-Craven Electric Cooperative (EC), Central EMC, Edgecombe-Martin County EMC, Four County EMC, French Broad EMC, Haywood EMC, Jones-Onslow EMC, Lumbee River EMC, Pee Dee EMC, Piedmont EMC, Pitt & Greene EMC, Randolph EMC, Roanoke EMC, d/b/a Roanoke Electric Cooperative, South River EMC, Surry-Yadkin EMC, Tideland EMC, Tri-County EMC, Union EMC, d/b/a Union Power Cooperative, and Wake EMC. In addition, NCEMC states that it performs REPS compliance services on behalf of Mecklenburg EC, headquartered in Chase, Virginia; Broad River EC, headquartered in Gaffney, South Carolina; and the Town of Oak City (Oak City), which is a wholesale customer of Edgecombe-Martin County EMC, whose requirements include those of Oak City. The town of Fountain is a wholesale customer of Pitt and Greene EMC, whose requirements also include those of Fountain.

[2] On August 31, 2018, NTE filed a letter stating that, effective January 1, 2018, the Towns of Black Creek, Lucama, Sharpsburg, Statonsburg, and Winterville are full requirements power supply customers of NTE, and that the City of Concord and the City of Kings Mountain will similarly become full requirements customers of NTE on January 1, 2019. NTE states that these municipalities were previously wholesale power customers of Duke Energy Carolinas, LLC, or Duke Energy Progress, LLC, and during the transition period these municipalities were uncertain of the number of RECs that would be transferred from the respective Duke utility. Therefore, NTE filed the 2018 REPS compliance plans on behalf of these municipalities belatedly.

On May 23, 2019, the Public Staff filed supplemental comments (May 23 comments) addressing the updated 2017 REPS compliance report filed by EnergyUnited on March 13, 2019. The Public Staff recommends Commission approval of EnergyUnited's updated 2017 REPS compliance report.

REPS REQUIREMENTS FOR EMCS AND MUNICIPALITIES

For 2017, N.C.G.S. § 62-133.8(c) requires that each EMC or municipality that sells electric power to retail electric power customers in the State meet the equivalent of six percent of its 2016 retail sales by using renewable energy or by reducing energy consumption through implementation of DSM or EE measures. Within this six percent requirement, each EMC and municipality must meet the requirements of the REPS by using a specified amount of renewable energy from solar, swine waste, and poultry waste resources. These EMCs and municipalities are permitted to incur incremental costs to comply with the REPS requirements up to the total annual limit established in N.C.G.S. § 62-133.8(h)(3) and (4). As reflected in the following discussion, the Commission considered the 2017 REPS compliance reports and 2018 REPS compliance plans filed in this docket and the comments of the Public Staff in determining whether these EMCs and municipalities met their REPS obligations and reporting requirements.

REPS Set-Aside Requirements

The REPS set-aside requirements are established in N.C.G.S. § 62-133.8(d) for solar, subsection (e) for swine waste, and subsection (f) for poultry waste. For 2017, the solar set-aside requirements provide that each EMC and municipality shall supply 0.14 percent of its 2016 retail sales through the use of solar energy resources. For 2018, the solar set-aside requirements increase to 0.20% of 2017 retail sales. Pursuant to the authority granted to the Commission in N.C.G.S. § 62-133.8(i)(2), the 2017 swine and poultry waste set-aside requirements were modified and/or delayed by the Commission's Order Modifying the Swine and Poultry Waste Set-Aside Requirements and Providing Other Relief, issued on October 16, 2017, in Docket No. E-100, Sub 113 (2017 Delay Order). The 2017 Delay Order further modified the swine and poultry waste set-aside requirements by (1) delaying the 2017 swine waste set-aside requirements, and the scheduled increases in those requirements, for one additional year; (2) maintaining the 2017 poultry waste set-aside requirements at the same level as the 2016 requirement (170,000 MWh), and (3) delaying the scheduled increases in the poultry waste set-aside requirements by one year. Similar to the 2017 Delay Order, the Commission's Order Modifying the Swine and Poultry Waste Set-Aside Requirements and Providing Other Relief issued on October 8, 2018, in Docket No. E-100, Sub 113 (2018 Delay Order), modified the swine waste set-aside requirements by delaying the 2018 swine waste set-aside requirements and the scheduled increases by one additional year, as applicable to EMCs and municipalities, and modified the 2018 poultry waste set-aside requirements by maintaining the 170,000 MWh requirement and delaying the scheduled increases by one year.

In its comments, the Public Staff states that all of the EMCs and municipalities met the solar set-aside requirements. The Public Staff notes that EMCs and municipalities have not been able to comply with the swine and poultry waste set-aside requirements. The Public Staff further states that from 2014 through 2018, that it has held stakeholder meetings as requested by the Commission. The attendees have included farmers, the North Carolina Pork Council, the North

Carolina Poultry Federation, waste-to-energy developers, financiers, state environmental regulators, and the electric power suppliers. The Public Staff states that the meetings have been productive insofar as they have allowed the stakeholders to network and voice their concerns to the other parties. The Public Staff states its intentions to hold more meetings in the future as requested by the Commission, but the 2019 meeting has not yet been scheduled. The Public Staff asserts that there are many reasons for the inability of the swine and poultry waste-to-energy industry to produce enough energy to meet the set-aside requirements, including that North Carolina is on the leading edge of the development of animal waste technology and continues to be the only state with swine and poultry set-aside requirements, and that as with any technology development, speculative technologies are often too large of a risk for many financers as well as for utilities to sign high price purchase contracts that are deemed too expensive.

The Commission finds the Public Staff's comments addressing the set-aside requirements helpful and directs the Public Staff continue to file comments specifically addressing compliance with the solar, swine, and poultry waste set-aside requirements in future proceedings established to review EMCs and municipalities' REPS compliance.

REPS Spending Limits

North Carolina General Statutes section 62-133.8(h)(3) and (4) limit an electric power supplier's annual REPS spending by providing that the total annual incremental costs to be incurred by an electric power supplier and recovered from the electric power supplier's customers shall not exceed an amount equal to the per-account annual charges applied to the total number of customers. "Incremental costs" means all reasonable and prudent costs incurred by an electric power supplier to comply with the REPS requirements that are in excess of the electric power supplier's avoided costs. N.C.G.S. § 62-133.8(h)(1). For 2017, the total annual spending limit, or "cost cap," that applies to each electric power supplier is the total of the following annual per-account charges applied to the total number of customers: $27 for each residential customer-account; $150 for each commercial customer account; and $1,000 for each industrial customer account. N.C.G.S. § 62-133.8(h)(3) and (4).

In its comments, the Public Staff states that the incremental costs of REPS compliance incurred by each EMC and municipality were below the annual spending limit for 2017. The Public Staff summarizes REPS compliance and compliance costs for 2017 in Table 1 of its comments. The Public Staff summarizes projected REPS incremental costs, as compared to the future annual cost caps, in Table 3 of its comments. The Public Staff's comments and the summary table both indicate that each EMC and municipality is projected to be well below its respective spending limit through 2020.

The Commission finds the Public Staff's comments helpful and directs the Public Staff continue to file comments in future proceedings specifically addressing compliance with the REPS spending limits.

EECs from Lighting Programs

North Carolina North Carolina General Statutes section 62-133.8(c)(2) permits EMCs and municipalities to meet the REPS requirements by reducing energy consumption through the implementation of EE measures. An "energy efficiency measure" means an equipment, physical, or program change implemented after January 1, 2017, that results in less energy used to perform the same function. N.C.G.S. § 62-133.8(a)(4). Commission Rule R8-67(c)(ix) requires each EMC and municipal electric supplier to include in its REPS compliance report a measurement and verification (M&V) plan for each energy efficiency or demand-side management program. The Commission specifically addressed lighting programs implemented by EMCs and municipalities in the Order Approving 2014 REPS Compliance Reports, issued on March 29, 2016, in Docket No. E-100, Sub 145. Pursuant to that Order, for the 2015 REPS compliance reports, the Commission requires EMCs and municipalities to use M&V studies that are no older than 2015 for EE programs implementing compact florescent lighting (CFL) measures. The Commission tracks the implementation of EE programs or measures through issuance, tracking, transferring, and retiring of energy efficiency credits (EECs). In the Order Approving 2015 Compliance Reports, issued on June 14, 2017, in Docket No. E-100, Sub 149, the Commission concluded that each EMC and municipal electric power supplier that is claiming EECs from lighting measures should be required to address in its M&V study process whether a new baseline for lighting-based EE programs is appropriate.

In its comments on the individual compliance reports and compliance plans, the Public Staff discusses the EE programs that the EMCs and municipalities use to meet their REPS requirements by reducing energy consumption. With regard to lighting programs, the Public Staff observes that only EnergyUnited, FWPC, NCEMC, and Halifax included EECs from lighting measures. The Public Staff further observes that the remaining EMCs and municipalities either did not include any EECs from lighting measures or stated that they would no longer offer EE lighting programs, and that no electric service providers claim EECs from CFL measures based on new installations. The Public Staff notes that with regard to the non-lighting related EE programs used to earn EECs, these programs[1] comply with current standards and should be accepted for the generation of EECs.

The Public Staff discusses the rapid transformation of the EE lighting market in North Carolina. It states that the EE lighting market in North Carolina appears to be transforming at a faster rate than the rest of the nation, and non-specialty LED lighting will likely become the baseline standard for general service bulb technologies[2] by January 2020, as phase 2 of the federal government's Energy Independence and Security Act (EISA) goes into effect and that this will result in decreased savings from EE lighting programs. Furthermore, the Public Staff states that it is not aware of any new information that would suggest that federal proposals to revise lighting standards are being delayed or modified. Therefore, the Public Staff recommends that if any EMCs or municipalities decide to proceed with lighting related measures as a means of generating EECs after 2020, then they should, at a minimum, comply with the EISA Backstop[3] which is set to begin

[1] The Public Staff notes one exception – EnergyUnited's Heat Pump Rebate Program, which is addressed later in this order.

[2] "General service bulb technologies" refer to the technologies found in residential lamp shade fixtures for general use.

[3] The "Energy Independence and Security Act 2020 Backstop" is a group of amendments to the EISA under which, if certain criteria specified in the statute are not met, the federal Department of Energy must adopt a rule prohibiting sales of general service lamps that do not meet a minimum standard of 45 lumens per watt.

in January of 2020, unless further directed by the federal government. The Public Staff argues that this updated lighting standard should be reflected in future REPS Plans starting with the upcoming filing to be made by September 1, 2019.

With regard to these issues, NCEMC responded to the Public Staff's recommendations through its comments filed on March 4, 2019. NCEMC requests that the Commission merely note the Public Staff's recommendations and revisit the issue in a future docket, if appropriate, as NCEMC is scheduled to work with GDS Associates, Inc., NCEMC's M&V consultant, again in the 2021-2022 timeframe - if not sooner - to once again revise and update its M&V documentation.

The Commission appreciates the Public Staff's attention to this issue over the past several years in several of the Commission's dockets. The Commission recognizes the complexities involved in the M&V process and the time, effort, and expense that electric power suppliers incur in conducting these studies. To strike an appropriate balance between the considerations of ensuring an appropriate baseline is used for determining the efficiency of lighting measures in the context of a rapidly changing market for lighting measures and the practical considerations of implementing M&V procedures and reporting on those procedures, the Commission will not adopt the Public Staff's recommendation on the timeline proposed. Instead, the Commission will allow electric suppliers to address this recommendation more fully in the proceeding established to review their 2018 REPS compliance reports and 2019 REPS compliance plans, which are due to be filed on September 1, 2019. Absent significant objections received in that proceeding, the Commission is inclined to adopt the Public Staff recommendation effective for the REPS compliance filings due to be filed on September 1, 2020. Finally, the Commission finds the Public Staff's comments on these issues quite helpful and directs the Public Staff continue to file comments in future proceedings specifically addressing the earning of EECs from lighting-based EE measures where EMCs and municipalities seek to use EECs derived from these measures to meet their REPS compliance obligations.

2017 REPS COMPLIANCE REPORTS

Each EMC and municipality (or its utility compliance aggregator) required to do so filed in this docket the 2017 REPS compliance report required by Commission Rule R8-67(c). In its comments, the Public Staff reviewed and commented on each REPS compliance report filed in this docket. Based on its review, the Public Staff states that all EMC and municipal electric power suppliers met the 2017 general REPS requirements of N.C.G.S. § 62-133.8(c) and the 2017 solar set-aside requirements of N.C.G.S. § 62-133.8(d). As reflected in Table 1 in the Public Staff's comments, the Public Staff concludes that the total 2017 incremental costs incurred by each EMC and municipality to meet its REPS requirements were below the total annual cost cap established by N.C.G.S. § 62-133.8(h)(3) and (4). As reflected in the following discussion, in determining whether each EMC or municipality met its 2017 REPS obligations and reporting requirements, the Commission reviewed and considered the 2017 REPS compliance reports filed by each EMC or municipality (or its compliance aggregator), the records in NC-RETS, the Public Staff's comments and supplemental comments, as well as the comments filed by or on behalf of the EMCs and municipalities, as applicable.

EnergyUnited

On August 20, 2018, EnergyUnited filed its 2017 REPS compliance report. EnergyUnited's report demonstrates that EnergyUnited's 2016 total retail sales were 2,582,511 MWh; therefore, EnergyUnited's general REPS obligation of six percent of 2016 retail sales is 154,951 RECs, and its solar set-aside requirement, based on 0.14 percent of 2016 sales, is 3,616 solar RECs. Further, EnergyUnited's share of the 2017 poultry waste requirement is 3,101 poultry waste RECs. EnergyUnited's 2017 compliance sub-account in NC-RETS demonstrates that EnergyUnited met its 2017 REPS requirements by submitting the required number of RECs for retirement based upon the foregoing sales levels and REPS requirements.

In its February 6 comments, the Public Staff states that EnergyUnited's compliance report and NC-RETS sub-account indicate that EnergyUnited met its REPS requirements for 2017. The Public Staff notes that EnergyUnited included EECs from two programs, the Commercial Lighting Program and the Heat Pump Rebate Program, neither of which involve distribution of CFL's. The Public Staff further states that to support the number of EECs generated by these programs, EnergyUnited relies upon a 2009-2011 Bellwether Management M&V report. The Public Staff asserts that it did not object to the use of this M&V study when it was first presented in Docket No. E-100 Sub 139 (proceeding established to review REPS compliance filings of September 1, 2013); however, it notes that there have been significant market shifts since this report was completed, and the input methodology may not be reflective of the most recent data available. Consequently, EnergyUnited's method of determining the savings from its Heat Pump Rebate Program is inaccurate, and the input methodology should be updated. Therefore, the Public Staff initially recommended that the Commission not approve EnergyUnited's 2017 REPS compliance report, nor the EECs claimed by EnergyUnited for its Heat Pump Rebate Program, until EnergyUnited and the Public Staff reach agreement on a new methodology, which can then be used to quantify the EECs earned by the Heat Pump Rebate Program in 2017, and can also be used in the subsequent years.

On March 13, 2019, EnergyUnited filed an updated 2017 REPS compliance report, in which EnergyUnited calculates the savings for each unit using information contained within the EnergyStar savings calculator, as had been suggested in conversations between Energy United and the Public Staff.

On May 23, 2019, the Public Staff filed supplemental comments specifically to address the updated 2017 REPS compliance report filed by EnergyUnited. In its May 23 comments, the Public Staff notes that the revised calculations filed by EnergyUnited with its updated 2017 REPS compliance report take into account the number of heating and cooling hours expected for EnergyUnited's service territory, the difference in the seasonal energy efficiency ratio (SEER) between the installed unit and the baseline of SEER, the number of cooling hours expected for a year, the difference in the heating seasonal performance factor (HSPF) between the installed unit and the baseline of 8.5 HSPF, the total heating hours expected for a given year, and the tonnage of the installed unit. The Public Staff states that this modification to the M&V methodology results in a reduction in EECs that are claimed and banked by EnergyUnited going forward, but does not impact the number of EECs that are retired for 2017 compliance. Additionally, the Public staff notes that the decrease in EECs generated in future years should have no impact on EnergyUnited's ability to achieve REPS compliance. Further, the Public Staff states that based on EnergyUnited's updated 2017 REPS compliance report, it now recommends that the Commission approve EnergyUnited's updated 2017 REPS compliance report.

Based upon the foregoing and the entire record in this proceeding, including EnergyUnited's 2017 REPS compliance report and its updated 2017 REPS compliance report, the data in EnergyUnited's 2017 compliance sub-account in NC-RETS, and the comments of the Public Staff, the Commission finds that EnergyUnited complied with its 2017 REPS requirements, and that the RECs and EECs in EnergyUnited's 2017 compliance sub-account in NC-RETS should be retired. The Commission further finds that EnergyUnited's 2017 REPS compliance report includes the information and supporting documentation required by Commission Rule R8-67(c), and the Commission, therefore, concludes that EnergyUnited's 2017 REPS compliance report should be approved.

FPWC

On August 31, 2018, FPWC filed its 2017 REPS compliance report. FPWC's report indicates that FPWC's 2016 total retail sales were 2,054,941 MWh; therefore, FPWC's general REPS obligation of six percent of 2016 retail sales is 123,297 RECs, and its solar set-aside requirement, based on 0.14 percent of 2016 sales, is 2,877 solar RECs. Further, FPWC's share of the 2017 poultry waste requirement is 2,645 poultry waste RECs. FPWC's 2017 compliance sub-account in NC-RETS demonstrates that FPWC met its 2017 REPS requirements by submitting the required number of RECs for retirement based upon the foregoing sales levels and REPS requirements.

The Public Staff, in its February 6 comments, states that FPWC's report and its NC-RETS sub-account indicate that it met its REPS requirements for 2017 and that FPWC did not use any EECs for REPS compliance in 2017, but has four programs that generate EECs: (1) Refrigerator Incentive Program (RIP), (2) Residential HVAC (Heating, Ventilation, and Air Conditioning) Program, (3) Energy Efficient Lamp Distribution Program, and (4) LED (Light Emitting Diode) Street Light Program. The Public Staff notes that FPWC has performed M&V and banked EECs for the LED Street Lighting Program and the Residential HVAC Program and that for M&V, Fayetteville used data from the DEP "EM&V Report for the 2012 Energy Efficient Lighting Program" filed on July 17, 2013 by DEP in Docket No. E-2, Sub 950, and data from version 4 of the 2014 Mid-Atlantic Technical Reference Manual (Mid-Atlantic TRM), both of which the Public Staff considers acceptable. The Public Staff further notes that the most recent version of the Mid-Atlantic TRM, version 8, was published in May 2018, and recommends that Fayetteville utilize an updated version of this free report in its next REPS compliance filing.

In its supplemental comments filed on May 9, 2019, the Public Staff states that it has reviewed FPWC's sources and costs of RECs, its incremental compliance costs, and the number and sources of RECs to be carried over from 2017 for use in future years. Based upon this review, the Public Staff believes that FPWC has complied with N.C.G.S. § 62-133.8 and Commission Rule R8-67. Further the Public Staff states that in order to meet its REPS requirements, FPWC plans to purchase RECs through short term agreements and on the spot market. FPWC is actively seeking swine and poultry waste RECs through a buyers group and through its own purchases and expects to receive approximately 4,000 Southeastern Power Administration RECs annually through the planning period. Additionally, the Public Staff states that FPWC is implementing a community solar facility that may produce RECs for REPS compliance, but the Public Staff cautioned that FPWC should make clear in marketing any community solar program that it intends to use for REPS compliance purposes that subscribers will not be purchasing renewable energy (and RECs) for their own use, but rather, the renewable energy (and RECs) produced will be used for FPWC's REPS compliance purposes. Further, the Public Staff states that FPWC is implementing an EE program that tracks EE efforts of the Cumberland County School system. This is a collaborative effort between Fayetteville, Cumberland County Schools, and Sustainable Sandhills, a non-profit corporation. FPWC notified the Public Staff that it will provide details of the M&V methodology for this program in its subsequent compliance plan(s). Also of note, the Public Staff states that FPWC plans to continue recognizing EECs produced from each of its existing EE programs, and is developing a "Voltage Reduction Strategy" demand-side management program that is currently in the pilot stage. Finally, the Public Staff recommends that the Commission approve FPWC's 2017 REPS compliance report.

Based on the foregoing and the entire record herein, the Commission finds that FPWC has complied with its 2017 REPS requirements, and that the RECs and EECs in FPWC's 2017 compliance sub-account in NC-RETS should be retired. The Commission further finds that FPWC's 2017 compliance report includes the information and supporting documentation required by Commission Rule R8-67(c), and, therefore, the Commission concludes that FPWC's 2017 REPS compliance report should be approved.

Halifax

On September 4, 2018, Halifax filed its 2017 REPS compliance report. Halifax's report indicates that Halifax's 2016 total retail sales were 186,153 MWh; therefore Halifax's general REPS obligation of six percent of 2016 retail sales is 11,170 RECs, and its solar set-aside requirement, based on 0.14 percent of 2016 sales, is 261 solar RECs. Further, Halifax's share of the 2017 poultry waste requirement is 251 poultry waste RECs. Halifax's 2017 compliance sub-account in NC-RETS demonstrates that Halifax met its 2017 REPS requirements by submitting the required number of RECs for retirement based upon the foregoing sales levels and REPS requirements.

In its comments, the Public Staff states that Halifax's Report and its 2017 NC-RETS sub-account indicate that it met the REPS requirements for 2017. The Public Staff notes that Halifax earned EECs from the following programs: (1) CFL Program – Halifax provides free CFLs to its members, but claims EECs only from installations occurring in 2010 and 2011; (2) Heat Pump Rebate Program – this program provides rebates to encourage the installation of high efficiency heat pump and air conditioning systems. In support of the calculations for this program, Halifax has provided spreadsheets showing the efficiency ratings of the units removed and the new units installed. Halifax determined the program savings by using a widely accepted energy savings calculator, developed by ENERGY STAR, which the Public Staff states it deems satisfactory; (3) Residential Appliance Credit Program – Customers who have an energy audit and implement the recommendations will receive a credit on their electric bill. The Public Staff states that it has reviewed the energy savings calculations from the program records and has found them to be satisfactory; and (4) LED Street Lights and Outdoor Lights – Savings from the replacement of less efficient lights with LEDs earn EECs. Based on this information and its investigation, the Public Staff recommends that the Commission approve Halifax's 2017 Report.

Based upon the foregoing and the entire record in this proceeding, including Halifax's 2017 REPS compliance report, the data in Halifax's 2017 compliance sub-account in NC-RETS, and the comments of the Public Staff, the Commission determines that Halifax complied with its 2017 REPS requirements, and that the RECs and EECs in Halifax's 2017 compliance sub-account in NC-RETS should be retired. Further, the Commission finds that Halifax's 2017 compliance report includes the information and supporting documentation required by Commission Rule R8-67(c), and, therefore, the Commission concludes that Halifax's 2017 compliance report should be approved.

NCEMC

On August 30, 2018, NCEMC filed its 2017 REPS compliance report. NCEMC's compliance report indicates that NCEMC's 2016 total retail sales were 12,981,788 MWh; therefore, NCEMC's general REPS obligation of six percent of 2016 retail sales is 778,908 RECs, and its solar set-aside requirement, based on 0.14 percent of 2016 sales, is 18,175 solar RECs. Further, NCEMC's share of the 2017 poultry waste requirement is 16,427 poultry waste RECs. NCEMC's 2017 compliance sub-account in NC-RETS demonstrates that NCEMC met its 2017 REPS requirements by submitting the required number of RECs for retirement based upon the foregoing sales levels and REPS requirements.

In its February 6 comments, the Public Staff states that NCEMC's 2017 REPS compliance report and its NC-RETS sub-account indicate that it met its REPS requirements for 2017. The Public Staff notes that NCEMC provides REPS compliance services for Mecklenburg Electric Cooperative based in Virginia, and Broad River Electric Cooperative based in South Carolina. However, NCEMC does not consider these two EMCs to be members of NCEMC, and therefore it reports their compliance data separately to the Commission. The Public Staff additionally notes that NCEMC's members earned EECs from the following programs: (1) Energy Star Lighting Program – NCEMC participants distribute CFLs to their members through various channels. However, NCEMC does not claim EECs earned from CFLs installed after 2013, because it considers CFLs now to be a baseline technology; (1) Water Heating Efficiency Program – NCEMC members distribute kits that include water heater blankets, pipe insulation, and low flow faucet and shower head aerators; (3) Community EE and Community EE Low Income Programs – These two programs provide home air sealing and insulation measures to residential customers. Both of these programs represent small portions of the overall EE savings and (4) Agriculture EE, Commercial EE, Commercial New Construction, Energy Star Appliances, Energy Star New Homes, Energy Star Lighting, Energy Cost Monitor, and Refrigerator/Freezer Replacement Programs – Supporting calculations for the energy savings associated with these programs are based on data and analyses from multiple market potential studies conducted by GDS Associates, Inc., as well as other customer-specific reports. GDS relies heavily on the Mid-Atlantic TRM and other M&V reports from North Carolina investor-owned electric utilities (IOUs) to support the updated kWh per measure savings for the purpose of calculating the EECs that NCEMC uses for REPS compliance purposes. Much of this information is reviewed by the Public Staff during its review of EE rider proceedings filed pursuant to Commission Rule R8-69 by the IOUs, and the Public Staff states that it considers this information to be a reliable resource. For future REPS compliance reports, the Public Staff recommends that NCEMC or its M&V consultant include the specific citation to the data or findings used, the reports it relies upon for the measure savings, and any net-to-gross or other adjustments made to the savings identified in those reports, as well as any other information that would assist the Public Staff in understanding any differences between the actual savings claimed and those referenced in the cited reports. The Public Staff further recommends that the Commission approve NCEMC's 2017 REPS compliance report, including the M&V results for the EECs NCEMC earned in 2017.

Based upon the foregoing and the entire record in this proceeding, including NCEMC's 2017 REPS compliance report, the data in NCEMC's 2017 compliance sub-account in NC-RETS, and the comments of the Public Staff, the Commission determines that NCEMC complied with its 2017 REPS requirements, and that the RECs and EECs in NCEMC's 2017 compliance sub-account in NC-RETS should be retired. Further, the Commission finds that NCEMC's 2017 compliance report includes the information and supporting documentation required by Commission Rule R8-67(c), and, therefore, the Commission concludes that NCEMC's 2017 REPS compliance report, including the M&V results for EECs earned in 2017, should be approved.

NCEMPA

On August 29, 2018, NCEMPA filed its 2017 REPS compliance report. NCEMPA's compliance report states that NCEMPA's total 2016 retail electric sales was 7,213,809 MWhs. Based on six percent of its 2016 retail sales, NCEMPA's 2017 REPS obligation is 432,829 RECs, and, based on 0.14 percent of NCEMPA's total 2016 retail sales, its solar set-aside obligation is 10,100 solar RECs. NCEMPA's share of the poultry waste set-aside requirement is 9,122 poultry waste RECs. Consistent with these requirements, the data in NC-RETS evidences that NCEMPA submitted the required number of RECs for retirement based upon the foregoing sales levels and REPS requirements.

In its comments, the Public Staff states that NCEMPA's 2017 REPS compliance report and NC-RETS compliance sub-account indicate that NCEMPA met its REPS requirements for 2017. The Public Staff notes that NCEMPA implements EE programs, it no longer tracks EE savings or use EECs for compliance due to high M&V costs. The Public Staff recommends that the Commission approve NCEMPA's 2017 REPS compliance report.

Based upon the foregoing and the entire record in this proceeding, including NCEMPA's 2017 REPS compliance report, the data in NC-RETS, and the Public Staff's comments, the Commission determines that the NCEMPA municipalities met their 2017 REPS obligations, and, therefore, the RECs in NCEMPA's 2017 compliance sub-account in NC-RETS should be retired. Further, the Commission finds that NCEMPA's 2017 REPS compliance report includes the information and supporting documentation required by Commission Rule R8-67(c). The Commission, therefore, concludes that NCEMPA's 2017 REPS compliance report should be approved.

NCMPA1

On August 29, 2018, NCMPA1 filed its 2017 REPS compliance report. NCMPA1's compliance report states that NCMPA1's total 2016 retail sales was 5,088,213 MWhs. Based on six percent of its 2016 total retail sales, NCMPA1's 2017 REPS obligation is 305,293 RECs. Based upon the 2017 solar set-aside requirement of 0.14 percent, NCMPA1's solar set-aside obligation is 7,124 solar RECs, and its share of the poultry waste set-aside requirements is 6,367 poultry waste RECs. Consistent with these requirements, the data in NC-RETS evidences that NCMPA1 met its 2017 REPS requirements by submitting the required number of RECs for retirement based upon the foregoing sales levels and REPS requirements.

In its comments, the Public Staff states that NCMPA1's compliance report and NC-RETS compliance sub-account indicate that NCMPA1 met its REPS requirements for 2017. The Public Staff notes that NCMPA1 implements EE programs, it no longer tracks EE savings or use EECs for compliance due to high M&V costs. The Public Staff recommends that the Commission approve NCMPA1's 2017 REPS compliance report.

Based upon the foregoing and the record in this proceeding, including NCMPA1's 2017 compliance report, the data in NC-RETS, and the Public Staff's comments, the Commission concludes that the NCMPA1 municipalities met their 2017 REPS obligations, and therefore, the RECs in NCMPA1's 2017 compliance sub-account in NC-RETS should be retired. Further, the Commission finds that NCMPA1's 2017 REPS compliance report includes the information and supporting documentation required by Commission Rule R8-67(c). The Commission, therefore, concludes that NCMPA1's 2017 REPS compliance report should be approved.

<u>TVA</u>

On August 31, 2018, TVA filed its 2017 REPS compliance report. As noted above, TVA reports on REPS compliance on behalf of Blue Ridge Mountain Electric Membership Corporation, Mountain Electric Cooperative, Murphy Electric Power Board, and Tri-State Electric Membership Corporation. TVA's 2017 REPS compliance report indicates that its total 2016 retail sales were 615,629 MWhs. Based upon the six percent requirement, TVA's 2017 REPS requirement is 36,938 RECs. Based on the solar set-aside requirement of 0.14 percent, TVA's 2017 solar set-aside requirement is 862 solar RECs. TVA's share of the 2017 aggregate poultry waste set-aside requirement is 769 poultry waste RECs. The data in TVA's 2017 compliance sub-account in NC-RETS evidences that TVA met its REPS requirements for 2017 by submitting the required number of RECs for retirement based upon the foregoing sales levels and REPS requirements.

In its comments, the Public Staff states that TVA's 2017 compliance report and NC-RETS compliance sub-account demonstrates that TVA met the requirements for general RECs and solar RECs for 2017. The Public Staff notes that TVA did not use any EECs for REPS compliance in 2017, and that TVA provides REPS compliance services at no cost to the four distributors of its electricity in North Carolina. The Public Staff recommends that the Commission approve TVA's 2017 REPS compliance report.

Based upon the foregoing and the entire record in this proceeding, including TVA's 2017 REPS compliance report, the data in NC-RETS, and the Public Staff's comments, the Commission determines that TVA's electric distributors met their 2017 REPS requirements, and that the RECs and EECs in TVA's 2017 compliance sub-account in NC-RETS should be retired. Further, the Commission finds that TVA's 2017 REPS compliance report includes the information and supporting documentation required by Commission Rule R8-67(c). The Commission, therefore, concludes that TVA's 2017 REPS compliance report should be approved.

Waynesville

On August 31, 2018, Waynesville filed its 2017 REPS compliance report. Waynesville's compliance report indicates that its total 2016 retail sales were 90,743 MWhs. Based upon the six percent general REPS requirement, Waynesville's total 2017 REPS compliance obligation is 5,445 RECs. Based upon the solar set-aside requirement of 0.14%, Waynesville's solar set-aside requirement is 128 solar RECs. Waynesville's share of the 2017 aggregate poultry waste set-aside requirement is 117 poultry waste RECs. The data in Waynesville's 2017 compliance sub-account in NC-RETS demonstrates that Waynesville met its REPS requirements for 2017 by submitting the required number of RECs for retirement based upon the foregoing sales levels and REPS requirements.

In its comments, the Public Staff states that Waynesville's 2017 REPS compliance report and NC-RETS compliance sub-account indicate that Waynesville met the requirements for general RECs and solar RECs for 2017. The Public Staff further states that Waynesville did not use any EECs for REPS compliance in 2017. The Public Staff recommends that the Commission approve Waynesville's 2017 REPS compliance report.

Based upon the foregoing and the entire record in this proceeding, including Waynesville's 2017 REPS compliance report, the data in NC-RETS, and the Public Staff's comments, the Commission determines that Waynesville met its 2017 REPS requirements, and that the RECS in Waynesville's compliance sub-account in NC-RETS should be retire. Further, the Commission finds that Waynesville's 2017 REPS compliance report includes the information and supporting documentation required by Commission Rule R8-67(c). The Commission, therefore, concludes that TVA's 2017 REPS compliance report should be approved.

2018 REPS COMPLIANCE PLANS

Each EMC and municipal electric power supplier (or its utility compliance aggregator) filed in this docket the 2018 REPS compliance plan required by Commission Rule R8-67(b). In its comments, the Public Staff states that the REPS compliance plans filed in this docket contain the information required by Commission Rule R8-67(b) to demonstrate how each municipal and EMC electric service provider intends to comply with the REPS requirements for 2018, 2019, and 2020 (the relevant planning period for the 2018 REPS compliance plans). The Public Staff further states that all of the EMC and municipal electric service providers indicate that they will satisfy the general REPS requirements and the solar set-aside requirements during the planning period, and that their incremental costs to do so will not exceed the annual cost cap established in N.C.G.S. § 62-133.8(h)(3) and (4). The Public Staff notes that the majority of the EMC and municipal electric power suppliers do not expect to be able to comply with the swine or poultry waste set-aside requirements during the planning period unless they receive assistance from a larger utility. The Public Staff also commented on each REPS compliance plan filed in this docket. In determining whether each EMC or municipal electric power supplier met its reporting requirements for REPS compliance planning, the Commission reviewed and considered the 2018 REPS compliance plan filed by each EMC or municipal electric power supplier (or its utility compliance aggregator) and the comments of the Public Staff.

Based upon the foregoing and the entire record in this proceeding, including the 2018 REPS compliance plans filed by each EMC and municipal electric service provider (or its utility compliance aggregator), and the comments on the plans filed by the Public Staff, the Commission concludes that each of these EMC and municipal electric service providers, has met its obligation under Commission Rule R8-67(b) and, therefore, these REPS compliance plans should be accepted.

CONCLUSIONS

Based on the foregoing, and the entire record in this proceeding, the Commission concludes that the EMC and municipal electric service providers have met their respective 2017 REPS compliance requirements and filed 2017 REPS compliance reports and 2018 REPS compliance plans that meet the requirements of Commission Rule R8-67. The Commission further concludes that the incremental costs incurred by each of these EMC and municipal electric service providers to satisfy the 2017 REPS requirements are below the total annual spending limit applicable to each electric power supplier as established in N.C.G.S. § 62-133.8(h)(3) and (4). Finally, the Commission concludes that these electric power suppliers have demonstrated sufficient planning to meet their future REPS obligations, including, individually and collectively making reasonable efforts to achieve compliance with the swine and poultry waste set-aside requirements.

IT IS, THEREFORE, ORDERED as follows:

1. That EnergyUnited, FPWC, Halifax, NCEMC, NCEMPA, NCMPA1, TVA, and Waynesville met their 2017 REPS obligations or those obligations on behalf of the electric power suppliers that they serve, and that the RECs and/or EECs in the 2017 REPS compliance sub-accounts in NC-RETS of each of these electric power suppliers or utility compliance aggregators shall be retired;

2. That EnergyUnited, FPWC, Halifax, NCEMC, NCEMPA, NCMPA1, TVA, and Waynesville filed 2017 REPS compliance reports that meet the requirements of Commission Rule R8-67, and that these 2017 REPS compliance reports shall be, and hereby are, approved;

3. That EnergyUnited, FPWC, Halifax, NCEMC, NCEMPA, NCMPA1, TVA, and Waynesville filed 2018 REPS compliance plans that meet the requirements of Commission Rule R8-67, and that these 2018 REPS compliance plans shall be, and hereby are, accepted; and

4. That the Chief Clerk shall send a copy of this Order to Duke Energy Carolinas, LLC, Duke Energy Progress, LLC, Virginia Electric Power Corporation, d/b/a/ Dominion Energy North Carolina, and the NC-RETS Administrator.

ISSUED BY ORDER OF THE COMMISSION.
This the 13th day of August, 2019.

NORTH CAROLINA UTILITIES COMMISSION
A. Shonta Dunston, Deputy Clerk

DOCKET NO. E-100, SUB 164

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Investigation of Energy Storage in North Carolina	))	ORDER INITIATING INVESTIGATION

BY THE COMMISSION: Session Law 2017-192 (House Bill 589) required, among other things, that the North Carolina Policy Collaboratory at the University of North Carolina at Chapel Hill conduct a study on energy storage technology. That study was to address how energy storage technologies may or may not provide value to North Carolina consumers based on factors such as capital investment, value to the electric grid, net utility savings, net job creation, and impact on consumer rates and service quality. The law also required that the study address the feasibility of energy storage in North Carolina, including services energy storage can provide that are not being performed currently, the economic potential or impact of energy storage deployment in North Carolina, and the identification of existing policies and recommended policy changes that may be considered to address a statewide coordinated energy storage policy.

As required by House Bill 589, the Collaboratory published its report, "Energy Storage Options for North Carolina,"[1] on December 1, 2018. On May 20, 2019, several of the report's authors presented the study findings to the Commission. The report outlines a variety of approaches and tactics available to State policy makers as a starting point for further deliberations in the development of a statewide coordinated energy storage policy. Without endorsing any particular policy changes at this time, the Commission agrees with the report that there is a need to prepare for increased storage deployment. Energy storage issues are currently presenting themselves in the Commission's integrated resources planning,[2] avoided cost,[3] interconnection procedures,[4] competitive procurement of renewable energy,[5] utility pilot,[6] and other Commission dockets. The Commission believes that additional foundational education regarding energy storage would allow it to build on that presented in the Collaboratory's Energy Storage Options report and increase the Commission's preparedness for addressing storage-related issues as they are presented going forward.

[1] The complete report is available at: https://energy.ncsu.edu/storage/.

[2] Docket No. E-100, Sub 157.

[3] Docket No. E-100, Sub 158.

[4] Docket No. E-100, Sub 101.

[5] Docket Nos. E-2, Sub 1159 and E-7, Sub 1156.

[6] E.g., Docket No. E-2, Sub 1185.

Therefore, the Commission will initiate a series of educational presentations by invited experts on various discrete energy storage-related topics. This docket is being established to provide a repository for transcripts of those presentations and to serve as a mechanism for providing public notice. Additional notice will be provided on the Commission's calendar and website, and users of the Commission's electronic docket system may subscribe to email notification in this docket to receive notice of scheduled presentations. Interested persons may file written statements in this docket, including recommendations for speakers and topics, and the presentations will be open to the public; however, participation at the presentations will be limited to questions by the Commission.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 4th day of September, 2019.

NORTH CAROLINA UTILITIES COMMISSION
A. Shonta Dunston, Deputy Clerk

DOCKET NO. ER-100, SUB 6
DOCKET NO. ER-16, SUB 0
DOCKET NO. ER-16, SUB 1
DOCKET NO. ER-16, SUB 2
DOCKET NO. ER-17, SUB 0
DOCKET NO. ER-17, SUB 1
DOCKET NO. ER-17, SUB 2
DOCKET NO. ER-64, SUB 0
DOCKET NO. ER-64, SUB 1

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Cancellation of Certificates to Resell	)	ORDER CANCELING CERTIFICATES
Electric Service	)	TO RESELL ELECTRIC SERVICE

BY THE COMMISSION: On January 7, 2019, the Commission issued an Order in Docket No. ER-100, Sub 6, giving notice of intent to cancel the certificates of the electric resellers listed on Appendix A to this Order for failure to file 2018 quarterly regulatory fee report(s) and/or pay applicable fee(s), in violation of N.C.Gen.Stat. § 62-36 and Commission Rules R1-32 and R15-1. The Order also provided that the cancellation would become effective 30 days after the date of service of the Order, unless the public utility filed all delinquent report(s) and paid all outstanding fee(s) owed prior to the expiration of the 30-day period.

Of the four public utilities listed on the Commission's January 7, 2019 Order, one has since filed all outstanding reports and/or paid all outstanding fees for the pertinent parts of their 2018 operations. As February 28, 2019, however, the three public utilities listed on Appendix A, attached hereto, have failed to so comply.

The Commission, therefore, finds good cause to affirm its January 7, 2019 Order in Docket No. ER-100, Sub 6, and to cancel the certificates to resell electric service held by the public utilities listed on Appendix A to this Order accordingly.

IT IS, THEREFORE, ORDERED as follows:

1. That the certificates to resell electric service held by each public utility listed on Appendix A to this Order, as issued by this Commission, are hereby canceled;

2. That the Order entered in Docket No. ER-100, Sub 6 on January 7, 2019, is hereby affirmed; and

3. That the Public Staff shall monitor the compliance with this Order of each entity listed on Appendix A, and, within 90 days following the date of this Order, file with the Commission a report containing the results of any investigation undertaken to determine such compliance.

ISSUED BY ORDER OF THE COMMISSION.
This the 4th day of March, 2019.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

APPENDIX A

ELECTRIC RESELLERS DELINQUENT FOR FILING NC UTILITIES COMMISSION REGULATOR FEE REPORTS AND/OR FEES FOR FISCAL YEAR 2018
02/28/2019

Entity Number	Display Name	Certificate Issue Date	Certificate Cancel Date	Fiscal Year	Q1	Q2	Q3	Q4
ER-16	CARRBORO II LLC	03/06/2014		2018	FILED	FILED	X	X
ER-17	NORTH CAROLINA CARRBORO LIMITED PARTNERSHIP	03/06/2014		2018	FILED	FILED	X	X
ER-64	BRECKENRIDGE GROUP WILMINGTON NORTH CAROLINA, LLC	12/28/2017		2018	N/A	X	X	X

DOCKET NO. M-100, SUB 147

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Amendment to Certain Rules	)))))	ORDER AMENDING RULE R1-28 TO REQUIRE PAPER COPIES OF TESTIMONY AND EXHIBITS TO BE SEPARATED BY COLORED DIVIDERS

BY THE CHAIR: In an effort to provide for judicial economy and to assist Commission and Clerk staff in the execution of duties, the Chair finds good cause to amend Rule R1-28(e) in Chapter 1, Practice and Procedure of the Commission's Rules and Regulations to require colored paper dividers separating testimony and exhibits of expert witnesses.

IT IS, THEREFORE, ORDERED that Commission Rule R1-28(e) is amended effective as of the date of this Order as set forth herein in Appendix A.

ISSUED BY ORDER OF THE COMMISSION.
This the 31st day of July, 2019.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

APPENDIX A

Rule R1-28. GIVING NOTICE OR FILING PAPERS WITH THE COMMISSION BY MAIL; ELECTRONIC FILING.

(e) The following documents should be filed electronically; provided, however, fifteen (15) three-hole punched paper copies of the entire filing, one of which shall be single-sided, must be provided to the Commission on the following business day in lieu of the number of copies required pursuant to the applicable statute, rule, or order. If such filing is made electronically on the day of or day before a hearing on the matter, the paper copies shall be provided to the Commission no later than one (1) hour prior to the scheduled start of the hearing. The failure to provide the required number of paper copies within the prescribed timeframe may result in the electronic filing being rejected and excluded from the record in that proceeding.

(1) For all Class A and B electric, telephone, natural gas, water, and sewer utilities, applications for or filings of a general increase in rates, fares, or charges for revenue purposes or to increase the rate of return on investment or to change transportation rates, fares, etc. pursuant to Rule R1-17, and all testimony and exhibits of expert witnesses filed by any party to the general rate case proceeding.

(2) For all Class A and B electric utilities, applications for changes in rates in annual rate rider proceedings pursuant to G.S. 62-133.2, 62-133.8, and 62-133.9, and Rules R8-55, R8-67, and R8-69, and all testimony and exhibits of expert witnesses filed by any party to such proceeding.

(3) For all Class A and B natural gas utilities, applications for changes in rates in annual prudency review proceedings pursuant to G.S. 62-133.4 and Rule R1-17(k), and all testimony and exhibits of expert witnesses filed by any party to such proceeding.

(4) Other documents, such as testimony and exhibits of expert witnesses, as ordered in specific proceedings.

<u>In addition to the above requirements, when applicable, copies of testimony and exhibits of each expert witness shall be separated, one from the other, by the use of colored paper dividers such that one witness' testimony or separate exhibit shall not begin on the reverse side of the same page as another when provided to the Chief Clerk's Office.</u>

DOCKET NO. M-100, SUB 152

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of

Petition for Declaratory Ruling by	)	ORDER ISSUING
Cube Yadkin Generation, LLC	)	DECLARATORY RULING

BY THE COMMISSION: On March 8, 2019, Cube Yadkin Generation, LLC (Cube or Petitioner) filed a verified Petition requesting that the Commission issue a declaratory ruling that its proposal to enter into one or more leasing arrangements, whereby electricity and other utility services will be bundled together with real estate and related landlord services for a flat monthly rental rate, would fall within the landlord/tenant exception in N.C. Gen. Stat. § 62-3(23)d and, therefore, would not cause Cube to be considered a "public utility," or to otherwise be furnishing public utility service under applicable North Carolina law and regulations.

In its filing, Cube stated that it owns and operates four hydroelectric stations, dams and reservoirs along a 38-mile stretch of the Yadkin River, and that these facilities were built and used by Alcoa Corporation and its predecessors to supply energy for its aluminum production operations in Badin and currently are being used by Cube to supply energy into the wholesale market under Cube's federal authority as an exempt wholesale generator (EWG). Cube further stated that it seeks to enter into bundled-service, flat rental rate lease arrangements with tenants that have defined, high-intensity energy needs at the former site of the Alcoa aluminum production facilities, which is now under redevelopment as Badin Business Park.

Specifically, Cube stated that it proposes, either directly or through an affiliate, to lease portions of the Badin Business Park to various industrial tenants. As a component of these lease arrangements, Cube proposes to provide typical landlord services, such as the construction of any needed tenant improvements and maintenance, property management, and security services, in addition to certain bundled utility services, such as electricity, water, sewer, and telecommunications/broadband. The utility services that Cube proposes to provide to each tenant will be bundled as part of the overall package of lease services and will not be separately metered or billed, or be subject to any kind of true-up. Cube further stated that the lease agreement, as proposed, will prohibit tenants from reselling or otherwise making available to third parties the utility services provided by Cube. According to Cube, the central premise of its proposed leasing model is for it to provide space, services, and utilities to tenants for one flat, bundled rental rate. Cube opined that this will benefit energy-intensive tenants that seek significant amounts of space and intend to expand their operations over time.

Cube further stated that preliminary contact has been made with a number of potential tenants in order to gauge interest and assess needs, and that based on these discussions Cube has reason to believe that, if the declaratory ruling sought by its Petition is granted, binding lease agreements could be reached with one or more tenants. Cube noted that the proposed revitalization of Badin Business Park could lead to substantial new investment in the Stanly County community, including the creation of new jobs and expansion of the local tax base.

Cube also opined that its proposal is analogous to a prior proceeding in which the Commission issued a declaratory ruling finding that Catawba County's plan to construct and lease greenhouses, and provide energy generated by the County's qualifying facility (QF), to a third party on up to 100 acres within the perimeter of the County's "EcoComplex" did not subject the County to treatment as a public utility. In re Request for Declaratory Ruling by Catawba County, Order on Request for Declaratory Ruling, Docket No. SP-100, Sub 22 (Oct. 19, 2006) (Catawba County Order). Petitioner further argued that granting the Petition would be consistent with the principles established by the Commission's other decisions concerning the landlord/tenant exemption. See Robertson Brothers Utilities, Order Canceling Franchise and Requiring Customer Notice, Docket No. W-837, Sub 1 (Jan. 23, 2002); Complaint of Colin Stafford, Order Granting in Part, and Denying in Part Relief, Docket No. E-7, Sub 956 (May 11, 2011); Public Staff-North Carolina Utilities Commission v. Campus-Raleigh, LLC, and Campus Apartments, LLC, Order Determining Utility Status, Denying Request for Declaratory Ruling, Requiring the Cessation of Unlawful Charges for Utility Service, and Requiring Refunds, Docket No. M-89, Sub 8 (June 1, 2012); and In re Public Utility Status of American Homes 4 Rent – Public Staff Request for a Declaratory Ruling, Order Issuing Declaratory Ruling, Docket No. M-100, Sub 144 (Oct. 18, 2016) (American Homes Order).

On April 22, 2019, Duke Energy Carolinas, LLC (DEC), and Duke Energy Progress, LLC (DEP, collectively Duke), filed petitions to intervene in this docket. In summary, Duke stated that it determined that Cube's facility is located near the border of DEP's and DEC's assigned service areas, and is located in DEC's assigned territory. Therefore, according to Duke, it has a direct interest in this matter because Cube is seeking an exemption from regulation to provide service in Duke's exclusive franchise territory established by N.C.G.S. § 62-110, and other provisions of the Public Utilities Act.

Also, on April 22, 2019, the Public Staff presented this matter to the Commission at its Regular Staff Conference. The Public Staff stated that it had reviewed Cube's Petition and had concluded that Cube's proposal, if implemented as described in the Petition, would fall within the statutory exemption for landlord/tenant arrangements and the Commission's precedent interpreting that exemption. The Public Staff, therefore, recommended that the Commission issue an order declaring that, based upon the specific regulatory circumstances presented and the statements by Cube in the Petition, Cube's proposal falls within the landlord/tenant exemption in N.C.G.S. § 62-3(23)d and, accordingly, Cube would not be considered a public utility as a result of the activities described in the Petition.

At the Staff Conference, Lawrence B. Somers, Deputy General Counsel for Duke Energy Corporation, requested that the Commission grant Duke's petitions to intervene, and allow Duke two weeks to file a response to Cube's Petition. Mr. Somers maintained that Duke had not received adequate notice of Cube's Petition, and that it is the Commission's usual practice to allow comments on such petitions for declaratory rulings.

Marcus W. Trathen, an attorney with Brooks, Pierce, McLendon, Humphrey & Leonard, LLP, appeared on behalf of Cube at the Staff Conference. Mr. Trathen stated that on the date the Petition was filed Cube telephoned Duke personnel, including a Duke attorney, and informed those persons of the filing. Mr. Trathen further noted that Cube is under some time pressure to finalize these lease arrangements with potential tenants of Badin Business Park.

On the same day after the Staff Conference, the Commission issued an Order Allowing Petition to Intervene, and Allowing Filing of Response and Reply. The Order granted the petitions to intervene of DEC and DEP. In addition, the Order allowed Duke to file a response to Cube's Petition not later than 10 days after the date of the Order. Finally, the Order allowed Cube to file a reply to Duke's response, to the extent that Cube deemed a reply necessary, within seven days after the date of Duke's filing.

Also on the same day, North Carolina Electric Membership Corporation (NCEMC), filed a Petition to Intervene.

On April 23, 2019, Dominion Energy North Carolina (DENC) filed a Petition to Intervene.

On April 24, 2019, ElectriCities of North Carolina, Inc., North Carolina Eastern Municipal Power Agency, and North Carolina Municipal Power Agency Number 1 (collectively, Power Agencies) filed a joint Petition to Intervene.

On April 24 and 25, 2019, Cube filed objections to NCEMC's, DENC's and Power Agencies' petitions to intervene. In addition, Cube requested that if the Commission allowed intervention by NCEMC, DENC, and Power Agencies that the Commission require them to submit comments, if any, in the same timeframe that the Commission set for Duke's response.

On April 25, 2019, the Commission issued an Order Denying Petitions to Intervene and Granting Limited Amicus Curiae Status, denying the petitions to intervene filed by NCEMC, DENC and Power Agencies, but allowing those entities to participate as amicus curiae by filing responses to Cube's Petition in the same timeframe set by the Commission for Duke's response. In addition, the Commission directed that the Public Staff file a statement of its position within seven days after the responses filed by Duke, NCEMC, DENC and Power Agencies.

On May 2, 2019, responses to Cube's Petition were filed by Duke, NCEMC, DENC, and Power Agencies.

On May 9, 2019, Cube and the Public Staff filed separate replies to the other parties' responses.

SUMMARY OF RESPONSES

Duke

Duke maintained that Cube is proposing to sell electricity to the public for compensation, and, therefore, is a public utility under N.C.G.S. § 62-3(23)a.1, which defines a "public utility" as a person

> [o]wning or operating in this State equipment or facilities for:
>
> Producing, generating, transmitting, delivering or furnishing electricity, piped gas, steam or any other like agency for the production of light, heat or power to or for the public for compensation ....

Duke stated that Cube's assertion that it is not a public utility is based on Cube's flawed reading of N.C.G.S. § 62-3(23)d, which provides, in pertinent part:

> The term "public utility," except as otherwise expressly provided in this Chapter, shall not include a municipality, an authority organized under the North Carolina Water and Sewer Authorities Act, electric or telephone membership corporation; or any person not otherwise a public utility who furnishes such service or commodity only to himself, his employees or tenants when such service or commodity is not resold to or used by others.

Duke placed emphasis on the statute's phrases "except as otherwise expressly provided," and "not otherwise a public utility," and contended that Cube and the Public Staff have read this landlord/tenant exception in isolation, without regard to the other express provisions of Chapter 62. According to Duke, the Commission must read the landlord/tenant exemption narrowly and in pari materia with the other pertinent provisions of Chapter 62, citing the recent North Carolina Court of Appeals decision in State ex rel. Utils. Comm'n v. N.C. Waste Awareness and Reduction Network, __ N.C. App. __, __, 805 S.E. 2d 712, 717 (2017), aff'd per curiam, 371 N.C. 109, 812 S.E.2d 804 (2018) (NC WARN).

> [S]tatutory pronouncements of policy are meant to coexist with North Carolina's well-established ban on third-party sales of electricity rather than supersede it .... If the legislature desires to except these types of third-party sales, it is within its province to do so and it is not for this Court to determine the advisability of any change in the law now declared in the Public Utilities Act.

Duke stated that Cube's primary purpose is to sell electricity to retail customers. Duke noted that Cube does not own sufficient generating capacity to meet its future tenants' needs, and, thus, will supplement its own generation supply with electricity purchased on the wholesale market. Cube's Petition, ¶ 15, at 7; DEC/DEP Exhibit 1, pp. 3-4 [Information provided by Cube, indicating that Cube's generating plants have a total capacity of 216 MW and the substation at Bladen Business Park "gives Cube the ability to provide tenants up to 400 MW of electricity service."][1]

Duke opined that the landlord/tenant exception to the definition of public utility applies to a landlord who purchases electricity from its incumbent supplier, or who generates electricity primarily for its own use, to provide ancillary electricity services to a tenant located in the same premises as the landlord. Duke further contended that there is no rational legal argument that the exemption was intended to apply to a wholesale generator like Cube Yadkin who proposes to acquire a business park and become a landlord for the primary purpose of creating a retail market for its wholesale generation facilities. Duke stated that the seminal case addressing the issue of whether an entity is selling utility service to the public is State ex rel. Utils. Comm'n v. Simpson, 295 N.C. 519, 246 S.E.2d 753 (1978) (Simpson), and quoted several statements from Simpson in support of its position.

In addition, Duke contended that electric service is fixed with a public interest, and the marketplace is best served by investor-owned utilities, electric cooperatives and municipalities that have service areas assigned exclusively by the Commission, and whose rates and service are regulated by the Commission. According to Duke, Cube would be exempt from regulation, and approval of its proposal would open the door for other merchant facilities, renewable and non-renewable, to provide retail utility service all around the state, and outside the regulatory framework established by Chapter 62 and applicable precedent. Duke maintained that such a bifurcated system would not serve the public interest. Citing NC WARN, Duke further submitted that allowing unregulated providers to serve the selected commercial and industrial customers would leave burdensome, less profitable service to the regulated incumbent utilities, and result in higher rates to the remaining customers.

> [S]pecifically, such a stamp of approval by this Court would open the door for other organizations like NC WARN to offer similar arrangements to other classes of the public, including large commercial establishments, which would jeopardize regulation of the industry itself.

NC WARN, __ N.C. App. __, 805 S.E.2d at 716.

Moreover, Duke contended that the Commission orders cited by Cube in support of its Petition were based on facts very different from those underlying Cube's novel approach. For example, Duke stated that in the Catawba County Order the Commission concluded that Catawba County's plan to construct and lease greenhouses to a third party on up to 100 acres within the perimeter of the County's Eco-Complex, and including energy generated by the County's QF, did not subject the County to treatment as a public utility. Duke noted that the Commission specified that its order should not be considered precedent. Further, Duke stated that Catawba County's proposal differed from Cube's in that Catawba County developed the Eco-Complex, including the QF, on land that it already owned, that the provision of steam was the primary purpose of the

[1] DEC/DEP Exhibit 1, although marked "Private and Confidential," is a document provided to Duke in discovery. Cube waived the confidentiality of the document for the purpose of this proceeding.

arrangement, with electricity an ancillary service, and that Catawba County did not propose to provide or resell additional electricity to its tenants from the wholesale market.

In addition, Duke discussed other Commission dockets cited by Cube, and surmised that these cases concerned residential landlord/tenant arrangements that did not equate to the scale and scope of Cube's proposal. Duke contended that the Commission's Order on Request for Declaratory Ruling and Notice of Intent to Revoke Registration of New Renewable Energy Facilities, In re Application of W.E. Partners, LLC for Registration of a Renewable Facility, Docket No. SP-729, Sub 1 (September 17, 2012) (WEP Order), is a more analogous decision. In that docket, W.E. Partners (WEP) proposed to produce electricity with a combined heat and power facility and to provide it free of charge to a third party with whom it had existing and future financial arrangements. The Commission denied WEP's request, stating:

> [W]ere the Commission to rule otherwise it would open a Pandora's box of scenarios in which an electric generator could provide electrical services "free of charge" to a third party and build in compensation to recover its costs via other arrangements, thus, avoiding the statutory definition of a public utility in G.S. 62-3(23)a.1.

WEP Order, at 4.

Duke maintained that Cube's lease arrangement, if approved by the Commission, could be replicated by others, and that merchant plants and other wholesale electric generators could provide electrical service free of charge, building the compensation to recover their costs into the rent. According to Duke, the primary purpose of Cube's arrangement is to provide retail electric service to commercial and industrial customers.

Finally, Duke contended that Cube's Petition does not meet the requirements for a declaratory judgment because it is largely speculative, based on the following factors: (1) Cube does not own the land it purports to lease, but stated in its Petition that it will "obtain site control of the Badin Business Park which is still owned by Alcoa." Cube Petition, ¶ 17, at 7; (2) Cube states it will secure "site control" through either a purchase of the land or a leasing agreement with Alcoa, and, thus, it is unknown whether that agreement will be consummated or the form it may take; and (3) Cube has not filed a proposed lease agreement for review by the Commission, making the terms of the proposed arrangement speculative.[1]

Power Agencies

Power Agencies contended that Commission approval of Cube's proposal for the unregulated provision of up to 400 MW of electric service would create an exception that swallows the guidelines requiring a certificate of public convenience and necessity (CPCN), and prohibiting third-party electricity sales. According to Power Agencies, Cube would be an unregulated de facto public utility providing electricity to the public for compensation. Power Agencies further stated that the precedent set by the Commission could expose all investor-owned utilities (IOUs),

[1] As Exhibit B to its Reply Comments, Cube attached the template of its Industrial Lease Agreement. In a cover letter, Cube stated that although Exhibit B is marked "Confidential and Proprietary," that designation is waived by Cube for the purpose of this proceeding.

cooperatives, and municipal service providers to the same arrangements being deployed in their assigned service territories, thereby eroding their exclusive service rights. Power Agencies maintained that Cube should not be allowed to circumvent North Carolina's ban on third-party sales of electricity, as recently recognized by the Commission and the Court of Appeals in NC WARN.

Moreover, Power Agencies stated that, contrary to the landlord/tenant situation contemplated by N.C.G.S. § 62-3(23)d, Cube would not be in the core business of renting property, but, rather, would target attractive electricity intensive business customers for electric sales, with property rental being ancillary to this main purpose. In addition, Power Agencies submitted that there is no Commission precedent supporting Cube's proposal, and pointed out the distinguishing facts of the Catawba County Order, including those discussed by Duke. In addition, Power Agencies stated that Catawba County was already selling the power from its landfill gas-fueled QF to Duke under a power purchase agreement. Power Agencies also opined that Duke did not oppose the County's request because the County was not proposing to furnish electricity from its QF to its greenhouse tenants, but, instead, would simply recover some part of Duke's charges for electricity to the County through monthly rents paid by the County's greenhouse tenants.

In addition, Power Agencies maintained that the Commission should not consider issuing a declaratory ruling in Cube's favor without first receiving significantly more detailed information about Cube's proposal, and without reviewing and approving the lease language which Cube proposes to utilize. Power Agencies stated that the concern noted by the Commission in the WEP Order about hidden compensation for "free electricity" is present in this docket, and can only be addressed by requiring Cube to submit its proposed lease language regarding utility services for review and approval by the Commission.

DENC

DENC contended that the Commission should engage in a thorough review of Cube's proposed arrangements, including requiring Cube to provide the details of (1) its legal rights in the property at Badin Business Park, (2) the terms and conditions of the proposed leasing arrangements, including the utility services to be provided by Cube, (3) Cube's plans to supply its tenants, at least in part, with electricity purchased by Cube in the wholesale market, and (4) Cube's use of its transmission and distribution facilities to serve retail customers.

In addition, DENC stated that the unique circumstance of Cube's hydro facilities having preceded the Commission's CPCN requirements for new generating facilities supports a close examination of whether Cube's proposed business arrangements constitute public utility operations subject to the Commission's regulation. According to DENC, the Commission has used the CPCN process to, among other things, consider whether a person proposing a novel business arrangement involving the generation and sale of electricity should be regulated as a public utility, and, if so, whether the CPCN should include specific regulatory conditions.

Moreover, DENC maintained that Cube intends to furnish retail electric service for use by prospective tenants at the Badin Business Park "for compensationto or for the public," as defined in the Commission's prior orders and the North Carolina Supreme Court's decision in Simpson. In addition, DENC cited the NC WARN decision as illustrative of the fact that Cube's proposed business arrangement would result in retail electric competition with Duke. DENC asserted that Cube has creatively attempted to mask its activities in a proposed exemption applicable to landlords under N.C.G.S. § 62-3(23)d, and that the effect of the proposed arrangement is an important consideration for electric customers and regulated retail electric suppliers in North Carolina. As examples of these concerns, DENC points to potential uncertainties about customer recourse for inadequate service, disputes over the lease terms applicable to electric service, and affiliate relationships. In addition, DENC stated that a ruling in Cube's favor would create the potential for other generation owners and wholesale market participants to pursue similar business arrangements across the state, and that in NC WARN the Supreme Court recognized that such business arrangements could jeopardize the state's regulated utility model. According to DENC, the potential for such business arrangements could also jeopardize the Public Utilities Act's (the Act's) stated policies of promoting the inherent advantages of regulated public utilities, the provision of adequate, reliable and economic utility service, and continuous service of public utilities on a well-planned and coordinated basis. N.C.G.S. § 62-2.

Further, DENC stated that N.C.G.S. § 62-3(23)d provides for exemption from regulation only where a person "furnishes such service or commodity only to himself, his employees or tenants when such service or commodity is not resold to or used by others," and that Cube, as an EWG, is also furnishing power into the wholesale market and is, therefore, not furnishing electricity only to itself or its tenants. DENC opined that the primary legislative purpose of the narrow landlord/tenant exception is to allow a landlord receiving utility service from its incumbent, regulated electric, gas, or water supplier to avoid public utility regulation by providing bundled utility services within a single lease payment without seeking separate, metered compensation based upon the tenant's actual metered usage, citing the American Homes Order, at 17-18. DENC contended that Cube seeks to significantly expand the exception by furnishing its own unregulated generation at rates and on terms set by Cube. DENC stated that in the more than 50 years since N.C.G.S. § 62-3(23)d was enacted, the Commission has never considered a business arrangement like that proposed by Cube. DENC submitted that the facts in the Catawba County Order are readily distinguishable from Cube's proposed arrangement, as discussed by Duke and Power Agencies.

Finally, DENC stated that the Territorial Assignment Act, N.C.G.S. § 62-110.2, provides an avenue by which Cube could obtain certification as a regulated public utility seeking to provide retail electric service at the Badin Business Park, and negotiate with Duke to lawfully reassign the obligation to serve the Park to Cube, or, if unsuccessful in negotiations, pursue a Commission order authorizing Cube to serve the Park.

NCEMC

NCEMC stated that the Commission should first review Cube's proposed lease language before considering granting Cube the relief it seeks. Citing NC WARN and the WEP Order, NCEMC posited that a full review of the lease language is needed to avoid a decision that could jeopardize the public utility industry. Further, NCEMC contended that Cube is not a "person not otherwise a public utility," within the meaning of N.C.G.S. § 62-3(23)d, as indicated by the fact that absent the declaratory ruling requested by Cube it will not pursue lease arrangements with tenants of the Badin Business Park. Cube Petition, ¶ 18, at 9. In addition, NCEMC maintained that Cube is not the type of landlord the statute was intended to exempt from the definition of "public utility" because Cube is an energy provider looking for a way to mask its energy sales in the language of a commercial lease. According to NCEMC, the premise of Cube's argument is that the Commission must read the word "tenants" in a vacuum, which is contrary to the Commission's obligation to read the exemption narrowly and in pari materia with the other pertinent provisions of Chapter 62.

NCEMC discussed the Catawba County Order, and stated that it was based on facts distinguishable from Cube's Petition in several respects, including those previously noted by Duke, Power Agencies, and DENC.

SUMMARY OF REPLIES

Cube Yadkin

Cube stated that it is proposing a solution to a vexing problem for the Town of Badin by providing a means to stimulate economic activity and investment at the industrial site that for many decades was the focal point of the Town's economic activity, but has lain dormant since 2007. Cube stated there is no entity other than Cube that is in a position to develop the Badin Business Park, and that Cube's proposal will result in significant private investment in the Town of Badin. Attached to Cube's Reply as Exhibit A was a letter from the Town of Badin in support of Cube's proposal.

In addition, Cube stated that the unique historical circumstances that support granting its Petition include: (1) the 100-year history of electric service by the hydro facilities and Alcoa, and not the incumbent utilities; (2) Cube's and its affiliates' ownership of the transmission lines and distribution substation that would be used to support the provision of tenant services under the lease agreements; and (3) operation by a Cube affiliate of the balancing authority encompassing Badin Business Park. Further, Cube provided an overview of the history of Alcoa's development and operation of the hydro plants and smelter, and the closing of Alcoa's smelter in 2007.

Cube stated that in 1999, in Docket No. E-56, Sub 1, In re Application of Tapoco, Inc. and Yadkin, Inc., for Authorization under G.S. 62-11 to Combine, Order Withdrawing Application (Dec. 2, 1999) (Alcoa), the Commission determined that Yadkin, Inc., Alcoa's generation subsidiary, was not a public utility when it provided energy generated from its hydro plants, combined with purchases from the wholesale market under its federal authority, to its affiliated entities for use at Badin Works (now Badin Business Park) in connection with Alcoa's aluminum and related manufacturing activities. Cube explained that the basis for the filing with the Commission was a proposed reorganization that consolidated all of the generation owned by Alcoa's subsidiaries, including the four hydroelectric plants now owned by Cube Yadkin, into one of Yadkin's sister companies, Tapoco, Inc., whose name was then changed to Alcoa Power Generating, Inc. (APG). APG subsequently provided electricity to the Badin smelter and all but one of Alcoa's other smelters and bought and sold through Alcoa Power Marketing, Inc., on the wholesale market for its own benefit and to serve the Badin smelter. Cube stated that this determination by the Commission shows the Commission's appreciation of the special circumstances surrounding the Badin hydro facilities and their critical connection to the industrial activity at the Badin site, and lends support to Cube's position in the present docket, where Cube effectively seeks to replicate Alcoa's operations. Cube further noted that Duke did not seek to intervene or otherwise raise objections in the 1999 proceeding.

With regard to Duke's comments herein, Cube contended that Duke's statutory interpretation would effectively write the landlord/tenant exemption out of Chapter 62, and that Duke would have the Commission engraft upon the express statutory language various qualifications and restrictions that were not intended by the General Assembly. Cube asserted that the Commission has already rejected the argument advanced by Duke, citing the American Homes Order. Cube stated that the Commission engaged in an extensive consideration of the landlord/tenant exemption in light of other provisions of Chapter 62, and concluded that N.C.G.S. § 62-3(23)d is the "only statute that clearly, unambiguously, and specifically sets forth language defining when a landlord is a public utility and when a landlord is not." Id. at 14. Further, Cube cited the following portion of the American Homes Order:

> As the Commission noted above, G.S. 62-3(23)d., is the only section in G.S. 62-3(23) providing specific guidance on the circumstances by which a landlord who provides utility service to his tenants will be considered to be a public utility. The other more broadly based provisions in the same statute and the Public Utilities Act which relate generally to the same subject matter do not. Under those circumstances, the Lumbee River EMC decision [State ex rel. Utilities Commission v. Lumbee River Electric Membership Corporation, 275 N.C. 250, 260, 166 S.E. 2d 635(1973)] holds that, if G.S. 62-3(23)d., is clear and understandable on its face, the Commission must be guided by G.S. 62-3(23)d., i.e., the specific statute, in making a decision in this case.

American Homes Order, at 14-15. Cube stated that Duke failed to distinguish this reasoning, or to otherwise call into question the line of cases cited by the court in the Lumbee River EMC decision.

Moreover, Cube stated that Duke has not demonstrated that it has exclusive rights to serve the area of the Badin Business Park, and contended that Duke is uncertain about such rights. Cube questioned whether there was ever an assignment of the area now known as Badin Business Park, since it was previously served by Alcoa. According to Cube, Stanly County is served by multiple providers, including Union EMC, Pee Dee EMC, the Town of Albemarle, and DEP, and the Commission has identified Stanly County as an "overlapping" territory as between DEP and DEC.[1] Further Cube refuted Duke's claims that Duke has engaged in discussions about developing the business park, noting that Duke offered no evidence of the extent of such discussions or its present ability to serve customers in the park.

Responding to Duke's concern that Commission approval of Cube's proposal would open up retail electric service to merchant plants, Cube listed several factors that it contended would make such a result impossible. Further, Cube maintained that Duke's merchant plant example serves to highlight Cube's unique circumstances as a legacy generating facility that commenced operations under its prior owner for support of affiliated industrial activities prior to the existing

[1] See, e.g., North Carolina Utilities Commission 2018 Informational Review, https://www.ncuc.net/documents/overview.pdf, at 19. An examination of the maps for Stanly County in Docket Nos. ES-10 and ES-44 (1966) discloses that the Badin Business Park is located in an area assigned for retail electric service to DEC. Thus, it is not located in unassigned territory, nor was it assigned to Cube's predecessor, Yadkin, Inc.

certification regime, and having its own transmission lines and distribution substation. Cube stated that no merchant plant or other entity can replicate this fact situation. For similar reasons, Cube contended that the Power Agencies' hypothetical of a developer building a 50-MW solar farm and serving a business park would be impractical and unlikely.

In addition, Cube contended that Duke's and the amici's efforts to distinguish the facts underlying the Catawba County Order from those of Cube's proposal are unavailing. Further, Cube maintained that Duke's argument that the WEP Order is applicable to Cube's proposal is incorrect because that order did not involve application of the landlord/tenant exception.

With respect to Duke's contention that Cube's Petition is speculative and, therefore, does not meet the requirements of the Declaratory Judgment Act, Cube enumerated several reasons why Duke's arguments are not valid. In addition, Cube asserted that its Petition meets all of the requirements for declaratory relief because this is a case in which there is an actual or real controversy between parties having adverse interests, and a Commission declaratory order will clarify and settle the legal issues.

With regard to DENC's comments, Cube stated that DENC's approach to the interpretation of N.C.G.S. § 62-3(23)d is erroneous, and that the adoption of DENC's approach would write the landlord/tenant provision out of Chapter 62. Further, Cube stated that DENC's concern with Cube's EWG status is misplaced. Cube stated that it is working with its FERC counsel, and it appears that Cube will need to relinquish its EWG status, which Cube is prepared to do, if the Commission grants the requested declaratory ruling approving Cube's lease arrangement. Moreover, Cube stated that DENC's contention that Cube's tenants would have no recourse if they have service failures or other complaints about their electric service is unfounded because tenants will have the contractual remedies that they negotiate in the lease agreement. With respect to DENC's contention that Cube can find relief under the territorial assignment provisions of the Act, Cube stated that this is not a viable option because it would require that Cube become a public utility under the Act.

Finally, Cube stated that to the extent the Commission is concerned about the possibility that Cube's provision of electric service to tenants in Badin Business Park could grow beyond a defined level without Commission awareness, Cube is willing to stipulate that it will not expand the 400 MW import capacity into the park without first filing notice with the Commission and giving the Commission the opportunity to consider if such an expansion of capacity would be appropriate.

Public Staff

The Public Staff stated that its position remains the same as its recommendation at the April 22, 2019 Regular Staff Conference to grant the declaratory relief requested by Cube, based on the provisions of N.C.G.S. § 62-3(23).

In its Reply Comments, the Public Staff further recommended that Cube be required to file, in advance, any leasing arrangements or lease terms that depart from the proposal as described in the Petition and draft lease, so that the Commission can review new terms and determine whether Cube continues to be exempt from public utility status under North Carolina law.

The Public Staff summarized each main point made by DENC in DENC's response, stated that it disagreed with each point, or found DENC's point irrelevant, and explained the reasons for its disagreement.

With regard to Duke's response, the Public Staff stated that the NC WARN decision is distinguishable from Cube's proposed arrangement because the church was not a tenant of NC WARN, and, thus, the exception to public utility status under N.C.G.S. § 62-3(23)d did not apply.

In response to Duke's and the amici's concerns about incumbent utilities losing customers and revenue, the Public Staff opined that this is a policy matter that would more appropriately be addressed by the General Assembly.

DISCUSSION

The questions presented to the Commission by the parties and those filing as amici curiae are whether Cube's proposed activities pursuant to a leasing arrangement would cause it to be a "public utility" under the provisions of the Act as that term is used in N.C.G.S § 62-3(23)d; if so, whether Cube would be exempt from regulation pursuant to N.C.G.S. § 62-3(23)d by virtue of its status as a landlord; and if not a public utility, whether Cube would be exempt from regulation by the Commission pursuant to N.C.G.S. § 62-3(23)d when furnishing utility service to its tenants.

A. Is Cube a public utility as that term is used in N.C.G.S. § 62-3(23)d?

The Act includes numerous provisions defining the term "public utility," and numerous exceptions to the definition of "public utility." At least two definitions of "public utility" pertinent to the present case are found in N.C.G.S. §§ 62-3(23)a.1 and 2. In pertinent part they state:

> "Public utility" means a person, whether organized under the laws of this State or under the laws of any other state or country, now or hereafter owning or operating in this State equipment or facilities for:
>
> 1. Producing, generating, transmitting, delivering or furnishing electricity, piped gas, steam or any other like agency for the production of light, heat or power to or for the public for compensation; provided, however, that the term "public utility" shall not include persons who construct or operate an electric generating facility, the primary purpose of which facility is either for (i) a person's own use and not for the primary purpose of producing electricity, heat, or steam for sale to or for the public for compensation . . . ;
>
> 2 Diverting, developing, pumping, impounding, distributing or furnishing water to or for the public for compensation, or operating a public sewerage system for compensation; provided, however, that the term "public utility" shall not include any person or company whose sole operation consists of selling water to less than 15 residential customers . . . ;

N.C.G.S. § 62-3(23)a.1 and 2. The exception to the above-cited definitions, pertinent in part to the instant petition for declaratory judgment, provides:

> The term "public utility," except as otherwise expressly provided in this Chapter, shall not include . . . any person not otherwise a public utility who furnishes such service or commodity only to himself, his employees or tenants when such service or commodity is not resold to or used by others.

N.C.G.S. § 62-3(23)d.

Another statute of importance in the present docket contains the definition of "service."

> "Service" means any service furnished by a public utility, including any commodity furnished as a part of such service and any ancillary service or facility used in connection with such service.

N.C.G.S. § 62-3(27).

The parties agree that, as with all of the Act's provisions, the definitions of "public utility" and the exception for landlords must be read in pari materia, giving full effect to each provision. See Brisson v. Santoriello, 351 N.C. 589, 595, 528 S.E.2d 568, 573 (2000). However, the parties differ in the appropriate methodology for applying these two provisions, and in particular how to apply the "person not otherwise a public utility" language in N.C.G.S. § 62-3(23).

Cube contends that the "not otherwise a public utility" analysis should begin with a determination of whether Cube's current business activity, not its proposed activity, makes it a public utility under the Act, and, if the answer is "no," then the Commission should determine whether Cube qualifies as a landlord exempt from regulation as a public utility under N.C.G.S. § 62-3(23)d with respect to Cube's proposed lease arrangement. On the other hand, Duke and DENC contend that the analysis for the purpose of ruling on the Petition for a declaratory judgment should begin with whether Cube's proposed activity, without regard to its proposed role as a landlord, would make Cube a public utility. If so, the implication would be that the Commission's analysis would end there and the landlord/tenant exception on its face would not apply to Cube.

The Commission concludes that the plain express language of the N.C.G.S. § 62-3(23)d landlord exemption does not apply to any person, landlord or not, who is a "public utility" as the term is defined under the Act. Cube has filed this declaratory judgment action, not seeking a declaration that it is a landlord, but rather that under its proposed lease arrangement it is a landlord entitled to the § 62-3(23)d exemption from regulation. If Cube is a landlord who is a public utility, then it is not a landlord or person entitled to the § 62-3(23)d exemption from regulation and would not be entitled to the declaratory relief sought. Cube appears to have acknowledged as much when it recognized the necessity of asserting in its Petition that it is "an entity that is not otherwise a public utility under North Carolina law." Petition, ¶ 27, at 14. Thus, the analysis of whether the landlord exemption will apply to Cube must begin with whether Cube's planned activities under its lease with its potential tenants will cause it to be a public utility under the definition found in N.C.G.S. § 62-3(23)a.

Definition of "Public Utility"

Section 62-3(23)a.1 of the Act is clear and unambiguous in establishing four criteria that define a public utility as the term applies to a person supplying electricity: (1) ownership or operation of facilities in North Carolina, (2) which are used for producing, generating, transmitting, delivering or furnishing electricity, (3) to or for the public, (4) for compensation. The same criteria apply to one supplying water except that "diverting, developing, pumping, impounding, distributing or furnishing water" is substituted for criterion (2). N.C.G.S. § 62-3(23)a.2. A person providing sewer service is a public utility if it (1) owns or operates equipment or facilities in this State, (2) for operating (3) a public sewerage system, (4) for compensation. N.C.G.S. § 62-3(23)a.2. With respect to the first two criteria as they apply to electricity service, there is no dispute that Cube is presently the owner of electric production and generating facilities in this State, and it is using its facilities to produce and generate electricity.[1] As Cube stated in its Petition, it is an EWG that owns four hydroelectric plants and sells electricity in the FERC-jurisdictional wholesale market. Now, through its proposed leasing arrangement, Cube would provide rental space, certain non-utility services, and electricity, water, and sewer to industrial tenants. To provide electricity to these retail, end-user tenant-customers, Cube would use the production and generation facilities that it owns to furnish electricity to its tenant-customers. As to water and sewer, it is presumed that Cube would use facilities it owns or operates to furnish water and sewer service to its tenant-customers under its proposed lease agreement.[2] Hence, in the case of electricity, water, and sewer, the first two statutory criteria in N.C.G.S. § 62-3(23)a.1 and 2 for a public utility are met.

With regard to criterion (3), the Commission must determine whether Cube's producing, generating, and furnishing electricity to its proposed retail, end-user tenant-customers is producing, generating, and furnishing electricity "to or for the public" — and whether Cube's diverting, developing, pumping, impounding, distributing, or furnishing water or operating a sewer system to or for its proposed retail, end-user tenant-customers is being done "to or for the public." Based on review of Cube's proposed lease agreement and its representations in its pleading and reply, the Commission concludes that what Cube proposes to do to supply electricity to its tenants is to transmit, deliver, and/or furnish electricity to or for the public as that phrase is used and intended in N.C.G.S. § 62-3(23)a. Likewise, what Cube proposes to do to supply water and sewer service to its tenants is to furnish water and operate a sewer system to or for the public.

The leading case on whether utility service is being provided "to or for the public" is State ex rel. Utils. Comm'n v. Simpson, 295 N.C. 519, 246 S.E.2d 753 (1978) (Simpson). Simpson

[1] Cube's affiliate, Cube Yadkin Transmission LLC owns the transmission and distribution facilities and under the proposed lease agreement presumably would receive compensation from Cube to transmit and deliver service to Cube's tenants. Query whether under this presumed arrangement Cube's affiliate would be a public utility under N.C.G.S. § 62-3(23)b.

[2] There is no information in the Petition, or otherwise in the record before the Commission, indicating the source of water/sewer service to be provided by Cube to its tenants. Given that supplying electricity is the main business of all parties (including Cube) and amici appearing in the docket, they have focused on the electric utility service to be supplied by Cube and not other utility services included in the proposed lease terms. The Commission notes that the burden is on Cube to provide the Commission with sufficient information to render a decision on its Petition. N.C.G.S. § 62-75. For the purpose of discussion, the Commission will assume that Cube will use facilities it owns and/or operates to provide water/sewer service to its tenant-customers.

supports the Commission's determination that Cube's proposed activity is to furnish utility service to or for the public. In Simpson, a physician owning a telephone answering service began operating a two-way radio communication service offered exclusively to members of the Cleveland County Medical Society, a small group of 55 to 60 persons. The Commission concluded that the two-way radio communication service was being provided to the public. On appeal, the Supreme Court affirmed the Commission's order and wrote:

> One offers service to the "public" when he holds himself out as willing to serve all who apply up to the capacity of his facilities. It is immaterial, in this connection, that [the owner-operator's] service is limited to a specified area and his facilities are limited in capacity. For example, the operator of a single vehicle within a single community may be a common carrier.

Simpson, at 522, 246 S.E.2d at 755 (quoting State ex rel. Utils. Comm'n v. Carolina Tel. & Tel. Co., 267 N.C. 257, 268, 148 S.E.2d 100, 109 (1966)).

> What is the "public" in any given case depends . . . on the regulatory circumstances of that case. Some of these circumstances are (1) nature of the industry sought to be regulated; (2) type of market served by the industry; (3) the kind of competition that naturally inheres in that market; and (4) effect of non-regulation or exemption from regulation of one or more persons engaged in the industry.

Id. at 524, 246 S.E.2d at 756.

> [W]hether any given enterprise is a public utility does not depend on some abstract, formalistic definition of "public" to be thereafter universally applied. What is the "public" in any given case depends rather on the regulatory circumstances of that case. . . . The meaning of "public" must in the final analysis be such as will, in the context of the regulatory circumstances, and as already noted by the Court of Appeals, accomplish "the legislature's purpose and comports with its public policy."

Id., at 524, 246 S.E.2d at 756-57. See also State ex rel. Utils. Comm'n v. Mackie, 79 N.C. App. 19, 388 S.E.2d 888 (1986) (Court held that a person providing water and sewer service to some but not all residents of a subdivision was nonetheless a public utility.)

Simpson's determination of the meaning of "to or for the public" was recently applied and further explained in the NC WARN case cited by the parties. In NC WARN, the Court of Appeals affirmed the Commission's declaratory ruling that NC WARN's power purchase agreement (PPA) with a church in Greensboro, under which the electricity was provided by a solar array owned by NC WARN and installed on the roof of the church, rendered NC WARN a public utility. With regard to whether NC WARN was providing or furnishing service "to or for the public," the Court applied Simpson's four regulatory circumstances and held that NC WARN was acting as a public utility. The court focused its analysis on two of Simpson's four circumstances: 1) the kind of competition that naturally inheres in the electricity market, and 2) the effect of non-regulation or exemption from regulation of one or more persons engaged in the industry. The court noted that NC WARN intended to engage in similar arrangements with other non-profit organizations if its

PPA arrangement was upheld and NC WARN was found not to be a public utility. Further, the court discussed the exclusive franchise feature of the Act, a franchised electric utility's obligation to serve all persons, and the danger that allowing third-party (nonregulated) providers to draw customers away from the incumbent utility could result in increased rates due to the cost of serving the remaining less-profitable customers. NC WARN, __ N.C. App. __, 805 S.E.2d at 715-16.

In the present docket, the regulatory circumstances surrounding Cube's proposal, and those identified by the Simpson Court's analysis of what is "service to the public," are very similar. Under the first Simpson criterion, the nature of the industry sought to be regulated, Dr. Simpson's two-way radio communication service was a form of local telephone service, and was essentially the same type of local telephone service being provided by Two-Way Radio of Carolina, Inc. (Two-Way Radio), a radio common carrier certificated under the Act and operating in several western counties, including Cleveland County. Likewise, the retail electric service that Cube proposes to furnish its tenants is the same as the regulated retail electric service provided by Duke under the Act.

With regard to the second Simpson criterion, the type of market served by the industry, Cube proposes to provide retail electric service of up to 400 MW to commercial and industrial customers in the Badin Business Park. The generating capacity of Cube's hydro-electric plants is only 216 MW. Cube stated that when its tenants' electric needs exceed 216 MW it plans to supplement its generating capacity with purchases from the wholesale market. Retail electric service to commercial and industrial customers is a type of market also served by Duke. Indeed, high-load factor commercial and industrial customers are a primary market of Duke and other regulated utilities based on the large amount of utility service required by such customers, the efficiencies obtained due to their high-load factor, and the close proximity of such customers in business and industrial parks.

With respect to the third Simpson criterion, the kind of competition that naturally inheres in the market, the retail electric market in North Carolina does not naturally or otherwise support retail electric competition. As previously discussed, the overriding purpose of the Act, i.e., the legislatively adopted policy of the State, is to provide for end-use customers to receive utility service from franchised monopoly providers whose rates, services, operations and expansion are regulated by the Commission. See N.C.G.S. §§ 62-2 and 62-110.2, NC WARN, __ N.C. App. __, 805 S.E.2d 712, 716. In particular, the retail electric market is completely vertically integrated, with the electric public utilities charged with the obligation of producing, generating, and furnishing electricity to the end-use customers in their assigned retail service territories. Similarly, where a water/sewer utility has been assigned a franchised area there is no "competition that naturally inheres" in that market. Indeed, the awarding of a water/sewer franchise establishes that there will be no competition for such services in the franchisee's assigned area. As stated in N.C.G.S. § 62-2(a)(2), one of the policies underlying the Act is to "promote the inherent advantage of regulated public utilities." Among the inherent advantages of public water/sewer utilities is the avoidance of duplicate water/sewer lines, and the assurance that a regulated entity is present and accountable for providing essential water and sewer services.

Finally, the fourth Simpson criterion is the effect of non-regulation or exemption from regulation of one or more persons engaged in the industry. This was the "public" criteria most discussed by the Simpson Court. After concluding that the nature of the industry was such that users could be divided into definable classes, the Court noted that doctors were especially prominent users of the two-way radio services being provided by Dr. Simpson in competition with the certificated carrier, Two-Way Radio, and that while Dr. Simpson had nine doctors subscribing to his service, Two-Way Radio had no doctors among its 12 subscribers in Cleveland County. The Court expressed concern that this targeting of a particular class of professional customer (doctors) by an unregulated person could result in a substantial portion of the market being served by unregulated providers, and an attendant significant loss of profits by the regulated provider, with the result being higher cost service for the remaining customers of the regulated provider. The Commission shares this same concern in the present docket.

Cube stated in its Reply that

> [A] feature of Cube Yadkin's leasing model will be to provide space, services and utilities to tenants for a flat, bundled rental rate. This will benefit energy-intensive tenants that seek ample space and intend to scale up their operations over time.

Cube's Reply, at 6. A business park with customers using anywhere from 216 MW to 400 MW of electricity is a prized electric customer. Electricity, water, and sewer service to such a business park is a strong indicator of service "to the public."

The electricity, water, and sewer industries can be divided into a number of classes of users. Cube proposes to serve commercial and industrial classes of customers that are large volume users of electricity, water, and sewer. "Were a definition of 'public' adopted that allowed [Cube and other] prospective offerors of services to approach these separate classes without falling under the statute, the industr[ies] could easily shift from . . . regulated to . . . largely unregulated . . . ." Simpson, at 525, 246 S.E.2d at 757. Regulated utility providers could be left with the more difficult to serve, lower use customers, resulting in higher prices for the regulated service to be paid by those who remain in the less-profitable low-use classes of customers.

Moreover, Cube's proposal to provide electric service to a discrete population, the businesses that will be located at Badin Business Park, is comparable to Dr. Simpson's provision of telephone service to a limited number of members in the Medical Society. Both are somewhat closed populations, but they are groups in which the "membership" could change, by adding new members/tenants or replacing existing members/tenants. The Simpson Court's statement with respect to Dr. Simpson's two-way telephone service, that it is immaterial that the "service is limited to a specified area and his facilities are limited in capacity," is equally applicable to Cube's proposal. Likewise, in NC WARN the Court of Appeals decisively held that NC WARN's provision of retail electric service to the church constituted service "to or for the public," particularly given NC WARN's express intent to enter into similar arrangements with other non-profit organizations. See also State ex rel. Utils. Comm'n v. Buck Island, Inc., 162 N.C. App. 568, 577-78, 592 S.E.2d 244, 251 (2004) (water and sewer service provided to anyone who purchased a lot in the Buck Island development, up to the limit of available capacity, constituted service by a "public utility"); Public-Staff-North Carolina Utils. Comm'n v. Campus-Raleigh, LLC, and Campus Apartments, LLC, Order Determining Utility Status, Denying Request for Declaratory Ruling, Requiring the Cessation of Unlawful Charges for Utility Service, and Requiring Refunds, Docket No. M-89, Sub 8, at 12 (June 1, 2012) (service to any person who became a tenant in apartment building constituted service "to or for the public").

With its 216 MW of generating capacity and 400 MW of substation capacity, Cube obviously intends to serve several commercial or manufacturing customers, thereby cherry-picking high load factor customers more easily served due to their close proximity to one another. Regardless, if the Commission were to accept that Cube's offer to tenants of the Badin Business Park was not the furnishing of utility service "to or for the public," the regulated industries implicated by Cube's proposed leasing activities, particularly the electric service industry, could transition to unregulated industries without the General Assembly having any opportunity to weigh in on whether its long-established policy that regulated public utilities best serve the people of North Carolina should be changed or abandoned.

In addition, with respect to furnishing electricity, the tenants to whom Cube proposes to provide retail electric service are persons who would be served by Duke, a franchised public utility, as a part of Duke's legal obligation to provide retail electric service. A public utility's exclusive franchise comes not only with a legal obligation to serve and a protection of the utility's right to serve present customers, but also with assurance that the utility will enjoy the benefits of customer growth in its assigned service area. If there is the potential for new industrial customers in Badin Business Park, and Cube obviously believes there is, then that customer growth opportunity belongs to Duke, not Cube. Going forward, the impact on Duke of losing that opportunity to serve new prime industrial customers could be substantial. Equally important, the impact on Duke would be felt by its customers as well. Duke incurs fixed costs in its generation and delivery of electricity, and is entitled to a reasonable opportunity to recover its prudently incurred costs from its customers. The more customers among which Duke can spread its fixed costs, the less burdensome those costs are per customer. Industrial customers, with their high load factors and consistent demand, are particularly valuable customers for the purpose of spreading fixed costs. Duke's loss of the opportunity to serve industrial customers in Badin Business Park would result in the loss of an opportunity to reduce fixed costs for all of Duke's ratepayers. Indeed, in DEP's and DEC's last general rate cases, though addressing the retention of existing industrial load, the Commission recognized the importance of industrial customers to Duke and its ratepayers. The Commission approved pilot Job Retention Riders (JRRs) for DEP and DEC designed to help stem the loss of industry and industrial jobs in Duke's service territories.

> [T]he Commission views the Company's proposed JRR as an effort to retain industrial jobs in North Carolina and concludes that implementation of the rider is in the public interest. As with other economic development tariffs previously approved by this Commission, approval of the JRR is based in part on an evaluation of the expected economic benefits resulting from the tariff. The Commission has considered the economic impact of the continuing decline of the North Carolina industrial base as well as the impact of the recovery rider on non-participating ratepayers, and concludes that the JRR strikes the appropriate balance between the two.
>
> ...
>
> The Company, as well as ratepayers, benefit from the retention of industrial jobs, and the load related to the retention of industrial jobs.

Order Accepting Stipulation, Deciding Contested Issues and Granting Partial Rate Increase, Docket No. E-2, Sub 1042, at 135, 137 (Feb. 23, 2018); Order Accepting Stipulation, Deciding Contested Issues and Requiring Revenue Reduction, Docket No. E-7, Sub 1146, at 198-206 (June 22, 2018).

Finally, the fourth and last criterion pertinent to the "public utility" determination is the provision or furnishing of utility service to the public "for compensation." Cube proposes to charge its commercial and/or industrial tenants a lease payment that includes or covers its cost of providing utility service (electricity, water, sewer) to them. The Commission views this as the landlord's furnishing utility services to the tenants for compensation.

"Compensation" is not defined in the Act, so the Commission must look to the plain and ordinary meaning of the word. State v. Curtis, 371 N.C. 355, 358, 817 S.E.2d 187, 189 (2018). According to the American Heritage Dictionary, New College Edition, at 271 (Houghton Mifflin Co., 1978), compensation means "something given or received as an equivalent or as reparation for a loss, service, or debt . . . ." It is noteworthy that this definition states "as an equivalent ... for a ... service." In the present context, while Cube may not know or be able to predict the exact amount or value of the electricity or other utility service used by its tenants, it nonetheless will surely include an equivalent amount in the rent "for compensation" from the tenants for the utility services provided or furnished to the tenants.

On the issue of compensation, in the W. E. Partners docket, WEP proposed to donate the electric output of its combined heat and power (CHP) facility to its steam host, Perdue. WEP contended that this "gift" of the electricity would take WEP outside the "compensation" element of the definition of public utility. The Public Staff opposed WEP's arrangement with Perdue on the basis that

> [i]f third parties are allowed to furnish electric service as non-utilities when the transaction is without such direct compensation, the party receiving the service will often have a strong incentive to provide hidden or indirect compensation to the party providing the service.

WEP Order, at 3. In addition, the Public Staff stated that the scenario proposed by WEP might be a "boiler masquerading as a CHP." Id. The Public Staff's point, well taken, was that no person is likely to give away a commodity as valuable as electricity. WEP was going to charge Perdue something for the electricity, perhaps by including the cost of the electricity in the cost of steam. The Commission agreed with the Public Staff's concerns, and declined to approve WEP's proposal.

In the present docket, the facts likewise suggest, and the Commission can reasonably infer, that Cube will charge its tenants for utility service provided, apparently by including (though not on a dollar for dollar basis) the costs of the utilities in the lease payments. According to its Petition, Cube's proposal is that "energy would be provided as part of an overall lease arrangement."

> The rent payable under each lease will be developed as the result of an arms-length negotiation that will account for each tenant's particular business model. Specifically, . . .its baseline rental request will be calculated in a 'bottoms up' manner, adding together the forecasted and known costs Cube would incur for the

> space, services, and utilities that the individual tenant requires (plus an allocation for profit), taking into consideration . . .Space Costs [and] Lease Services . . ., including but not limited to: . . .Water and Sewer [and] Electricity . . . .
>
> The specific services to be provided will vary depending on the needs of the individual tenant and the outcome of the related lease negotiation. Certain potential tenants have indicated that they will require different packages of services and utilities for different uses within their lease premises. To address such needs, Cube Yadkin will negotiate a different flat rental rate for each type of use that a particular tenant requires.

Petition at 7-8. [Emphasis added.] Cube clearly states that its baseline rental request will be a summation of its costs, which will reflect its site control costs, the aggregate of which will reflect the bundle of service and utilities to be provided to tenants according to their differing and individual business models, i.e., needs. Id. Thus, the rental calculated for each tenant likely will vary due to the nature of the tenant's permitted use of the premises and will reflect such considerations, among others, as the tenant's expected consumption of water and electricity attributable to the stipulated permitted use. The draft lease cautions that this "permitted use" provision will be vigilantly policed and enforced. Where a tenant will have multiple permitted uses, a separate base rental may be calculated for each of the permitted uses, again based on the tenant's expected consumption of utility services. The lease will assign to each permitted use a maximum capacity allocation for electricity usage, a percentage guaranty of availability, and will contain provisions governing the landlord's right to interrupt service. These provisions are assuredly meant to protect the landlord against the economic consequences of excessive utility consumption by tenants, but they are equally important for the purpose of designing and producing a revenue stream that will be sufficient to compensate Cube for its capital and operating costs to generate electricity at its hydroelectric facilities and, presumably, to yield a return for Cube on its investment in those facilities. In the prototypical lease, in setting rents the landlord will certainly consider and attempt to estimate its tenants' likely usage of utility services furnished by the landlord, but the utility component of the rent is usually of no greater prominence than the other components of the rent, such as insurance cost, property taxes, expected maintenance expenses, and the like. Here, however, utility costs, and in particular electricity costs, appear to be a significant and, perhaps, a principal driver in setting tenant rental rates at Badin Business Park.

A landlord knows how many square feet are in the building, can obtain data on the cost of operating appliances and other machinery, and, in most instances, will have a usage history to use in setting a portion of the rent to compensate himself for electric, water, and sewer usage by the tenant. Here, the reasonable and obvious inference is that Cube will charge each tenant rent that will cover utility costs incurred by Cube plus an amount for profit. The proposed lease arrangement contemplates that tenants will pay Cube a negotiated rental fee that will include reimbursement and a level of profit for utility usage unique to each individual tenant. Therefore, the Commission concludes that Cube, regardless of how it decides to measure and set the portion of rent it charges tenants for electricity, water, and sewer service, will be providing utility service "for compensation," within the meaning of N.C.G.S. § 62-3(23)a.1.

Thus, the Commission determines that Cube's proposal constitutes retail electric service and water and sewer service masquerading as nothing more than a landlord/tenant relationship.

The rent charged will include "compensation" for water, sewer, and electricity service. The controlling fact here is that Cube proposes to be not only the landlord, but to also be the provider of retail utility service to its tenants, using production and generation facilities and equipment that it owns which are located in North Carolina.

The Commission notes that the Public Staff's position in the case at hand is different than in W. E. Partners in that the Public Staff does not believe Cube is proposing to provide utility service for compensation because it would charge a flat all inclusive rental charge to tenants with no usage charge for electric service. The Public Staff is correct that in the typical landlord/tenant arrangement approved by the Commission as an exception from regulation under N.C.G.S. § 62-3(23)d, the landlord proposes to pay the incumbent utility for the electricity used by the tenant based on the actual metered consumption at the premises, and to charge the tenant a flat amount as a portion of the rent, rather than a separate charge based on usage. In essence, the typical landlord who qualifies for the exemption buys the electricity from the incumbent utility on a metered basis and "resells" it to the tenant on a non-metered basis.[1] However, the Public Staff is mistaken in its assumption that there is no compensation where the landlord provides utility service without a usage charge. The definitions in N.C.G.S. § 62-3(23)a.1 and 2 do not provide that the electricity, water, or sewer must be furnished to or for the public "for compensation based on usage." The statutory language simply states that the service must be provided "for compensation." To engraft onto the statute the words "based on usage" would be adding a criterion that was not intended by the legislature to be included in the definition of "public utility." For the purpose of the "public utility" analysis to determine whether N.C.G.S. § 62-3(23)d is applicable in the first instance, the Commission looks to the definitions in N.C.G.S. § 62-3(23)a.1 and 2, which only require compensation and are blind to the form or basis of the compensation. If the landlord is not found to be a public utility, under § 62-3(23)a.1 and 2, then under § 62-3(23)d he may be exempt from regulation unless he provides utility service by an individual meter.

With regard to Cube's contention that in deciding the Petition for a declaratory judgment the Commission is limited to looking at Cube's current status separate and apart from what it proposes to do through its proposed lease, the Commission finds Cube's position disingenuous and seriously misguided. Cube's argument is the same as saying that because it is not a public utility today it would still not be a utility tomorrow if it then began engaging in the very activities making one a public utility, i.e., generating, transmitting, delivering, or furnishing electricity or power to the public for compensation. No person or landlord is a public utility until it starts performing the definitional activities prescribed in N.C.G.S. § 62-3(23)a. A first-time applicant for a CPCN is not a (de jure) public utility until it starts engaging in the § 62-3(23)a activities. Similarly, here, Cube would not be a public utility per the definition prior to acting as it proposes in its petition to the Commission. Moreover, Cube's request for declaratory relief would be moot or unnecessary if every landlord were exempt under N.C.G.S. § 62-3(23)d. Cube recognizes as much in seeking declaratory relief despite having clearly cast itself as a landlord under its proposed leasing arrangement. That is to say, there is no legitimate issue or uncertainty on the issue of Cube's status as a landlord such that it would need to be determined by declaratory relief. Furthermore, Cube expressly, if tacitly, recognizes that the determination of whether it is a public

[1] Recent amendments to the Act have created exceptions that allow landlords to pro-rate or submeter the electric, natural gas, and/or water services provided by the incumbent utility, resell the utility services, and charge tenants an administrative fee. N.C.G.S. § 62-110(g), (h) and (i).

utility is key to meeting the § 62-3(23)d landlord/tenant exception, having taken care to first set forth that it is not a public utility. Petition, ¶, at 14. The fundamental question presented by Cube's petition is whether its proposed activities under its landlord-tenant agreement will cause Cube to be a public utility.

Also, if the phrase "not otherwise a public utility" applies solely to Cube's present "pre-lease" business activities, then, likewise, a declaratory ruling would be unnecessary since the Commission already decided in its 1999 Alcoa Order that the activities currently being performed by Cube, the business successor to Alcoa, do not cause one to be a public utility under the Act. In fact, Cube has relied on the Commission's 1999 determination that Alcoa was not a public utility to establish that it cannot be a public utility as the term is used in N.C.G.S. § 62-3(23)d, since, according to Cube, what it proposes under the lease arrangements to be used in the Badin Business Park is functionally identical to Alcoa's activities at the Badin site. Cube Reply, at 12. The Commission disagrees with Cube's functionally identical characterization in the context of applying N.C.G.S. § 62-3(23)d to the facts alleged in the Petition.

In Alcoa, Tapoco, Inc., and Yadkin, Inc., filed an application under N.C.G.S. § 62-111 to obtain the Commission's approval of their proposed reorganization. Yadkin and Tapoco were wholly-owned subsidiaries of Alcoa. Yadkin was the owner of the four hydro-electric facilities now owned by Cube. Yadkin had one customer — the Alcoa smelting plant in Badin. The proposed reorganization would consolidate all of the generation owned by Alcoa's subsidiaries into Tapoco and change Tapoco's name to Alcoa Power Generating, Inc. (APG). The basis for the Commission's jurisdiction over the reorganization was a prior Commission determination that Alcoa and Tapoco were public utilities in North Carolina because of Alcoa's ownership of Nantahala Power & Light Company, a jurisdictional utility under the Act. However, at the time of the reorganization application, Alcoa no longer owned Nantahala, having sold it to Duke in 1988. As a result, Yadkin and Tapoco requested to withdraw their application if the sale of Nantahala meant they were no longer public utilities. In an Order Withdrawing Application (Alcoa Order), the Commission noted that Yadkin provided electric service to Alcoa at Alcoa's Badin plant, and that Yadkin "has never been found to be a public utility other than by implication because of its association with Alcoa." Alcoa Order, at 2. The Commission concluded that:

> [A]lcoa, Tapoco, and Yadkin, by virtue of their current activities, their proposed reorganization and their proposed activities, should not be considered public utilities under North Carolina law and Tapoco and Yadkin should be allowed to withdraw their application.

Id. [Emphasis added].[1]

Yadkin, as a wholly-owned subsidiary of Alcoa, was not a public utility when the application was before the Commission because it was operating its electric generating facilities to provide service to Alcoa. The legal effect of Yadkin furnishing electricity to Alcoa fell under the N.C.G.S. § 62-3(23)a.1 "single identity/primary purpose" exception for a person who

[1] Contrary to Cube's contention that only existing activities are relevant to the "public utility" determination, the Commission notes that in Alcoa it considered both existing and proposed activities.

> construct[s] or operate[s] an electric generating facility, the primary purpose of which facility is . . . for . . . a person's own use and not for the primary purpose of producing electricity, heat, or steam for sale to or for the public for compensation.

Thus, Yadkin was, in effect, furnishing electricity to itself with no plan to sell electricity to the public for compensation. As discussed above, according to the Petition, Cube proposes to furnish utility services, including electricity, water, and sewer, to the public, i.e., its several anticipated or potential industrial tenants, which are not Cube, for compensation. Cube is not the owner and/or operator of manufacturing facilities in the Badin Business Park. Thus, unlike Yadkin, which was not a public utility under N.C.G.S. § 62-3(23)a.1, Cube is a public utility under N.C.G.S. § 62-3(23)a.1 and for the purposes of N.C.G.S. § 62-3(23)d. Indeed, Cube's proposal is, in fact, functionally the polar opposite of the Yadkin/Alcoa Badin operations. Rather than operating the hydro-electric facilities for the primary purpose of its own use, Cube will be operating the facilities exclusively for its tenants' use.

Finally, to interpret the "not otherwise a public utility" phrase of N.C.G.S. § 62-3(23)d as applying solely to the existing business activities of the person seeking exemption from regulation would mean that only an incumbent electric public utility (as the only certificated provider) could ever be "otherwise a public utility" restricted from supplying electricity to its tenants, a result that would be extremely limited and illogical.

In sum, pursuant to N.C.G.S § 62-3(23)a.1 and 2, if Cube engages in the activities proposed in the lease arrangement now before the Commission, it would be a "public utility" as that term is used in the landlord exemption provided for in N.C.G.S § 62-3(23)d and as it is defined in N.C.G.S § 62-3(23)a. It would be the owner and operator of facilities in North Carolina used to produce and generate electricity or used to distribute or furnish water or to operate a sewerage system to or for the public for compensation. Thus, under N.C.G.S § 62-3(23)d, Cube cannot be a person who is not otherwise a public utility.

B. As a public utility who is a landlord proposing to furnish utility service to its several tenants, does the N.C.G.S. § 62-3(23)d exception under the Act apply to Cube?

As the Commission has determined that Cube would be a public utility, the exception for one who furnishes a utility service or commodity only to himself, his employees, or his tenants cannot apply to Cube. The exception applies only to one who is not otherwise a public utility, and that is clearly not Cube.

Pursuant to the Act, it is the policy of the State of North Carolina to provide adequate, reliable, and economical utility service to all citizens of the state, and to do so by promoting the inherent advantages of regulated public utilities. N.C.G.S. § 62-2(a). The legislature has determined that this policy is to be effectuated through the award of exclusive franchises to public utilities which would allow end-use customers to receive utility service from franchised monopoly providers. N.C.G.S. § 62-110. One of the primary mechanisms for implementation of this public policy is the Commission's oversight of the rates and service of the franchised public utility. N.C.G.S. § 62-30, <u>et seq.</u> The Act charges the Commission with the responsibility for implementing the General Assembly's intent in a manner that serves the public interest.

In construing the language of the Act, the Commission is guided by the principal that the intent of the legislature controls. In re Hardy, 294 N.C. 90, 95, 240 S.E.2d 367, 371 (1978). The intent is gleaned first from the words, but also from the nature and purpose of the statute and the consequences which would follow from a construction one way or another. In re Estate of Kirkman, 302 N.C. 164, 167, 273 S.E.2d 712, 715 (1981). The words, phrases, and individual expressions of a statute must be interpreted in context and as a part of the composite whole to uphold and give effect to the reason for and the purpose of the statute. Id.; Hardy, at 96, 240 S.E.2d at 371-72. Statutory provisions that are part of the same act must be read in harmony with the purposes of the Act and not interpreted to defeat or impair the object of the statute if it can be avoided without violence to the statutory language. Hardy, at 95-96, 240 S.E.2d at 371-72. The purpose of the law should control over a strict literal interpretation if that interpretation goes against or circumvents the law's purpose; thus, exceptions to an act dealing comprehensively with a subject matter or a problem that prompted the legislation must be narrowly construed. See Id.; Publishing Co. v. Interim Bd. of Edu., 29 N.C. 37, 47, 223 S.E.2d 580, 586 (1976).

In construing N.C.G.S. § 62-3(23)d, it follows that the General Assembly did not intend, as suggested by Cube, to create a huge exception that would indiscriminately exempt every landlord leasing to tenants from the regulated monopoly model of utility service it adopted in Chapter 62. As has been discussed above, such an interpretation as urged and supported by Cube and the Public Staff could lead to many persons avoiding regulation and essentially causing the purpose of the Act to fail. The Act states that rates, services, and operations of public utilities are affected with the public interest. N.C.G.S. § 62-2(a). In enacting the Act, the legislature intended that the Commission would protect the public from any overreach by monopolistic public utilities. Thus, the Act establishes that it is the Commission who sets retail rates, as well as other conditions of service, in the public interest. Contracts between private parties may not displace the Commission's authority over retail rates and terms of service. The utilities are not to have the opportunity to press their monopoly advantage in contravention of the Act through negotiated contracts with ratepayers as would be the case under the expansive interpretation of N.C.G.S. § 62-3(23)d urged by Cube. As the Commission stated in NC WARN:

> The General Assembly has been successful in determining the best policy for the state resulting in consistently low electric rates compared to the nation. This policy is one of providing regulated exclusive service area franchises to a utility to provide electric service. Until the General Assembly amends Chapter 62, it is not the Commission's role to alter the paradigm.

NC WARN Order, at 21.

The intent of the legislature in adopting N.C.G.S. § 62-3(23)d was to create a narrow exception and convenient arrangement for a landlord to place and maintain retail electric service provided by a public utility, electric membership corporation, or municipality in the landlord's name, pay the deposit, pay the electric bill, and include compensation for the electric service in the amount of rent paid by the tenant.[1] Looking first to the words of the exception, it is clear that

[1] The Commission's discussion herein focuses on electric service, but the Commission notes that the exception Cube advocates for landlords could well be applied to natural gas, water, and wastewater utility services as well.

the Act does not contemplate that one in the business of being a utility, furnishing service with its own facilities, is to be permitted to serve its tenants at rates and on terms that are not set and overseen by the Commission. As generally provided in N.C.G.S. § 62-3(23)a, a person or utility is only allowed to be unregulated when he provides service to himself. The self-supply exception, and the recently enacted electric generator leasing (EGL) statute, N.C.G.S. § 62-126.6, et seq., are the only exceptions applicable to a utility business. This is underscored by the N.C.G.S. § 62-3(23)d exception which on its face states that it does not apply to one who is "otherwise a public utility." This phrase is designed to convey to a utility that it is not to look to the § 62-3(23)d exception to avoid having its rates and services regulated by the Commission, and that it may only look to N.C.G.S. § 62-3(23)a or the EGL statute for situations under which it will not be considered a regulated public utility. Construing the landlord/tenant exception to find that any person renting property and charging for the cost of utility service in a flat rent charge without regard to whether such person is a public utility would be an expansive construction of a narrow exception and would constitute statutory interpretation in a vacuum. It would ignore the express proviso "any person not otherwise a public utility." Indeed, application of the phrase as proposed by Cube would result in an exception that would eviscerate the definition of "public utility" under N.C.G.S. § 62-3(23)a.1, and the exclusive franchise rights of incumbent utilities under N.C.G.S. § 62-110. These are consequences that are contrary to and would circumvent the intent and purpose of the legislature in adopting the Act.

Continuing to look further at the words of the statute, the Commission observes that N.C.G.S. § 62-3(23)d is written in such a way as to prevent competition with a franchised utility. It states, in essence, that a person (not a public utility) "who furnishes such service or commodity only to . . . his . . .tenants" shall not be a public utility for purposes of the Act (Emphasis added). As noted in the discussion above, "service" is a defined term in the Act. Specifically, it is service that is furnished by a public utility. N.C.G.S. § 62-3(27). Pursuant to the definition, service includes the commodity and the ancillary service or facility furnished or used in connection with the service. The use of the defined term "service" in N.C.G.S. § 62-3 (23)d supports the view that the exception applies to a landlord whose main business is not the provision of utility service, but who, along with or connected to the activity of leasing space or real estate, simply passes through or furnishes to his tenants the service provided to the landlord by an incumbent public utility (keeping the customer account with the utility in the landlord's own name). This is not Cube, whose primary business is the ownership and operation of hydro-electric generation facilities, and who proposes to enter into leases that have as a "central premise" the provision of utility service to large, high energy- consuming tenant-customers. Petition at 6-7. Cube's proposed activity is to provide its tenants with retail utility service, including the commodities of electricity and water and other necessary ancillary service, using the facilities it owns and operates. By contrast, an exempted landlord is one who is supplying or furnishing utility service supplied by a Commission-certificated public utility — not a landlord who produces and generates or who otherwise pumps or distributes the commodity to its tenants using facilities it owns and/or operates for such purpose, for example, Cube. This point is clear from reading the phrase and definition of "service" in pari materia with the other relevant provisions of the Act; the legislature did not intend to allow a landlord to compete with an incumbent public utility by furnishing utility service where that service is otherwise the right and obligation of the incumbent franchised utility to provide.

Prior Orders of the Commission

Cube relies mainly on the Commission's prior decisions in In re Catawba, In re Matter of Public Utility Status of American Homes 4 Rent – Public Staff Request for a Declaratory Ruling, and In re Robertson Brothers Utilities. In Catawba, the County owned an electric generating facility that was a qualifying facility (QF) under the Public Utility Regulatory Policies Act of 1978 (PURPA). Duke, as the incumbent public utility, had an obligation under PURPA to purchase the full electric output of the County's QF. As a result, the County was selling the electric output of the QF to Duke at avoided cost rates under a PPA. In its petition for a declaratory order, the County stated that it intended to enter into a landlord/tenant relationship with Glasshouse, Inc., in which Glasshouse would lease greenhouses from the County, and the lease would include a portion of the electricity supplied from the QF. Duke did not intervene in the docket or protest the County's proposal, and no other person intervened in the docket. Based on the facts presented by the County in its petition, and the recommendation of the Public Staff, the Commission, for reasons it did not delve into, apparently found the situation before it to be factually unique and summarily held that the County's

> [p]roposed provision of electricity to Glasshouse, as its tenant without separately metering or charging for it, falls within the landlord/tenant exception of G.S. 62-3(23)d. The Commission notes that the present decision is limited to the facts set forth in this Order and in Catawba County's petition and should not be regarded as a precedent for any other person engaging in activities other than those found in this case.

Catawba County Order, at 2.

As the Supreme Court stated in Simpson, the determination of whether a person is operating as a public utility depends on the facts in each case and does not depend on a formalistic definition to be universally applied. Simpson, 295 N.C. at 524, 246 S.E.2d at 756-57. The Catawba County Order is an excellent example of that principle, as the facts in that docket are significantly different from those presented herein by Cube. Of key significance is that the provision of steam, not electricity, was the main purpose of the arrangement at issue, and the fact that Duke chose not to intervene, object to or otherwise comment on the County's proposal to provide service in its assigned service area. Hence, Duke either acquiesced or agreed to the County's serving its single tenant. In the present case, the Commission has determined that Cube will be a public utility under its proposed lease arrangements. Therefore, pursuant to N.C.G.S. § 62-110.2(d), and subject to Commission approval, Duke could agree to allow Cube to provide electric service to Cube's tenants in the Badin Business Park, even though the park is within DEC's assigned service territory. However, unlike in Catawba County, Duke has not acquiesced or agreed to Cube's proposal to provide electricity to its tenants.

In addition, because Duke was required to purchase any of the Catawba County QF's output not supplied to the tenant, the result of the County's furnishing electricity to its tenant was inconsequential to Duke as far as increasing or decreasing its retail sales of electricity or as far as the impact on costs to be covered by ratepayers, who would have otherwise continued to be responsible for the costs of Duke's required purchases from the QF. The County's petition stated that the anticipated electricity sales to Glasshouse were a maximum of 52,000 kWh per acre per year. Duke could have objected on grounds that it was entitled to sell that 52,000 kWh per acre to Glasshouse as Duke's retail customer, but then Duke would have had to continue buying that 52,000 kWh per acre from the County's QF. A reasonable inference from the fact of Duke's decision not to object was that the net result was that while Duke would not sell that amount of electricity to the County, it also would not have to buy that amount of electricity from the County. That give-and-take net balance is entirely different from Cube's proposal. Cube does not have a PPA with Duke, and, therefore, Duke has no contractual obligation to buy any of Cube's electricity. More importantly, Cube's proposed electric sales to its future tenants in the Badin Business Park would displace electric sales that Duke would be entitled to make to the future commercial and manufacturing customers in the park because Badin Business Park is within Duke's assigned service territory.

A further distinction between the present docket and Catawba County concerns Duke's legal obligation, as a franchised public utility under the Act, to provide electric service to all retail customers in its service territory. Cube has no such retail service obligation. In Catawba County, Glasshouse faced no real risk of loss of electric service, as Duke's distribution lines were there at the County's Eco-Complex site serving the County's QF. Thus, if the County ended its electric service under the lease with Glasshouse, then Glasshouse could have immediately turned to Duke for electric service under Duke's mandatory obligation to provide retail service. On the other hand, Cube's tenants will not have that option. If Cube decided to end its electric service with a Badin Business Park tenant, Duke would have no distribution facilities on site to provide electricity to that customer — leaving that tenant without service. Creating the obligation to serve and avoiding the risk of service interruptions to customers are primary reasons why North Carolina has chosen the regulated public utility model. Nothing in the Act demonstrates an intent by the legislature to abandon that model, and place tenants at risk of losing electric service, through passage of the landlord exception of N.C.G.S. § 62-3(23)d.

With respect to the American Homes Order, the Commission concludes that the same case-by-case analysis applies in interpreting and applying N.C.G.S. § 62-3(23). In American Homes, the landlord, American Homes4 Rent (AH4R), proposed to purchase water and sewer service from the incumbent regulated utility and resell it, with an administrative fee, to its tenants. Thus, the overriding distinguishing factor in American Homes was that AH4R was neither producing the water or sewer treatment service, nor displacing a franchised utility from continuing to serve AH4R's tenants, the utility's assigned retail customers. In contrast, Cube proposes to use its generating facilities to supply electricity to its tenants, electric service that would otherwise be supplied by Duke under its monopoly franchise.

In Robertson Brothers, the two brothers who owned the water and sewer utility were also the owners and lessors of the 22 manufactured housing lots being served by the water and sewer utility. They applied for a cancellation of their utility franchise so that they could include a flat amount for water and sewer in each lot rental. They stated that this would allow them to provide water and sewer service at a lower cost by eliminating the need to maintain meters, read the meters, and prepare and process monthly utility bills. Thus, unlike the present case, in Robertson Brothers the applicant for relief, the utility, already held the exclusive franchise, it applied to cancel its franchise, and there was no opposition to its application. The Commission acknowledges that in Robertson Brothers, and perhaps in other prior orders of the Commission, the analysis did not include a discussion and application of the "not otherwise a public utility" proviso in

N.C.G.S. § 62-3(23)d. That Robertson Brothers or any other prior decision of the Commission applied the § 62-3(23)d landlord exception without first discussing the "not otherwise a public utility" requirement should not be read as a Commission holding or determination that the phrase is superfluous with no meaning, purpose or applicability to the landlord/tenant exception. Further, the Commission acknowledges that in Robertson Brothers the provisions of N.C.G.S. § 62-112, which authorize the Commission in its discretion to accept the surrender of a public utility's franchise, would have been a more appropriate basis for the Commission's decision. Order Canceling Franchise and Requiring Customer Notice, Docket No. W-837, Sub 1 (Jan. 23, 2002).

In conclusion, based on the facts in the present docket the Commission is not persuaded that the above orders, or the other Commission decisions cited by the parties, are controlling precedent.

CONCLUSION

Based on the foregoing and the record, the Commission finds and concludes that Cube's proposed landlord/tenant arrangement at Badin Business Park would cause Cube to be a public utility under the Act. As a result, the declaratory relief requested by Cube should be denied and its Petition dismissed, with prejudice.

The Commission appreciates Cube's initiative in attempting to attract prime customers and bring new economic life to the Badin Business Park, but one of the Commission's obligations under the Act is to promote the inherent advantages of regulated public utilities. The arrangement proposed by Cube could well result in significant disadvantages for Duke and its ratepayers, precisely for the reasons discussed in Simpson and NC WARN. Nevertheless, the Commission would encourage Cube and Duke to come together in the interest of promoting the economic development of the State and the local area affected by this proceeding. It would seem that demand for industrial load will not come to the area unless there are assurances of reliable and reasonably economical electric power supply. It would also seem in the absence of evidence to the contrary that it could be likely that Cube may be the entity uniquely able to furnish Duke with wholesale electricity and other related service on reasonably prudent terms, as Duke has not previously provided service in the implicated portion of its service territory and would incur costs to enable service in the area. While Duke and Cube attempt to resolve their issues and perhaps come to a standoff, it is the local area, the State of North Carolina, and possibly the Duke ratepayers who are caught in the middle — each perhaps adversely impacted.

Finally, although for the reasons thoroughly discussed above, the Commission's obligations under the Act have led it to deny Cube's Petition for declaratory relief, Cube may consider obtaining an exception from the General Assembly allowing it to serve the Badin Business Park for purposes of economic development of the area.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 4th day of September, 2019.

NORTH CAROLINA UTILITIES COMMISSION
A. Shonta Dunston, Deputy Clerk

Commissioner Daniel G. Clodfelter concurs.
Chair Charlotte A. Mitchell joins Commissioner Clodfelter's concurring opinion.

DOCKET NO. M-100, SUB 152

Commissioner Daniel G. Clodfelter, concurring:

I join in the reasoning and the result reached in the Commission's opinion. If a person falls within the definition of "public utility" contained in N.C.G.S. § 62-3(23)a, then that person may not claim exemption from regulation as a public utility pursuant to N.C.G.S. § 62-3(23)d merely because some or even all of its customers are also its tenants. This to me is the plain English meaning of the language of the exemption contained in N.C.G.S. § 62-3(23)d stipulating that a landlord claiming the exemption cannot "otherwise [be] a public utility." I believe that the Commission's opinion correctly applies the criteria articulated in State ex rel. Utils. Comm'n v. Simpson, 295 N.C. 519, 246 S.E.2d 753 (1978) (Simpson), in determining that Cube Yadkin's proposed activities would make it a "public utility" under N.C.G.S. § 62-3(23)a.1, and I do not propose to add anything to the Commission's discussion and analysis of the Simpson factors. In this concurrence I wish to offer some additional observations about why I conclude that the exemption in N.C.G.S. § 62-3(23)d does not apply to Cube Yadkin's proposal for the Badin Business Park.[1] These observations I believe provide further support for the Commission's decision based on textual analysis.

[1] The petitioner in this case is Cube Yadkin Generation, LLC, which I refer to as "Cube Yadkin." It owns and operates four hydroelectric generating plants acquired from a subsidiary of Alcoa, Inc. Cube Yadkin's sister company, Cube Yadkin Transmission, LLC, owns and operates certain transmission lines and a distribution substation which it also acquired from the Alcoa subsidiary. The common parent of these two companies is Cube Hydro North Carolina, LLC. In its papers Cube Yadkin indicates that either it or an as yet unidentified affiliate will be the landlord of the Badin Business Park. Cube Yadkin does not take the position that it is material which entity will actually be the landlord, nor does it argue that the separate identities of itself and its affiliate are of any significance in deciding the issue for which declaratory ruling is being sought. For this reason I treat Cube Yadkin and its affiliate as if they were a single entity and have not considered whether their status as separate legal entities makes any difference to the outcome here.

The Commission follows the well-accepted canon of statutory construction that the provisions of N.C.G.S. § 62-3(23)a and N.C.G.S. § 62-3(23)d must be read in pari materia. Cube Yadkin, the Public Staff, and all the objecting parties[1] likewise agree on this point. There are two further principles of construction that I believe are pertinent to the case at hand. Section 62-3(23)d cautions that the exclusion provided therein may not be invoked by someone who is "otherwise a public utility" and further emphasizes the point by limiting the exclusion to persons who furnish utility service "solely" to themselves, their employees or their tenants.[2] While these two elements are not identical, taken together I believe they counsel restraint in applying the exemption, especially to cases that do not neatly fit the prototype for the statutory provision. See, Fitzgerald v. Chrysler Corp., 116 F.3d 225, 227 (7^{th} Cir. 1997)(broadly worded statutes should be interpreted in reference to the prototypical case to which the statute is addressed and degree to which proposed interpretation bears a "family resemblance" to the prototype). Accordingly, my interpretation of the language of N.C.G.S. § 62-3(23)d is mindful of the admonition that statutes should not be applied or interpreted in a way that would undermine or circumvent the basic purposes of the legislation. E.g., Campbell v. First Baptist Church, 298 N.C. 476; 484 259 S.E.2d 558, 564 (1979)(court should always construe provisions in a way that prevents the statute from being circumvented) and the reluctance of our courts to give a broad interpretation to exemptions from a statute's coverage provisions. E.g., Good Hope Hospital, Inc. v. North Carolina Dept. of Health & Human Services, 175 N.C. App. 309, 312; 623 S.E.2d 315, 318 (2006)(statutory exceptions to a general scheme of regulation should be construed narrowly).

My examination of the exemption in N.C.G.S. § 62-3(23)d begins with the definition of "public utility" contained in N.C.G.S. § 62-3(23)a. Section 62-3(23)a.1 lists a number of activities that are engaged in by someone who may be an "public utility." Those activities are "producing, generating, transmitting, delivering, or furnishing" electricity. Similarly, N.C.G.S. § 62-3(23)a.2 identifies "diverting, developing, pumping, impounding, distributing, or furnishing" water as activities of someone who may be a "public utility." While there are other elements to these definitions, for the present I focus on the types of activities that are enumerated in the definition. By contrast to the language used in N.C.G.S. § 62-3(23)a, the exemption in N.C.G.S. § 62-3(23)d speaks only of a landlord's "furnishing" a utility service such as electricity; it makes no mention of the more specific activities of "producing, generating, transmitting, or delivering" electricity.

"Furnishing" is a word of some generality, commonly understood to be equivalent in meaning to "providing" or "making available for use" or "giving access to." E.g., Queensboro Steel Corp. v. East Coast Machine & Iron Works, Inc., 62 N.C. App. 182, 185-86; 346 S.E.2d 248, 250 (1986)(defining "furnish" to mean supply, provide, or equip for a particular purpose, and

[1] For shorthand convenience I use "objecting parties" to refer collectively to the intervenors and the amici.

[2] Some of the objecting parties argue that Cube Yadkin is not eligible for the exemption in N.C.G.S. § 62-3(23)d because it will not be furnishing electricity "solely" to tenants, pointing out that Cube Yadkin will continue to make wholesale sales of electricity to the extent tenants at the Badin Business Park do not take all of Cube's available capacity or energy. I do not consider this objection to be fatal. Wholesale transactions are non-jurisdictional, as the Commission itself has repeatedly held, and that was also the case at the time Chapter 62 was enacted. E.g., In Re Francis X. De Luca, Docket No. SP 100, Sub 32 (August 22, 2017), aff'd, 2018 N.C. App. LEXIS 913, 817 S.E.2d 919 (2018)(unpublished opinion); In re Duke Energy Fossil-Hydro, LLC, Docket No. E-7, Sub 694 (September 26, 2002). The term "solely" used in G.S. 62-3(23)d must be read with this gloss in mind.

further holding that for purposes of mechanics' lien statutes, the term "furnish" did not require a lien claimant to personally make delivery of materials to worksite, merely that it arrange for such delivery to be made, thus distinguishing between "furnishing" and "delivering".); Adams v. Feiges, 206 Wis. 183, 239 N.W. 446 (Wisc. 1931)(agreement to "furnish" architectural services meant merely that party would "provide" or "supply" such services, not that party would actually perform such services itself).[1]

What should be made of the fact that N.C.G.S. § 62-3(23)d uses the term "furnish" but omits to include all the other listed activities called out in N.C.G.S. § 62-3(23)a.1? The statute does not directly answer this question, and, as might be expected, there is little case authority on the point. There are a number of decided cases from a variety of jurisdictions that consider simple definitions of the term "furnish," but my research has turned up only one case that addresses how the term "furnish" should be understood when it is listed along with other more specific activities. In Laubach v. Arrow Service Bureau, 987 F.Supp. 625 (N.D. Ill. 1997) (Laubach), the court was called upon to determine whether the defendant had violated a provision of the Fair Debt Collection Practices Act requiring the defendant to have engaged in "designing, compiling and furnishing" a certain form. The court recognized that designing, compiling and furnishing were distinct activities and that the statute's use of the conjunctive "and" required that a defendant have engaged in all three of the identified activities. 987 F.Supp. at 14-15. In the Court's analysis, "furnishing" was to be read to include not only the act of delivering or disseminating but also the other activities of creating, designing and compiling. Thus, the defendant, who had only disseminated the form but had been uninvolved in designing or creating it could not be found to have violated the statute.

The Laubach court also relied upon the principle of ejusdem generis and on materials drawn from the legislative history to conclude that the term "furnish" should be read to encompass something more than simply providing or disseminating material. In the present case for at least two reasons I do not believe the concept of ejusdem generis can be used to extend the meaning of "furnish" to include the other specific activities listed in N.C.G.S. § 62-3(23)a.1. First, the matter of interpretation here does not involve how the word "furnish" should be understood when it appears once in a series of terms in a statute; instead, the question here is how to interpret the term when it is used in one place in the statute (N.C.G.S. § 62-3(23)a) to designate one among a list of multiple activities but is used later in the very same statute (N.C.G.S. § 62-3(23)d) by itself and without the other items included in the earlier series. Second, and more importantly, in contrast to the statute before the court in Laubach N.C.G.S. § 62-3(23)a.1 uses the disjunctive "or," and not the conjunctive "and," which I believe indicates a legislative intent that the listed activities be considered and understood for their distinctness or difference and not for their likeness or sameness. Generally see, Bryan v. Wilson, 259 N.C. 107, 109; 130 S.E.2d 68, 71 (1963)(ejusdem generis not applicable where listing is one of things that may be of different types); State ex rel. Utilities Commission v. Environmental Defense Fund, 214 N.C. App. 364, 368-69; 716 S.E.2d 370, 372 (2011),(ejusdem generis not applicable where words in a sequence refer to specific things

[1] I can find no definition for the term "furnish" in Black's Law Dictionary (Tenth Edition). The word is defined in the American Heritage College Dictionary (Third Edition) to mean "to equip with what is needed," "to supply," or "to give."

that do not share a common characteristic).[1] In other words, N.C.G.S. § 62-3(23)a.1 should be read to say that any one or more of the different types of activities listed may cause a person to be treated as a public utility, provided all other elements of the definition of public utility are satisfied. I cannot conclude that the omission of the words "producing, generating, transmitting or delivering" from N.C.G.S. § 62-3(23)d is simply accidental, nor can I conclude that the word "furnish" is to be read as merely an abbreviation or shorthand reference to more specific series "producing, generating, transmitting, delivering, or furnishing." See, Midrex Technologies, Inc. v. North Carolina Department of Revenue, 369 N.C. 250, 258; 794 S.E.2d 785, 792 (2016)(courts should interpret statutes based on the language actually used, neither deleting words used nor inserting words not used); In re Guyer, 60 N.C. 66, 67 (1863)(same words in the same statute should be given same meaning, not different meanings).

Under N.C.G.S. § 62-3(23)d a landlord's mere "furnishing" utility service to its tenants, in the general and essentially passive sense of "making available" that service, does not make the landlord a public utility, provided, as the exclusion requires, that electricity is not then resold to or used by others. But a landlord who also generates, transmits, and distributes the electricity it provides to its tenants is doing more than simply "furnishing" that service. Based on the available technology and the industry model prevailing at the time of enactment of Chapter 62, it is highly unlikely that the General Assembly contemplated or thought to provide for the case where a landlord also generates, transmits, or delivers (i.e., distributes) the electricity that it "makes available to" its tenants. This observation is an artifact of the times when Chapter 62 was enacted, but it is nonetheless pertinent to the scope to be given to the statute's definitions and to the exclusion from regulation provided for landlords.

I note two additional provisions that support a limited reading of the term "furnishes" as it is used in N.C.G.S. § 62-3(23)d. That same section also provides that a landlord who individually meters and bills tenants for electricity "furnished," or one who supplies electricity to tenants by means of coin-operated meters, shall be a public utility, without further ado and regardless of what other activities the landlord may or may not have undertaken. I read this to indicate that it is the simple act of "furnishing" that is the subject matter addressed by N.C.G.S. § 62-3(23)d and that the section is not speaking to or about any of the other types of activities of a public utility that are identified in N.C.G.S. § 62-3(23)a.1. Second, I find interesting the "self-generation" exception to the definition of "public utility" that is embodied in N.C.G.S. § 62-3(23)a.1. A person who generates electricity principally for its own use is called out for specific exclusion from the definition of "public utility" by that provision. Section 62-3(23)d also excludes from the definition of "public utility," in addition to landlords, a person who "furnishes" electricity for his or its own use. If the General Assembly had intended the term "furnish" to include such other public utility activities as "generation" or "transmission" or "delivery," then there would have been no need for the special "self-generation" exception provided in N.C.G.S. § 62-3(23)a.1, since the same result would have obtained under the "self-furnish" exception in N.C.G.S. § 62-3(23)d. I do not believe the language of N.C.G.S. § 62-3(23)d should be read in a way that renders the "self-generation" exclusion in N.C.G.S. § 62-3(23)a.1 superfluous, and thus I must conclude that the term

[1] Ejusdem generis is also used as a principle of limitation, to confine or restrict the meaning of a term. I am unfamiliar with instances where it has been used to broaden the meaning of a term, which would be the case if it were applied here to expand the meaning of "furnish" to include the activities of "generating," "transmitting," or "delivering."

"furnishes" is limited in scope to the simple act of "making available for use" and does not include the other activities of producing, generating, transmitting, or distributing electricity.

I acknowledge that there are objections that can be lodged against the foregoing interpretation. For example, it is not uncommon, nor was it uncommon when Chapter 62 was enacted, for landlords to furnish or provide space heating to tenants by means of steam produced from a boiler owned by the landlord, located in a service area in the rented premises, and distributed through piping to radiators in the premises. Similarly, there are and have been cases where a landlord supplies water to tenants drawn from a well constructed and owned by the landlord, located on the landlord's premises, and distributed to the tenants' premises through piping owned by the landlord. The Commission has not historically considered these types of activities by a landlord as within the ambit of regulation, even though under the statutory interpretation advanced above such situations would not be eligible for the exemption from regulation established for landlords in N.C.G.S. § 62-3(23)d. However, my review of prior Commission orders relating to situations such as the two just described indicates that the Commission has most commonly, though not uniformly or invariably, relied not on the "landlord" status of the provider, i.e., the exclusion provided in N.C.G.S. § 62-3(23)d, but instead has made a determination that the cases do not involve a sale "to or for the public for compensation," sometimes buttressing that determination with the observation that the nature of the service being provided is not typically considered a typical "public utility" commodity or service. E.g., In re Carolina Power & Light Company and Duke Power Company, Docket Nos. E-2, Sub 663 and E-7, Sub 452 (Feb. 13, 1995)(utility's leasing of excess dark fiber capacity to single, affiliated entity not a sale to or for the public); In re Request for Declaratory Ruling by Pharr Yarns, LLC, Docket No. W-1260, Sub 0 (sale of sewage treatment capacity by textile plant to local municipality not a sale to or for the public, also citing to a number of other Commission decisions involving landfill gas); Request for Declaratory Ruling by Natural Power, Inc. and Raleigh Landfill Gas Corp., Docket No. SP-100, Sub 1 (Dec. 22, 1988)(use of landfill gas to produce process steam for bargained for sale to single manufacturer not within the definition of public utility); In re Request for Declaratory Ruling by Panda-Rosemary Company, Docket No. SP-100, Sub 15 (Oct. 21, 1997)(production of distilled water and sale to two commercial users not activities of a public utility). Very often, these precedents involve services, such as landfill gas for steam or electricity production, or steam for manufacturing process use or space heating, that the Commission has concluded are not commonly provided as utility services and therefore do not require the same degree of regulation as do other services. E.g., In re Request for Declaratory Ruling by Corn Products International, Inc., Docket No. SP-100, Sub 16 (May 22, 1998)(observing that "steam is not as common a utility function as other services and traditionally has not been regulated to the same degree").

On the facts of this case I also find it significant that Cube Yadkin approaches its proposed project not from an historical vantage point as a developer, owner, and manager of industrial parks, commercial office parks, or residential apartment buildings but as a generator and supplier of electricity to the marketplace. As far as the record presented to the Commission discloses, Cube Yadkin has no prior history as a landlord or owner of properties such as the proposed Badin Business Park. What the record does show is that Cube Yadkin made several other attempts to identify a business model that is suitable and profitable for a generator and producer of electricity before it hit upon the idea of acquiring and leasing the facilities at the proposed Badin Business

Park to customers who would also take its available capacity for generating electricity. (Petition for Declaratory Ruling, p. 5.) While I do not find this fact, standing alone, to be determinative of whether Cube Yadkin qualifies as a "landlord" under N.C.G.S. § 62-3(23)d, I do find it relevant when thinking about how far Cube Yadkin's current proposal departs from the prototypical situation addressed by that statutory exemption. Fitzgerald v. Chrysler Corp., supra.

Finally, I offer my own thoughts about the applicability of two of the Commission's prior determinations that are relied upon heavily by Cube Yadkin and by the Public Staff. Principal reliance is placed on the Commission's decision in In re Request for Declaratory Ruling by Catawba County, Docket No. SP-100, Sub 22, to the present petition. Although one portion of that ruling has been taken by Cube Yadkin and by the Public Staff as authority supporting application of the exclusion in N.C.G.S. § 62-3(23)d to the proposed business arrangement now before the Commission, from a review of the entire circumstances of the Catawba County matter I do not find it to be controlling precedent in this case. The objecting parties note that the Commission's Catawba County order cautions that it should not be treated as precedential, and for the following reasons I am unwilling to find it to be a precedent for this case:

a. Catawba County proposed to construct an integrated complex of facilities at the site of its former Blackburn landfill. These included a facility to produce manufacturing process steam and steam for heating and for drying kilns using wood waste and bio-waste as fuel and a regional wastewater sludge processing facility. They also included a small electric generation facility fueled by landfill gas which was to operate as a qualifying facility under PURPA and as certificated by the Commission in Docket No. SP-112, Sub 0 ((December 3, 1996). The County's filings represented that this was to be an integrated development in which all parts were complementary and interdependent, and the Commission's order treats them as such.

b. The County's filing with the Clerk transmitting its petition to the Commission described the proposed project as a request for ruling that its sale of steam from the complex would not cause it to be treated as a public utility. The focus of the petition itself is manifestly on the steam production component of the larger project. Only a single paragraph in the petition addresses the supply of electricity to the two greenhouses the County proposed to construct at the complex. The petition specifically represented that the steam produced at the complex would not be used to generate electricity.

c. The output of the electric generating facility fueled by landfill gas was to be sold to Duke Energy Carolinas, LLC (DEC), under a power purchase agreement at avoided cost rates. The certificate of public convenience and necessity obtained by the County for this facility discloses that the maximum capacity of the facility was to be no more than 1520kW, with the actual generating output dependent on the availability of landfill gas. Id. According to the County's petition for declaratory ruling, the maximum annual consumption of electricity used by the two greenhouses, assuming full buildout, would be no greater than 520 MWh per year. Although the lessee of the greenhouse space was a commercial enterprise, some of the greenhouse space served by the generating plant was to be made available to or reserved for two public universities for their research purposes. Although the record does not disclose either the expected or actual operating characteristics of the generating facility, making an assumption that the facility operated every day on a twenty-four hour basis at a 69.6% capacity factor,[1] then the maximum anticipated consumption of electricity at the two greenhouses located at the landfill site, assuming full buildout of the facilities, would have been no more than 5.6% of the total energy produced by the County's qualifying facility, the remainder of which would have been sold to DEC under the bulk power purchase agreement. The Commission has not historically considered such bulk power sales by qualifying facilities under PURPA to be within the scope of its regulatory authority, aside from setting avoided cost rates, and in the context of all the activities proposed for the Catawba County complex, the generation of electricity for the two greenhouses takes on a de minimis prospect. In re Request for Declaratory Ruling by Cogentrix of North Carolina, Inc., Order on Request for Declaratory Ruling, Docket No. SP-100, Sub 0 (February 29, 1984).

d. It does not appear from the record in the Catawba County proceeding that any person voiced an objection to the County's proposed complex of facilities or to the exemption of those facilities from regulation. The Commission's decision applying the exclusion in N.C.G.S. § 62-3(23)d to the supply of electricity to the two greenhouses contained no analysis of the statutory language or discussion of any policy considerations; it merely stated a bare conclusion without explanation.

Considering the integrated nature of the Catawba County venture, the predominance of the steam facility in the County's request for declaratory ruling, the fact that the landfill gas generating facility was already functioning as a qualified facility selling electricity at wholesale to an existing regulated public utility, the relatively minimal amount of electricity proposed to be supplied to a single customer, the fact that some of the users of that electricity were to be public universities for research purposes, the fact that the Commission's order contained no analysis or discussion of N.C.G.S. § 62-3(23)a or d as relates to the supply of electricity to the two greenhouses, and the explicit declaration by the Commission that its ruling was not precedential, the declaratory ruling in Catawba County cannot support the weight placed on it by Cube Yadkin and the Public Staff.

The second Commission decision cited by Cube Yadkin is In re Application by Robertson Brothers Utilities for Authority to Discontinue Water and Sewer Utility Service, Docket No. W-837, Sub 1 (January 23, 2002). I concur fully in the Commission's analysis of this ruling and offer only two additional observations about the petition. At the time Robertson Brothers Utilities petitioned to discontinue its franchise as a water and sewer utility, it was serving only 22 residential customers in a single mobile home park, a total number only slightly in excess of the 15-customer threshold for exemption from regulation provided in N.C.G.S. § 62-3(23)a.2. The scale of the operation considered in Robertson Brothers was considerably different from the scope of the operation contemplated by Cube Yadkin in the present case. Second, I note that like in the Catawba County ruling, the Commission's order in this matter did not include any detailed analysis of the actual statutory language of N.C.G.S. § 62-3(23)d, and, in part for that reason, I would find that the Robertson Brothers Utilities matter was not correctly decided and should not be given precedential effect.

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[1] This figure represents the average annual capacity factor for the years 2013 through 2018 for utility scale generators fueled by landfill gas as reported in the U.S. Energy Information Administration's March, 2019, Electric Power Monthly Report.

In summary and in addition to the reasoning set forth in the Commission's opinion, I conclude that the landlord exemption contained in N.C.G.S. § 62-3(23)d does not apply on the facts of this particular case because Cube Yadkin will be doing considerably more than merely "furnishing" utility services to its tenants. Section 62-3(23)d must be read in a more limited way than Cube Yadkin and the Public Staff advocate if it is truly to be construed in pari materia with N.C.G.S. § 62-3(23)a. It may well be that in this new era of distributed generation public policy should permit, for example, developers, owners, and managers of large scale office parks or industrial developments or apartment complexes to generate and distribute electricity to their tenants, but I do not believe this is the policy embodied in the current text of N.C.G.S. § 62-3(23)d nor was it likely within the contemplation of the General Assembly at the time that statute was enacted. Such a policy change is within the province of the General Assembly and not the Commission.

/s/ Daniel G. Clodfelter
Commissioner Daniel G. Clodfelter

DOCKET NO. M-100, SUB 153

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Rulemaking Proceeding to Revise Procedural	)	ORDER ADOPTING
Deadlines in Water and Sewer General Rate	)	REVISIONS TO RULE R1-24
Cases	)	

BY THE COMMISSION: On March 27, 2019, the Commission issued an Order Initiating Rulemaking Proceeding and Requesting Comments in the above-captioned docket. In its Order, the Commission noted that in an order entered March 26, 2019, in Docket No. W-100, Sub 58, the Commission modified the dates set forth in Commission Rule R1-24(g)(2) for the pre-filing of written expert witness testimony by the parties in general rate cases involving Class A and B water and sewer utilities. In so doing, the Commission adopted dates for the filing of Public Staff and other intervenor direct testimony and applicant rebuttal testimony in Class A and B water and sewer utility general rate cases that are different from those currently provided for in the Rule for Class A and B electric, telephone, and natural gas utilities.

In the March 27, 2019 Order, the Commission determined that it would be to the benefit of parties and the Commission if the procedural deadlines for the pre-filing of written expert witness testimony were consistent among all of the named industries. Therefore, the Commission initiated this rulemaking proceeding to consider further amending Commission Rule R1-24(g)(2) to modify the procedural deadlines for the pre-filing of written expert witness testimony and applicant rebuttal testimony in Class A and B electric, telephone, and natural gas general rate cases to be consistent with those recently adopted in Docket No. W-100, Sub 58.

The following companies filed timely motions to intervene and initial comments: Dominion Energy North Carolina; Public Service Company of North Carolina, Inc.; Duke Energy

Progress, LLC; Duke Energy Carolinas, LLC; and Piedmont Natural Gas Company, Inc. None of these companies oppose the proposed changes to the Rule, and no concerns were expressed. No other parties filed initial comments.

On May 8, 2019, the Public Staff filed Reply Comments stating that it does not oppose the proposed changes to the Rule. However, the Public Staff notes that under some circumstances, when agreed upon by the parties, it may be appropriate for the Commission to adopt a procedural schedule that may be different from the schedule in the Rule. This has been the practice in the past, and the Public Staff believes that it would be desirable to continue this practice in the future.

The Commission, therefore, finds good cause to adopt the revisions to Rule R1-24(g)(2) attached hereto as Appendix A (redlined) and Appendix B (clean). As noted by the Public Staff, the testimony deadlines set forth in the Rule are the default to be applied, but may vary, when requested or necessary, in specific cases; the actual deadlines for the filing of testimony, particularly if different from that provided for in the Rule, shall be set forth in the scheduling order in each case.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 22nd day of May, 2019.

NORTH CAROLINA UTILITIES COMMISSION
A. Shonta Dunston, Deputy Clerk

APPENDIX A
Page 1 of 1

Rule R1-24. Evidence.

(g) Exhibits by Expert Witnesses.

(2) Time of Filing. — Except as provided below, the testimony for the applicant of such expert witnesses shall be filed with the Commission at least 60 days prior to the date set for the hearing in general rate cases, and at least 30 days prior to the date set for the hearing in all other cases. Testimony of such expert witness in rebuttal shall be prepared in the same manner and form, and shall be filed with the Commission at least 10 days prior to the date fixed for the hearing. The Commission Staff, Public Staff, Attorney General and all other Intervenors or Protestants shall file all testimony, exhibits and other information which is to be relied upon at the hearing 20 days in advance of the scheduled hearing. When filed, all such exhibits shall be made available immediately to adverse parties of record, and to others having an interest in the proceeding.

Class A & B electric, telephone, natural gas, water, and sewer utilities shall file with and at the time of any general rate case application all testimony, exhibits and other information upon which any such utility will rely at the hearing. Class C water and sewer utilities shall file 45 days prior to the hearing on the general rate case application all testimony upon which such utility will rely. In general rate cases of Class A & B electric, telephone, natural gas, water and sewer utilities, the Commission Staff, Public Staff, Attorney General and all other Intervenors or Protestants shall file all testimony, exhibits and other information which is to be relied upon at the hearing 30 days in advance of the scheduled hearing, and any testimony for the utility in rebuttal shall be filed 15 days prior to the hearing.

APPENDIX B
Page 1 of 1

Rule R1-24. Evidence.

(g) Exhibits by Expert Witnesses.

(2) Time of Filing. — Except as provided below, the testimony for the applicant of such expert witnesses shall be filed with the Commission at least 60 days prior to the date set for the hearing in general rate cases, and at least 30 days prior to the date set for the hearing in all other cases. Testimony of such expert witness in rebuttal shall be prepared in the same manner and form, and shall be filed with the Commission at least 10 days prior to the date fixed for the hearing. The Commission Staff, Public Staff, Attorney General and all other Intervenors or Protestants shall file all testimony, exhibits and other information which is to be relied upon at the hearing 20 days in advance of the scheduled hearing. When filed, all such exhibits shall be made available immediately to adverse parties of record, and to others having an interest in the proceeding.

Class A & B electric, telephone, natural gas, water, and sewer utilities shall file with and at the time of any general rate case application all testimony, exhibits and other information upon which any such utility will rely at the hearing. Class C water and sewer utilities shall file 45 days prior to the hearing on the general rate case application all testimony upon which such utility will rely. In general rate cases of Class A & B electric, telephone, natural gas, water and sewer utilities, the Commission Staff, Public Staff, Attorney General and all other Intervenors or Protestants shall file all testimony, exhibits and other information which is to be relied upon at the hearing 30 days in advance of the scheduled hearing, and any testimony for the utility in rebuttal shall be filed 15 days prior to the hearing.

DOCKET NO. M-100, SUB 154

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Rulemaking Proceeding to Consider Hire North Carolina Rule	))	ORDER ADOPTING RULE

BY THE COMMISSION: On April 23, 2019, the Commission issued an Order Initiating Rulemaking Proceeding and Requesting Comments in the above-captioned docket seeking comments on the proposed Hire North Carolina rule. The proposed rule, which would be adopted as Chapter 25 of the Commission's Rules and Regulations, would serve as a tool to encourage and measure public utility utilization of North Carolina resident contractors, subcontractors, vendors and businesses, including women- and minority-owned businesses. This rule would foster utility engagement with potential North Carolina suppliers and contractors, providing ways to inform North Carolina companies of business opportunities. This rule would apply to electric, telephone, and natural gas distribution companies subject to rate regulation of the Commission and to all water and wastewater companies with annual operating revenues in excess of $250,000. The Commission further stated, however, this rule should not be interpreted to supersede any state statute, and nothing in this rule should be construed to prevent a utility from choosing the lowest and best bidder for any project or interfering with the mandate to serve the ratepayers or adequately respond to emergencies or support outages, nor to prohibit any utility from performing services covered by this rule with its own regularly-employed workforce.

Initial comments were filed on June 7, 2019, by Duke Energy Carolinas, LLC (DEC), Duke Energy Progress, LLC (DEP), and Piedmont Natural Gas Company, Inc. (Piedmont; collectively, Duke); Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina (DENC) and Public Service Company of North Carolina, Inc. (PSNC; collectively, Dominion); Toccoa Natural Gas (Toccoa); Aqua North Carolina, Inc. (Aqua N C); Carolina Water Service, Inc. of North Carolina (CWSNC); and the Public Staff. Reply comments were filed jointly by the above utilities and the Public Staff on June 14, 2019.

One consumer statement of position letter was filed on May 13, 2019, by Gerry McCants, Co-Chair of the Greensboro Business League (GBL), a nonprofit advocacy organization focusing on public spending and eliminating racial economic disparities facing African American businesses and the voice of African American contractors and business people throughout the Triad region, in support of the proposed rule. The GBL states that if the Hire North Carolina rule is adopted, this would serve as a major economic investment and benefit for minority and women-owned contractors in North Carolina.

SUMMARY OF INITIAL COMMENTS

Duke

In its initial comments, Duke states that it currently provides significant support for economic development in North Carolina: in 2018 Duke Energy contributed $2.4 billion and over 4,360 jobs to economic development in North Carolina. Thus, while it fully support the goal and spirit of the proposed Hire North Carolina Rule and the intent of encouraging and measuring public utility utilization of North Carolina resident contractors, subcontractors, vendors and businesses, including women- and minority-owned businesses, Duke recommends in its comments changes to certain provisions of the proposed rule.

For example, regarding the rule's applicability, Duke recommends that the proposed rule be amended to clarify that it only applies to projects located in the State of North Carolina. Duke further recommends that the threshold for included projects be increased from $200,000 to $700,000, the current floor for the prime contractor subcontracting plan established by the federal government and currently incorporated in Duke's Legal Terms and Conditions templates for both diverse and local subcontractors. Duke also recommends that the rule apply only to contracts entered into after July 1, 2020, to avoid problematic retroactive application to existing contracts and to allow utilities time to implement the proposed rule. Duke further recommends that "goods, products, and materials" be removed from the scope of the proposed Rules R25-1(a) and R25-5; and that "goods" be removed from the definitions of "Local Business Enterprise," "Prime Contractor" and "Subcontractor" in Rule R25-1(c). The term "goods, products, and materials" produced or supplied in North Carolina can, as an example, include items as small as nuts, bolts and washers, which could conceivably require the Hire North Carolina List to include every independent hardware store in the State, making the list inefficient to maintain without adding significant value. Duke also recommends that Rule R25-1(b) be revised to exclude contracts for planned or unplanned outage work, to make clear that "nothing in this rule should be construed ... [as] interfering with the mandate to serve the ratepayers or adequately respond to emergencies or support outages...." Noting that a subcontractor rarely assumes a portion of the prime contractor's obligations, Duke recommends deleting the second sentence of the definition of "subcontractor" in proposed Rule R25-1(c)(5), which states, "A subcontractor shall be treated as a prime contractor hereunder to the extent the subcontractor assumes any portion of the prime contractor's obligation under any contracts with the utility." Regarding the required periodic newspaper publication, Duke recommends that the frequency be modified to be annual, rather than quarterly due to the cost and burden. Arguing that newspaper publication in the legal/classified ads is not an effective means of communicating with the target supplier audience, Duke recommends that publication of notice be provided through other media, such as through the utilities' websites or other means, and that publication not be required in newspapers. Duke also recommends that the Commission reconsider the unbundling requirement of proposed Rule R25-4, as such unbundling is typically not cost-effective. Regarding the notification requirement of proposed Rule R25-5, Duke recommends that this notification occur as bid events come to fruition. In general, the Duke would plan to notify a reasonable number of Hire North Carolina List qualified bidders, based on geographical proximity, as bids come to fruition, electronically and via its bidding tool. Rather than the feedback mechanism proposed in Rule R25-6, which it argues would be "extremely inefficient and unproductive," Duke recommends that the Commission consider periodic audits of bid events, which would allow the Commission to review and gain confidence in the utilities' contract evaluation and awards processes. Regarding the annual compliance report proposed in Rule R25-7, which it characterizes as burdensome and inefficient, Duke recommend that the Commission adopt a more streamlined reporting requirement or an annual random audit process overseen by the Public Staff to provide the Commission with information about the effectiveness and compliance with the Hire North Carolina Rule.

Dominion

In its initial comments, Dominion states that it is supportive of the proposed rule's purpose and overarching policy objectives, and believe that it is good business to expand their competitive and qualified supplier base and to invest in the communities that Dominion serves: "[Dominion] is fully committed to expanding supplier diversity and sets goals each year to continuously increase the overall spend with diverse suppliers across the enterprise." Dominion states that it is already undertaking robust efforts to promote small and diverse businesses in the communities in which it serves and are supportive of the policy objectives of the proposed Hire North Carolina Rules. For example, at the corporate parent level, Dominion

> formed an Executive Diversity Council in 2010 to promote [the utility subsidiaries'] commitment to workforce diversity and contracting with diverse suppliers, including minority-owned, women-owned, veteran-owned, LGBT-owned, disability-owned, service disabled veteran-owned, HUBZone, and small disadvantaged businesses. With oversight and guidance from the Executive Diversity Council, the Companies are committed to doing business with small, local, and diverse businesses in the States and communities in which DENC and PSNC serve. In order to facilitate the Companies' diversity procurement goals and to foster relationships with qualified local and diverse suppliers, Dominion has also established partnerships with numerous local, regional, and national advocacy organizations.

Dominion representatives annually attend supplier diversity events that allow the utilities' Business Units and Supply Chain Management Department to interact with local and diverse suppliers and discuss upcoming bid opportunities, and Dominion expects its prime contractors to engage in similar supplier diversity programs to encourage spend with women- and minority-owned subcontractors. Additionally, in accordance with applicable federal regulations, Dominion requires prime contractors for projects over $700,000 to complete subcontracting plans that promote contracting opportunities for small businesses.

Dominion, however, recommends in its comments changes to certain provisions of the proposed rule. For example, consistent with federal procurement requirements, Dominion recommends that the threshold for included projects in proposed Rule R25-1 be increased from $200,000 to $700,000. Dominion also recommends that the rule be amended to apply only to contracts for construction, extension and/or repair of facilities located exclusively in North Carolina, particularly since the majority of DENC's operations, facilities, and customers are located in Virginia. As Duke suggested, Dominion also recommends that contracts for "goods" be removed from the scope of the rule and that the applicability section explicitly exclude planned or emergency outage work. Dominion further agrees with Duke that the newspaper publication requirement in Rule R25-3 should be amended to simply require publication on the utilities' websites as a more effective and less costly means of communication. Moreover, resident contractors should be allowed to initially self-certify their qualification to perform contracts within the relevant utility's scope of work. Dominion also agrees with Duke that unbundling contract goods and services, as required by Rule R25-4, is often an inefficient and costly process that could ultimately have a negative impact on customers' rates and service, and requests that the

Commission reconsider proposed Rule R25-4. Regarding the notification requirements of proposed Rule R25-5, Dominion states that requiring an annual posting of all planned contract solicitations across its operations and inviting all potential resident contractors to bid on applicable construction work will impose excessive burdens in the competitive bidding implementation and evaluation process with little added value. Dominion believes it would be more appropriate to identify potentially qualified contractors on the Hire North Carolina List based upon their capabilities and geographic proximity to the project being bid and to notify those contractors when bids are solicited. Regarding Rule R25-6, Dominion has significant concerns with allowing an unsuccessful resident contractor bidder to seek additional competitively sensitive information after the solicitation, notes that this provision will be difficult to administer and may be used to pursue a competitive advantage in future solicitations, and recommends that it be deleted. Regarding the annual compliance report required in Rule R25-7, Dominion states that certain provisions are impractical, burdensome, and unnecessary, and recommends deleting the requirement for that information.

Toccoa

In its initial comments, Toccoa recognizes that the Hire North Carolina rule has important purposes, but notes that it is a municipal gas system mostly serving customers in Georgia. Of its approximately 90 miles of transmission main, only 17 miles are located in North Carolina, and only approximately 71 of its 418 miles of distribution main miles are in North Carolina. Toccoa argues that

> compliance with the Hire North Carolina rule would be a substantial burden on Toccoa. As a municipal gas system, Toccoa does not have the amount of resources that many of the other public utilities made parties to this docket have. Compliance with the rule would require Toccoa to invest its limited resources to maintain a Hire North Carolina list, publish notice of competitive bidding, provide feedback to unsuccessful North Carolina bidders, and prepare detailed compliance reports on an annual basis.

Lastly, Toccoa states that it is aware of other municipal gas distributors located in the state; but that it would be the only North Carolina municipal gas distributor that is potentially subject to the Hire North Carolina rule. Toccoa, therefore, requests that it be exempt from participation in the Hire North Carolina program.

Aqua NC

In its initial comments, Aqua NC states that it supports the Commission's goals and objectives that underpin the Hire North Carolina rule, but does not support adoption of the proposed rule. Aqua NC notes that its current policies regarding contractor selection already align with the proposed rule, and it does not believe that a state-mandated "outreach and assistance" program would provide the intended benefit due to: (a) the limited applicability of the proposed rule to Aqua NC's small number of eligible projects; (b) the existence of internal policies already designed to accomplish the goals of the program; and (c) its significant use already of vendors who are located in North Carolina. In particular:

> out of approximately 185 specifically identifiable capital projects in 2018, excluding recurring maintenance projects that are almost 100% completed by local contractors, only 23 (or 12%) cost more than $200,000, and thus would have been impacted by the Proposed Rule. Twenty-two of the 23 projects were either sourced to a North Carolina-based vendor, or a North Carolina vendor contributed to completion of the project.

Aqua NC notes that it has both a company-wide Purchasing and Supplier Diversity policy along with a Supplier Diversity program, which tracks and periodically reports the use of diverse and small business (local) vendors and utilizes a subscription to a data service that tracks by category small businesses, women-owned businesses, minority business enterprises, and other indicia of diversity. Aqua NC's purchasing policies and programs follow supply chain best practices as well as other utility best practices; it currently seeks bids from qualified contractors based on local ability to serve, and recognizes that local vendors are often able to provide services at less cost because of their geographic proximity to the facilities. Therefore, Aqua NC relies heavily on these local resources to provide bids and complete the necessary work. Aqua NC thus recommends rather than attempting to develop new lists of potential resident contractors, utilizing available existing resources to expand a utility's local qualified contractor pool, such as the Office of Historically Underutilized Businesses (HUB) maintained by the North Carolina Department of Administration, which promotes economic opportunities for historically underutilized businesses and includes a certification program to properly classify businesses as such. Although Aqua NC has not utilized HUB services, it intends to explore them.

<u>CWSNC</u>

CWSNC, in its initial comments, similarly states that it understands the Commission's intent and appreciates the objectives of the proposed rule, but does not support adoption of the Hire North Carolina rule. As Aqua NC noted, CWSNC prioritizes engaging local contractors and employees to provide safe and reliable water and wastewater services to communities across the state of North Carolina and believes its current business activities align with the objectives of the rule:

> In the past three years alone, CWSNC has invested nearly $45 million across more than 100 major projects and numerous smaller improvements. Of those projects, all were completed using prime contractors from North Carolina.

CWSNC objects to the proposed rulemaking because of three primary concerns: (1) the proposed rule will increase costs for construction; (2) the proposed rule will increase operation and maintenance costs; and (3) CWSNC's existing procurement practices already produce the results intended by the proposed rule. CWSNC specifically estimates the potential costs associated with compliance, including additional staff, costs which would ultimately be passed along to customers: "In an industry which has continued to see rising operating costs, the Proposed Rule further challenges our ability to provide quality service at a reasonable price."

CWSNC further states that the unbundling required by proposed Rule 25-4 would shift the risk of management of additional aspects of the project from the prime contractor to the utility, and ultimately to its customers, and would likely lead to higher bid costs due to the administrative burden put on the utility to manage additional project components on which bids are received, as well as the bidder feedback requirements of proposed Rule 25-6. CWSNC argues that new hurdles imposed by the rule, including the requirement for prime contractors to consult the Hire North Carolina List when choosing subcontractors for the project, could deter contractors from bidding on projects, especially in a strong construction economy where contractors have more work opportunities than they can accept. CWSNC states that it has spent many years developing strong working relationships with a diverse group of local contractors, subcontractors, vendors, and suppliers, and it is concerned the requirements of proposed Rule 25-4 will work against its desire to have readily-available contractors to bid on projects at the lowest price possible for its customers.

> The Company expects the result of the burdens placed on contractors under the Proposed Rule to be a reduction of the contractor and supplier pool, rather than an expansion as intended. ... Because almost all of CWSNC's contractors are currently North Carolina-based businesses, the Proposed Rule is simply not worth the additional costs to our customers.

Public Staff

In its initial comments, the Public Staff, too, supports the goals of increasing regulated utility use of North Carolina resident contractors, subcontractors, vendors and businesses, including women- and minority-owned businesses, and making the bid and hire opportunities of regulated utilities as widely known and accessible as reasonably possible. It cautions, however, that these goals should be harmonized with least cost principles to ensure utilities are not passing along costs to customers that are higher than reasonable. Thus, the Public Staff recommends that the annual reports of the utilities required in proposed Rule R25-7 also include (1) data on contractor and vendor hires where businesses other than the low bidder were selected, with such data to indicate all the reasons why the low bidder was not selected, and (2) information showing each utility's incremental costs and benefits of implementing the rule, relative to benchmark data from the three years prior to the rule's promulgation.

SUMMARY OF REPLY COMMENTS

In their joint reply comments, the utilities and the Public Staff stated that they had engaged in further discussions since the filing of initial comments and attached a single revised draft of the proposed rule for consideration by the Commission. Toccoa reiterated its request for an exemption from the rule, which was joined by Aqua NC and CWSNC.

DISCUSSION AND CONCLUSIONS

The Commission recognizes and appreciates the efforts to engage local North Carolina contractors, subcontractors, vendors and businesses, including women- and minority-owned businesses, undertaken by the utilities filing comments in this docket. However, while the Commission acknowledges that the requirements of the proposed Hire North Carolina Rule will impose some additional effort and cost on the part of those utilities, it remains convinced that an additional measure of transparency, scrutiny, and accountability is necessary to encourage, as much as possible, the utilization of local businesses, including women- and minority-owned businesses, and to support the economy of this State. The Commission is persuaded, though, that the incremental benefits provided by the proposed rule may be outweighed by the cost to smaller utilities in the State. Thus, while application of the rule initially excluded water and wastewater companies with annual operating revenues in excess of $250,000, the Commission finds good cause to amend the rule to apply only to the major electric and natural gas utilities operating in the State: DEP, DEC, DENC, Piedmont, and PSNC. Nevertheless, the Commission encourages all other jurisdictional utilities to maintain their efforts to comply with the spirit of this rule, and reserves the right, as always, to broaden the scope of the rule in the future if circumstances warrant.

The Commission further appreciates the level of review and detail provided in the comments on the actual provisions in the rule itself. The Commission finds the comments, suggestions, and recommendations extremely helpful, and encourages similar collaboration, where possible, in future rulemaking proceedings. Except as discussed below, the Commission agrees that the rule is intended to apply only to contracts for construction, extension and/or repair of facilities or other utility projects, such as coal ash removal, located in North Carolina, and the commenters' non-repetitive suggestions will be harmonized, where possible, and incorporated into the final rule.

With regard to the suggested changes to the last two sentences of proposed Rule R25-3, the Commission is not persuaded that any change is required: a utility must at some point in order to report compliance with the rule determine for itself that the contractor applying to be included on the utility's Hire North Carolina List qualifies as a resident contractor, but the initial certification to the utility by the applicant contemplated by the rule is, in fact, a self-certification. Lastly, the joint reply comments do not include Duke's recommendation in its initial comments that the annual reporting requirement should be discarded in favor of an audit by the Public Staff. The joint reply comments also do not propose including in the annual report the additional information requested by the Public Staff in its initial comments. The Commission concurs.

Therefore, after careful consideration of and based upon the comments filed in this docket, the Commission finds good cause to adopt the revised Hire North Carolina Rule as Chapter 25 of the Commission's Rules and Regulations, attached hereto in black-lined and clean versions as Attachments A and B. The rule, as recommended by Duke in its initial comments and as provided in revised Rule R25-1(b), will be effective with contracts solicited by or on the behalf of any utility on or after July 1, 2020, and the first annual report by the utilities to which the revised rule applies will be required to filed on or before March 1, 2021.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 18th day of June, 2019.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

Chapter 25

Hire North Carolina, Resident Contractor Utilization

Rule R25-1. Purpose; applicability; definitions

(a) Purpose. — For the purpose of promoting economic development, creating jobs, and improving the communities served by the utilities, the Commission urges utilities to maximize, consistent with law, the use of ~~goods, products, and materials produced~~resident contractors for utility projects undertaken in the State of North Carolina. This rule shall serve as a tool to encourage and measure ~~public~~ utility utilization of North Carolina resident contractors, subcontractors, vendors and businesses, including women- and minority-owned businesses. This rule is created to foster utility engagement with potential North Carolina ~~suppliers and~~ contractors, providing ways to inform North Carolina companies of business opportunities. However, this rule shall not be interpreted to supersede any state statute, and nothing in this rule shall be construed to prevent a utility from choosing the lowest ~~and~~or best bidder for any project, or ~~interfering~~ interfere with the mandate to serve the ratepayers or adequately respond to emergencies or support outages.

(b) Applicability. — All contracts for construction, extension and/or repair of facilities or other utility projects located in North Carolina in excess of ~~$200,000.00~~$700,000.00 solicited by or on the behalf of any utility on or after July 1, 2020, shall be governed by this rule; provided, however, this rule shall not apply to planned or unplanned outage work, and nothing contained herein shall prohibit any utility from performing services covered by this rule with its own regularly-employed work-force.

(c) Definitions. — As used in this rule, the following definitions shall apply:

~~(1) Local Business Enterprise — A resident contractor determined by the utility to be qualified to furnish goods and services to the utility and placed on the utility's Hire North Carolina list pursuant to Rule R25-3 below.~~

~~(2)~~ Nonresident ~~Contractor~~ contractor — A prime contractor or subcontractor, be they corporate, individual or partnership, domiciled or having its principal place of business in a location other than the State of North Carolina that wishes to enter into any agreement with the utility or prime contractor for any purpose covered by this rule.

(~~3~~2) Prime ~~Contractor~~ contractor — Any party or person (who is not an employee of the utility or its affiliated or associated companies) who directly enters into any agreement with a utility for the furnishing of ~~goods or~~ services.

(~~4~~3) Resident ~~Contractor~~ contractor — A prime contractor or subcontractor, be they corporate, individual, or partnership, domiciled or having its principal place of business in the State of North Carolina that wishes to enter into any agreement with the utility or prime contractor for any purpose covered by this rule.

(~~5~~4) Subcontractor — Any party or person, who is not an employee of the prime contractor or the utility, who directly enters into any agreement with a prime contractor: (i) for the furnishing of ~~goods or~~ services; or (ii) under which any portion of the prime contractor's obligation under any contracts with the utility is performed or undertaken. ~~A subcontractor shall be treated as a prime contractor hereunder to the extent the subcontractor assumes any portion of the prime contractor's obligation under any contracts with the utility.~~

(~~6~~5) Utility — ~~Any electric, telephone, natural gas, water, or wastewater public utility as defined in G.S. 62-3(23) subject to rate regulation by the Commission; provided, however, that "utility" shall not mean any water or wastewater public utility with annual operating revenues of $250,000 or less~~The following public utilities providing electric and natural gas service in North Carolina: Duke Energy Carolinas, LLC; Duke Energy Progress, LLC; Dominion Energy North Carolina; Public Service Company of North Carolina, Inc.; and Piedmont Natural Gas Company, Inc.

Rule R25-2. Resident Contractor Outreach and Assistance

Each utility shall actively seek out opportunities to identify and assist potential resident contractors, including women- and minority-owned businesses, in order to expand the utility's contracting source pool within the State of North Carolina. The utility shall help enable contracting relationships with resident contractors by exercising reasonable efforts to explain utility qualification requirements, bid and contracting procedures, materials requirements, invoicing and payment schedules, and other procurement practices and procedures. The utility shall make available ~~to resident contractors~~ on its website lists of contract categories ~~which may~~ to assist resident contractors in determining which contract categories best align with the resident contractor's stated qualifications. The utility shall develop marketing program literature to provide to resident contractors and the business community summarizing its efforts pursuant to this rule. Such summaries shall state that the resident contractor will be furnished a complete copy of this rule upon request. Such summaries shall encourage the participation of resident contractors as prime contractors and subcontractors. The utilities are encouraged to explore opportunities for outreach involving North Carolina's institutions of higher education, community colleges, and other trade and technical schools to raise awareness of career opportunities in fields utilized by the public utility sector, with special emphasis on explanation of the contract bidding process.

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Rule R25- 3. Hire North Carolina List

Each utility shall maintain a Hire North Carolina list consisting of resident contractors, including women- and minority-owned businesses, determined by the utility to be qualified to perform contracts within the scope of proposed utility projects. ~~At least every 3 months, the~~The utility shall publish ~~in a newspaper in each county in the utility's certificated area,~~ on its website a notice requesting names of qualified resident contractors. ~~Special attention shall be paid to counties which have no daily local paper to make reasonable efforts to reach potential contractors through cost-effective available avenues which may include, without limitation, electronic communications.~~ A contractor wishing to be included on the Hire North Carolina list may certify to the utility that the contractor is a resident contractor as defined in Rule R25-1 above by any means the utility deems reasonable. Upon such certification, the utility shall add said contractor to the Hire North Carolina list.

Rule R25-4. ~~Unbundling of Contract Goods and Services~~

~~When efficient or cost-effective, a utility shall unbundle and separate scopes and specifications to accommodate the inclusion of resident contractors in sourcing activities.~~

~~Rule R25-5.~~ Publication of Competitive Bidding

In addition to the publication requirements of Rule R25-3 above, each utility is encouraged to pursue any additional means of publication in trade journals, ~~local newspapers,~~ social media, or any other reasonable avenue available. ~~Resident contractors who operate within the area in which the scope of goods or services will be performed under the applicable contracts and who furnish the goods and services sought, at a minimum of once per calendar year, shall be notified of any known upcoming bids for contracts containing scopes of goods or services furnished by the resident contractor via U.S. mail or electronic means, if available.~~ No contract shall be awarded to any prime contractor without the utility first providing to the prime contractor the utility's Hire North Carolina list for consideration of awarding subcontracts arising out of the prime contract.

Rule R25-~~6~~5. Resident Contractor Bid Feedback

In any case in which a resident contractor is unsuccessful in a bid on a contract which is awarded to a nonresident contractor, the utility shall, at the request of any unsuccessful resident contractor bidder, and only after the contract has been executed, provide general, non-confidential information concerning the overall evaluation process between the resident contractor's bid as contrasted with the successful bid. ~~Information on additional selection criteria, such as warranty periods, maintenance costs, and delivery capability, shall be provided under confidentiality~~

~~protections when requested if disclosure would not violate the proprietary nature of the specific contract element or otherwise violate contractual obligations of confidentiality.~~

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Rule R25-~~7~~6. Annual Report ~~Requirements~~

On or before March 1 of each year, the utility shall file a report with the Commission addressing compliance with this rule during the preceding calendar year. The report shall include relevant and material information from the prior year, including ~~proofs of publication,~~ a copy of the utility's most recent Hire North Carolina list, a listing of all student outreach event opportunities afforded by the utility, ~~and the number of bid feedback requests received pursuant to Rule R25-6.~~

~~Additionally, the utility shall report~~ the total number of contracts subject to this rule awarded by the utility in the previous year, a breakdown of how many of those contracts were awarded to resident contractors, including women- and minority-owned businesses, and how many to nonresident contractors, and a brief description of ~~each contract's scope of work or supply~~the type of work performed. ~~In cases where nonresident contractors are used, the utility shall provide a brief explanation of why the nonresident contractor was chosen over a resident contractor. However, the utility shall not be required to provide confidential competitive advantage or proprietary information in these disclosures. Such explanation shall not disclose the identity of the resident contractor not chosen or the nonresident contractor in order to not harm the reputation of the resident contractor. The Commission and/or the utility reserves the right to request such information be filed confidentially when deemed necessary to fulfill the goals of this rule or to comply with contractual confidentiality obligations.~~

~~The report shall specify the percentage of each contractor's employees that are North Carolina residents to the extent reported to the utility by the contractor. If within the reporting period 75% of those employed pursuant to resident contractor contracts are North Carolina residents, the Commission shall award a certificate to the utility naming it a North Carolina Champion.~~

The utilities shall also summarize any outreach efforts undertaken pursuant to Rule R25-2 above, including the response to and perceived impact of such efforts.

Upon request of the utility or by order of the Commission, a public hearing for discussion of the annual report may be held after it has been filed by the utility. The public hearing should protect confidential information including, but not limited to, the identity of the contractors and costs.

Rule R25-~~8~~7. Cost Recovery

The utilities shall be allowed to recover all prudently incurred incremental costs associated with compliance with this rule.

APPENDIX B
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Chapter 25

Hire North Carolina; Resident Contractor Utilization

Rule R25-1. Purpose; applicability; definitions

(a) Purpose. — For the purpose of promoting economic development, creating jobs, and improving the communities served by the utilities, the Commission urges utilities to maximize, consistent with law, the use of resident contractors for utility projects undertaken in the State of North Carolina. This rule shall serve as a tool to encourage and measure utility utilization of North Carolina resident contractors, subcontractors, vendors and businesses, including women- and minority-owned businesses. This rule is created to foster utility engagement with potential North Carolina contractors, providing ways to inform North Carolina companies of business opportunities. However, this rule shall not be interpreted to supersede any state statute, and nothing in this rule shall be construed to prevent a utility from choosing the lowest or best bidder for any project, or interfere with the mandate to serve the ratepayers or adequately respond to emergencies or support outages.

(b) Applicability. —All contracts for construction, extension and/or repair of facilities or other utility projects located in North Carolina in excess of $700,000.00 solicited by or on the behalf of any utility on or after July 1, 2020, shall be governed by this rule; provided, however, this rule shall not apply to planned or unplanned outage work, and nothing contained herein shall prohibit any utility from performing services covered by this rule with its own regularly-employed workforce.

(c) Definitions. —As used in this rule, the following definitions shall apply:

(1) Nonresident contractor — A prime contractor or subcontractor, be they corporate, individual or partnership, domiciled or having its principal place of business in a location other than the State of North Carolina that wishes to enter into any agreement with the utility or prime contractor for any purpose covered by this rule.

(2) Prime contractor — Any party or person (who is not an employee of the utility or its affiliated or associated companies) who directly enters into any agreement with a utility for the furnishing of services.

(3) Resident contractor — A prime contractor or subcontractor, be they corporate, individual, or partnership, domiciled or having its principal place of business in the State of North Carolina that wishes to enter into any agreement with the utility or prime contractor for any purpose covered by this rule.

(4) Subcontractor — Any party or person, who is not an employee of the prime contractor or the utility, who directly enters into any agreement with a prime contractor: (i) for the furnishing of services; or (ii) under which any portion of the prime contractor's obligation under any contracts with the utility is performed or undertaken.

(5) Utility —The following public utilities providing electric and natural gas service in North Carolina: Duke Energy Carolinas, LLC; Duke Energy Progress, LLC; Dominion Energy North Carolina; Public Service Company of North Carolina, Inc.; and Piedmont Natural Gas Company, Inc.

Rule R25-2. Resident Contractor Outreach and Assistance

Each utility shall actively seek out opportunities to identify and assist potential resident contractors, including women- and minority-owned businesses, in order to expand the utility's contracting source pool within the State of North Carolina. The utility shall help enable contracting relationships with resident contractors by exercising reasonable efforts to explain utility qualification requirements, bid and contracting procedures, materials requirements, invoicing and payment schedules, and other procurement practices and procedures. The utility shall make available on its website lists of contract categories to assist resident contractors in determining which contract categories best align with the resident contractor's stated qualifications. The utility shall develop marketing program literature to provide to resident contractors and the business community summarizing its efforts pursuant to this rule. Such summaries shall state that the resident contractor will be furnished a complete copy of this rule upon request. Such summaries shall encourage the participation of resident contractors as prime contractors and subcontractors. The utilities are encouraged to explore opportunities for outreach involving North Carolina's institutions of higher education, community colleges, and other trade and technical schools to raise awareness of career opportunities in fields utilized by the public utility sector, with special emphasis on explanation of the contract bidding process.

Rule R25-3. Hire North Carolina List

Each utility shall maintain a Hire North Carolina list consisting of resident contractors, including women- and minority-owned businesses, determined by the utility to be qualified to perform contracts within the scope of proposed utility projects. The utility shall publish on its website a notice requesting names of qualified resident contractors. A contractor wishing to be included on the Hire North Carolina list may certify to the utility that the contractor is a resident contractor as defined in Rule R25-1 above by any means the utility deems reasonable. Upon such certification, the utility shall add said contractor to the Hire North Carolina list.

Rule R25-4. Publication of Competitive Bidding

In addition to the publication requirements of Rule R25-3 above, each utility is encouraged to pursue any additional means of publication in trade journals, social media, or any other reasonable avenue available. No contract shall be awarded to any prime contractor without the utility first providing to the prime contractor the utility's Hire North Carolina list for consideration of awarding subcontracts arising out of the prime contract.

Rule R25-5. Resident Contractor Bid Feedback

In any case in which a resident contractor is unsuccessful in a bid on a contract which is awarded to a nonresident contractor, the utility shall, at the request of any unsuccessful resident contractor bidder, and only after the contract has been executed, provide general, non-confidential information concerning the overall evaluation process between the resident contractor's bid as contrasted with the successful bid.

Rule R25-6. Annual Report

On or before March 1 of each year, the utility shall file a report with the Commission addressing compliance with this rule during the preceding calendar year. The report shall include relevant and material information from the prior year, including a copy of the utility's most recent Hire North Carolina list, a listing of all student outreach event opportunities afforded by the utility, the total number of contracts subject to this rule awarded by the utility in the previous year, a breakdown of how many of those contracts were awarded to resident contractors, including women- and minority-owned businesses, and how many to nonresident contractors, and a brief description of the type of work performed.

The utilities shall also summarize any outreach efforts undertaken pursuant to Rule R25-2 above, including the response to and perceived impact of such efforts.

Upon request of the utility or by order of the Commission, a public hearing for discussion of the annual report may be held after it has been filed by the utility. The public hearing should protect confidential information including, but not limited to, the identity of the contractors and costs.

Rule R25-7. Cost Recovery

The utilities shall be allowed to recover all prudently incurred incremental costs associated with compliance with this rule.

DOCKET NO. P-100, SUB 133
DOCKET NO. P-100A, SUB 133
DOCKET NO. P-100, SUB 110

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. P-100, SUB 133 In the Matter of Local Exchange and Local Exchange Access Telecommunications Competition DOCKET NO. P-100A, SUB 133 In the Matter of Reports Filed Pursuant to Commission Rule R17-2(k) DOCKET NO. P-100, SUB 110 In the Matter of Telecommunications Relay Service (TRS), Relay North Carolina	)	ORDER GRANTING PETITION FOR ELIMINATION OF ACCESS LINE REPORTING REQUIREMENT FOR ILECS AND CLPS AND AMENDING COMMISSION RULE R17-2(k)

BY THE COMMISSION: On September 11, 2019, AT&T North Carolina (AT&T) filed a Petition for Elimination or Waiver of Access Line Reporting Requirements (petition).

In its petition, AT&T requested that the Commission eliminate or, alternatively, waive the requirement to file access line reports. AT&T maintained that the access line reports were originally designed to allow the Commission to monitor the level of competition when telecommunications services were primarily wireline and the industry was more heavily regulated and far less competitive than today. AT&T stated that to remove this unnecessary administrative burden on telecommunications carriers, the Public Staff, and the Commission, access line reports required by Commission Rules R1-32 and R17-2(k) should be eliminated, or in the alternative, the filing requirements waived for all incumbent local exchange companies (ILECs) and competing local providers (CLPs).

On September 16, 2019, the Commission issued an Order Requesting Comments on AT&T's Petition for Elimination or Waiver of Access Line Reporting Requirements.

Initial comments were filed on September 30, 2019 by Carolina Telephone & Telegraph Company, LLC d/b/a CenturyLink, Central Telephone Company d/b/a CenturyLink, Mebtel, Inc., d/b/a CenturyLink, and CenturyLink Communications, LLC (collectively referred to as CenturyLink). Also on September 30, 2019, the Public Staff filed a letter in lieu of comments in response to the September 16, 2019 Order.

No party filed any reply comments.

THE PETITION

AT&T maintained in its petition that the access line reports were originally designed to allow the Commission to monitor the level of competition when telecommunication services were primarily wireline, and the industry was more heavily regulated and far less competitive than today. AT&T asserted that given the now largely deregulated and vibrantly competitive state of the industry, these access line reports are no longer relevant and serve no useful purpose. AT&T argued that to remove this unnecessary administrative burden on telecommunications carriers, the Public Staff, and the Commission, access line reports required by Commission Rules R1-32 and R17-2(k) should be eliminated, or in the alternative, the filing requirements waived for all ILECs and CLPs.

AT&T asserted that the access line reporting requirements contained in Commission Rules R1-32 and R17-2(k) are antiquated vestiges of the past, initiated at a time when the Commission was concerned with making on-going semi-annual determinations of whether the regulated telecommunications industry was competitive. AT&T stated that now, however, there is no question that the telecommunications market is highly competitive. AT&T further argued that there is no question that the market today is dominated by Commercial Mobile Radio Services (CMRS, i.e., cellular service) and Voice over Internet Protocol (VoIP) services and that traditional wireline services (the only services reflected in the access line reports at issue here) are in continuous decline. AT&T maintained that given these market developments, the access line reporting requirement which only ILECs and CLPs are subject to (and not CMRS or VoIP carriers) cannot provide an accurate picture of the competitive landscape and the state of the industry today. AT&T stated that as a practical matter, traditional telephone companies have become providers of Internet Protocol (IP)-based information services more so than traditional regulated landline voice service. AT&T noted that beginning with the introduction of Digital Subscriber Lines (DSLs), carriers' IP-based services have been considered information services rather than traditional telephone services and have never been reported as traditional access lines.

AT&T provided two charts: one to show the dramatic decrease in AT&T's access lines in North Carolina, in juxtaposition with the simultaneously dramatic increase in CMRS subscribers; and another chart to show the rapid expansion of VoIP subscribers throughout the State.

AT&T stated that, in their current form, the Rules state as follows:

> **Rule R1-32(e1).**[1] In lieu of filing annual report forms furnished or approved by the Commission, or otherwise filing any other information as provided for in Sections (a) through (e) above, incumbent local exchange companies (ILECs) that are price regulated under G.S. 62-133.5(a), and any carrier electing regulation under

[1] AT&T noted that this Rule outlines an annual reporting requirement for telephone companies including the Station Development Report (SDR). The Access Line Report resulted from a modification to the SDR by the Commission's May 12, 2009 Order Amending Monthly Access Line Report issued in Docket No. P-100, Sub 58a. However, the Commission notes that the May 12, 2009 Order does not reference Commission Rule R1-32 Filing of Annual Reports by Public Utilities.

G.S. 62-133.5(h), may instead satisfy all of their annual reporting obligations by providing the following as soon as possible after the close of the calendar year, but in no event later than the 30th day of April of each year for the preceding calendar year:

(1) Publicly traded ILECs may provide the Commission with a link to their annual filings with the SEC;

(2) ILECs that are not publicly traded may annually file copies of their audited financial statements with the Commission;

(3) CLPs with COLR [carrier of last resort] responsibilities that are publicly traded may provide the Commission with a link to their annual filings with the SEC; and

(4) CLPs with COLR responsibilities that are not publicly traded may annually file copies of their audited financial statements with the Commission.

<u>Rule R17-2(k)</u>. By the 15th day of each July and January, respectively, each CLP shall file a report with the Chief Clerk reflecting the number of local access lines subscribed to at the end of the preceding month in each respective geographic area served by the CLP, listing separately for business and residential service. CLPs electing regulation under G.S. 62-133.5(h) are only required to file total access lines. Other operating statistics are not required to be filed except upon specific request of the Commission or the Public Staff.

AT&T further stated that these Rules reflect changes the Commission made to them in its June 30, 2011 Order in response to a March 16, 2011 petition filed by the North Carolina Telecommunications Industry Association, Inc. (NCTIA)[1] requesting modification or elimination of certain ILEC and CLP reporting requirements. AT&T noted that the prior version of the Rules contained more frequent and onerous reporting requirements which the Commission found to be inappropriate for an emerging competitive market and amended the requirements in 2011.

AT&T maintained that although the NCTIA sought primarily to limit the scope and frequency of access line filings, Verizon South Inc. and MCImetro Access Transmission Services LLC d/b/a Verizon Access Transmission Services requested in their comments in the docket the total elimination of the reporting requirements for generally the same reasons set forth by AT&T in its current petition: the lack of the report's usefulness given clear evidence of a competitive industry, and the myopic view of the industry given that data from CMRS and VoIP providers are not required.

[1] AT&T noted that as a reflection of the massive changes and restructuring within the industry, the NCTIA has been dissolved. AT&T stated that, however, at the time of the 2011 filing, the NCTIA's membership included 13 companies.

AT&T argued that competition is more vibrant in 2019 than it was in 2011, and the diversity of offerings and customer choices for service outside of the scope of traditional services are now much more robust. AT&T further noted that in addition to orders by the Commission, the North Carolina General Assembly has taken steps over the years to deregulate the industry further. AT&T stated that the latest actions occurred in the enactment of Session Law 238 in 2009 and Session Law 291 in 2011. AT&T asserted that, therefore, the rationale for eliminating the reports is even more compelling today.

AT&T also noted that it is aware that, at least for wireline services, the Telecommunications Relay Service (TRS) surcharge has historically been based on access line counts. AT&T stated that, however, last year the North Carolina Department of Health and Human Services (DHHS) filed a petition in Docket No. P-100, Sub 110 to revise the TRS surcharge by lowering it from $0.10 per access line to $0.08 per access line which the Commission granted. AT&T maintained that the DHHS stated in its petition that since the Public Staff no longer has access to the number of wireline and wireless access lines, the DHHS establishes the number of access lines based on revenues received divided by the rate. Therefore, AT&T asserted, given that the access line reports are limited to time division multiplexing (TDM)[1] data, and the DHHS has its own policies and procedures for access line accounting, the access line reports are not required by the DHHS or useful in its administration of the TRS. AT&T noted that the Commission's Order did not take issue with the DHHS' method of calculating the TRS surcharge.

AT&T maintained that the Commission should complete the beneficial work it began in 2011 and take the next appropriate step by eliminating access line reporting entirely. AT&T stated that as Verizon maintained in 2011, and AT&T echoes now, in a market that is highly competitive and increasingly deregulated the reports no longer serve a useful purpose.

AT&T requested that the Commission grant its petition and eliminate, or in the alternative, waive all access line reporting requirements for ILECs and CLPs.

INITIAL COMMENTS

CenturyLink stated that it fully supports AT&T's petition for elimination of the access line reporting requirements for ILECs and CLPs. CenturyLink asserted that given the highly competitive state of the North Carolina telecommunications marketplace, these reports are no longer necessary and should be eliminated.

CenturyLink maintained that the robust telecommunications market in North Carolina has provided customers more choice, innovative technologies, and new services than ever before. CenturyLink asserted that this competitive environment has enabled the growth of intermodal telecommunications technologies such that customers are subscribing to voice, video, and data services not only from traditional wireline providers regulated by the Commission, but also from wireless, cable, satellite, and VoIP providers as well. CenturyLink noted that customers are adopting these alternative technologies at ever-increasing rates: the latest United States Center for

[1] TDM phone technology is based on electrical circuits that are physically switched on the public switched telephone network.

Disease Control state-specific statistics on wireless substitution show that 53.2% of the households in North Carolina are wireless only (which reflects 2017 data that was compiled in March 2019). CenturyLink maintained that this is consistent with wireless substitution on a national level, where the United States Center for Disease Control data shows wireless substitution at an all-time high of 57.1% (which reflects preliminary data from July through December 2018). CenturyLink stated that, thus, as depicted by AT&T in its petition, the access line reports that only reflect wirelines currently filed by North Carolina ILECs and CLPs capture only a fraction of the total marketplace. CenturyLink argued that with much of the marketplace not being subject to an access line reporting obligation, it is difficult to see what value these reports provide.

CenturyLink further stated that the Commission and the Public Staff have acknowledged that this competitive telecommunications marketplace in North Carolina is much more than wireline ILEC and CLP providers. CenturyLink noted that several years ago, the Commission stated on page 14 of its June 30, 2011 Order Ruling on the NCTIA's Petition for Modification or Elimination of Certain Reporting Requirements Relating to ILECs and/or CLPs, and Amending Rule R1-32 and Rule R17-2(k) issued in Docket Nos. M-100, Sub 4; P-100, Sub 72b; P-100, Sub 133; P-100A, Sub 133; P-55, Sub 1022; P-55, Sub 1022A; and P-100, Sub 110 that "[w]hile the Public Staff believes that access line reporting does not provide an entirely accurate picture of the competitive landscape inasmuch as it does not include wireless or VoIP providers, it does allow the Commission to track the state of competition among regulated carriers." CenturyLink stated that the Public Staff also noted the use of access line data for the TRS program as an additional justification to maintain the reporting requirement.

CenturyLink argued that the telecommunications market has continued to evolve since that time. CenturyLink stated that regulated providers face even greater competition from unregulated providers as evidenced by their increasing market share at the expense of traditional, regulated providers. CenturyLink maintained that, moreover, as AT&T noted in its petition, access line data from these reports is no longer required as part of the administration of the TRS program. CenturyLink maintained that in light of the competitive pressures faced by regulated providers and the changes in the marketplace over time, it is appropriate for the Commission to eliminate this outdated regulatory requirement that no longer serves its purpose and burdens only a subset of the market sector.

CenturyLink maintained that this approach is consistent with the deregulatory posture the Commission and the North Carolina legislature have taken. CenturyLink noted that in the Commission's 2013 Report to the Joint Legislative Commission on Governmental Operations regarding the status of telecommunications service in a changing competitive environment, the Commission opined in support of its recommendation to abolish the biannual report:

> It has now been more than 18 years since the passage of HB 161, and the regulatory environment in which the Utilities Commission operates in telecommunications has evolved considerably. In addition to intramodal landline competition from competing local providers (CLPs), incumbent local exchange companies (ILECs) under our jurisdiction face intermodal competition from wireless providers, cable providers, and voice over Internet Protocol (VoIP) providers. . . Because of provisions in federal and/or state law, the Commission does not regulate wireless service, cable television, long distance service, or broadband service, reflecting a

movement toward greater reliance on market forces... The last decade and a half have been transformative in the telecommunications industry and there has been a corresponding transformation in the kind and degree of regulation of that sector that the General Assembly has authorized. The new model for regulation has been universally in the direction of more reliance on market forces and less on traditional forms of regulation. This approach has generally worked well for both providers and their customers.

CenturyLink stated that it agrees that the market forces present in 2013 are continuing to work well. CenturyLink asserted that in order to keep those forces functioning in a healthy manner, a subset of the market should not be saddled with the administrative burden of outdated regulatory requirements that other members are not.

Finally, CenturyLink argued that in support of AT&T's petition, CenturyLink notes that other states have already eliminated access line reporting and there have been no negative consequences or unforeseen hardships. CenturyLink stated that, for example, the Florida Public Service Commission initiated a rulemaking in 2011 after passage of the final telecom deregulation by the Florida legislature and eliminated the majority of their telecommunications retail rules including the requirement for access line reporting by ILECs. CenturyLink also noted that, more recently, it became aware that Illinois eliminated the requirement to produce and submit an annual competition report which required access line reporting. CenturyLink noted that the relief requested in AT&T's petition is consistent with other action across the country in light of the changing telecommunications marketplace.

CenturyLink requested that the Commission grant AT&T's petition and eliminate all access line reporting requirements for ILECs and CLPs.,

The **Public Staff** filed a letter in lieu of comments in response to the Commission's September 16, 2019 Order. The Public Staff stated that it does not oppose AT&T's request for the Commission to eliminate or, alternatively, waive the requirement to file access line reports. The Public Staff noted that it is its understanding that the DHHS does not currently use these reports in reviewing the TRS surcharge. Further, the Public Staff maintained that it has contacted personnel at the Federal Communications Commission (FCC) and has been informed that the Public Staff or the Commission can obtain access line data from the FCC upon request. The Public Staff asserted that the Commission or the Public Staff should be able to obtain access line information from regulated carriers if necessary such as to audit the TRS pursuant to North Carolina G.S. §62-157(d).

Therefore, the Public Staff recommended that the Commission: (1) waive the requirement for ILECs to file access line reports; and (2) revise Commission Rule R17-2(k) as follows:

Rule R17-2(k) ~~By the 15th day of each July and January, respectively, each CLP shall file a report with the Chief Clerk reflecting the number of local access lines subscribed to at the end of the preceding month in each respective geographic area served by the CLP, listing separately for business and residential service. CLPs electing regulation under G.S. 62-133.5(h) are only required to file total access~~

~~lines.~~ The number of access lines or o~~O~~ther operating statistics are not required to be filed except upon specific request of the Commission or the Public Staff.

REPLY COMMENTS

No party filed any reply comments.

DISCUSSION AND CONCLUSIONS

After reviewing the comments filed in response to AT&T's petition, the Commission notes that all of the parties agree that it is appropriate to no longer require access line reporting by ILECs and CLPs. As the parties noted, CMRS and VoIP providers are not required to file access line data with the Commission and currently a substantial number of access lines in the State are provided by CMRS and VoIP providers. Further, the Commission finds it important to note that there are other sources of this access line data if it is ever needed by the Commission or the Public Staff in the future. Therefore, the Commission concludes that it is appropriate to grant AT&T's petition thereby eliminating the requirement for ILECs and CLPs to file access line reports and revising Commission Rule R17-2(k) as follows:

> Rule R17-2(k) ~~By the 15th day of each July and January, respectively, each CLP shall file a report with the Chief Clerk reflecting the number of local access lines subscribed to at the end of the preceding month in each respective geographic area served by the CLP, listing separately for business and residential service. CLPs electing regulation under G.S. 62-133.5(h) are only required to file total access lines.~~ The number of access lines or o~~O~~ther operating statistics are not required to be filed except upon specific request of the Commission or the Public Staff.

IT IS, THEREFORE, ORDERED as follows:

1. That the requirement for ILECs and CLPs to file access line reports is hereby eliminated; and

2. That Commission Rule R17-2(k) is amended as shown on Appendix A attached hereto.

ISSUED BY ORDER OF THE COMMISSION.
This the 22nd day of November, 2019.

NORTH CAROLINA UTILITIES COMMISSION
A. Shonta Dunston, Deputy Clerk

Commissioner Kimberly W. Duffley and Commissioner Jeffrey A. Hughes did not participate in this decision.

APPENDIX A

Redlined copy of Rule R17-2(k):

Rule R17-2(k) ~~By the 15th day of each July and January, respectively, each CLP shall file a report with the Chief Clerk reflecting the number of local access lines subscribed to at the end of the preceding month in each respective geographic area served by the CLP, listing separately for business and residential service. CLPs electing regulation under G.S. 62-133.5(h) are only required to file total access lines.~~ The number of access lines or o~~O~~ther operating statistics are not required to be filed except upon specific request of the Commission or the Public Staff.

Clean copy of Rule R17-2(k):

Rule R17-2(k) The number of access lines or other operating statistics are not required to be filed except upon specific request of the Commission or the Public Staff.

DOCKET NO. P-100, SUB 165
DOCKET NO. P-100, SUB 165a
DOCKET NO. P-75, SUB 82
DOCKET NO. P-76, SUB 71
DOCKET NO. P-60, SUB 89
DOCKET NO. P-21, SUB 78

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. P-100, SUB 165 In the Matter of Implementation of Subsection (h) Price Plans Pursuant to House Bill 1180, Session Law 2009-238 and House Bill 466, Session Law 2010-173 DOCKET NO. P-100, SUB 165a In the Matter of Implementation of Price Plans Pursuant to Senate Bill 343, Session Law 2011-52 DOCKET NO. P-75, SUB 82 DOCKET NO. P-76, SUB 71 DOCKET NO. P-60, SUB 89 DOCKET NO. P-21, SUB 78 In the Matter of Petition for Exemption of Incumbent Local Exchange Companies from the Application of N.C. Gen. Stat. § 62-160 and 161 and Amendment to Commission Rule R1-16	ORDER GRANTING PETITION AND AMENDING COMMISSION RULE R1-16(a)

BY THE COMMISSION: On April 1, 2019, Barnardsville Telephone Company, Saluda Mountain Telephone Company, Service Telephone Company, and Ellerbe Telephone Company (Petitioners) filed a Petition requesting that the Commission exempt any local exchange company (LEC) that has elected regulation pursuant to N.C. Gen. Stat. § 62-133.5(h) or (m) from the application of the requirements set forth in N.C. Gen. Stat. § 62-160 and 161 and amend Commission Rule R1-16 as shown in the Petition.

The Petitioners stated that the Public Staff had authorized them to state that the Public Staff supports the Petition.

On April 24, 2019, the Commission issued an Order allowing any interested party to file comments on the Petition on or before May 8, 2019. Appendix A attached to that Order showed the requested amendments to Commission Rule R1-16(a).

No party filed comments.

CONCLUSION

After careful consideration of the Petition, the lack of opposition to the request, and the entire record in these proceedings, the Commission concludes that it is appropriate to grant the Petition and that the requirements regarding financing in N. C. Gen. Stat. § 62-160 and 161 should not be enforceable for any LEC that has elected regulation pursuant to N.C. Gen. Stat. § 62-133.5(h) or (m). Further, the Commission concludes that Commission Rule R1-16(a) should be amended as shown in Appendix A to this Order and as amended in Appendix B to this Order.

IT IS, THEREFORE, ORDERED that:

1. A LEC that has elected regulation pursuant to N.C. Gen. Stat. § 62-133.5(h) or (m) is hereby exempt from the provisions of N.C. Gen. Stat. § 62-160 and 161; and

2. Commission Rule R1-16(a) is hereby amended and attached to this Order as Appendix B, effective as of the date of this Order.

ISSUED BY ORDER OF THE COMMISSION.
This the 14th day of May, 2019.

NORTH CAROLINA UTILITIES COMMISSION
A. Shonta Dunston, Deputy Clerk

APPENDIX A

Redlined Version of Rule R1-16(a)

(a) No public utility except Payphone Service Providers, Competing Local Providers, and utilities providing only intraLATA long distance service, interLATA long distance service and/or long distance operator service, <u>and local exchange carriers that have elected regulation pursuant to G.S. § 62-133.5(h) or (m)</u> shall pledge its assets, issue securities, or assume liabilities of the character specified in G.S. 62 161, except after application to and approval by the Commission. Such applications shall be made under oath, filed with the Commission with twenty (20) copies, and shall contain the following specific information:

APPENDIX B

Amended Rule R1-16(a)

(a) No public utility except Payphone Service Providers, Competing Local Providers, and utilities providing only intraLATA long distance service, interLATA long distance service and/or long distance operator service, and local exchange carriers that have elected regulation pursuant to G.S. § 62-133.5(h) or (m) shall pledge its assets, issue securities, or assume liabilities of the character specified in G.S. 62 161, except after application to and approval by the Commission. Such applications shall be made under oath, filed with the Commission with twenty (20) copies, and shall contain the following specific information:

DOCKET NO. P-100, SUB 170

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Tariff Filings Made by Local Exchange	)	ORDER GRANTING THE PUBLIC
Carriers in Compliance with the Federal	)	STAFF'S MOTION WITH AN
Communications Commission's Connect	)	EFFECTIVE DATE OF
America Fund Order	)	JULY 2, 2019 FOR RATE CHANGES

BY THE COMMISSION: On May 22, 2019, the Public Staff filed a Motion for Order Requiring Filing of Information Regarding July 2, 2019[1], Access Rate Changes.

In its Motion, the Public Staff requested that the Commission issue an order requiring filings from certain carriers showing their compliance with the seventh set of intrastate access rate changes mandated by the Federal Communications Commission's November 18, 2011, Universal Service Fund (USF)/ Intercarrier Compensation (ICC) Transformation Order as soon as practicable, but no later than June 17, 2019.

The Public Staff further noted that it has reviewed last year's responses and compiled a list of carriers as reflected in Appendix A to its Motion that the Public Staff proposes should make an appropriate filing regarding their 2019 switched access rate changes. The Public Staff stated that, additionally, any carrier that is not listed in Appendix A, but whose status has changed from last year should also be required to make an appropriate filing.

On May 23, 2019, the Commission issued an Order Requesting Comments on the Public Staff's Motion.

[1] The Federal Communications Commission modified the effective date of this year's filings from July 1, 2019, to July 2, 2019 (See *July 1, 2019 Annual Access Charge Tariff Filings*, WC Docket No. 19-47, Order, DA 19-246 (WCB April 4, 2019)).

No party filed initial comments on the Public Staff's Motion.

Based on the record, the Commission finds it appropriate to grant the Public Staff's Motion. Therefore, the carriers identified in Appendix A to the Motion, which is incorporated by reference herein, and any carrier that is not listed in Appendix A but whose status has changed from last year, must make the required filings as soon as practicable, but no later than Monday, June 17, 2019 with an effective date of July 2, 2019, as appropriate.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 4th day of June, 2019.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

DOCKET NO. T-100, SUB 49

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Petition of the North Carolina Movers Association, Inc., for Amendments to the Maximum Rate Tariff No. 1 – To Clarify Outside Stair Carry Charges	))))	ORDER GRANTING PETITION TO AMEND THE MAXIMUM RATE TARIFF NO. 1 TO CLARIFY STAIR CARRY CHARGES

BY THE COMMISSION: On September 26, 2019, the North Carolina Movers Association, Inc. (NCMA) filed a petition with the North Carolina Utilities Commission (Commission) requesting an amendment to the current Commission-approved Maximum Rate Tariff No. 1 (MRT) to clarify stair carry charges.

As currently written, Section IV, Item 20 (Elevator, Stair, and Excessive Distance Carry Charges), Notes 1 and 7 of the MRT do not address nor allow carriers to bill shippers for outside stair carry charges in situations where the outside stairs are the only access to the interior of a single family dwelling.

In its petition, the NCMA requested that the Commission modify Section IV, Item 20, Notes 1 and 7 of the MRT to allow carriers to charge outside stair carry charges if the outside stairs provide the only access in or out of a single family dwelling. Specifically, the NCMA proposed that the following language be added to Section IV, Item 20, Notes 1 and 7 of the MRT:

> (Note 1) **Inside** elevator and stair carry charges will not apply when pickup or delivery is within a single family dwelling. **Outside a single family dwelling, stair carry charges will apply if the stairs are the only way to get in or out of the single family dwelling.**
>
> (Note 7) Outside a building or **dwelling,** the first flight shall consist of 8 but not more than 20 steps. Steps less than 8 will not be considered a flight. **In a single family dwelling, if pick-up or delivery requires outside stairs, the outside stair carry charge will apply.**

In support of its petition, the NCMA submitted that as currently written, the MRT does not address the situation where outside stairways provide the only access to the inside of a single family dwelling, and therefore must be navigated during pickup and delivery. The NCMA asserted that this is particularly common for coastal dwellings.

On October 7, 2019, the Commission issued an Order Requesting Comments on Petition.

On October 28, 2019, Armstrong Relocation Co., Inc., All American Relocation, Inc., Horne Moving Systems, Inc., and the Public Staff filed comments in support of the NCMA's petition.

The Commission did not receive any reply comments.

INITIAL COMMENTS

Horne Moving Systems, Inc., All American Relocation, Inc., and Armstrong Relocation Co., Inc., filed brief comments expressing their agreement with the NCMA's petition.

The Public Staff stated that it is generally in agreement with the NCMA's proposed tariff change and that the proposed tariff changes would align the rule with the standard in the industry. The Public Staff recommended that the proposed tariff change be adopted by the Commission.

WHEREUPON, the Commission now reaches the following

CONCLUSIONS

Based upon the record of evidence in this proceeding, including the NCMA's petition and the initial comments filed thereafter, the Commission finds it appropriate to grant the NCMA's petition to amend the MRT to clarify that outside stair carry charges will apply for pickup and delivery where the outside stairs provide the only access in and out of a single family dwelling.

The Commission recognizes that all of the parties that filed comments agreed that modifying the MRT for these purposes is appropriate and warranted and the Commission agrees. Currently, Section IV, Item 20, Notes 1 and 7 of the MRT clearly state that stair carry charges will not apply within a single family dwelling. However, the Commission is of the opinion that the intent of Notes 1 and 7 is that stair carry charges would not be applied or assessed in a two-story house. Additionally, the clarification of Notes 1 and 7 would assist in the clarification of outside stair charges for the carrier and shipper, particularly in the case of coastal dwellings that are built on stilts.

The Commission concurs with the Public Staff's recommendation that the NCMA's proposed tariff changes be adopted.

IT IS, THEREFORE, ORDERED as follows:

1. That the NCMA's petition for the modification of the MRT to clarify outside stair carry charges is hereby granted with the clarifications as set forth in this Order;

2. That Section IV, Item 20, Notes 1 and 7 of the MRT shall be amended as outlined in the NCMA's petition; and

3. That copies of this Order shall be served by the Chief Clerk's Office to all Commission-certified household goods movers, the Public Staff, and the North Carolina Movers Association, Inc.

ISSUED BY ORDER OF THE COMMISSION.

This the 27th day of November, 2019.

NORTH CAROLINA UTILITIES COMMISSION
Kimberley A. Campbell, Chief Clerk

DOCKET NO. W-100, SUB 57

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Impact of The Federal Tax Cuts and Jobs Act on Contributions in Aid of Construction for Water and Wastewater Companies	))))	ORDER ADDRESSING FEDERAL INCOME TAXES ON CONTRIBUTIONS IN AID OF CONSTRUCTION

BY THE COMMISSION: On December 22, 2017, President Trump signed into law the Tax Cuts and Jobs Act (the Federal Tax Cuts and Jobs Act or the Tax Act). Among other provisions that are contained in this tax reform are provisions that, upon implementation, changed the taxability of Contributions in Aid of Construction (CIAC) for all water and wastewater companies. Specifically, the Tax Act has now made CIAC taxable again for water and wastewater public utilities.

On October 5, 2018, in this docket, the Commission issued an Order Establishing Docket to Consider Impacts of 2017 Federal Tax Cuts and Jobs Act on Contributions in Aid of Construction and Requesting Initial and Reply Comments. In the October 5, 2018 Order, the Commission: (1) made all certificated water and wastewater companies a party to the proceeding; (2) ordered that all certificated water and wastewater companies shall collect the income tax on CIAC from contributors of plant for new contributions contracted for on or after the date of the Order using the full gross-up method on an interim basis until the Commission makes a final decision after comments are received on this matter; requested that interested parties file initial comments by no later than October 25, 2018 addressing the appropriateness of using the full gross-up method and the present value method, as proposed by the Public Staff in its reply comments filed in Docket No. M-100, Sub 148, along with any other issues for the Commission to consider related to CIAC and the Tax Act and that reply comments shall be filed by no later than November 14, 2018; and (4) requested that the Public Staff review all water and wastewater utility tariffs to determine if any changes to those tariffs are required due to the Tax Act and to file a report with the Commission providing a summary of its review including specific recommendations for the Commission to consider by no later than November 2, 2018.

Initial comments were filed on October 24, 2018 by the Public Staff and on October 25, 2018 by Aqua North Carolina, Inc. (Aqua), Carolina Water Service, Inc. of North Carolina (CWSNC), and Old North State Water Company, LLC (ONSWC).

On November 2, 2018, the Public Staff filed its Report on Tariff Changes Required by the Tax Act.

Reply comments were filed on November 14, 2018 by the Public Staff. On November 30, 2018, Aqua filed late-filed reply comments. The Commission also received a letter dated December 19, 2018 from the North Carolina Home Builders Association (NCHBA) that was filed into the docket as a consumer statement of position and a letter dated December 20, 2018 from

Tom Hankins, a Wake county residential developer and custom homebuilder, that was filed into the docket on January 2, 2019 as a consumer statement of position.

BACKGROUND

Docket No. M-100, Sub 113

As background on this issue (the taxability of CIAC), the Commission notes that on October 22, 1986, the Federal Tax Reform Act of 1986 (Federal 1986 Tax Act) was signed into law; among other provisions contained in that tax reform, it required CIAC to be included as taxable income for electric, natural gas, water, and wastewater public utilities. The Commission opened a generic docket to consider the impacts of the Federal 1986 Tax Act in Docket No. M-100, Sub 113.

On August 26, 1987, the Commission issued its Order Establishing Procedures Related to Taxes on Contributions in Aid of Construction (1987 CIAC Order) wherein the Commission concluded that water and wastewater companies must use the full gross-up method with respect to collections of CIAC unless the Commission gave prior approval for a different method in a particular case or unless the Company applied for and was granted approval to use the present value method. Further, water and wastewater companies were required to include the following information in their annual reports to the Commission: (1) nontaxable CIAC collected; (2) taxable CIAC collected; and (3) tax collected on CIAC. The 1987 CIAC Order also included a table as Appendix A to be used by water and wastewater companies using the full gross-up method to compute the increase in contributions needed to recover the taxes on CIAC.

Subsequently, on August 20, 1996, President Clinton signed into law the Small Business Job Protection Act of 1996 (the 1996 Tax Act). Section 1613 of the 1996 Tax Act, concerning the tax treatment of CIAC, restored the CIAC provisions that were repealed by the federal Tax Reform Act of 1986 for regulated public utilities that provide water or wastewater disposal services (i.e., made CIAC not taxable) effective for amounts received after June 12, 1996.

On August 27, 1996, the Commission issued its Order Concerning Gross-Up for Taxes On Contributions in Aid of Construction and Requiring Refunds wherein the Commission ordered all water and wastewater companies to cease collecting gross-up on collections of CIAC received after June 12, 1996 and to refund any gross-up collected by water and wastewater companies on CIAC received after June 12, 1996, with a 10% interest per annum. Therefore, CIAC received after June 12, 1996 by water and wastewater companies has not been included in taxable income for the companies.

On March 7, 2001, the Commission issued an Order Concerning Gross Up for Taxes on Contributions in Aid of Construction to address the Internal Revenue Service's (IRS's) January 11, 2001 issuance of its final regulations concerning the definition of contributions in aid of construction. The Commission concluded in its March 7, 2001 Order that, consistent with the IRS's final regulations, for water and wastewater companies, connection fees and service lines (also known as tap on fees) are not CIAC and therefore <u>are</u> taxable. The IRS's final regulations stated that the term customer connection fee includes any amount of money or other property transferred to the utility representing the cost of installing a connection or service line (including the cost of meters and piping) from the utility's main water or sewer lines to the line owned by the customer or potential customer. The Commission noted in its Order that the Public Staff had stated that the taxes on customer connection fees would not have a significant impact on water and sewer utilities overall and that the taxability of CIAC was basically a timing difference; therefore, the Public Staff recommended that the Commission not allow the use of the full gross-up method except with prior approval in the rare case of an existing utility whose financial condition was such that paying the taxes itself would make the utility nonviable. The Commission agreed with the Public Staff and concluded that water and sewer companies should not be allowed to use the full gross-up method on taxable CIAC (i.e., connection fees and service lines – also known as tap on fees) received after January 11, 2001 except with prior approval in the rare case of an existing utility whose financial condition is such that paying the taxes itself would make the utility nonviable. The Commission notes that in the case of customer connection fees and service lines (also known as tap on fees), the "contributor" is the actual customer (or homeowner) not a developer or home builder.

Docket No. M-100, Sub 148

In response to the recent federal Tax Act, the Commission issued an Order on January 3, 2018, that, among other things, requested initial and reply comments from interested parties in a generic rulemaking proceeding, Docket No. M-100, Sub 148. The Public Staff recommended in its reply comments in that docket that the Commission follow the previous Commission precedent of requiring water and wastewater companies to collect the income tax on CIAC from the contributor using the full gross-up method. The Public Staff further recommended that the Commission allow individual companies seeking to use the present value method to do so with prior approval by the Commission. The Public Staff requested that the Commission open a new docket and provide notice of this change in the taxability of CIAC to all water and wastewater companies, not just the utilities subject to Docket No. M-100, Sub 148.[1] The Public Staff specified that the Commission should direct all water and wastewater companies to seek to collect the income tax on CIAC from contributors of plant for new contributions contracted for on or after the date of the opening of that new docket.

INITIAL COMMENTS[2]

Aqua filed the affidavit of Shannon V. Becker, State President, Aqua, presenting Aqua's comments. Mr. Becker recommended that the Commission not adopt either the full gross-up method or the present value method wherein the water and wastewater companies collect the income tax on CIAC from the contributor. Instead, Mr. Becker requested that the Commission adopt the utility financing method whereby the utility receiving the taxable CIAC is responsible to pay the applicable taxes and is allowed to recover the payment of those taxes in rate base.

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[1] In its January 3, 2018 Order in Docket No. M-100, Sub 148, the Commission excluded water and wastewater companies with $250,000 or less in annual operating revenues from participation in the proceeding.

[2] These comments and the rest of the body of this Order are presented in regard to the present matter in Docket No. W-100, Sub 57.

Mr. Becker noted that in support of utilizing the utility financing method, which places the responsibility exclusively on the utility to pay for the taxes on contributed property, Aqua provides the following rationales:

1. Provides consistency with current tax payment responsibility for tap fees:

    - Tap fees (or customer connection fees) are fees contributed by a customer to a utility company to reimburse the company for the cost incurred in connecting that customer's premise to the utility system. Tap fees are another means of a contribution to a utility, similar in many respects to CIAC[1], in that it is recorded as a reduction to a utility's rate base and recorded within the CIAC account. Since the 1990s, the Commission has required utility companies to pay tax on these tap fees (both federal and state income tax). The tax incurred as a result of the receipt of CIAC should be treated consistently with the tax incurred as a result of the receipt of tap fees[2].

2. Tax expense should follow the benefits of the additional utility revenues being generated. The developer does not benefit from the utility-generated revenues, therefore it seems unjust to require the developer's contribution towards the tax.

3. All other federal and state taxes are spread over the entire body of utility customers regardless of the driver or generational source. Consistency with this basic tenant of ratemaking has merit.

4. Removes the disincentive for developers to work with regulated utilities, which supports growth.

    - Developers contribute a significant amount of utility property to private regulated water and wastewater utilities.

    - Requiring developers to additionally contribute cash for the taxes on CIAC increases their costs to do business and provides a disincentive to work with regulated water and wastewater utilities. This places regulated utilities at a competitive disadvantage to attracting new development growth, which helps minimize customer rate increases.

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[1] Based on the IRS's January 11, 2001 final regulations concerning the definition of CIAC, the IRS found that a customer connection fee is not CIAC for tax purposes.

[2] The Commission notes that tap on fees or customer connection fees are paid directly by an individual homeowner and, generally, other forms of CIAC are received from developers or homebuilders. As noted earlier herein, the Commission's March 7, 2001 Order stated that the Public Staff had represented that the taxes on customer connection fees would not have a significant impact on water and sewer utilities overall.

- The recommended utility financing method provides that the additional tax costs would become part of the utility's revenue requirement and spreads the cost to all utility customers. However, the utility's customers benefit more directly from the economic development and new customer growth, since the utility revenue generated by these additional customers provides for greater economies of scale. [Mr. Becker noted that Exhibit A attached to his affidavit provides a hypothetical example to demonstrate the economic benefits of customer growth to a utility's existing customer base.]

5. Promotes continued professional regulated utility operations ownership and management:

   - Developers that are required to contribute additional cash for taxes on CIAC would be less likely to turn over (contribute) applicable assets and operation of a utility system to a professional regulated utility company whose primary focus is on operating water and wastewater utilities.

   - Developers would, alternatively, be incented to retain ownership and operation of their small utility systems or find alternative non-regulated utility partnerships.

   - Requiring the utility to maintain sole responsibility to pay the taxes on CIAC under the utility financing method lessens the likelihood of developers and homeowners' associations (HOAs) continuing to operate small systems. In an era of technology challenges, regionalization, increasingly stringent water quality regulations and customers who demand higher reliability and service standards, customers are better served by a utility provider who has access to required capital and water quality expertise.

6. Smaller tax bill:

   - The tax bill due when the developer is responsible to contribute cash to also cover taxes on CIAC using the present value or full gross-up methods is significantly more than if the tax bill was calculated and paid directly by the utility without collecting additional cash from the developers for taxes on CIAC.[1]

[1] Aqua's affidavit of Mr. Becker included an Exhibit B which provided Mr. Becker's example of taxes due under the three methods. His example was of $334,000 in CIAC (taxable income), and he showed that the taxes due would be as follows: using the utility financing method: $78,056; using the present value method: $92,987; and using the full gross-up method: $101,870. His numbers represent that using the full gross-up method would increase the taxes due by approximately 30%.

> • The utility is required to pay taxes on the cost of total contributions (plant and cash) received from a developer. If the developer is required to contribute cash to cover taxes on the CIAC, using any method, present value method or full gross-up, the taxable income amount reported by the utility company, and the resulting tax bill, is higher than if the utility company paid the tax on the historical cost of contributed capital only. In this case, the taxable income is higher because it includes not only the tax on the value of utility assets contributed, but also the amount of additional tax required to be paid on the contributed taxes charged to the contributor (tax on tax). . . . [Mr. Becker noted that Exhibit B to his affidavit is an example of the difference in taxes paid to the IRS and the state under each methodology.] The amount of tax ultimately paid on contributed assets will likely end up being fully recovered from the consumer either through lot costs or utility bills. As such, the customer benefits by ensuring the payment of taxes is minimized to the extent legally allowed by regulation.
>
> • The purpose of CIAC is to protect the financial interests of existing utility customers from the private utility taking on risk in development growth. The developer builds a utility system and donates it to a private utility provider, thus placing both the initial cost of the utility system and the risk that the development will not fully build out, on the developer. Whether the private utility pays the tax, it does not significantly change the purpose of the CIAC, which is to protect the utility from making major capital investments in utility systems which may not be built out. If the private utility pays the tax on the contribution, this tax will ultimately be returned through tax depreciation deductions occurring over the tax life of the utility property.

Mr. Becker noted that if the Commission does require a developer to contribute cash for taxes on CIAC, the next preferred method for Aqua would be the net gross-up method, also known as the present value method. Mr. Becker stated that under this method, the developer pays the tax, including the tax on tax, minus the net present value of the future benefits of tax depreciation. Mr. Becker maintained that the result of this method is that the developer would still pay to the utility the tax on the contribution, but the amount would be smaller than the tax payment would be if the full gross-up method was utilized, but more than if the utility financing method were required.

Mr. Becker further provided that a third alternative is the full gross-up method. Mr. Becker asserted that this is the least preferable method of collecting the tax on the CIAC property, from Aqua's perspective. Mr. Becker maintained that the full gross-up method requires the developer to gross-up the advance or the CIAC by the full amount of the taxes due on the contribution. Mr. Becker noted that because this amount added to the advance or CIAC for taxes is also deemed to be taxable, the gross-up must be further increased to pay the tax on the tax.[1] Mr. Becker argued that considering the federal corporate income tax rate of 21% and the North Carolina corporate income tax rate of 3%, the base CIAC amount received would have to be grossed up by 130.4%. Mr. Becker maintained that the full gross-up method places the entire burden of the tax on the contributor-developer, who expectedly passes the inflated tax bill on through higher prices of those who purchase the lot/homes. Mr. Becker stated that the utility and the existing ratepayers do not incur any additional costs. Mr. Becker noted that, however, this is the most expensive alternative for the developer, and this method may place the utility at a competitive disadvantage with nearby municipalities that do not pay income taxes, and therefore, require no tax gross-up.

CWSNC filed the affidavit of Anthony Gray, Senior Financial and Regulatory Analyst for CWSNC, presenting CWSNC's comments. Mr. Gray stated that as part of the Tax Act, contributions to the Company of cash and property are no longer excluded from taxation for water and wastewater companies and that while this provision also affects contributions received by the Company such as grants and debt forgiveness, the primary effect concerns CIAC.

Mr. Gray observed that, thus, effective January 1, 2018, water and wastewater companies like CWSNC will have to begin paying income taxes on cash and property CIAC they receive. Mr. Gray asserted that this change will negatively affect CWSNC's opportunity to earn a reasonable return on its property used and useful in public service if the Company is not allowed to collect the appropriate tax on the CIAC received.

Mr. Gray maintained that there are three alternatives generally accepted by regulators when considering tax gross-up of CIAC for utilities. First, he noted that the full gross-up method requires the contributor or developer to provide the gross-up for income taxes in addition to the principal contribution, sufficient to cover the tax burden of the utility. Mr. Gray stated that the utility would then reimburse the developer for the tax benefit of the contribution as the asset is depreciated on future tax returns. Mr. Gray noted that the second alternative is the present value method that nets the full gross-up contribution with the present value of future tax benefits from depreciation. Mr. Gray further stated that the third alternative is the utility financing method that does not require the contributor to pay any tax on the contribution, leaving the tax obligation on the utility. Mr. Gray maintained that the tax gross-up paid by the utility would result in a deferred tax debit that would reduce over the life of the asset as the tax benefits of depreciation are realized.

Mr. Gray argued that the full gross-up method results in the full tax impact being borne by the contributor. Mr. Gray noted that using the current blended state income tax and federal income tax effective rate of 23.37% (3% for the state income tax rate and 21% for the federal income tax rate) produces an additional charge to the contributor of 30.5% above the contributed amount (1 / (1 – 23.37%)) – 1). Mr. Gray asserted that this method results in the highest overall cost, as it requires a tax on tax for the gross-up to provide full coverage of the resulting tax liability.

Mr. Gray stated that the present value method results in a tax charge being passed to the contributor, but not to the same degree as the full gross-up method, as the contributor would obtain

[1] So as an example, if a utility collected $1,000 in CIAC, it would need to be grossed-up to collect the taxes due by $304 and then would need to be further grossed-up to collect the taxes due on $304 in taxes (i.e., the tax on the tax).

the present value of expected future tax benefits as an up-front offset to the tax gross-up. However, Mr. Gray asserted that this method still results in a sizable additional cost to the contributor of approximately 16% as shown in Exhibit 1 attached to his affidavit. Mr. Gray maintained that the present value method would result in a smaller initial deferred tax debit than the utility financing method, as the overall gross-up and tax benefit impacts are effectively shared by the utility and contributor.

Mr. Gray further noted that the utility financing method results in the full tax impact being initially borne by the utility. Mr. Gray stated that this will result in a deferred tax debit and an increase to rate base for the utility's funding of the income tax charge tied to accepting the contribution. He explained that over time, the utility will realize tax depreciation benefits from the contributed property in future tax returns that will generate deferred tax credits and offset the initial debit. Mr. Gray asserted that, in effect, the utility is providing up-front funding, or financing, of the tax charge and being reimbursed over time as tax benefits accrue.

Mr. Gray maintained that CWSNC recognizes that there are positives and negatives related to each method. Mr. Gray stated that, however, the Company recommends the Commission adopt the utility financing method for contributions. Mr. Gray asserted that it is generally the case that developer activity (that is, contributing property and new customers to a utility's water and wastewater systems) is a benefit to existing utility customers in many ways. Mr. Gray stated that the rate base and maintenance expenses per customer added is much less than that of existing customers, as the property is treated as cost-free capital for ratemaking and newly built systems require minimal regular maintenance. Mr. Gray maintained that, additionally, operating expenses are only incremental to existing levels due to economies of scale, and new customers add to the revenue base at a level comparable to existing customers on a per-capita basis. Mr. Gray stated that, in short, existing customers benefit from contributions through lower per-customer costs in the Company's revenue requirement.

Mr. Gray further noted that the full gross-up method and, to a lesser extent, the present value method both require a contributor to provide considerable up-front cash to facilitate the transfer of property. Mr. Gray stated that, as such, this puts utilities such as CWSNC at a competitive disadvantage in attracting developer business. Mr. Gray argued that developers are incentivized to create a stand-alone, non-regulated water and wastewater system that is operated by a HOA, which impairs the need within the overall water and wastewater industry to facilitate interconnected systems which take advantage of economies of scale. Mr. Gray also noted that an adjacent government-owned utility could create an incentive for a developer to find a way to circumvent the regulated utility's exclusive service territory.

Mr. Gray maintained that in utilizing the utility financing method, the flow of developer projects will not be harmed by the new provisions of the Tax Act. He noted that this method is also the lowest overall cost alternative, as it avoids the "tax on tax" gross-up process[1] with the full gross-up and present value methods. Mr. Gray stated that, moreover, CWSNC contends that although there would be an initial increase in rate base due to the deferred tax debit created, the amount would be far less than if the assets were constructed by the Company itself, and

[1] In other words, taxes must be paid on the taxes collected on the CIAC.

per-customer savings in operating and maintenance expense would add to the existing customer benefit.

Mr. Gray stated that to the extent smaller regulated water and wastewater utilities would be unduly burdened by the utility financing method's upfront tax impact, CWSNC recommended the present value method be approved for such entities. Mr. Gray noted that although the calculations required to maintain records for the present value method may be the most cumbersome of these three options, it would provide value to existing customers by limiting the passing of the tax burden fully to contributors.

__ONSWC__ noted that effective January 1, 2018, water and wastewater utilities, such as ONSWC, will have to begin paying income taxes on cash and property CIAC that they receive. ONSWC asserted that this change will negatively affect its opportunity to earn a reasonable rate of return on its property used and useful in service if ONSWC is not allowed to collect the appropriate tax on the CIAC received.

ONSWC stated that it is one of the regulated water and wastewater utilities within North Carolina specifically requested by the October 5, 2018 Order to file with the Commission initial comments by October 25, 2018, and to include the following information in the comments; "[T]he appropriateness of using the full gross-up method and present value method as proposed by the Public Staff along with any other issues for the Commission to consider related to CIAC and the Tax Act." ONSWC requested that the Commission approve both the full gross-up method and the present value method, and allow the individual company to use either the full gross-up method or the present value method.

The __Public Staff__ noted in its comments that the Tax Act changed the taxability of CIAC by making CIAC taxable for water and wastewater companies. The Public Staff maintained that it continues to support the use of the full gross-up method and the requirement that the companies collect the income tax on CIAC from the contributor. The Public Staff noted that it also supports the ability of individual companies to use the present value method with prior Commission approval.

PUBLIC STAFF'S REPORT ON TARIFF CHANGES

The Public Staff stated that it has reviewed the tariffs of the water and wastewater public utilities and recommends that the tariffs be changed to reflect the changes in the Tax Act that make CIAC taxable. The Public Staff recommended that all water and wastewater tariffs should be amended to include the following language: "The utility shall collect the full gross-up on all contributions in aid of construction, including connection fees and tap fees."

The Public Staff maintained that based on its experience in previous dockets, specifically Docket No. M-100, Sub 138 concerning the recent State corporate income tax reductions, the Public Staff contends that the most expedient way to ensure that all water and wastewater tariffs are amended appropriately is to allow the Public Staff to draft revised tariffs and submit the tariffs to the Commission for approval. The Public Staff stated that before revising the tariffs to add the language proposed by the Public Staff, the tariffs must be carefully reviewed for accuracy and to ensure that the appropriate version is revised. The Public Staff asserted that given the large number of water and wastewater companies and the upcoming holidays, it would take up to six months to complete the process of revising tariffs for all of the water and wastewater companies.

The Public Staff stated that it would propose to begin its process of revising the tariffs of water and wastewater companies once the Commission issues an order directing it to do so. The Public Staff further proposed to inform the Commission of its progress on the tariff revision process every 90 days after the Commission issues such an order.

REPLY COMMENTS

The **Public Staff** noted in its reply comments that both Aqua and CWSNC recommended in their initial comments that the Commission adopt the utility financing method, which would allow utilities receiving taxable CIAC to pay the applicable taxes without collecting the taxes from the contributor of CIAC. The Public Staff maintained that ONSWC recommended in its initial comments that the Commission approve both the full gross-up method and the present value method for the collection of federal income taxes from the contributor of CIAC.

The Public Staff commented that the Commission faced a similar decision in 1986 with the enactment of the Federal 1986 Tax Act, which also made CIAC contributions subject to federal income tax. The Public Staff noted that after a careful and thorough investigation, which included an evidentiary hearing, the Commission issued its 1987 CIAC Order. The Public Staff stated that in the 1987 CIAC Order, the Commission directed water and wastewater companies to use the full gross-up method on the collection of CIAC. The Public Staff commented that, however, a company could request to use a different method for a particular case, or a company could use the present value method upon prior Commission approval.

The Public Staff maintained that in the 1987 CIAC Order, the Commission specifically found that "[n]either the present value method nor the full gross-up method . . . will result in any additional costs being passed on to the ratepayers." (1987 CIAC Order, p. 4) The Public Staff commented that the Commission also noted that "the full gross-up method places the risk on the developer, rather than the utility, for the ultimate completion of a project," thereby avoiding "the potentially adverse situation where a water or sewer utility pays from its own funds the tax related to a substantial contribution of a large system serving a generally undeveloped area." (1987 CIAC Order, p. 10)

The Public Staff further noted that in the 1987 CIAC Order, the Commission found that, "[u]nder the no gross-up or partial gross-up method, rate base treatment of the tax cost of CIAC may have a significant impact on customer rates of water and sewer companies." (1987 CIAC Order, p. 4) The Public Staff stated that in support of this finding, the Commission noted that "contributed plant is a material and, in many cases, the single most important component of plant additions implemented by water and sewer companies." (1987 CIAC Order, p. 7)

The Public Staff commented also that in the 1987 CIAC Order, the Commission required water and wastewater companies to include in their annual reports information regarding nontaxable CIAC collected, taxable CIAC collected, and tax collected on CIAC.

The Public Staff opined that the provisions in the 1987 CIAC Order protected the financial status of the Commission-regulated water and wastewater utilities and ensured that their customers were not burdened with increased rates.

The Public Staff further maintained that the current federal and state corporate income tax rates are significantly lower than in 1987. The Public Staff asserted that the full gross-up multiplier, as shown in Appendix A of the 1987 CIAC Order for the 34% federal income tax rate and state income tax rate of 7%, was 69.7% for water companies and 73.5% for wastewater companies. The Public Staff noted that the current federal income tax rate is 21% for all corporate taxable income, and the state income tax rate effective January 1, 2019, will be 2.5%. Therefore, the Public Staff commented, the full gross-up multiplier after January 1, 2019, will be approximately 29.65%.

The Public Staff asserted that the gross-ups paid by the developers should not result in developers retaining ownership of the new water and wastewater systems or transferring the systems to a HOA. The Public Staff stated that developers develop real estate and some construct houses and that developers have no expertise and historically no interest in owning and operating water or wastewater utility systems.

The Public Staff maintained that should a developer retain ownership of the system or plan to transfer the water or wastewater system to a HOA, the developer would still be subject to the relevant state regulations for water and wastewater systems. The Public Staff stated that if a developer retains a water or wastewater utility system, the developer would need to apply to the Commission for a certificate of public convenience and necessity and post the required bond. The Public Staff noted that a developer planning to transfer a system to a HOA would be required to operate each system in compliance with North Carolina Department of Environmental Quality (DEQ) regulations until the HOA has a reasonable number of members to assume operation of each system. The Public Staff asserted that it is in the developer's interest to sell real estate as rapidly as possible, and not experience delays including those resulting from non-compliance with state regulations.

The Public Staff opined that the assertion by CWSNC and Aqua that developers will transfer their new systems to towns, cities, counties, and other government owned utilities to avoid payment of gross-up is without merit.

Further, the Public Staff stated that it strongly opposes the utility financing method recommended by both CWSNC and Aqua that allows the utility to pay the income taxes on CIAC, with the taxes then later added to rate base, thereby increasing customer rates. The Public Staff argued that customers should not be required to finance the utilities' growth. The Public Staff noted that, in addition, both CWSNC and Aqua allocate their out of state corporate headquarters expenses by customer ratio, and, therefore, North Carolina customer growth leads to greater expense allocations.

The Public Staff maintained that it does not oppose the use of the utility financing method with prior Commission approval for a specific utility's CIAC, provided that none of the taxes paid are added to rate base, and are not included in revenue requirement calculations and customer rates. The Public Staff asserted that it is appropriate for the utility's shareholders, who normally are assigned 100% of the gains on sale, to finance the utility's growth.

The Public Staff noted that CWSNC maintained that, under the full gross-up method, the utility would reimburse the developer for the tax benefit of the contributions as the asset is depreciated on future tax returns. The Public Staff asserted that this reimbursement was not required in the 1987 CIAC Order and is not appropriate now. The Public Staff argued that the tax depreciation period is 25 years; many development companies, particularly limited liability companies, exist for limited time periods. The Public Staff maintained that many developer limited liability companies exist only until particular development projects are completed; therefore, reimbursements to developers as proposed by CSWNC are not practical. The Public Staff recommended that the future tax depreciation benefits resulting from the full gross-up be used to calculate a reduction of the income tax expense in the utility's general rate case, thereby reducing the revenue requirement.

The Public Staff noted that the Commission's October 5, 2018 Order in this docket directed water and wastewater companies to collect income tax on CIAC from contributors of plant contracted for on or after the date of the Order using the full gross-up method on an interim basis until a final order is issued in the docket. The Public Staff recommended that the Commission clarify the treatment of CIAC that was contracted for between the dates of the Commission's January 3, 2018 Order in Docket No. M-100, Sub 148, and the October 5, 2018 Order. The Public Staff recommended that, for contracts entered into prior to October 5, 2018, the water and wastewater companies should be authorized to pay the taxes on the CIAC, but the taxes paid should not be added to rate base or included in revenue requirement calculations or customer rates.

The Public Staff argued that the Commission's findings and conclusions in the 1987 CIAC Order requiring water and wastewater companies to use the full gross-up method with respect to CIAC as discussed in its comments, including the reporting requirement, are appropriate and should be adopted by the Commission in this proceeding. The Public Staff maintained that should, however, the Commission approve the utility financing method, the Commission should require companies to exclude the taxes on CIAC from rate base.

LATE-FILED REPLY COMMENTS

Aqua requested that the Commission allow the late-filing of its reply comments. Aqua stated that it did not file reply comments since it thought it had fully discussed the issues in its initial comments. Aqua noted that its late-filed comments were specifically prompted by some portions of the Public Staff's reply comments and that Aqua had discussed its intent to file with the Public Staff as part of a conversation which discussed the need for clarification regarding certain issues. Aqua maintained that by its comments, Aqua brings forward both its differences with certain aspects of the Public Staff's position as revealed in the Public Staff's reply comments, and discusses the need for clarification of certain issues. Aqua requested that the Commission consider its comments as it brings forward matters that were not contemplated by Aqua until after the Public Staff's reply comments and significantly impact Aqua and the developers with whom it contracts.

Aqua's late-filed reply comments consist of the affidavit of Mr. Becker.

Mr. Becker defined the utility financing method, which was recommended by both CWSNC and Aqua in their initial comments, as a method which allows the utility to pay the income taxes on CIAC, with the taxes later added to rate base.

Mr. Becker noted that the primary prompt for Aqua's request to file its reply comments is the Public Staff's recommendation that the requirement to collect developer funding for taxes on contributions be applicable to contracts entered into prior to October 5, 2018, and that any related taxes paid by the utility applicable to those contracts should not be added to rate base or included in revenue requirement calculations or customer rates.

Mr. Becker stated that Aqua continues to support the utility financing method versus the full gross-up method or the present value method that requires developers to fund taxes on CIAC as initially recommended by the Public Staff.

Mr. Becker noted that the Public Staff's reply comments referenced the Commission's 1987 CIAC Order, stating that the Commission specifically found that neither the present value method nor the full gross-up method will result in any additional costs being passed on to the ratepayers. Mr. Becker asserted that this is a correct statement when exclusively considering the recovery of the increased taxes that would be paid by the developer and can be assumed to be passed on to consumers via an increased lot cost. Mr. Becker maintained that while the utility's rates may not increase because of the developer's reimbursement of these taxes to the utility, the increased cost to develop lots would surely be passed along to these same consumers as part of their lot/home purchase. Additionally, Mr. Becker stated that the tax liability paid to the IRS related to contributions received by the utility is greater if recovered from a developer using the full gross-up method or the present value method than if funded by the utility using the utility financing method as the developer must pay taxes on the cash contributed to the utility to pay the tax on the original contribution (i.e., effectively a tax on tax). Mr. Becker argued that the utility financing method avoids this tax on tax, thereby reducing the overall tax liability.

In addressing the Commission's conclusion in its October 5, 2018 Order that all water and wastewater companies shall collect the income tax on CIAC from contributors of plant for new contributions contracted for on or after October 5, 2018 using the full gross-up method on an interim basis until the Commission makes a final decision on the issue, Mr. Becker noted that Aqua regularly closes on phases of developments that include lots and developer plant contributions throughout the year on a monthly, and even weekly, basis. Mr. Becker stated that Aqua maintains a significant inventory of lots that have not yet closed, and contributions have not yet been received, that were contracted for prior to the date of the Commission's October 5, 2018 Order.

Mr. Becker asserted that the interim Order requires water and wastewater utilities to collect from developers the tax due on contributions contracted after October 5, 2018. Mr. Becker argued that including this requirement into new contracts after this date affords utilities a reasonable opportunity to negotiate and include modified terms in new contracts with developers that will require future funding of taxes on contributed property. Mr. Becker stated that developers can be advised of this added cost prior to the execution of a contract, thus affording them an opportunity to more realistically assess the viability of a development project.

Mr. Becker maintained that under the Commission's interim Order requirement, and in consideration of his comments outlined above, Aqua therefore assumed that the utility is not expected to recover taxes on contributions received that were contracted prior to the date of the Order (i.e., October 5, 2018). Mr. Becker asserted that the Public Staff's reply comments, however, propose a contradictory position, recommending that for contracts entered into prior to October 5, 2018, the water and wastewater companies should be authorized to pay the taxes on the CIAC, but the taxes paid should not be added to rate base or included in revenue requirement calculations or customer rates.

Mr. Becker argued that a utility, including Aqua, may not unilaterally modify the terms of previously executed developer contracts. Mr. Becker noted that a utility is not reasonably able to alter the terms of previously executed contracts in an attempt to require funding of a new utility tax from the developer. Mr. Becker stated that developers do not have an incentive to renegotiate terms of an executed contract that will increase their costs to do business. Mr. Becker maintained that attempts by the utility to demand payment for charges outside of existing contracts would likely invite costly litigation against the utility. Mr. Becker stated that absent the utility's ability to collect these funds from the developer, the utility is left with the requirement to fund and pay for all taxes on contributions received from contracts executed prior to the date of the Order.

Mr. Becker further noted that recent consultations between Aqua and developers in the process of executing new contracts with Aqua have included discussion on the potential for the new tax on contributions made after the Order date. Mr. Becker stated that the developers are generally concerned and that Aqua has been asked to keep them apprised of the result so they can include it in their pro forma calculations to determine if the project continues to be financially viable given the potential increase in cost.

Mr. Becker asserted that in the ordinary course of its utility business operation, Aqua makes investments in utility plant, whether it be pipe or wells or equipment, and then recovers the investment and has the opportunity to earn a reasonable return on it, based on the prudency of such investment. Mr. Becker noted that in the event a developer contributes utility property to Aqua, and to the extent Aqua spends additional dollars to upgrade or bring on line this contributed utility plant, the amount of investment beyond the contributed asset basis would be an earning-asset and provide a return to the utility.

Mr. Becker maintained that should Aqua be required to fund a portion of the contributed property, in this case, an income tax payment, the additional utility plant investment should be similarly treated as an earning asset or investment. Mr. Becker argued that it is important to observe that the taxable event is created by the utility company and Aqua's pre-existing developer contracts contain no provisions for the tax to be paid by the developers.

Mr. Becker stated that regulated utility rates are based on actual costs of doing business. Mr. Becker noted that if Aqua is required to pay applicable federal taxes amounting to approximately 25% of the cost of developer-contributed property, this additional cost, above the amount governed by the pre-existing developer contract, should be eligible for inclusion in the

Company's rate base; thereby, allowing Aqua to receive a return on its investment in recognition of the fact that acceptance of the contributed property was prudent and necessary to the provision of utility services.

Mr. Becker maintained that given that the added cost is mandated by a federal law that requires a tax payment be made by the utility company as a result of the utility investment being made, Aqua asserts that this tax payment is similar to any other reasonable and prudent costs incurred in constructing or dedicating utility plant to service, such as water and wastewater pipe, labor, and engineering fees, and should be recoverable in rate base.

In addition, Mr. Becker noted that developer-funded tax on CIAC, including amounts paid to a utility for taxes on CIAC is like other known costs of doing business; it is recovered in the developer's lot cost and excluded from the utility's recoverable rate base. Mr. Becker stated that it follows that reasonable and prudent utility-funded costs that are not recoverable through contributions, including tax on contributions contracted prior to October 5, 2018, should be recoverable in the utility's rate base.

Mr. Becker stated that the Public Staff opined in its reply comments that customers should not be required to finance the utilities' growth. Mr. Becker maintained that Aqua respectfully suggests that this focus, under these facts, is both too narrow and fails to respect the equity and logic that supports some recovery of or on any legitimate, reasonable and prudent costs that the utility is required to pay, including this tax. Mr. Becker asserted that both customers and utility companies benefit from growth through increased revenues, dilution of fixed costs and revenue requirement, as well as furthering economies of scale. Mr. Becker noted that payment of taxes on CIAC is a required cost of doing business related to contributed utility property received in the normal course of doing business. Mr. Becker argued that it is not speculative and can be reasonably expected to benefit the utility and the utility's existing customer base included within a consolidated rate structure. Mr. Becker maintained that this property is necessary to serve, and related to, those lots being closed that will be added as new connections in the near future. Mr. Becker stated that utility shareholders should not be expected to solely bear this required incremental cost related to the Tax Act when the utility and customers both similarly benefit from growth. Mr. Becker argued that to do so is inequitable and prejudicial to Aqua in this circumstance.

Mr. Becker stated that the Public Staff's assertion that both CWSNC and Aqua allocate their out of state corporate headquarters expenses by customer ratio and that North Carolina customer growth leads to greater expense allocations is correct, but only partially reflective of the full picture. Mr. Becker maintained that a more complete view considers the beneficial utility billings generated by new customers, and the fact that Aqua's North Carolina share of corporate expenses is allocated based on actual customer connections after the lot is closed and becomes revenue producing. Mr. Becker noted that the additional customers and related revenues more than offset the allocated expenses, and therefore benefit the customers favorably by diluting the utility's revenue requirement that results in lower customer rates. Mr. Becker stated that the Public Staff's focus only on additional allocated costs, although correct insofar as it goes, ignores the additional beneficial utility billings generated by the new customers, which exceed the additional allocated costs.

Mr. Becker also noted that the Public Staff commented that in the 1987 CIAC Order, the Commission required water and wastewater companies to include in their annual reports information regarding nontaxable CIAC collected, taxable CIAC collected, and tax collected on CIAC. Mr. Becker stated that if the Commission requires similar reports, Aqua requests that the Commission clarify the specific types of property and non-property related CIAC that are taxable, including contractually-negotiated connection fees, capacity fees, tap fees, and meter set fees, and for which of the types of CIAC the taxes should be recoverable from developers, if any.

In conclusion, Mr. Becker stated that Aqua strongly opposes the Public Staff's recommendation to disallow the Company from including taxes in rate base which were reasonably and prudently funded and paid by the utility related to contributions received pursuant to contracts executed prior to the date of the Commission's October 5, 2018 Order. Mr. Becker noted that Aqua continues to support the use of the utility financing method for contracts that either predate or postdate the Commission's October 5, 2018 Order.

DECEMBER 19, 2018 LETTER FROM THE NCHBA[1]

Tim Minton, Director of Government Affairs for the NCHBA, filed a letter with the Commission on this issue on behalf of the NCHBA. Mr. Minton stated that the NCHBA requests that the Commission direct that developers are not required to pay a gross-up fee to cover any utility's CIAC tax liabilities. Mr. Minton stated that this change in the federal tax law should be treated like any other income tax provision and included in the rate base of the utility. Mr. Minton asserted that utilities receive various tax requirements, some positive and some negative, that should be considered collectively as part of the rate base.

Mr. Minton maintained that developers who are donating hundreds of thousands of dollars in infrastructure to these utilities cannot afford this additional cost of taxes. He stated that this requirement will drive up the cost of housing and make it even more difficult for first-time buyers to purchase a home. Mr. Minton asserted that studies show that for every $1,000 in additional costs, more than 6,300 households in North Carolina are priced out of the market. He stated that many of these utility systems are in rural areas where this type of cost would have an even greater impact.

Further, Mr. Minton stated that the utility and its rate base receive the benefit of the infrastructure contribution with increased assets for he company. He argued that developers should not be required to pay this tax when the utility and its rate base are receiving this benefit.

Finally, Mr. Minton noted that the State of Missouri Public Service Commission (Missouri Commission) recently ruled that the new CIAC requirements shall be part of the consideration for rates. Mr. Minton encouraged the Commission to do the same. He attached a copy of the Missouri Commission's ruling to his letter.

[1] Neither the NCHBA nor Mr. Minton is a party of record in this proceeding, and his letter has been recognized by the Commission as a Consumer Statement of Position.

DECEMBER 20, 2018 LETTER FROM MARQUIS HOMES & COMPANY[1]

Mr. Tom Hankins, President, Marquis Homes & Company filed a letter dated December 20, 2018 concerning this issue. Mr. Hankins stated that he is a Wake county residential developer and a custom homebuilder. He stated that most of his development projects are in the North Raleigh area within the Falls Lake watershed, where municipal water services are not available. Mr. Hankins noted that he typically constructs community water systems that get passed on to Aqua to own and administer. Mr. Hankins stated that Aqua recently informed him that the gross-up tax for CIAC has been reinstated as a part of the Tax Act. He maintained that, as a result, he has been told that if Aqua is not allowed to pay the tax and pass it along through their rate structure, parties that provide the CIAC will be responsible for paying it.

Mr. Hankins noted that on the most recent project that Marquis Homes & Company currently has under construction, using the full gross-up method for CIAC would have added $45,500 in total or $1,750 in cost per lot. He stated that on a current 65-lot neighborhood Marquis Homes & Company is preparing to submit to Wake County Planning it would increase their lot cost by more than $2,000 per lot. Mr. Hankins maintained that part of this erodes Marquis Homes & Company's margins, but the lion's share gets passed onto the builders and ultimately the new homeowners, but only after a multiplier effect for increases in real estate commissions, loan origination fees, increased monthly mortgage payments, and property taxes are applied, all furthering the expense to own a new home.

Mr. Hankins asserted that with development costs already spiraling out of control, due to increased regulations, new tariffs, and labor shortages, this gross-up tax has the potential to be yet another burden in trying to make housing affordable. Mr. Hankins urged the Commission to allow Aqua to pay this gross-up tax and pass it along through its rate structure.

DISCUSSION AND CONCLUSIONS

After reviewing all of the comments received on this issue, the Commission has determined that there are five issues that need to be addressed, as follows: (1) what is the appropriate methodology to apply to CIAC after the Tax Act; (2) how should CIAC contracted for between January 3, 2018 and October 4, 2018 be treated; (3) should the tariffs of water and wastewater companies be amended after the Tax Act; (4) is it appropriate under the full gross-up method for the utility to reimburse the developer for the tax benefit of the contribution as the asset is depreciated on future tax returns; and should the Commission require on-going reporting on CIAC and the taxes collected on CIAC by the water and wastewater companies? The Commission will address each issue separately below.

[1] Neither Mr. Hankins nor Marquis Homes & Company is a party of record in this proceeding, and Mr. Hankins' letter has been recognized by the Commission as a Consumer Statement of Position.

Methodology

Based on a review of the comments filed in this docket, the Commission notes that the parties support different methodologies for the Commission to adopt to apply to CIAC, as follows:

- Aqua and CWSNC recommended that the Commission adopt the utility financing method whereby the utility pays the taxes due on any collected CIAC and the taxes paid are then included in the company's rate base, thereby increasing rates, for recovery from all of the utility's ratepayers.

- ONSWC recommended that the Commission allow utilities to use either the full gross-up method whereby the entity providing the CIAC pays the applicable taxes to the utility collecting the CIAC or the present value method whereby the entity providing the CIAC pays the applicable taxes, less the amount of the present value of future depreciation.

- The Public Staff recommended that the Commission adopt the full gross-up method and the requirement that the companies collect the income tax on CIAC from the contributor but allow individual utilities to use the present value method with prior Commission approval. The Public Staff also stated that it does not oppose the use of the utility financing method with prior Commission approval for a specific utility's CIAC, provided that none of the taxes paid are added to rate base and are not included in revenue requirement calculations and customer rates.

After reviewing all of the comments filed on this issue, the Commission concludes that it is appropriate to allow the water and wastewater companies the most flexibility possible in determining which party pays the taxes due on CIAC while also holding the ratepayers harmless from any potential rate increases due to the taxes.

Therefore, the Commission concludes that, unless requested and approved otherwise, all certificated water and wastewater companies should collect the income tax on CIAC from contributors for new contributions contracted for on or after October 5, 2018 using the full gross-up method. However, any certificated water or wastewater company may file a request with the Commission to use the present value method and may use the present value method on a going-forward basis only after receiving approval from the Commission. Further, any certificated water or wastewater company may file a request with the Commission to use the utility financing method and may use the utility financing method on a going-forward basis only after receiving approval from the Commission. However, if a utility is granted approval from the Commission to use the utility financing method, the Commission concludes that no amount of the taxes paid by the utility may be included in the company's rate base or otherwise reflected in the company's revenue requirement. The Commission finds that ratepayers should be held harmless when the utility financing method is used. The Commission finds that its decision herein allows each utility to examine the three options available to it concerning an appropriate CIAC tax methodology to use and determine which methodology will work best in managing its business.

However, if a company requests to use the utility financing method and receives Commission authority to use the method without rate base recovery, the Commission finds it appropriate to allow companies to request a waiver from the Commission for recovery of the taxes paid in certain limited circumstances. For example, the Commission finds that if a situation arises wherein contributed plant will benefit the operations of the utility and serve to benefit all of the company's ratepayers, such as contributed plant that increases the well or storage capacity on a per customer basis for the utility's entire system, the utility may seek a waiver for recovery of the taxes paid from the Commission for that particular case of CIAC. The Commission will seek comments from interested parties on each individual waiver request and will issue a final decision on whether the tax on that particular CIAC will be allowed recovery through the utility's rate base. The Commission expects that this waiver mechanism will be the exception and not the rule so as to not create an administrative burden for the Commission or interested parties including the Public Staff.

In reaching this decision, the Commission is persuaded by the Public Staff's assertions that the precedent on this issue as outlined in the Commission's 1987 CIAC Order continues to be reasonable and appropriate. As the Public Staff noted, the provisions of the 1987 CIAC Order protected the financial status of the Commission-regulated water and wastewater utilities and ensured that their customers were not burdened with increased rates. The Commission finds that this result is also appropriate now in this pending docket.

Further, the Commission is persuaded by the Public Staff's comments that ratepayers should not be required to finance a utility's growth. Although Aqua noted in its late-filed reply comments that both customers and utility companies benefit from growth and even provided a limited economic benefit analysis in Exhibit A as attached to Aqua's initial comments, the Commission finds that no compelling evidence has been provided to quantitatively support the real magnitude or degree of this assertion. The Commission finds that any cost/benefit analysis of Aqua's assertion would by necessity be full of estimates and assumptions and would need to reflect quantitative as well as non-quantitative analysis. A key non-quantitative input is risk. As alluded to by the Public Staff, use of the utility financing method would shift risk from the developers to the utility (and ultimately the utility's ratepayers) for the ultimate completion of a project, such as a large housing subdivision. Aqua's Exhibit A attached to its initial comments does not include such non-quantitative factors. In addition, the Public Staff provided quotes in its reply comments from the Commission's 1987 CIAC Order to this effect as follows:

> [n]either the present value method nor the full gross-up method . . . will result in any additional costs being passed on to the ratepayers." (1987 CIAC Order, p. 4) The Commission also found that, "the full gross-up method places the risk on the developer, rather than the utility, for the ultimate completion of a project," thereby avoiding "the potentially adverse situation where a water or sewer utility pays from its own funds the tax related to a substantial contribution of a large system serving a generally undeveloped area." (1987 CIAC Order, p. 10)

In addition, the Commission finds that its decision herein applies the appropriate ratemaking principle of cost causation that the cost causer pays for the incremental infrastructure and associated costs. As Aqua noted in its initial comments, use of the full gross-up method places the entire burden of the tax on the contributor/developer, who expectedly passes the tax bill on through higher prices to those who purchase the lots/homes. The Commission concludes that this result is appropriate. The Commission finds that applying the cost causation principle will result in the tax burden being placed on the person purchasing a lot/home and not on the entire universe of the utility's ratepayers.

Further, the Commission notes that Mr. Minton stated in his letter that the Missouri Commission recently ruled that the new CIAC requirements should be part of the consideration for rates, and he encouraged the Commission to do the same. Mr. Minton attached a copy of the Missouri Commission's ruling to his letter.

The Commission notes that on December 5, 2018, the Missouri Commission issued a Notice That Tariff Will Be Allowed To Go Into Effect (the Notice). The Notice concerns an August 21, 2018 tariff filed by Missouri-American Water Company with a proposed effective date of September 20, 2018. The tariff changes how the Missouri-American Water Company accounts for income taxes that accrue from CIAC. The specific language included in the tariff is as follows:

> Any Federal, State or Local income tax incurred by the Company due to the receipt of taxable Advances or Contributions in Aid of Construction, as defined by the Internal Revenue Service, the State of Missouri, or other taxing authority, and not otherwise paid by a third party, will be paid by the Company. Such income taxes shall be segregated in a deferred account for inclusion in rate base in the Company's next general rate proceeding.

The staff of the Missouri Commission filed a motion to suspend the tariff and conduct proceedings to determine whether to adopt or reject the proposed tariff. The Missouri Commission suspended the tariff until December 7, 2018. The staff filed a recommendation arguing that the deferral of CIAC income tax impacts, as contemplated in the tariff, should only be authorized to continue until such time as new rates go into effect from Missouri-American Water Company's next general rate proceeding. The Missouri Commission ruled in its December 5, 2018 Notice that, given the staff's recommendation and no opposition to the tariff taking effect, the tariff filed by Missouri-American Water Company would be allowed to take effect by operation of law on December 7, 2018.

The Commission finds that the situation in Missouri is very different in several key respects from this proceeding. First, the Notice concerns a tariff filing by one specific water company in Missouri. The Commission here is reviewing this issue within the context of a generic proceeding with comments and reply comments filed by the parties. In addition, the staff of the Missouri Commission recommended that the tariff be allowed to be effective until Missouri-American Water Company's next general rate case. In North Carolina, the Public Staff, representing the using and consuming public, has recommended the use of the full gross-up method wherein the tax is paid by the contributor, not the utility company. Further, in Missouri, no party filed any opposition to the proposed tariff. Again, here, the record of evidence shows that the parties do not agree on the method to be used to account for the taxability of CIAC. Therefore, the Commission places very little weight on the Notice by the Missouri Commission. Further, the Commission notes that no party provided any additional information on how other state commissions are deciding this issue for the Commission to consider.

In addition, the Commission notes that in its recent Orders in three dockets concerning alternative gas pilot programs the Commission determined that Piedmont Natural Gas Company's (Piedmont's) ratepayers should be held harmless if Piedmont is required to pay income taxes on any capital payments made by a third-party to Piedmont. More specifically, on February 4, 2019, the Commission issued an Order Approving Participation in Pilot Program with Conditions in Docket No. G-9, Sub 735. Ordering Paragraph No. 3 of that Order specified, "[t]hat Piedmont's ratepayers shall be held harmless if Piedmont is required to pay income taxes on any capital payments made by Catawba to Piedmont". Further, on March 11, 2019, the Commission issued an Order Approving Participation in Pilot Program with Conditions in Docket No. G-9, Sub 728. Ordering Paragraph No. 3 of that Order specified, "[t]hat Piedmont's ratepayers shall be held harmless if Piedmont is required to pay income taxes on any capital payments made by GESS to Piedmont." Finally, on April 16, 2019, the Commission issued an Order Approving Participation in Pilot Program with Conditions in Docket No. G-9, Sub 739. Ordering Paragraph No. 3 of that Order specified, "[t]hat Piedmont's ratepayers shall be held harmless if Piedmont is required to pay income taxes on any capital payments made by Foothills to Piedmont." The Commission's decision herein is consistent with these recent natural gas Orders.

Based upon the foregoing, the Commission concludes that, unless requested and approved otherwise, all certificated water and wastewater companies should collect the income tax on CIAC from contributors for new contributions contracted for on or after October 5, 2018 using the full gross-up method. However, any certificated water or wastewater company may file a request with the Commission to use the present value method and may use the present value method on a going-forward basis only after receiving approval from the Commission. Further, any certificated water or wastewater company may file a request with the Commission to use the utility financing method and may use the utility financing method on a going-forward basis only after receiving approval from the Commission. However, if a utility is granted approval from the Commission to use the utility financing method, the Commission concludes that no amount of the taxes paid by the utility may be included in the company's rate base or otherwise reflected in the company's revenue requirement. The Commission finds that ratepayers should be held harmless when the utility financing method is used. The Commission will allow individual waiver requests as discussed above.

<u>CIAC Contracted for Between January 3, 2018 and October 4, 2018</u>

The Commission concluded in its October 5, 2018 Order that all water and wastewater companies should collect the income tax on CIAC from contributors of plant for new contributions contracted for on or after October 5, 2018 using the full gross-up method on an interim basis until the Commission makes a final decision on the issue. In their comments, the parties have raised the question of how CIAC contracted for between the Commission's January 3, 2018 Order establishing the generic federal corporate income tax docket and the Commission's October 5, 2018 Order requiring the full gross-up method on an interim basis should be treated.

The Public Staff recommended that the Commission conclude that for contracts entered into prior to October 5, 2018, the water and wastewater companies should be authorized to pay the taxes on the CIAC, but the taxes paid should not be added to rate base or included in revenue requirement calculations or customer rates. Aqua strongly opposed that recommendation in its late-filed reply comments and instead proposed that the Commission find that the water and wastewater companies should be authorized to pay the taxes on the CIAC and that the taxes paid should be added to rate base or included in revenue requirement calculations or customer rates.

The Commission is persuaded by Aqua's late-filed reply comments in this regard wherein Aqua argued that a utility, including Aqua, may not unilaterally modify the terms of previously executed developer contracts. As noted by Aqua, a utility is not reasonably able to alter the terms of previously executed contracts in an attempt to require funding of a new utility tax from the developer and that developers do not have an incentive to renegotiate terms of an executed contract that will increase their costs to do business. As Aqua noted, absent the utility's ability to collect these funds from the developer, the utility is left with the requirement to fund and pay for all taxes on contributions received from contracts executed prior to the date of the Order (i.e., October 5, 2018).

The Commission also notes that this decision is consistent with the 1987 CIAC Order wherein the Commission concluded on page 18:

> Evidence supporting this finding of fact is found in the record as a whole, and particularly the testimony of Carolina Water Service witness O'Brien, the testimony of Charles Smith of Charles Smith Builders, and the testimony of the Public Staff witnesses. Witness Smith testified that CIAC gross-up requirements should not interfere with existing contracts between developers and utilities. In addition, this concern was expressed by the Public Staff witnesses and is noted in the proposed order of North Carolina Natural Gas Corporation. Based on the foregoing, the Commission concludes that the rules and procedures contained in this Order are applicable to CIAC subject to taxation that was not under oral or written contract prior to February 3, 1987[1], the date of the Commission's Interim Order requiring gross-up procedures. Consistent with this conclusion, the Commission concludes that utilities receiving CIAC that were under contract prior to February 3, 1987, should be authorized to pay any related taxes on CIAC from the utility's funds.[2]

Therefore, the Commission finds it appropriate to allow utilities to use the utility financing method on CIAC contracted for between January 3, 2018 and October 4, 2018 and only during this limited time period, to reflect the taxes paid by the utility in the utility's rate base. Utilities may also use the full gross-up method during this time period. The Commission's decision herein reflects a balancing of interests of all of the parties to this proceeding and appropriately and fairly treats the CIAC contracted for between January 3, 2018 and October 4, 2018.

[1] On February 3, 1987, the Commission issued an Order which, among other things, required full gross-up of CIAC pending a final decision in the docket.

[2] It is unclear whether utilities were allowed to reflect any taxes paid in this regard in rate base.

Tariff Revisions

The Public Staff recommended that all water and wastewater tariffs should be amended to include the following language: "The utility shall collect the full gross-up on all contributions in aid of construction, including connection fees and tap fees." The Public Staff stated that it would propose to begin its process of revising the tariffs of water and wastewater companies once the Commission issues an order directing it to do so.

The Public Staff's proposed language was based on its recommendation concerning the appropriate method to apply to CIAC. The Public Staff's proposed language does not reflect the Public Staff's recommendation that water and wastewater utilities be allowed to request to use the present value method or the Public Staff's statement that it would not oppose the use of the utility financing method with prior Commission approval for a specific utility's CIAC, provided that none of the taxes paid are added to rate base and are not included in revenue requirement calculations and customers rates.

Based on the information currently available to the Commission, it appears that the tariffs of the water and wastewater companies will need to be updated to reflect the Commission-approved methodology for each company. However, the tariffs cannot be updated until the specific types of CIAC are identified (as addressed hereinbelow) and each company determines which methodology it will seek Commission approval to use, as appropriate, and the Commission approves, as appropriate, the use of such methodology.

Therefore, the Commission requests that the Public Staff determine when is the appropriate time to begin tariff revisions and to file a request at that time with the Commission to begin the process of updating the tariffs of the water and wastewater companies, as applicable.

Reimbursement to Developers

CWSNC stated in its initial comments that under the full gross-up method, the utility would reimburse the developer for the tax benefit of the contribution as the contributed asset is depreciated on future tax returns. The Public Staff stated in its reply comments that this reimbursement was not required in the 1987 CIAC Order and is not appropriate now. The Public Staff argued that the tax depreciation period is 25 years and that many development companies, particularly limited liability companies, exist for limited time periods. The Public Staff further maintained that many developer limited liability companies exist only until particular development projects are completed and that therefore, reimbursements to developers as proposed by CWSNC are not practical. The Public Staff recommended that the future tax depreciation benefits resulting from the full gross-up be used to calculate a reduction of the income tax expense in the utility's general rate case, thereby reducing the revenue requirement.

The Commission is persuaded by the Public Staff's arguments in this regard and therefore finds that, based on the reasons provided by the Public Staff, when a utility uses the full gross-up method, the future tax depreciation benefits generated should be used to calculate a reduction of the income tax expense in the utility's general rate case.

<u>Reporting on CIAC and the Taxes Collected on CIAC</u>

In the 1987 CIAC Order, the Commission required water and wastewater companies to include in their annual reports information regarding nontaxable CIAC collected, taxable CIAC collected, and the tax collected on CIAC. The Public Staff argued in this proceeding that the Commission's conclusion in the 1987 CIAC Order regarding the reporting requirement is appropriate and should be adopted by the Commission in this proceeding. Aqua commented that if the Commission requires similar reports, Aqua requests that the Commission clarify the specific types of property and non-property related CIAC that are taxable, including contractually-negotiated connection fees, capacity fees, tap fees, and meter set fees and for which of the types of CIAC the taxes should be recoverable from developers, if any. The Public Staff did not file any specific comments on Aqua's request in this regard.

Based upon the foregoing, the Commission finds that it does not have sufficient information at this point in time to require a specific format for reports on CIAC and the taxes on CIAC collected by the water and wastewater companies. The Public Staff is requested to work with both Aqua and CWSNC, and any other interested water or wastewater company, to develop a list of the specific types of property and non-property related to CIAC that are taxable and develop a format agreeable to all parties for the CIAC reporting to follow within the context of the annual report. The Public Staff is requested to file a report including specific recommendations in this regard within 45 days of this Order.

IT IS, THEREFORE, ORDERED as follows:

1. That Aqua's November 30, 2018 late-filed reply comments are hereby accepted and recognized by the Commission.

2. That unless requested and approved otherwise, all certificated water and wastewater companies shall collect from contributors the income tax on CIAC for new contributions contracted for on or after October 5, 2018 using the full gross-up method.

3. That any certificated water or wastewater company may file a request with the Commission to use the present value method and may use the present value method on a going-forward basis only after receiving approval from the Commission.

4. That any certificated water or wastewater company may file a request with the Commission to use the utility financing method and may use the utility financing method on a going-forward basis only after receiving approval from the Commission. If a utility is authorized to use the utility financing method on a going-forward basis, no amount of the taxes paid by the utility shall be included in the company's rate base or otherwise reflected in the company's revenue requirement. Ratepayers should be held harmless when the utility financing method is used.

5. That if a company requests to use the utility financing method and receives Commission authority to use the method without rate base recovery, companies shall be allowed to request a waiver from the Commission for recovery of the taxes paid in certain limited circumstances as discussed herein. The Commission will seek comments from interested parties

on each individual waiver request and will issue a final decision on whether the tax on that particular CIAC will be allowed recovery through the utility's rate base. The Commission expects that this waiver mechanism will be the exception and not the rule so as to not create an administrative burden for the Commission or interested parties including the Public Staff.

6. That only for contracts entered into between January 3, 2018 and October 4, 2018, the water and wastewater companies are authorized to pay the taxes on the CIAC and are allowed to add any such taxes paid to rate base to be included in revenue requirement calculations. Utilities may also use the full gross-up method during this time period.

7. That the Public Staff shall determine when is the appropriate time to begin tariff revisions and shall file a request at that time with the Commission to begin the process of updating the tariffs of the water and wastewater companies, as appropriate.

8. That when a utility uses the full gross-up method, the future tax depreciation benefits generated should be used to calculate a reduction of the income tax expense in the utility's general rate case.

9. That the Public Staff is requested to work with both Aqua and CWSNC, and any other interested water or wastewater company, to develop a list of the specific types of property and non-property related to CIAC that are taxable and develop a format agreeable to all parties for the CIAC reporting to follow within the context of the annual report. The Public Staff is requested to file a report including specific recommendations in this regard within 45 days of this Order.

ISSUED BY ORDER OF THE COMMISSION.
This the 26th day of August, 2019.

NORTH CAROLINA UTILITIES COMMISSION
A. Shonta Dunston, Deputy Clerk

DOCKET NO. W-100, SUB 58

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Rulemaking Proceeding to Revise	)	ORDER ADOPTING REVISIONS
Procedural Deadlines in Water and	)	TO RULES R1-17 AND R1-24
Sewer General Rate Cases	)	

BY THE COMMISSION: On December 3, 2018, the Commission issued an Order Initiating Rulemaking Proceeding and Requesting Comments in the above-captioned docket. In its Order, the Commission noted that the procedural deadlines in water and sewer utility general rate cases are different from those in electric and natural gas rate cases. It further expressed an opinion that there were benefits to parties and the Commission if the procedural schedules were consistent among the named industries and proposed changes to Rule R1-17(b) and R1-24(g) to require Class A and B water and sewer utilities to file initial supporting expert witness testimony together with the application as required of Class A and B electric, telephone, and natural gas utilities.

The December 3 Order was served on all regulated water and sewer utilities, the Public Staff, and the Attorney General. Interested persons were invited to file petitions to intervene, and deadlines were established for the filing of initial and reply comments. No petitions to intervene were filed with the Commission; however, comments were filed by the Public Staff, Aqua North Carolina, Inc. (Aqua), and Carolina Water Service, Inc., of North Carolina (CWSNC).

The Public Staff filed initial comments in this docket on January 7, 2019. In its comments, the Public Staff supported the Commission's proposal to require Class A and B water and sewer utilities to file testimony with the application, suggesting minor changes to the Commission's proposal. The Public Staff further recommended requiring Class C water and sewer utilities to file testimony, exhibits, and other information in support of a general rate increase at least 45 days prior to hearing.

Aqua and CWSNC filed their initial comments via affidavits on January 9, 2019. They agreed to the Commission's proposed changes, but also recommended additional time between the hearing and the filing of intervenor direct and applicant rebuttal testimony.

Aqua, CWSNC, and the Public Staff filed joint reply comments on March 7, 2019. The parties stated that they are in agreement with the Commission's proposal to require Class A and B water and sewer utilities to file initial direct expert witness testimony with the application, consistent with their initial comments. Additionally, the parties identified a number of procedural recommendations applicable to Class A and B water and sewer utility general rate cases that would help address many of the issues raised in Aqua and CWSNC's initial comments, including:

1. Require the filing of Public Staff and other intervenor testimony 30 days prior to the evidentiary hearing and the filling of utility rebuttal testimony 15 days prior to the evidentiary hearing.

2. Include discovery rules and guidelines in scheduling and suspension orders to ensure reasonable and timely discovery requests and responses.

3. Conduct public hearings as soon as reasonably practical following issuance of customer notice so that the utility has adequate opportunity to investigate and respond in writing to customer concerns.

4. Include the utility and the Public Staff in scheduling conversations prior to issuance of a scheduling order.

5. Assign a designee to convene periodic meetings among all the parties, as necessary, to oversee the progress of the cases.

After careful consideration, the Commission finds good cause to adopt the parties' joint recommendations regarding the timing for filing of parties' direct and rebuttal testimony in general rate cases for Class A and B water and sewer utilities.[1] As noted in the comments, this will alleviate the compressed time schedule between the filing of Public Staff testimony and the hearing when additional applicant discovery may be necessary and the parties are typically engaged in settlement negotiations.

Regarding discovery guidelines, the Commission has adopted such guidelines in a number of other cases, and agrees that it might be helpful to include such guidelines in future procedural orders in general rate cases for Class A and B water and sewer utilities.

The Commission notes that in recent Class A and B water and sewer utility general rate cases it has required the applicant to file a report with the Commission responding to service concerns expressed by customers at the public witness hearings. The Commission will take into consideration in establishing the hearing schedule in future general rate cases the joint recommendation that public witness hearings be scheduled sooner after filing of the application to allow more time for the applicant to file such reports, if necessary. The Commission notes, however, that procedural schedules in general rate cases have historically been placed on the Commission's regular staff conference by the Public Staff with a recommendation for approval by the Commission, and that there is already considerable coordination between the applicant, the Public Staff, and the Commission to find hearing dates that may be accommodated by the Commission's already crowded calendar and the mandate of N.C. Gen. Stat. § 62-81 that such cases be given priority over all other cases or proceedings pending before the Commission.

Regarding the recommendation that the Commission assign a designee to convene periodic meetings among all the parties, as necessary, to oversee the progress of the cases, the Commission notes that a Presiding Commissioner, Hearing Commissioner, or Hearing Examiner is assigned to every general rate case and is available to address any procedural issues that may arise during the pendency of the case. The Commission, therefore, declines to designate any other individual to convene periodic meetings among the parties or to otherwise oversee the proceeding.

Lastly, the Commission notes that the procedural deadlines set forth in Rule R1-17(b)(13) are duplicative of the dates established in Rule R1-24(g)(2) for the filing of expert witness testimony. To avoid the potential for confusion and the possibility of inconsistencies in the rules, the Commission finds good cause to repeal the redundant provisions in Rule R1-17(b)(13). A further revision has been made to Rule R1-24(g)(2) to correct the reference to rebuttal testimony to be that of the applicant.

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[1] While the deadlines adopted herein for Class A and B water and sewer utilities for filing of the intervenors' direct and the applicant's rebuttal testimony may be consistent with the deadlines established in recent Class A and B electric and natural gas utility rate cases, it varies from the requirement stated in the Commission's rules, and the Commission will initiate a further generic proceeding to allow the participation of those utilities in considering whether to further amend Rule R1-24(g)(2) to make the dates in the Rule consistent for all Class A and B electric, telephone, natural gas, water, and sewer utilities.

Therefore, based upon the foregoing, the Commission finds good cause to adopt the revisions to Rules R1-17(b)(13) and R1-24(g)(2) attached hereto as Appendix A (redlined) and Appendix B (clean) consistent with the above discussion and conclusions.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 26th day of March, 2019.

NORTH CAROLINA UTILITIES COMMISSION
A. Shonta Dunston, Deputy Clerk

APPENDIX A
Page 1 of 2

Rule R1-17. Filing of Increased Rates; Application for Authority to Adjust Rates.

(b) Contents of Filing or Application. —

(13) ~~Class A & B electric, telephone and natural gas utilities shall file with and at the time of any general rate application all testimony, exhibits and other information which any such utility will rely on at the hearing on such increase. Class A and B water and sewer utilities shall file 45 days prior to the hearing on the general rate case application all testimony which such utility will rely on. Class A and B water and sewer utilities shall file with the application all exhibits supporting the general rate increase. The application, testimony and exhibits and other information shall be filed in sets which are separately numbered and separately bound, boxed, or rubber banded. The originals shall be in Set No. 1. The Commission Staff, the Public Staff, the Attorney General and all other Intervenors or Protestants shall file all testimony, exhibits and other information to be relied upon at the hearing 20 days in advance of the scheduled hearing.~~

Rule R1-24. Evidence.

(g) Exhibits by Expert Witnesses.

(2) Time of Filing. — <u>Except as provided below, the</u> ~~The~~ testimony for the applicant of such expert witnesses shall be filed with the Commission at least ~~sixty (60)~~ days prior to the date set for the hearing in general rate cases, and at least ~~thirty (30)~~ days prior to the date set for the hearing in all other cases. Testimony ~~for Protestants~~ of such expert witness in rebuttal shall be prepared in the same manner and form, and shall be filed with the Commission at least ~~ten (10)~~ days prior to the date fixed for the hearing

The Commission Staff, Public Staff, Attorney General and all other Intervenors or Protestants shall file all testimony, exhibits and other information which is to be relied upon at the hearing 20 days in advance of the scheduled hearing. When filed, all such exhibits shall be made available immediately to adverse parties of record, and to others having an interest in the proceeding.

Class A & B electric, telephone ~~and~~, natural gas, water, and sewer utilities shall file with and at the time of any general rate case application all testimony, exhibits and other information upon which any such utility will rely ~~on~~ at the hearing ~~on such increase~~. ~~All~~Class C water and sewer utilities shall file 45 days prior to the hearing on the general rate case application all testimony upon which such utility will rely ~~on~~. ~~Class A and B water and sewer utilities shall file with the application all exhibits supporting the general rate increase.~~ In general rate cases of Class A & B water and sewer utilities, the ~~The~~ Commission Staff, Public Staff, Attorney General and all

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other Intervenors or Protestants shall file all testimony, exhibits and other information which is to be relied upon at the hearing ~~20~~ 30 days in advance of the scheduled hearing, and any testimony for the utility in rebuttal shall be filed 15 days prior to the hearing.

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Rule R1-17. Filing of Increased Rates; Application for Authority to Adjust Rates.

(b) Contents of Filing or Application. —

(13) Repealed.

Rule R1-24. Evidence.

(g) Exhibits by Expert Witnesses.

(2) Time of Filing. — Except as provided below, the testimony for the applicant of such expert witnesses shall be filed with the Commission at least 60 days prior to the date set for the hearing in general rate cases, and at least 30 days prior to the date set for the hearing in all other cases. Testimony of such expert witness in rebuttal shall be prepared in the same manner and form, and shall be filed with the Commission at

least 10 days prior to the date fixed for the hearing. The Commission Staff, Public Staff, Attorney General and all other Intervenors or Protestants shall file all testimony, exhibits and other information which is to be relied upon at the hearing 20 days in advance of the scheduled hearing. When filed, all such exhibits shall be made available immediately to adverse parties of record, and to others having an interest in the proceeding.

Class A & B electric, telephone, natural gas, water, and sewer utilities shall file with and at the time of any general rate case application all testimony, exhibits and other information upon which any such utility will rely at the hearing. Class C water and sewer utilities shall file 45 days prior to the hearing on the general rate case application all testimony upon which such utility will rely. In general rate cases of Class A & B water and sewer utilities, the Commission Staff, Public Staff, Attorney General and all other Intervenors or Protestants shall file all testimony, exhibits and other information which is to be relied upon at the hearing 30 days in advance of the scheduled hearing, and any testimony for the utility in rebuttal shall be filed 15 days prior to the hearing.

DOCKET NO. W-100, SUB 59

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Investigation of Rate Design for Major	)	ORDER ESTABLISHING
Water Utilities	)	GENERIC PROCEEDING
	)	AND REQUIRING COMMENTS

BY THE COMMISSION: On February 21, 2019, in Docket No. W-354, Sub 360, a general rate case initiated by Carolina Water Service, Inc. of North Carolina (CWSNC), the Commission issued an Order Approving Joint Partial Settlement Agreement and Stipulation, Granting Partial Rate Increase, and Requiring Customer Notice (Sub 360 Order). In the Sub 360 Order, the Commission concluded, among other things, that it is appropriate to open a generic docket to investigate issues related to rate design for water public utilities, and to require CWSNC, Aqua North Carolina, Inc. (Aqua) and the Public Staff to participate in such a proceeding.

In the rate case, CWSNC, among other things, sought to have the Commission address its concerns that declining levels of water consumption across its service territory, due in large part to improvements that have allowed for greater efficiencies in water usage and to low growth rates in customer base, make it increasingly difficult for it to generate stable revenue sufficient to cover its fixed costs of providing service to its customers. The Company proposed two solutions to its problem: a consumption adjustment mechanism or, alternatively, implementation of a rate design based on meeting sixty percent (60%) of its authorized revenue requirement through a fixed charge and the remaining forty percent (40%) through a volumetric charge.[1]

In rejecting both of the Company's proposals, the Commission noted

> CWSNC's requested changes in its rate design, and the Public Staff's opposition thereto, is not unique to this case. The Commission's experience in deciding the issues in this case and other general rate cases has informed the Commission's view that the problems that CWSNC asserts concerning declining consumption and revenue volatility due to the unpredictability and unexpected changes in weather patterns that make it difficult for the Company to generate revenue that is both stable and sufficient to cover its fixed costs of providing service to its customers is one that merits further consideration outside the context of a discrete general rate case. Although the tension between a utility's desire for stable and sufficient revenue generation, on the one hand, and policies that support conservation, on the other, is not a new phenomenon, the Commission acknowledges that there are new tools available to utilities and regulators and new research publications that may support addressing these issues in a more nuanced manner than the Company's proposal in this case.

Sub 360 Order at 108 (footnote omitted). Having recognized that the issue of rate design is a recurring issue in general rate cases involving water utilities generally,[2] the Commission stated it would open a generic docket with the goal of exploring and considering rate design proposals that may better achieve the utility's desire for revenue sufficiency and stability, while also sending appropriate signals to consumers that support and encourage water efficiency and conservation. Sub 360 Order at 108.

Accordingly, the Commission finds good cause to issue this Order establishing this proceeding for that purpose. The Commission further finds good cause to make CWSNC, Aqua and the Public Staff parties to this proceeding, and to require these parties to file comments.[3] CWSNC, Aqua, and the Public Staff should include in their initial comments a discussion of rate design proposals that may better achieve revenue sufficiency and stability while also sending appropriate efficiency and conservation signals to consumers. The parties' comments should also address the specific objectives that could be achieved from various types of rate structures (for example, but

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[1] The Commission did allow CWSNC to modify its rate design to place more emphasis on fixed charges than its previous fixed to volumetric ratio. The Sub 360 Order authorized a change in the ratio of fixed charges to volumetric charges from approximately 50%/50% to 52%/48%.

[2] See, e.g., Order Approving Partial Settlement Agreement and Stipulation, Granting Partial Rate Increase, and Requiring Customer Notice, at 176-177, N.C.U.C. Docket No. W-218, Sub 497 (2018) (discussing proposed rate design and approving a 40%/60% ratio of base charge to usage charge); Order Granting Partial Rate Increase, Approving Rate Adjustment Mechanism, and Requiring Customer Notice, at 30-31, N.C.U.C. Docket No. W-218, Sub 336 (2014) (discussing the differing cost structures of water utilities and sewer utilities and approving the rate design agreed and stipulated to by the Public Staff and Aqua North Carolina, Inc.).

[3] The Commission is requiring CWSNC and Aqua to participate in this generic docket as they are the largest privately owned water utilities providing water utility service in North Carolina. This order should not be read to exclude other water utility companies or interested persons from participation pursuant to Commission Rule R1-19.

without limitation, irrigation rates, seasonal rates, surcharges when supply is low or in a drought situation, increasingblock rates, multiple rate schedules, etc.), the impact on customers' monthly charges, and the anticipated impact on efficiency and conservation. In addition, CWSNC and Aqua should address whether more sophisticated or innovative rate designs based on the cost of service can be supported by consumption data collected through advanced metering technology when combined with their respective customer information systems, the extent to which consumption data is available and has been analyzed in this regard, the extent to which the utilities have engaged in planning to obtain, use and analyze this data going forward, and the quality of available data as it currently exists. All parties should support their comments by reference to relevant policy considerations beyond those arguments advanced in the recent general rate cases, including current state policy as applicable to both public utilities and other water utility service providers not regulated by the Commission, the policy of other states, and available academic literature and/or publications. In opening this docket, the Commission is seeking comments from the parties that substantively are more than a repeat of their positions stated in Docket Nos. W-354, Sub 360 and W-218, Sub 497.

IT IS, THEREFORE, ORDERED as follows:

1. That on or before Monday, May 13, 2019, Carolina Water Service, Inc. of North Carolina, Aqua North Carolina, Inc., and the Public Staff shall file comments responsive to the direction provided in this Order;

2. That the Chief Clerk shall serve a copy of this Order on Carolina Water Service, Inc. of North Carolina, Aqua North Carolina, Inc., and the Public Staff, and shall transmit a copy of this Order to other certificated water utilities;

3. That on or before Monday, May 13, 2019, other persons desiring to become formal parties to this proceeding may petition the Commission for leave to intervene;

4. That on or before Monday, June 10, 2019, all parties may file reply comments; and

5. That the Commission will proceed appropriately upon receipt of the parties' comments and reply comments.

ISSUED BY ORDER OF THE COMMISSION.
This is the 20th day of March, 2019.

NORTH CAROLINA UTILITIES COMMISSION
A. Shonta Dunston, Deputy Clerk

Commissioner Lyons Gray did not participate in this decision.

DOCKET NO. W-100, SUB 59

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Investigation of Rate Design for Major Water Utilities	))	ORDER REQUIRING VERIFIED INFORMATION

BY THE COMMISSION: On March 20, 2019, in the above-captioned docket, the Commission issued an Order Establishing Generic Proceeding and Requiring Comments which directed Carolina Water Service, Inc. of North Carolina (CWSNC), Aqua North Carolina, Inc. (Aqua), and the Public Staff – North Carolina Utilities Commission (Public Staff) to file comments that would allow the Commission to explore and consider rate design proposals that may better achieve the utility's desire for revenue sufficiency and stability, while also sending appropriate signals to consumers that support and encourage water efficiency and conservation. The Order provided that other persons desiring to become formal parties to the proceeding may petition the Commission for leave to intervene on or before May 13, 2019. The Order also established the date for the filing of comments and reply comments. On May 10, 2019, CWSNC and Aqua filed a joint motion for an extension of time to file comments and reply comments which was granted by Commission Order issued May 13, 2019.

On May 13, 2019, the Corolla Light Community Association, Inc. filed a petition to intervene which was granted by Commission Order issued May 23, 2019.

On May 22, 2019, joint comments were filed by CWSNC and Aqua (Joint Commenters) and initial comments were filed by the Public Staff.

In regard to the issue of rate design proposals concerning in-ground irrigation systems, the Commission observes that Session Law 2008-143, House Bill 2499 (HB 2499) was signed into law by then Governor Michael F. Easley and required among other things that, effective July 1, 2009, "local government water systems and large community water systems shall require separate meters for new in-ground irrigation systems that are connected to their systems".[1] HB 2499 defined a "large community water system" as "a community water system, as defined in G.S. 130A-313(10), that regularly serves 1,000 or more service connections or 3,000 or more individuals". As a result, the Commission acknowledges that this requirement of HB 2499 may apply to Aqua and CWSNC.

The Commission is of the opinion that in conjunction with its review and evaluation of alternative rate design proposals for the major water utilities and considering the separate metering requirements effective July 1, 2009 for all new in-ground irrigation installations resulting from the enactment of HB 2499, it is appropriate to require that the Joint Commenters file verified responses to the following four questions concerning their respective operations impacted by HB 2499. Such verified responses should indicate the Joint Commenters' respective rate division(s), where relevant:

[1] Pursuant to Section 9, Article 38 of Chapter 143 of the General Statutes; § 143-355.4. Water system efficiency.

1. How many new meters for in-ground irrigation systems have been installed since July 1, 2009?
2. Can the Joint Commenters accurately represent that no new connections have been made or accepted since July 1, 2009, where the meter provided service to both an in-ground irrigation system and all other domestic water uses at the meter service address?
3. If the answer to #2 is "no," then how many new connections have been made or accepted since July 1, 2009, where the meter did provide service to both an in-ground irrigation system and other domestic water uses at the meter service address?
4. What steps, if any, do the Joint Commenters plan to take to insure that developers offering new systems to the Joint Commenters have designed and constructed those systems to facilitate placement of separate meters for in-ground irrigation systems?

Further, in regard to the Commission's continuing oversight regarding the water quality and sufficiency of water supply in Aqua's Bayleaf Master System in Wake County, North Carolina, the Commission finds good cause to require Aqua to also provide verified responses to the above four questions specifically pertaining to its neighborhoods and developments served by the Bayleaf Master System.

Finally, the Commission concludes that the Joint Commenters should file their respective verified responses with the Commission on or before Friday, June 28, 2019. The Public Staff may file initial comments on these responses, if any, by Tuesday, July 16, 2019, and the Joint Commenters may file reply comments, if any, by Tuesday, July 30, 2019.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This is the 30th day of May, 2019.

NORTH CAROLINA UTILITIES COMMISSION
A. Shonta Dunston, Deputy Clerk

DOCKET NO. W-100, SUB 61

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Petition for Rulemaking to Implement N.C.	)	ORDER ESTABLISHING
Gen. Stat. § 62-133.12A, North Carolina	)	RULEMAKING PROCEEDING
Session Law 2019-88 (House Bill 529)	)	AND GRANTING PETITIONS
	)	TO INTERVENE

BY THE CHAIR: On October 31, 2019, in the above-captioned proceeding, the Public Staff – North Carolina Utilities Commission (Public Staff) filed a petition requesting that the Commission establish a rulemaking proceeding to implement N.C. Gen. Stat. § 62-133.12A, North Carolina Session Law 2019-88 (House Bill 529). The Public Staff further requests that the Commission, after receiving comments from interested parties, adopt its proposed Commission Rule R7-40 for water and Rule R10-27 for sewer attached to its petition as Exhibits A and B, respectively, with such modifications as may be appropriate. The Public Staff also included in its petition a detailed summary of the proposed rules attached thereto.

In support of its petition, the Public Staff states that the enactment of § 62-133.12A authorizes the Commission to adopt, implement, modify, or eliminate a rate adjustment mechanism for both water and wastewater for tracking and truing-up variations in customer usage from the levels approved in the general rate case proceeding, upon a finding that the rate adjustment mechanism is in the public interest.

On November 4, 2019, Aqua North Carolina, Inc. (Aqua), and Carolina Water Service, Inc. of North Carolina (CWSNC) filed petitions to intervene in this docket.

Based upon the foregoing and the entire record herein, the Chair finds good cause to issue this Order establishing a rulemaking proceeding in this docket and allowing Aqua and CWSNC to intervene as parties herein.

IT IS, THEREFORE, ORDERED as follows:

1. That this docket shall be, and is hereby, established as a rulemaking proceeding for the purpose of considering the adoption of Commission Rules R7-40 for water and R10-27 for sewer to implement N.C.G.S. § 62-133.12A, Session Law 2019-88 (House Bill 529);

2. That on or before November 22, 2019, any person having an interest in this proceeding may file a petition to intervene stating such interest;

3. That on or before December 16, 2019, the parties other than the Public Staff may file initial comments addressing the proposed rules attached as Exhibits A and B to the Public Staff's petition;

4. That on or before January 6, 2020, all parties may file reply comments addressing the initial comments filed by the other parties;

5. That the petition to intervene filed by Aqua North Carolina, Inc. shall be, and is hereby, granted;

6. That the petition to intervene filed by Carolina Water Service, Inc. of North Carolina shall be, and is hereby, granted; and

7. That the name and address of the attorney for Aqua North Carolina, Inc. and Carolina Water Service, Inc. of North Carolina are as follows:

Jo Anne Sanford
Attorney at Law
Sanford Law Office, PLLC
Post Office Box 28085
Raleigh, North Carolina 27611-8085
sanford@sanfordlawoffice.com.

ISSUED BY ORDER OF THE COMMISSION.
This is the 14th day of November, 2019.

NORTH CAROLINA UTILITIES COMMISSION
A. Shonta Dunston, Deputy Clerk

DOCKET NO. E-22, SUB 556

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application by Virginia Electric and Power	)	
Company, d/b/a Dominion Energy North	)	ORDER APPROVING DSM/EE
Carolina, for Approval of Demand Side	)	RIDER AND REQUIRING FILING
Management and Energy Efficiency Cost	)	OF CUSTOMER NOTICE
Recovery Rider Pursuant to N.C. Gen.	)	
Stat. § 62-133.9 and Commission Rule R8-69	)	

HEARD: Monday, November 8, 2018, in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Commissioner ToNola D. Brown-Bland, Presiding; Chairman Edward S. Finley, Jr.; Commissioners Jerry C. Dockham, James G. Patterson, Lyons Gray, Daniel G. Clodfelter, and Charlotte A. Mitchell

APPEARANCES:

For Dominion Energy North Carolina:

Andrea R. Kells, McGuireWoods LLP, 434 Fayetteville Street, Suite 2600, Raleigh, North Carolina 27601

E. Brett Breitschwerdt, McGuireWoods, LLP, 434 Fayetteville Street, Suite 2600, Raleigh, North Carolina 27601

Carolina Industrial Group for Fair Utility Rates I:

Ralph McDonald, Bailey & Dixon, LLP, Post Office Box 1351, Raleigh, North Carolina 27602

For the Public Staff:

Heather D. Fennell, Staff Attorney, Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4300

BY THE COMMISSION: General Statute 62-133.9(d) authorizes the North Carolina Utilities Commission (Commission) to approve an annual rider to the rates of electric utilities to recover all reasonable and prudent costs incurred for the adoption and implementation of new demand-side management and energy efficiency (DSM/EE) programs. In accordance with Commission Rule R8-69(b), such rider consists of the utility's reasonable and appropriate estimate of expenses expected to be incurred during the rate period and a DSM/EE experience modification factor (DSM/EE EMF) rider to collect or refund the difference between the utility's actual reasonable and prudent costs incurred during the test period and actual revenues realized during the test period under the DSM/EE rider then in effect. The Commission is also authorized to award incentives to electric utilities for adopting and implementing new DSM/EE programs, including appropriate rewards based on the sharing of savings achieved by the programs. These utility incentives are included in the utility's reasonable and appropriate estimate of expenses expected to be incurred during the rate period and DSM/EE EMF riders described above.

Further, Commission Rule R8-69(b) provides that the Commission will each year conduct a proceeding for each electric utility to establish an annual DSM/EE rider to recover DSM/EE related costs and utility incentives. Commission Rule R8-69(e) provides that the annual DSM/EE cost recovery rider hearing for each public utility will be scheduled as soon as practicable after the annual fuel and fuel-related charge adjustment proceeding held by the Commission for the electric public utility under Commission Rule R8-55.

On August 21, 2018, Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina (DENC or the Company), filed in this docket its Application for Approval of Cost Recovery for Demand-Side Management and Energy Efficiency Measures (Application), seeking approval of new DSM/EE rider rates to recover the Company's reasonable and prudent DSM/EE costs, common costs, taxes, net lost revenues (NLR), and a DSM/EE Portfolio Performance Incentive.

Pertinent Proceedings in Prior Dockets

The Commission most recently approved DENC's recovery of its reasonable and prudent DSM/EE costs and utility incentives by Order issued on December 21, 2017, in Docket No. E-22, Sub 545 (2017 Order).

On October 14, 2011, in Docket No. E-22, Sub 464, the Commission issued its Order Approving Agreement and Stipulation of Settlement, Approving DSM/EE Rider, and Requiring Compliance Filing (2010 Cost Recovery Order). In the 2010 Cost Recovery Order, the Commission approved the Agreement and Stipulation of Settlement between the Public Staff and the Company (Stipulation), filed on March 2, 2011, as well as the Cost Recovery and Incentive Mechanism (Mechanism), attached as Stipulation Exhibit 1 to the Stipulation (collectively, Stipulation and Mechanism).

On December 13, 2011, in Docket No. E-22, Sub 473, the Commission issued its Order Approving DSM/EE Rider and Requiring Customer Notice in DENC's 2011 DSM/EE cost recovery proceeding (2011 Cost Recovery Order). The 2011 Cost Recovery Order also approved a first Addendum to the Stipulation and Mechanism (Addendum I) related to jurisdictional allocation of DSM/EE costs. Addendum I was then incorporated as part of the Stipulation and Mechanism.

On April 29, 2013, in Docket No. E-22, Sub 486, the Commission issued its Order Granting Conditional Approval of Cost Assignment Proposal that approved a cost assignment methodology for allocating 100% of the incremental costs of DENC's prospective North Carolina-only Commercial Lighting Program and HVAC Upgrade Program to the North Carolina retail jurisdiction. On December 18, 2013, in Docket No. E-22, Sub 494, the Commission approved this cost assignment methodology for programs offered only in North Carolina as the second Addendum to the Stipulation and Mechanism (Addendum II). Addendum II was then incorporated as part of the Stipulation and Mechanism.

On May 7, 2015, in Docket No. E-22, Sub 464, the Commission issued its Order Approving Revised Cost Recovery and Incentive Mechanism and Granting Waiver (Order on Revised Mechanism). The Order on Revised Mechanism approved an updated Cost Recovery and Incentive Mechanism for Demand Side Management and Energy Efficiency Programs (Revised Mechanism). The Revised Mechanism is effective for projected DSM/EE costs and utility incentives on and after January 1, 2016, and for true-up of DSM/EE costs and utility incentives for the period beginning July 1, 2014, through December 31, 2014, and on a lagging calendar year basis thereafter. The Revised Mechanism replaced the similar Mechanism that had been in effect since 2011. However, it also contained a provision stating that beginning with 2017, DENC would switch the calculation of the bonus utility incentive approved for inclusion in its DSM/EE and DSM/EE EMF riders from a Program Performance Incentive to a Portfolio Performance Incentive (PPI).

On May 22, 2017, in Docket No. E-22, Sub 464, the Commission issued its Order Approving Revised Cost Recovery and Incentive Mechanism (2017 Mechanism). The 2017 Mechanism became effective as of May 22, 2017, for projected costs and utility incentives beginning January 1, 2018, and for true-ups of costs and utility incentives beginning January 1, 2017, and is used in this proceeding to calculate the Rider C billing rates related to DSM and EE measures projected to be installed or implemented for Vintage Year 2019 as well as the EMF true-up for DSM and EE measures installed or implemented during Vintage Year 2017.

Proceedings in the Present Docket

On August 21, 2018, DENC filed its Application for Approval of Cost Recovery for Demand-Side Management Programs and Energy Efficiency Measures consisting of the direct testimony of Michael T. Hubbard, and the direct testimonies and exhibits of Deanna R. Kesler, Jarvis E. Bates, Alan J. Moore, J. Clayton Crouch, and Debra A. Stephens. In summary, DENC's Application seeks recovery of DENC's reasonable and appropriate estimate of expenses and utility incentives expected to be incurred during the rate period, Rider C, and a DSM/EE EMF rider, Rider CE, to collect or refund the difference between DENC's actual reasonable and prudent costs and utility incentives incurred during the test period and actual revenues realized during the test period under the DSM/EE rider presently in effect.

On September 7, 2018, the Commission issued an Order Scheduling Hearing, Requiring Filing of Testimony, Establishing Discovery Guidelines, and Requiring Public Notice. The Order established deadlines for the filing of petitions to intervene, intervenor testimony and exhibits, Company rebuttal testimony and exhibits, and required DENC to publish a customer notice. The Commission scheduled a hearing to be held on Monday, November 5, 2018.

The intervention and participation in this docket by the Public Staff is recognized pursuant to N.C. Gen. Stat. § 62-15(d) and Commission Rule R1-19(e).

On September 28, 2018, the Public Staff filed a Motion to Amend Procedural Schedule to provide the Public Staff additional time to investigate, conduct discovery, and prepare testimony.

On October 2, 2018, the Commission issued an Order granting the Public Staff's Motion to Amend Procedural Schedule. The Order established a deadline of October 25, 2018, for the filing of petitions to intervene, and intervenor direct testimony and exhibits of expert witnesses. Further, the Order scheduled a public witness hearing for November 5, 2018, and an expert witness hearing for November 8, 2018.

On October 8, 2018, DENC filed corrected Schedules 1, 2, 4, and 7 to the testimony of Witness Kesler.

On October 15, 2018, Carolina Industrial Group for Fair Utility Rates I (CIGFUR) filed a Petition to Intervene.

On October 24, 2018, DENC filed corrected Schedules for Company witness Alan J. Moore. On this same date, DENC also filed its Affidavit of Publication.

On October 25, 2018, the Commission granted CIGFUR's Petition to Intervene.

On October 25, 2018, the Public Staff filed the testimony of David M. Williamson and Michael C. Maness.

On November 2, 2018, DENC filed a letter in lieu of rebuttal testimony accepting the recommendation of the Public Staff.

On November 5, 2018, the Public Staff filed a Joint Motion to Excuse Witnesses from appearing at the November 8, 2018, evidentiary hearing, stating that the Public Staff and DENC had reached agreement on all issues in this docket, and that all parties had agreed to waive cross-examination of each other's witnesses.

Also on November 5, 2018, the matter came on for the public witness hearing as scheduled. No public witnesses appeared at the hearing.

On November 6, 2018, the Public Staff's Joint Motion to Excuse Witnesses was granted.

On November 8, 2018, the Commission held the evidentiary hearing as scheduled. No public witnesses appeared at the hearing.

On December 7, 2018, DENC and the Public Staff filed a Joint Proposed Order.

Based upon DENC's Application, the testimony and exhibits received into evidence at the hearing, and the record as a whole, the Commission makes the following:

FINDINGS OF FACT

1. Virginia Electric and Power Company (VEPCO) operates in the State of North Carolina as DENC. VEPCO, d/b/a DENC, is engaged in the business of generating, transmitting, distributing, and selling electric power and energy to the public for compensation in North Carolina, and is subject to the jurisdiction of the North Carolina Utilities Commission as a public utility.

2. DENC is lawfully before the Commission based upon its Application filed pursuant to N.C. Gen. Stat. § 62-133.9 and Commission Rule R8-69.

3. Pursuant to the 2017 Mechanism, the test period for purposes of this proceeding is the 12-month period of January 1, 2017, through December 31, 2017.

4. The rate period for purposes of this proceeding is the 12-month period of February 1, 2019, through January 31, 2020.

5. It is appropriate to maintain the Rider C charges set by the Commission in Docket No. E-22, Sub 545 and to reduce the Rider CE charges to $0.00 for the entire month of January, 2019.

6. DENC has requested rate period recovery of costs and utility incentives (NLR and PPI) related to the following approved DSM/EE Programs: (a) the Phase I Air Conditioner Cycling Program; (b) the Phase III DSM/EE programs: Non-residential Lighting Systems and Controls Program, Non-residential Heating & Cooling Efficiency Program, and Non-residential Window Film Program; (c) the Phase IV Income and Age Qualifying Home Improvement Program; (d) the Phase V Small Business Improvement Program, (e) the North Carolina-only Residential Retail LED Lighting program; and (f) the Phase VI Non-Residential Prescriptive Program.

7. In addition, DENC has requested test period recovery of costs and utility incentives related to the following approved DSM/EE Programs: Residential Air Conditioner Cycling Program, Residential Heat Pump Tune Up Program, Residential Heat Pump Upgrade Program, Residential Home Energy Check Up Program, Residential Duct Sealing Program, Non-residential Duct Testing and Sealing Program, Non-residential Energy Audit Program, Non-residential Heating and Cooling Efficiency Program, Non-residential Lighting Systems and Controls Program, Residential Lighting Program, Non-residential Window Film Program, Small Business Improvement Program, North Carolina-only Residential LED Lighting Program, and the Residential Income and Age Qualifying Home Improvement Program.

8. Recovery of DENC's forecasted DSM/EE program costs, common costs, NLR, and PPI, as well as a true-up of DENC's test period DSM/EE program costs, common costs, NLR, and PPI, is subject to the terms of the 2017 Mechanism. DENC should be allowed to recover its projected rate period and actual test period costs and utility incentives associated with offering each of its approved programs as requested in its Application. The requested cost recovery of program costs, common costs, NLR, and PPI is reasonable and consistent with the 2017 Mechanism previously approved by the Commission.

9. DENC is not seeking recovery of projected period NLR in Rider C, and its request to true up NLR in Rider CE in future proceedings is reasonable.

10. DENC's proposed North Carolina retail DSM/EE Rider C rate period revenue requirement of $2,510,301, consisting of DSM/EE program costs, common costs, and a PPI, is reasonable.

11. For purposes of determining its DSM/EE EMF, Rider CE, DENC's reasonable and prudent North Carolina retail total revenue requirement for the DSM/EE EMF test period, consisting of DSM/EE program costs, common costs, and utility incentives, is $1,839,922.

12. Rider C as proposed in the Application is reasonable and appropriate, and consists of the following increment customer class billing factors: Residential – 0.062 ¢/kilowatt hour (kWh); Small General Service and Public Authority – 0.140 ¢/kWh; Large General Service – 0.147 ¢/kWh; and no charge for 6VP, NS, Outdoor Lighting, and Traffic Lighting. It is reasonable and appropriate for Rider C to become effective for usage on and after February 1, 2019.

13. Rider CE as proposed in the Application and corrected schedules is reasonable and appropriate, and consists of the following increment customer class billing factors: Residential – 0.059 ¢/kWh; Small General Service and Public Authority – 0.082 ¢/kWh; Large General Service – 0.086 ¢/kWh; and no charge for 6VP, NS, Outdoor Lighting, and Traffic Lighting. It is reasonable and appropriate for Rider CE to become effective for usage on and after February 1, 2019.

14. DENC requested the recovery of NLR in the amount of $375,822 and PPI in the amount of $257,971 for the test period, and a projected PPI of $302,935, but no NLR, for the rate period. DENC's calculation and proposed recovery of NLR and a PPI is consistent with the 2017 Mechanism, and is appropriate for recovery in this proceeding.

15. The jurisdictional and customer class cost allocations for Rider C and Rider CE included in the testimony and exhibits of Company witness Crouch are acceptable for purposes of this proceeding and are consistent with the 2017 Mechanism.

16. DENC satisfactorily explained its Company sponsorship and consumer education and awareness activities and the volume of activity associated with such initiatives during the test period, as directed by the Commission in its final order issued in the Company's 2016 DSM/EE cost recovery proceeding (2016 Order). It is appropriate for DENC to continue to provide such information to the Commission in future rider proceedings.

17. The evaluation, measurement, and verification (EM&V) analyses and reports prepared by DENC are reasonable for purposes of this proceeding. The EM&V data provided by DENC and reviewed by the Public Staff for vintage year 2017 and earlier vintages are sufficient to consider those vintage years complete for all programs operating in those years.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-3

These findings of fact are essentially informational, procedural, and jurisdictional in nature and are uncontroverted. The test period used by DENC is consistent with the 2017 Mechanism approved by the Commission in Docket No. E-22, Sub 464, and with Commission Rule R8-69.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 4-5

The evidence for this finding of fact is contained in the Company's Application and the testimony of Company witnesses Moore, Hubbard, and Stephens.

Witnesses Moore and Hubbard testified that, because Commission Rule R8-69(a) provides that the rate period for DSM/EE cost recovery is the same as the calendar year rate period for the fuel factor rider established under Rule R8-55, in previous years the Company has proposed Rider C rates be effective for a calendar year rate period. Based on discussions with the Public Staff following the conclusion of the Company's 2017 rider proceedings, DENC proposed updated Riders C and CE be effective for a February 1, 2019 through January 31, 2020 rate period, and proposed the same adjustment in its cost recovery rider applications filed pursuant to Rules R8-55 and R8-67. The witnesses explained that the Company was requesting this adjustment in order to extend the time for the Commission to issue orders in the Company's three annual rider proceedings and to allow the Company additional time to finalize rates and customer notices, and to allow reasonable time for Public Staff review, prior to the effective date of the updated annual riders. The witnesses stated that the Company intends to continue to use a February 1 through January 31 rate period in future rider cases.

Company witness Stephens testified that in order to effectuate the transition to a February 1 through January 31 rate period, the Company proposed to maintain Rider C as approved by the Commission in the Company's previous DSM/EE cost recovery proceeding, and to reduce Rider CE for all classes to zero during the January 1 through January 31, 2019 period.

The Public Staff's witnesses did not object to the Company's proposal to adjust the rate period for its DSM/EE cost recovery rider.[1]

Based on the evidence, the Commission finds and concludes that DENC's proposal to adjust the rate period for its DSM/EE cost recovery rider to February 1 through January 31 is reasonable and should be approved. Rates approved in this order will take effect February 1, 2019. For January 2019, the Company was authorized to and shall continue to charge Rider C as approved in the 2017 proceeding, and shall reduce the rate charged under Rider CE to zero, as proposed.

[1] The Company's proposal is consistent with the Petition filed by the Public Staff in Docket No. E-100, Sub 160 on September 6, 2018, which suggested that moving the effective date of DENC's new cost recovery riders to February 1 would alleviate the burden on the Commission, the Public Staff, and the Company to file and issue proposed and final orders and implement revised rates by January 1 each year. On October 11, 2018, the Commission issued an order adopting the Public Staff's recommendation.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 6-9

The evidence for these findings of fact is contained in DENC's Application, the direct testimony and exhibits of Company witnesses Hubbard, Kesler, Bates, and Moore, and the testimony of Public Staff witnesses Maness and Williamson.

Company witness Moore testified that he included in the Rider C (rate period) revenue requirement certain projected costs associated with: (a) the Phase I Air Conditioner Cycling Program; (b) the Phase III DSM/EE programs (Non-residential Lighting Systems and Controls Program, Non-residential Heating and Cooling Efficiency Program, and Non-residential Window Film Program); (c) the Phase IV Income and Age Qualifying Home Improvement Program; (d) the Phase V Small Business Improvement Program, (e) the Residential North Carolina-only Retail LED Lighting program; and (f) the Phase VI Non-Residential Prescriptive Program. Witness Moore also testified that he incorporated the projected PPI amounts provided by Company witness Bates in his development of the Rider C revenue requirement.

Company witness Moore also testified that the Rider CE revenue requirement in the present case includes true-ups for the Phase I, Phase II, Phase III, Phase IV, Phase V, and Phase VI programs during the January 1, 2017 to December 31, 2017 test period, incorporating actual costs, NLR, and PPI.

Company witness Bates identified and explained the nature of common costs that are incurred to support DSM/EE programs generally, but are not tied to specific programs.

Public Staff witness Williamson concurred with the programs listed by DENC for cost and incentive recovery in this proceeding.

Company witness Kesler presented testimony and exhibits setting forth the Company's estimated Utility Cost Test (UCT) and Total Resource Cost (TRC) test results for vintage year 2019 for the active DSM and EE programs that are not subject to closure or suspension. She explained that because the Company's system for modeling projected costs and benefits is based on the calendar year, she applied the projected costs for calendar year 2019 to the proposed February 1, 2019 through January 31, 2020 rate period. As shown on her exhibits, all programs have TRC results above 1.0, indicating cost effectiveness, with the exception of the Residential Income and Age Qualifying Home Improvement Program, which is a program in the public interest for which the Company is not seeking a PPI. All programs have UCT results above 1.0, again with the exception of the Residential Income and Age Qualifying Home Improvement Program.

Company witness Hubbard also testified that DENC has not projected NLR for the rate period, consistent with its approach in the 2014, 2015, 2016, and 2017 DSM/EE cost recovery riders. He proposed to true-up NLR in future proceedings. Witness Hubbard also stated that the Company had not identified any found revenues. The Commission finds the DENC approach to recovery of NLR, and the lack of found revenues, to be reasonable and supported by the evidence in this proceeding.

Consistent with the Commission's previous orders approving DENC's DSM/EE programs and the evidence in the record, the Commission finds and concludes that DENC should be allowed to recover its projected rate period and actual test period costs and utility incentives (NLR and PPI) associated with offering each of its approved Programs as requested in its Application and its direct testimony and exhibits. The Commission also finds and concludes that the requested cost recovery of program costs, common costs, NLR, and PPI is consistent with the 2017 Mechanism previously approved by the Commission. Further, the Commission finds and concludes that DENC's request to true-up NLR in Rider CE in future proceedings is reasonable.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 10-15

The evidence for these findings of fact is contained in the Company's Application; the direct testimony and exhibits of Company witnesses Hubbard, Kesler, Moore, Bates, Crouch, and Stephens; and the testimony of Public Staff witness Maness.

Company witness Bates determined the system-wide program and common costs for the DSM/EE programs in the rate period and in the test period. He also calculated the PPI for each program.

Company witness Crouch allocated the common costs among the DSM/EE programs. He then allocated a share of the system-wide program costs (including common costs as allocated to the individual programs) to the North Carolina retail jurisdiction. Pursuant to the 2017 Mechanism, DSM costs were allocated on the basis of the Company's coincident peak, and EE costs were allocated on the basis of energy. Finally, witness Crouch allocated the North Carolina retail jurisdictional costs among the North Carolina retail customer classes pursuant to the methodology set out in the 2017 Mechanism.

Company witness Moore used the operating expenses, capital costs, and PPI as provided by witness Bates, and as allocated jurisdictionally by witness Crouch, to develop a rate period revenue requirement for Rider C. He indicated the Company was not requesting any projected NLR amount be included in Rider C for recovery during the rate period. For capital costs, he used a 7.15% depreciation rate from the Company's updated depreciation study, and used a 9.90% rate of return based on the rate of return on common equity that was approved in the Company's most recent general rate case, Docket No. E-22, Sub 532.

Likewise, witness Moore developed the test period true-up revenue requirement for Rider CE by comparing the test period actual revenues, determined by the Company's accounting department, with the test period costs, NLR, and PPI, as provided by witness Bates and as allocated jurisdictionally by witness Crouch. For Rider CE, he determined the amount of NLR by taking the applicable non-fuel base rates provided by witness Stephens, and the jurisdictional energy savings as provided by witness Kesler, and then excluding lost revenues (1) outside the 36-month window established in the 2017 Mechanism, and (2) already recognized through non-fuel base rates. Further, he determined the carrying costs on deferrals and the financing costs on any over-recoveries.

Public Staff witness Maness testified that his investigation of DENC's filing in this proceeding focused on determining whether the proposed DSM/EE and DSM/EE EMF billing rates were calculated in accordance with the 2017 Mechanism, and otherwise adhered to sound ratemaking concepts and principles. He stated that among the other procedures performed by the Public Staff, the investigation included a review of the actual DSM/EE program costs incurred by DENC during the 12-month period ended December 31, 2017, through the selection and review of a sample of source documentation for test year costs for which the Company seeks recovery. This process was intended to test whether the actual costs included by the Company in the DSM/EE billing rates are either valid costs of approved DSM and EE programs or administrative (common) costs supporting those programs. Witness Maness concluded that the Company has generally calculated its proposed DSM/EE billing rates (included in Rider C) and DSM/EE EMF billing rates (included in Rider CE) in a manner consistent with N.C. Gen. Stat. § 62-133.9, Commission Rule R8-69, and the 2017 Mechanism. Witness Maness further stated that the Public Staff found no errors or other issues necessitating an adjustment to DENC's proposed billing rates in this proceeding.

Witness Maness also stated that the adjustment to the Vintage 2018 PPI related to the Vintage 2018 kWh savings adjustments recommended by witness Williamson and discussed further below under Finding of Fact No. 16 will be reflected in the Company's 2019 DSM/EE Rider proceeding. He also stated that with regard to witness Williamson's recommended adjustment to the Vintage 2017 PPI, also discussed further below, given the relative immateriality of the annual impact on the DSM/EE rider of the PPI associated with the LED Program and the fact that it would result in a rate increase, the Public Staff does not object to the initial true-up of the Vintage 2017 PPI for the LED program being included in the Company's 2019 DSM/EE proceeding (with the Public Staff's recommended adjustments). In its November 2, 2018, Letter in Lieu of Rebuttal Testimony, the Company stated that it accepts this recommendation. Witness Maness also noted that the Public Staff plans to monitor future biennial audits of the Company's DSM/EE rebate and incentive activities as ordered by the Virginia State Corporation Commission.

On Company Exhibit AJM-1, Schedule 1, page 1, as corrected on October 24, 2018, Company witness Moore calculated DENC's requested North Carolina retail rate period (February 1, 2019, through January 31, 2020) revenue requirement (for Rider C) as follows:

1.	Operating Expense	$2,071,198
2.	Capital Cost	$ 136,168
3.	NLR	$ 0
4.	PPI	$ 302,935
5.	Total	$2,510,301

On Company Exhibit AJM-1, Schedule 2 (and as also reflected in the testimony of Public Staff witness Maness, with a rounding difference of one dollar), witness Moore calculated DENC's requested North Carolina retail test period DSM/EE EMF (January 1, 2017, through December 31, 2017) revenue requirement (for Rider CE) as follows:

Operating expenses	$ 2,561,786
Capital costs (depr., rate base, prop. taxes)	$ 145,302
NLR	$ 375,822
PPI	$ 257,971
Test period Rider C revenues	($ 1,611,659)
Net revenue requirement subtotal	$ 1,729,222
Carrying costs	$ 110,700
Total Rider CE revenue requirement	$ 1,839,922

Company witness Crouch, in Exhibit JCC-1, Schedule 3, pages 2 and 4, allocated the Rider C and Rider CE revenue requirements among the North Carolina retail customer classes. The results of his allocations are shown below:

Rate Class	Rider C Amount	Rider CE Amount
Residential	$ 1,009,233	$ 962,357
SGS Co & Muni	$ 1,094,104	$ 639,643
LGS	$ 406,964	$ 237,922
6VP	$ 0	$ 0
NS	$ 0	$ 0
ST & Outdoor Lighting	$ 0	$ 0
Traffic Lighting	$ 0	$ 0

Company witness Stephens discussed how she calculated the Rider C and Rider CE rates proposed for the rate period. She determined the North Carolina retail forecasted net kWh sales for the rate period by revenue class, and further allocated those forecasted sales down to customer (rate) classes, less the kWh sales for customers who have opted out of the DSM/EE rider. Witness Stephens testified that she then divided the customer class revenue requirements by customer class forecasted kWh sales to calculate Rider C. She used the same methodology to calculate Rider CE for the test period.

Company witness Stephens also testified that she provided witness Moore with the monthly non-fuel average base rates for his use in determining lost revenues.

The Application, witness Stephens' Company Exhibit DAS-1, Schedule 1, page 10, and Company Exhibit DAS-1, Schedule 4, page 2 support the following customer class Rider C and Rider CE billing factors to be put into effect on February 1, 2019:

CUSTOMER CLASS	RIDER C RATE (cents/kWh)	RIDER CE RATE (cents/kWh)
Residential	0.062	0.059
Small General Service & Public Authority	0.140	0.082
Large General Service	0.147	0.086
6VP	0.000	0.000
NS	0.000	0.000
Outdoor Lighting	0.000	0.000
Traffic Lighting	0.000	0.000

The billing factors include the Regulatory Fee.

Based upon the evidence presented above and the entire record in this proceeding, the Commission finds and concludes that the DSM/EE EMF revenue requirement and proposed Rider CE billing factors to be charged during the rate period, as proposed in DENC's Application, direct testimony, and corrected schedules, are appropriate. The Commission also finds and concludes that the projected DSM/EE rate period revenue requirement and Rider C billing factors to be charged during the rate period, as proposed in DENC's Application and direct testimony, are appropriate. With regard to the requested recovery of NLR and PPI, the Commission finds and concludes that the amounts are appropriate for recovery in this proceeding and are calculated in a manner consistent with the 2017 Mechanism.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 16

The evidence for this finding of fact is contained in the direct testimony of Company witness Bates.

In response to Ordering Paragraph No. 5 of the Commission's 2016 Order, Company witness Bates provided information on consumer education and awareness initiatives conducted by the Company's Energy Conservation (EC) department during the test period. He explained that most of the Company's communication and outreach activities are tied directly to specific DSM/EE programs, so actual costs for general education and awareness are limited. Witness Bates stated that the EC department relies heavily on online tools for general education, that its web pages received around 89,000 visits in the test period, and that the web pages for the implementation contractor, Honeywell, also received over 99,000 visits. Witness Bates stated that the Company is continually growing social media presence, gaining over 74,000 and 58,000 followers on Facebook and Twitter, respectively.

The Public Staff did not oppose DENC's consumer education and awareness activities or costs.

Based on the evidence presented above and all the information in the record, the Commission finds and concludes that DENC's consumer education and awareness activities and costs are reasonable for purposes of this proceeding. Further, the Commission finds and concludes that the Company shall continue to include a list of consumer education and awareness activities and the volume of activity associated with each during the test period in its annual DSM/EE cost recovery filing.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 17

The evidence for this finding of fact is contained in the direct testimony of Company witness Kesler, the EM&V report filed by DENC on May 1, 2018, in Docket No. E-22, Sub 545, the corrections to the 2018 EM&V report filed on October 25, 2018, in Docket No. E-22, Sub 545, the corrected schedules of Company witness Kesler, and the testimony of Public Staff witness Williamson.

Company Witness Kesler provided and testified to the Company's projected EM&V costs during Calendar Year 2019 and actual EM&V costs during the 2017 test period. Witness Kesler noted that DENC plans to continue to file its annual EM&V report with the Commission on May 1 each year.

Public Staff witness Williamson testified that he had reviewed DENC's 2018 EM&V report for calendar year 2017 with the assistance of GDS Associates. He stated that DENC and its EM&V consultant implemented certain changes and corrections to the Vintage 2016 savings for several programs as recommended by the Public Staff and accepted by the Commission in the previous cost recovery proceeding. Witness Williamson stated that his review of the savings for Vintage Year 2017 in this proceeding confirmed that the changes and corrections identified by the Public Staff in the Sub 545 proceeding have been incorporated into the Vintage 2017 savings as identified in the 2018 EM&V Report.

In addition, based on his review of the 2018 EM&V Report, witness Williamson recommended two adjustments to the Company's Residential Retail LED Lighting Program. First, with respect to the Hours of Use (HOU) used to calculate Gross Deemed Savings, he testified that the Company and the Public Staff have agreed that since various other data assumptions for this program were applied from the Mid-Atlantic Technical Reference Manual (TRM), the HOU should also be from the Mid-Atlantic TRM. Second, with respect to the Net to Gross (NTG) percentage used in the report, the Company and the Public Staff agreed that the NTG used to calculate impacts on underlying data should be adjusted to 85% to be consistent with the EM&V Report. Witness Williamson recommended that the impacts from these changes be applied to the EMF for Vintages 2017 and 2018. He noted that the impacts of these changes will reduce the Net Adjusted Savings for the Residential Retail LED Lighting program for Vintages 2017 and 2018. He stated that to the extent the changes impact the Vintage 2017 and 2018 savings for this program, the Company should address those changes in its next DSM/EE rider proceeding in a manner consistent with the Company's practice of adjusting EM&V Vintage savings. Witness Williamson further testified that on October 25, 2018, the Company filed corrections to its May 1, 2018 EM&V report to incorporate these recommendations. He also stated that the Public Staff believes that with these corrections the Company adequately applied the Public Staff's recommendations to the 2018 EM&V Report. Finally, he concluded that DENC is appropriately incorporating the results of its EM&V efforts into the DSM/EE rider calculations, and that for purposes of this and previous DSM/EE cost recovery proceedings for DENC, the 2018 EM&V Report data used to true up program savings and participation for Vintage Year 2017 and earlier Vintages are sufficient to consider those Vintage years to be complete for all programs operating in those years.

Based on the foregoing, the Commission finds and concludes that the EM&V analyses and reports prepared by DENC are reasonable for purposes of this proceeding.

IT IS, THEREFORE, ORDERED as follows:

1. That the appropriate annual DSM/EE rider, Rider C, to become effective on and after February 1, 2019, consists of the following customer class billing factor increments (including Regulatory Fee): Residential – 0.062 ¢/kWh; Small General Service and Public Authority – 0.140 ¢/kWh; Large General Service – 0.147 ¢/kWh; and no charge for 6VP, NS, Outdoor Lighting and Traffic Lighting.

2. That the appropriate annual DSM/EE EMF rider, Rider CE, to become effective on and after February 1, 2019, consists of the following customer class increment billing factors (including Regulatory Fee): Residential – 0.059 ¢/kWh; Small General Service and Public Authority – 0.082 ¢/kWh; Large General Service – 0.086 ¢/kWh; and no charge for 6VP, NS, Outdoor Lighting and Traffic Lighting.

3. That DENC was authorized to and shall continue to charge the DSM/EE Rider C approved in Docket No. E-22, Sub 545 through January 31, 2019, and shall reduce to zero the rate charged under DSM/EE EMF Rider CE for the period January 1-31, 2019.

4. That DENC shall work with the Public Staff to prepare a joint notice to customers of the rate changes ordered by the Commission in this docket, as well as in Docket Nos. E-22, Subs 557 and 558, and the Company shall file such notice for Commission approval as soon as practicable, but not later than three working days after the Commission issues the last of its orders in the above-referenced dockets.

5. That DENC shall file appropriate rate schedules and riders with the Commission to implement the provisions of this Order as soon as practicable.

6. That DENC shall continue to provide a listing of the Company's event sponsorship and consumer education and awareness initiatives during the test period in future DSM/EE rider proceedings.

ISSUED BY ORDER OF THE COMMISSION.
This the 10th day of January, 2019.

NORTH CAROLINA UTILITIES COMMISSION
A. Shonta Dunston, Acting Deputy Clerk

DOCKET NO. E-35, SUB 49

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application by Western Carolina University for Approval of Purchased Power Adjustment Factor	)))	ORDER APPROVING PURCHASED POWER COST RIDER

BY THE COMMISSION: On December 12, 2018, in compliance with Commission orders in Docket No. E-35, Subs 17, 19, and 40, Western Carolina University (WCU) filed an application for a change in its Schedule CP Purchased Power Cost Rider (Rider) to be effective for the twelve monthly billings beginning with the bills rendered in January 2019. This filing included actual purchased power cost and recovery information only for the period January 2018 through November 2018. The purchased power cost to be recovered through the Rider contained elements of WCU's proposed recovery of coal ash costs, as approved by the Commission in Docket No. E-35, Sub 48 (Sub 48).

On January 10, 2019, the Public Staff filed a Motion for Extension of Time and Permanent Change in Effective Date of Purchased Power Adjustment Rider Rates in this matter, requesting that the Commission issue an order concluding (1) that the procedural schedule for this and future WCU purchased power adjustment (PPA) proceedings be extended by one month, with WCU's filing dates and test period for purposes of measuring the experience modification factor (EMF) remaining unchanged from current practice; (2) that the PPA adjustments in this and future WCU PPA proceedings be set to typically become effective for bills rendered in February of each year; and (3) that the ongoing procedural schedule and effective date of rates remain subject to case-by-case changes, as may be necessary. The purpose of the requested extension, as stated by the Public Staff, was to provide time for the parties to resolve all questions and issues, or bring unresolved questions to the Commission, in a more orderly and timely manner than what is provided under the current, somewhat compressed procedural schedule.

On January 17, 2019, the Commission issued an Order Granting Extension of Time and Permanent Change in Effective Date of Purchased Power Adjustments changing the effective month of WCU's annual PPA adjustments for 2019 and future years to February, with WCU's PPA filing dates and test period for purposes of measuring the EMF remaining unchanged from current practice.

On February 13, 2019, WCU filed its final rates for the Rider, which incorporated actual purchased power and coal ash costs and revenues through December 2018.

The net PPA factor (including coal ash cost components) requested by WCU for use in Schedule CP is a decrement of \$(0.00474) per kWh. This proposed factor would replace the currently expiring increment factor of \$0.00155 and would decrease a customer's monthly bill by \$6.29 for 1,000 kWh of usage. The requested factor is made up of three elements. The first is a decrement of \$(0.00221) per kWh to recover estimated purchased power costs for the period February 2019 through January 2020. The second element is an EMF decrement of

$(0.00228) per kWh to refund purchased power costs overcollected during the period January 2018 through December 2018. The EMF decrement includes (1) an embedded increment to reflect the January 2018 over- refunding of the EMF decrement from Docket No. E-35, Sub 47, and (2) an embedded increment to reflect interest accrued on the deferral of estimated coal ash expenses in last year's PPA proceeding (Sub 48). The third element is an EMF interest decrement of $(0.00025) per kWh calculated in conjunction with the overcollection of purchased power and coal ash costs.

The Public Staff presented this matter at the Commission's Regular Staff Conference on February 18, 2019, and recommended that the proposed Rider decrement be approved effective for the twelve monthly bills rendered on and after February 18, 2019, and before February 1, 2020. In support of this recommendation, the Public Staff stated that it has reviewed the calculations and documentation supporting the Rider requested by WCU and found them to be accurate. The Public Staff further stated that the approval of this Rider should be without prejudice to the right of any party to take issue with it in a general rate case.

After careful review of WCU's proposal and upon the recommendation of the Public Staff, the Commission concludes that the adjustment factor decrement of $(0.00474) per kWh proposed by WCU should be approved.

IT IS, THEREFORE, ORDERED as follows:

1. That WCU's Purchased Power Cost Rider, Schedule CP, which is attached to this order as Attachment A, is allowed to become effective for the twelve monthly bills rendered on and after February 18, 2019, and before February 1, 2020.

2. That the Purchased Power Cost Rider is approved without prejudice to the right of any party to take issue with the Rider in a general rate case.

3. That WCU shall give appropriate notice to its retail customers for the Purchased Power Cost Rider by bill insert in the bills issued in February 2019. A copy of this notice shall be filed with the Chief Clerk of the North Carolina Utilities Commission within five working days of the date of this Order.

4. That WCU shall file appropriate rate schedules and riders with the Commission in order to implement the approved purchased power adjustment no later than ten working days from the date of this Order.

ISSUED BY ORDER OF THE COMMISSION.

This the 19th day of February, 2019.

NORTH CAROLINA UTILITIES COMMISSION
A. Shonta Dunston, Deputy Clerk

ATTACHMENT A

WESTERN CAROLINA UNIVERSITY
DOCKET NO. E-35, SUB 49

SCHEDULE "CP" PURCHASED POWER COST RIDER

Each customer's twelve monthly bills rendered on and after February 18, 2019, for each month between February 18, 2019, and February 1, 2020, shall be adjusted by a decremental charge of $(0.00474) per kWh as determined to be appropriate by the North Carolina Utilities Commission.

This rate is determined as follows:

	$/kWh
Factor for estimated purchased power costs for the period February 2019 through January 2020	($0.00221)
Experience Modification Factor to reflect actual results for the period January 2018 through December 2018	($0.00228)
Experience Modification Factor Interest to reflect the over-collection of expenses for the period January 2018 through December 2018	($0.00025)
TOTAL RATE	($0.00474)

Effective for bills rendered on and after February 18, 2019, and before February 1, 2020.

DOCKET NO. E-22, SUB 567
DOCKET NO. E-22, SUB 568
DOCKET NO. E-22, SUB 569
DOCKET NO. E-22, SUB 570
DOCKET NO. E-22, SUB 571
DOCKET NO. E-22, SUB 572
DOCKET NO. E-22, SUB 573
DOCKET NO. E-22, SUB 574

DOCKET NO. E-22, SUB 567
In the Matter of
Application of Dominion Energy North Carolina for Approval of Residential Home Energy Assessment Program

DOCKET NO. E-22, SUB 568
In the Matter of
Application of Dominion Energy North Carolina for Approval of Residential Efficient Products Marketplace Program

DOCKET NO. E-22, SUB 569
In the Matter of
Application of Dominion Energy North Carolina for Approval of Residential Appliance Recycling Program

DOCKET NO. E-22, SUB 570
In the Matter of
Application of Dominion Energy North Carolina for Approval of Non-Residential Window Film Program

DOCKET NO. E-22, SUB 571
In the Matter of
Application of Dominion Energy North Carolina for Approval of Non-Residential Small Manufacturing Program

DOCKET NO. E-22, SUB 572
In the Matter of
Application of Dominion Energy North Carolina for Approval of Non-Residential Office Program

ORDER APPROVING DEMAND-SIDE MANAGEMENT AND ENERGY EFFICIENCY PROGRAMS

DOCKET NO. E-22, SUB 573)
In the Matter of)
Application of Dominion Energy North)
Carolina for Approval of Non-Residential)
Lighting Systems and Controls Program)
)
DOCKET NO. E-22, SUB 574)
In the Matter of)
Application of Dominion Energy North)
Carolina for Approval of Non-Residential)
Heating and Cooling Efficiency Program)

BY THE COMMISSION: On July 12, 2019, Dominion Energy North Carolina (DENC or the Company), filed applications in the above-captioned dockets requesting approval of the following programs as new demand-side management (DSM) and energy efficiency (EE) programs under N.C. Gen. Stat. § 62-133.9 and Commission Rule R8-68:

- Residential Home Energy Assessment Program;
- Residential Efficient Products Marketplace Program;
- Residential Appliance Recycling Program;
- Non-Residential Window Film Program;
- Non-Residential Small Manufacturing Program;
- Non-Residential Office Program;
- Non-Residential Lighting Systems and Controls Program; and,
- Non-Residential Heating and Cooling Efficiency Program.

The applications included estimates of each Program's impacts, costs, and benefits used to calculate the cost-effectiveness of each Program. DENC stated that its calculations indicate that each Program is cost-effective under the Total Resource Cost, the Utility Cost, and the Participant tests.

On July 25, 2019, the Commission granted the Public Staff and other interested parties an extension of time to October 10, 2019, in which to file comments on the proposed Programs. No party filed comments.

On October 22, 2019, the Public Staff filed a letter and a proposed order recommending that the Commission approve the Programs. On October 29, 2019, the Public Staff filed a correction to its letter and proposed order.

The Public Staff summarized the Programs as follows.

RESIDENTIAL HOME ENERGY ASSESSMENT PROGRAM

The Program is designed to provide an in-home energy assessment. Trained personnel will perform the assessment and offer several low cost measures related to lighting, hot water, and HVAC facilities. The average modeled incentive for the Program was $82 per participant. The actual incentives received by the participant will be contingent upon the measures that are installed as a result of the assessment.

The Public Staff noted that less than 10% of the participation and savings for the Program are associated with lighting measures. Hot water-related measures account for half of the participation, and HVAC-related measures account for approximately 70% of the energy savings potential from the Program.

RESIDENTIAL EFFICIENT PRODUCTS MARKETPLACE PROGRAM

The Program is designed to provide rebates for the purchase of energy efficient appliances and products through an online portal or retail store. The average modeled incentive for the Program was $2 per participant. The actual incentives received by the participant will be contingent upon the measures purchased.

The Public Staff noted that the Company projects at least 95% of the rebates offered will be given for lighting measures. The remaining rebates are expected to be given for the purchase of various household appliances.

RESIDENTIAL APPLIANCE RECYCLING PROGRAM

The Program will provide an incentive to recycle older less efficient refrigerators and freezers. Appliances must be in working condition at the time the appliance is retrieved. The average modeled incentive for the Program was $20 per appliance.

The Public Staff noted that the Company will recycle at least 95% of the materials from the appliances by contract vendors who are certified to recycle such materials.

NON-RESIDENTIAL WINDOW FILM PROGRAM

The Program will reinstate the previous program that was cancelled pursuant to an order dated October 16, 2018 in Docket No. E-22, Sub 509 resulting from actions taken by the Virginia State Corporation Commission. At that time the Company and Public Staff agreed that the Company could not cost-effectively offer a window film program on a North Carolina-only basis. The Program will reinstate the same measures that were part of the previous program. The average modeled incentive for the Program was $1 per square foot of window.

The Public Staff noted that the Sub 509 program had one participant in North Carolina during the four years that the Sub 509 program was offered.

NON-RESIDENTIAL SMALL MANUFACTURING PROGRAM

The Program is designed to provide small manufacturing customers with incentives to install a variety of energy efficient air compression-related measures following an assessment by the contract vendor. The average modeled incentive for the Program was $9,465 per participant. The actual incentives received by the participant will be contingent upon the measures that are installed.

NON-RESIDENTIAL OFFICE PROGRAM

The Program is designed to provide small office customers with a variety of measures related to lighting and HVAC following an assessment by the contract vendor. The average modeled incentive for the Program was $6,374 per participant. The actual incentives received by the participant will be contingent upon the measures that are installed.

The Public Staff noted that approximately 90% of the participation and savings for the Program are associated with HVAC-related measures. This includes measures that optimize the scheduling and temperature controls of the HVAC equipment itself.

NON-RESIDENTIAL LIGHTING SYSTEMS AND CONTROLS PROGRAM

The Program will replace the current North Carolina-only program that was approved pursuant to an order dated October 16, 2018 in Docket No. E-22, Sub 508. The Program will reinstate the system-wide program and update the measures offered. The average modeled incentive for the Program was $2,456 per participant.

The Public Staff noted that the Sub 508 program had 122 participants in North Carolina during the four years it was offered.

NON-RESIDENTIAL HEATING AND COOLING EFFICIENCY PROGRAM

DENC stated that the Program will replace the current North Carolina-only program that was approved pursuant to an order dated October 16, 2018 in Docket No. E-22, Sub 507. The Program will reinstate the system-wide program. The average modeled incentive for the Program was $1,901 per participant.

The Public Staff noted that the Sub 507 program had 15 participants in North Carolina in the four years it was offered.

In the letter filed October 22, 2019, the Public Staff stated that it had reviewed each application and concluded that: (1) the filings contained the information required by Commission Rule R8-68(c) and were consistent with N.C.G.S. § 62-133.9, Rule R8-68(c), and the Cost Recovery and Incentive Mechanism for Demand-Side Management and Energy Efficiency Programs (Mechanism), approved by Order dated May 22, 2017, in Docket No. E-22, Sub 464; (2) DENC's estimates of program costs and net lost revenue appeared to be consistent with the requirements of the Mechanism; and (3) pursuant to the Mechanism, DENC was eligible to receive a performance incentive for each program.

The Public Staff also stated that it reviewed the avoided cost benefits associated with the modeling used by DENC to evaluate the cost-effectiveness of each program. The Public Staff noted that DENC stated that the inputs related to these avoided capacity and energy benefits of the Programs are consistent with DENC's 2018 Integrated Resource Plan (IRP, filed on March 7, 2019, in Docket No. E-100 Sub 157), and the Mechanism. However, the Public Staff noted in its review that the Company modeled the Programs in a manner that the Public Staff believes could raise some concern with the inputs used to value the avoided capacity benefits. DENC's modeling for the proposed Programs included avoided capacity benefits that in certain years are based on the cost per kilowatt of a generic solar unit and market purchases, as outlined in Plan E of DENC's 2018 IRP. The Public Staff believes that the use of a combustion turbine is the appropriate input to the methodology used to determine the avoided cost rate for capacity, as compared to the use of other generation units which overstate the avoided capacity benefits of the Programs. However, the Public Staff stated that the impact was not material to the calculations of the cost effectiveness for the Programs. Further, the Public Staff stated that it intends to discuss the issue of avoided cost modeling with the Company in the context of the upcoming Mechanism review that is presently pending in Docket No. E-22, Sub 464, and DENC's 2020 DSM/EE rider proceeding.

Based on the foregoing and the entire record in this proceeding, the Commission finds and concludes that the proposed Programs meet the criteria required by N.C.G.S. § 62-133.9 and Commission Rule R8-68, are in the public interest, and should be approved as new DSM/EE programs. The Commission further finds and concludes that the appropriate ratemaking treatment for the Programs, including program costs, net lost revenues, and performance incentives, should be determined in DENC's annual DSM/EE cost recovery rider, pursuant to Commission Rule R8-69. Finally, DENC shall file evaluation, measurement and verification (EM&V) reports for the Programs beginning with its 2020 DSM/EE rider proceeding.

IT IS, THEREFORE, ORDERED as follows:

1. That the Residential Home Energy Assessment Program; Residential Efficient Products Marketplace Program; Residential Appliance Recycling Program; Non-Residential Window Film Program; Non-Residential Small Manufacturing Program; Non-Residential Office Program; Non-Residential Lighting Systems and Controls Program; and Non-Residential Heating and Cooling Efficiency Program are hereby approved as new demand-side management and energy efficiency programs pursuant to Commission Rule R8-68.

2. That the Commission shall determine the appropriate ratemaking treatment for the Programs, including program costs and incentives, in DENC's annual DSM/EE cost recovery rider, in accordance with N.C.G.S. § 62-133.9 and Commission Rule R8-69.

3. That the North Carolina-only versions of the Non-Residential Lighting Systems and Controls Program and the Non-Residential Heating and Cooling Efficiency Program approved in Docket Nos. E-22, Subs 508 and 507, respectively, shall be canceled effective upon implementation of the system-wide versions of these Programs as outlined in Subs 573 and 574, respectively.

4. That DENC shall file EM&V reports for each program with DENC's future DSM/EE rider applications, beginning in 2020.

5. That DENC shall file tariffs for each Program, including the effective date of eacl Program, within 10 days of the date of this Order.

ISSUED BY ORDER OF THE COMMISSION.
This the 13th day of November, 2019.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

Commissioner Kimberly W. Duffley did not participate in this decision.

ELECTRIC – CONTRACT/AGREEMENTS

DOCKET NO. E-22, SUB 476
DOCKET NO. E-22, SUB 477

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Request of Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina for Approval of a Revised Services Agreement, and Revised Affiliate Services Agreements	)	ORDER ACCEPTING AFFILIATE AGREEMENTS FOR FILING AND ALLOWING PAYMENT OF COMPENSATION

BY THE COMMISSION: On October 30, 2018, Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina (DENC or the Company), filed two petitions requesting acceptance of certain revised affiliate agreements. In Docket No. E-22, Sub 476, DENC requested that the Commission accept a revised services agreement under which Dominion Energy Services, Inc. (DES), would continue to provide accounting, legal, human resources, information technology, management, and other centralized services to DENC. In Docket No. E-22, Sub 477, DENC requested acceptance of six revised separate affiliate services agreements. DENC also requested acceptance of a form affiliate services agreement for future affiliates subject to monetary limitations and limited services. The revised services agreement, six revised separate affiliate agreements, and form affiliate services agreement are collectively referred to herein as the affiliate agreements.

On December 17, 2018, the Commission issued an Order on Affiliate Agreements. In summary, based on the recommendation of the Public Staff the Commission accepted the affiliate agreements for filing and the payment of compensation thereunder on an interim basis, with several conditions. The Commission noted that the Public Staff was in the process of its investigation and review of the affiliate agreements, and that once the Public Staff's review was complete it would provide the Commission with its final recommendations. Further, the Commission noted that the affiliate agreements were subject to review and approval by the Virginia State Corporation Commission (VSCC).

On January 15, 2019, the Public Staff filed a letter and proposed order in these dockets. The Public Staff stated that it had completed its review of the affiliate agreements. Further, the Public Staff noted that the affiliate agreements were approved by the VSCC by orders issued on December 19 and 21, 2018, in Case No. PUR-2018-00162 and Case No. PUR-2018-00161, respectively.

The Public Staff stated that its review of the affiliate agreements included a review of DENC's petitions, DENC's Regulatory Conditions and Code of Conduct approved by the Commission in its Order Approving Merger Subject to Regulatory Conditions and Code of Conduct (Dominion/SCANA Merger Order), in Docket No. E-22, Sub 551 (November 19, 2018), responses to data requests, and the VSCC orders. Based on its review, the Public Staff recommended that the Commission accept the affiliate agreements for filing and payment thereunder, with the following conditions.

ELECTRIC – CONTRACT/AGREEMENTS

1) That the affiliate agreements be accepted and payment thereunder authorized for two years, from January 1, 2019 through December 31, 2020, with DENC's ability to pay the affiliates subject to adjustment if found appropriate by the Commission upon its own motion, or a petition by the Public Staff or another party.

2) That if the Company wishes to extend the affiliate agreements beyond the two-year period, separate Commission approval will be required.

3) No changes may be made to any of the affiliate agreements without prior filing with the Commission, including changes in the terms and conditions, allocation methodologies, service category descriptions, and successors or assigns. DENC is required to file any proposed amendments prior to the execution of amended agreements and prior to any payment for services pursuant to an amended agreement.

4) The Commission's acceptance of the affiliate agreements and approval of payment thereunder shall have no accounting or ratemaking implications.

5) The Commission's acceptance of the affiliate agreements and approval of payment thereunder shall be limited to the specific services identified in the affiliate agreements. Should DENC wish to obtain additional services from affiliates other than those specifically identified in the agreements, separate Commission approval shall be required.

6) DENC shall be required to provide written notice to the Commission within fifteen (15) days of any election, by either DENC or the affiliates, of new services not currently selected in each of the respective revised agreements that it intends to take pursuant to such agreements, regardless of the cost of such services. If new services are selected, DENC shall include that information in its Annual Report of Affiliated Transactions (ARAT).

7) All terms of the affiliate agreements and the activities conducted pursuant thereto remain subject to DENC's compliance with its Regulatory Conditions and Code of Conduct approved by the Commission in the Dominion/SCANA Merger Order.

8) All services provided by each of the affiliates pursuant to the affiliate agreements shall be at the lower of cost or market. Supporting documentation for such transactions shall be made available for Public Staff and Commission review upon request, including the periodically conducted market price studies required by Regulatory Condition No. 4.2.

9) DENC shall have the burden of proving that any and all goods and services procured from its affiliates have been procured on the most favorable terms and conditions reasonably available in the relevant market, which shall include a showing that such goods and services could not have been procured at a lower price from qualified non-affiliate sources, or that DENC could not have provided the services or goods for itself on the same basis at a lower cost, as required by Regulatory Condition No. 4.2(a). Records of such investigations and comparisons shall be made available for Public Staff and Commission review upon request.

10) The Commission's approval of the affiliate agreements shall not be deemed, in connection with any future proceeding before the Commission, to determine and establish DENC's retail rates or for any other purpose, or to constitute Commission approval of any level of charges directly charged, assigned, or allocated to DENC under the agreements.

11) All terms of the affiliate agreements and the activities conducted pursuant thereto remain subject to ongoing review as to their appropriateness and reasonableness and to modification by the Commission upon its own motion, or upon a motion by the Public Staff or another party.

12) All goods and services rendered pursuant to the affiliate agreements and the costs and benefits directly charged, assigned, and/or allocated in connection with such services, and the determination or calculation of the bases and factors utilized to assign or allocate such costs and benefits, remain subject to ongoing review as to their appropriateness and reasonableness and to further action by the Commission upon its own motion or upon the motion of any party.

13) DENC shall include all transactions under the affiliate agreements in its ARAT filed with the Commission. The report of the transactions should include the docket number in which the affiliate agreements were approved, the name and type of activity performed by each direct and indirect affiliate/future affiliate to the agreements, and a schedule in Excel electronic spreadsheet format, with formulas intact, listing the prior year's transactions by month, type of service, FERC account, and the dollar amount (as the transaction is recorded on the Company's books).

14) DENC shall involve the Public Staff in the continuing work that the VSCC required DENC to engage in regarding the verification and auditing of DES charges.

15) DENC shall be required to include a Status Report in its ARAT describing DENC's progress toward implementing the DENC prepared Detailed Report's measures/recommendations set forth in Attachment D to the application filed in Docket No. E-22, Sub 477. DENC shall be required to maintain records that shall be made available to the Public Staff and Commission upon request to support any statement or claims made in the Detailed Report and the Status Report.

16) The Commission's acceptance of the affiliate agreements shall not be deemed to constitute the approval of any specific charges under the affiliate agreements, or a guarantee of any recovery of costs directly or indirectly related to the affiliate agreements.

17) DENC is exempted from the requirement to file pursuant to N.C. Gen. Stat. § 62-153 affiliate services agreements with any future affiliates that bill (a) less than $500,000 per service per year and (b) no more than $2 million total per year on a system wide basis to DENC, provided that the future affiliate executes the form agreement in the form as filed herein, with DENC having the burden of monitoring such billings and filing for approval, pursuant to N.C. Gen. Stat. § 62-153, prior to such billing exceeding either of the caps set forth in (a) and (b) above. Any such agreement, once executed, shall be filed in Docket No. E-22, Sub 551A, with DENC's next occurring ARAT, along with a report of any charges that have been incurred under such agreement.

18) The Commission reserves the right to revoke the exemption stated in the above paragraph at any time that such revocation is deemed to be in the public interest.

19) The Commission reserves the right to examine the books and records of DENC and any affiliate in connection with the affiliate agreements, whether or not such affiliate is regulated by the Commission;

20) Commission approval is required for DES, or another services company, to provide centralized services to DENC under the affiliate agreements by the engagement of affiliated third parties.

21) All requirements regarding the affiliate agreements shall also apply to transactions between DENC and future affiliates to which exemption from the filing and prior approval requirements apply.

22) DENC shall file with the Commission signed and executed copies of each of the affiliate agreements within thirty (30) days of the date of this order.

23) The foregoing conditions shall not replace, supersede, or modify the conditions previously approved by the Commission in Docket No. E-22, Sub 434, with respect to the currently effective Dominion Energy Fuel Services Agreement filed in that docket and in Docket No. E-22, Sub 515.

24) The Commission's acceptance of the affiliate agreements and authorization for DENC to make payments pursuant to the agreements does not constitute approval of the amount of fees or compensation paid by DENC under the agreements for ratemaking purposes, and the authority granted is without prejudice to the right of any party to take issue with any provision of the affiliate agreements in a future proceeding.

The Public Staff stated that DENC has agreed to the conditions proposed by the Public Staff. The Public Staff requested that the Commission issue an order consistent with the Public Staff's recommendation. In addition, the Public Staff noted, on behalf of DENC, that DENC is requesting issuance of an order on an expedited basis because it is required to file executed copies of the affiliate agreements with the VSCC on or before January 19, 2019.

Based on the foregoing and the record, the Commission concludes that pursuant to N.C. Gen. Stat. § 62-153 the affiliate agreements should be accepted for filing, and that DENC should be authorized to make payments for its receipt of services in accordance with the terms of the affiliate agreements, subject to the conditions recommended by the Public Staff, as set forth above.

IT IS, THEREFORE, ORDERED as follows:

1. That the Revised DES Services Agreement is accepted for filing;

2. That the six Revised Affiliate Services Agreements are accepted for filing;

3. That the Revised Form Affiliate Services Agreement is accepted for filing;

4. That DENC is authorized to make payments under the affiliate agreements in accordance with their terms; and

5. That the Commission's acceptance for filing and authorization for DENC to make payments under the affiliate agreements shall be subject to the conditions recommended by the Public Staff, as enumerated in the body of this order.

ISSUED BY ORDER OF THE COMMISSION.
This the 18th day of January, 2019.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

Commissioner Daniel G. Clodfelter did not participate in this decision.

DOCKET NO. E-2, SUB 1185

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of Duke Energy Progress, LLC for A Certificate of Public Convenience and Necessity to Construct a Microgrid Solar and Battery Storage Facility in Madison County, North Carolina	)	ORDER GRANTING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY WITH CONDITIONS

BY THE COMMISSION: On October 8, 2018, Duke Energy Progress, LLC ("DEP"or the "Company") filed a verified application pursuant to N.C.G.S. § 62-110.1 and Commission Rule R8-61 for a Certificate of Public Convenience and Necessity ("CPCN Application" or "Application") to construct the generation components of the Hot Springs Microgrid Solar and Battery Storage Facility (the "Hot Springs Microgrid") on DEP-leasedproperty in Madison County, North Carolina. The Company also requested appropriate approval from the Commission for its decision to construct and own the battery storage components of the Hot Springs Microgrid as consistent with the Company's commitmentandthe Commission's March 28, 2016 Order Granting Application, in Part, with Conditions, and Denying Application in Part in Docket No. E-2, Sub 1089 (the "Western Carolinas Modernization Project (WCMP) Order"). In support of the CPCN Application, the Company included exhibits and the supporting direct testimony of Jonathan A. Landy, Business Development Manager for Duke Energy Business Services LLC, an affiliate of DEP.

The intervention of the Public Staff has been recognized pursuant to N.C.G.S. § 62-15(d) and Commission Rule R1-19(e). On October 10, 2018, the North Carolina Sustainable Energy Association ("NCSEA") filed a motion to intervene, which was granted by the Commission on October 16, 2018.

On October 31, 2018, the Commission issued its Order Finding ApplicationIncomplete. On November 13, 2018, in response to the Commission's October 31 order, DEP filed the supplemental testimony and exhibits of witness Landy. On November 30, 2018, the Commission issued its Order Scheduling Hearings, Requiring Filing of Testimony, Establishing Discovery Guidelines and Requiring Public Notice ("Scheduling Order"). The Scheduling Order, among other things, scheduled a public witness hearing on the Company's Application to be held in Madison County on January 23, 2019, and anexpert witness hearing to be held in Raleigh on February 25, 2019. Further, the Scheduling Order required DEP to publish a notice containing a summary of the Application, the details of the public witness hearing and other information. The Company published notice in newspapers having general coverage in Madison County, as required, and also in the Asheville Citizen-Times.

On January 7, 2019, the State Environmental Review Clearinghouse ("State Clearinghouse") filed a letter with agency comments about the Hot Springs Microgrid, stating that no further action was needed on the Commission's part for compliance with the North Carolina Environmental Policy Act. On January 14, 2019, the State Clearinghouse filed additional comments from the Department of Cultural Resources requesting additional information, including the results of an archaeological survey to beconducted by an experienced archaeologist prior to construction. On January 22, 2019, the State Clearinghouse filed additional comments, from the Department of Agriculture and Consumer Services, encouraging preservation of productive farmland on the site.

On January 16, 2019, the Commission issued an order cancelling the public witness hearing scheduled for January 23, 2019, citing the lack of significant protest and the number of public statements filed in support of the Hot Springs Microgrid.

On January 30, 2019, the Public Staff filed the testimony of Jeff Thomas, an engineer with the Electric Division of the Public Staff. He recommended that the Hot Springs Microgrid be approved as a pilot project and that the certificate be granted, subject to certain conditions.

On February 7, 2019, DEP, the Public Staff and NCSEA jointly filed a motion requesting that the Commission cancel the expert witness hearing scheduled for February 25, 2019. In this motion, DEP explained that it agreed with recommended conditions proposed by the Public Staff as set forth in Confidential Attachment A, "Reporting, Study, Cap and Other Conditions Agreed to by the Parties" to the joint motion. No other parties intervened or filed testimony in this matter. On February 19, 2019, the Commission issued its Order Canceling Expert Witness Hearing and Receiving Evidence into Record. That order also required parties to file proposed orders on or before March 29, 2019.

DEP and the Public Staff filed a joint proposed order on March 22, 2019.

Based upon the Company's verified Application, the testimony and exhibits received into evidence, and the record as a whole, the Commission makes the following:

FINDINGS OF FACT

1. DEP is a public utility with an obligation to provide electric utility service to customers in its service area in North Carolina and is subject to the jurisdiction of the Commission.

2. The Commission has jurisdiction over the Application. Pursuant to N.C.G.S. § 62-110.1 and Commission Rule R8-61(b), a public utility must receive a CPCN prior to constructing electric generating facilities.

3. The Hot Springs Microgrid consists of an approximately 3 MW direct current ("DC") / 2 MW alternating current ("AC") solar photovoltaic ("PV") electric generator and an approximately 4 MW lithium-based battery storage facility to be constructed in Madison County, North Carolina. In addition to providing energy to the DEP system, the Hot Springs Microgrid will be capable of operating while disconnected from the grid (known as "islanding") to improve reliability for DEP customers connected to the Hot Springs 22.86 kV feeder, which runs for approximately ten miles from the Marshall Substation along the French Broad River and through the Great Smoky Mountains. While grid-tied, the Hot Springs Microgrid should be capable of providing ancillary system services, such as frequency, voltage, and ramping support, to the electric grid, and capacity during system peaks.

4. The Hot Springs Microgrid should improve reliability for customers in the Town of Hot Springs who are connected to the Hot Springs 22.86 kV distribution feeder.

5. DEP conducted a comprehensive siting process and appropriately selected the site for the Hot Springs Microgrid.

6. The short-term plan in DEP's 2017 Integrated Resource Plan ("IRP") Update called for investment in a limited number of battery storage projects to gain additional operation and technical experience with evolving utility-scale storage technologies. The Hot Springs Microgrid is included in DEP's 2018 IRP, filed with the Commission on September 5, 2018 in Docket No. E-100, Sub 157.

7. Because of the unique needs of the Hot Springs service area, exploring the wholesale market for the capacity and energy to serve those needs is not feasible.

8. The Company's confidential construction cost estimate for the Hot Springs Microgrid is reasonable and is hereby approved, subject to the conditions ordered below.

9. The Hot Springs Microgrid is consistent with the WCMP Order, in which the Commission noted DEP's commitment to work with customers in the Asheville region to site solar and battery storage facilities as part of the WCMP.

10. Though it is not clear that the Hot Springs Microgrid is the most cost effective way to address reliability and service quality issues at Hot Springs, the overall public convenience and necessity would be served by granting the certificate for the solar facility and approving the Hot Springs Microgrid as a pilot project. The system benefits from the Hot Springs Microgrid are material but are difficult to quantify accurately without real world experience in DEP's service territory. DEP will gain valuable experience by operating the Hot Springs Microgrid, and this experience and data collection and analysis will be beneficial in future cost-benefit analyses of projects with that proposed to include an energy storage component. For these reasons, pursuant to N.C.G.S. § 62-110.1, a Certificate of Public Convenience and Necessity for the solar generation-related components of the Hot Springs Microgrid proposed by DEP will be granted, and the Hot Springs Microgrid will be approved as a pilot, subject to (1) the reporting requirements, a study of frequency regulation, (3) the imposition of a cap on the above-the-line capital costs of the project, and (4) other conditions proposed by the Public Staff, all of which have been agreed to by DEP and are set forth more fully in the ordering paragraphs below.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NOS. 1-2

These findings are informational, procedural, and jurisdictional in nature and are uncontroverted.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NOS. 3-4

These findings are supported by the Application and exhibits, the direct and supplemental testimony and exhibits of DEP witness Landy, and the testimony of Public Staff witness Thomas.

DEP witness Landy testified that the Hot Springs Microgrid will be constructed as an approximately 3 MW direct current ("DC") / 2 MW alternating current ("AC") solar photovoltaic ("PV") electric generator and approximately 4 MW lithium-based battery energy storage system ("BESS") in Madison County, North Carolina, and will be situated on one parcel totaling approximately 15 acres. The entire facility will be located on land that DEP has leased from a local industrial company, as shown on the vicinity map attached as Figure 3 in Exhibit 2 to the Application. The Hot Springs Microgrid will be capable of providing energy to customers in Hot Springs even while disconnected from the DEP grid to mitigate outages for DEP customers connected to the Hot Springs 22.86kV feeder, which runs for approximately ten miles from the Marshall Substation along the French Broad River and through the mountainous Pisgah National Forest. While grid-tied, the Hot Springs Microgrid will be capable of providing essential reliability services to the DEP grid, such as frequency and voltage regulation, ramping support, and capacity during system peaks.

According to witness Landy, the Hot Springs Microgrid will consist of PV panels affixed to ground-mounted 20 degree fixed-tilt racking, solar inverters, a Microgrid controller, and a BESS. A lithium-based BESS will be connected and sized so that the Hot Springs Microgrid can provide backup power to customer loads during certain outage events. The nominal generation capacity for the PV generator will be approximately 3 MWDC / 2 MW AC. The nominal storage capacity for the battery will be approximately 4 MW. Additional equipment to support the Hot Springs Microgrid will include circuit breakers, combiners, surge arrestors, conductors, disconnect switches, inverters, and connection cabling. The anticipated useful life of the Hot Springs Microgrid is expected to be 25 years with anticipated replacement battery cells after the tenth year, depending on the degradation curves experienced by the BESS. DEP witness Landy testified that if Commission approval were obtained, the limited notice to proceed could be issued as early as March 2019, with site mobilization to begin in September 2019, and with final commissioning in January 2020.

Witness Landy further testified that the Hot Springs Microgrid will be interconnected to the single DEP-owned 22.86 kV distribution feeder serving the Town of Hot Springs. He stated that the Company chose this interconnection point in order to reduce potential failure modes and project costs. During normal operation, the Hot Springs Microgrid will be connected in parallel and will export energy to the DEP grid. The islanding capability will be managed through appropriate protection and control equipment, which switches service to customers from the Hot Springs feeder to the Hot Springs Microgrid.

Witness Landy explained that a primary need for the Hot Springs Microgrid is to improve the reliability of service to customers connected to the Hot Springs 22.86 kV distribution feeder, which is the single source of service for the Town of Hot Springs. The existing feeder has a history of incurring long-duration outage events and is expected to require high-cost equipment upgrades beginning in 2020. The Company evaluated two alternatives to the Hot Springs Microgrid. The first was to construct a second distribution feeder into the town by connecting to French Broad EMC, which serves the area adjacent to DEP's service territory. Witness Landy indicated that this option presented several challenges that made it infeasible; therefore, a detailed cost estimate for this option was not developed. Specifically, obtaining right of way in this region was anticipated to be extremely challenging. In addition, the requisite tie into the DEP system and the tie into French Broad EMC's system would also result in significant infrastructure investments.

Witness Landy testified that the second alternative that DEP evaluated was to reconductor and rebuild the existing 22.86 kV Hot Springs feeder to modern storm/mountain hardening standards. This alternative would involve replacing the existing poles and structures with higher class poles for greater strength, adding guying to each pole, and replacing the existing conductor. The capital-only cost of this upgradewas estimated to be **[BEGIN CONFIDENTIAL] [END CONFIDENTIAL]**, but would still leave Hot Springs with only a single feeder that would remain susceptible to outages in remote and rugged terrain and would not provide the additional ancillary benefits to DEPcustomers that are anticipated from the Hot Springs Microgrid.

Witness Landy testified that DEP determined that the Hot Springs Microgrid was abetter option to meet the needs of all DEP customers than these distribution upgrade alternatives. Witness Landy asserts that by utilizing new technology, the Hot Springs Microgrid will provide Hot Springs customers with multiple hours of back-up power to improve the reliability of electric service to the community.

Public Staff witness Thomas testified regarding the Public Staff's investigation of the Hot Springs Microgrid proposal. Witness Thomas testified that Hot Springs is a smalltown in Madison County, North Carolina, with approximately 600 DEP retail electric service customers in DEP's Western Region. Electric service in Hot Springs is supplied via a single radial 23-kV distribution line of approximately 10.5 miles that runs from DEP'sMarshall Substation to the southeast through rugged, mountainous terrain. DEP's Western Region has approximately 160,000 customers and covers all or parts of severalcounties in the general Asheville area. DEP's Western Region is geographically separate from DEP's Eastern Region and is somewhat isolated from other nearby electric utilitiesdue to limited transmission interties in the area.

Witness Thomas testified that during the summer of2016 the Public Staff began receiving complaints from DEP retail customers in the Hot Springs area regarding power outages and investigated commercial customer concerns about outages that were lastingfor an hour or more and occurring during weekends when local businesses, such as restaurants, had many customers to serve. At that time DEP pledged to improve servicereliability by conducting a thorough visual survey of the distribution line and performing moreaggressive vegetation management. The Public Staff subsequently contacted someof the commercial customers who attended the August 2016 meeting in early 2017, and they indicated that reliability had improved following DEP's actions.

Witness Thomas testified that the Hot Springs Microgrid could improve overall reliability at Hot Springs. During an outage event, i.e., a fault on the Hot Springs distribution line, the Hot Springs Microgrid would be able to supply power to Hot Springsin island mode. He explained that Hot Springs customers would notice a momentary power outage as the Hot Springs Microgrid disconnects from DEP's grid and begins supplying power to the town but that otherwise Hot Springs customers would not be immediately impacted by the distribution line fault. This power would come from the solarPV array based on its expected generation during daylight hours and from the battery system in hours when the PV array is not generating or capable of supplying the power needs of the area. Witness Thomas testified that according to a presentation provided to the

Public Staff in September of 2018, DEP indicates that the battery is sized to meet 100% of Hot Springs' peak load and is capable of providing for the 90th percentile load for approximately four hours without any contribution from the solar PV generation.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 5

This finding is supported by the Application and exhibits and by the direct and supplemental testimony and exhibits of DEP witness Landy.

DEP witness Landy explained that the Hot Springs Microgrid site was selected dueto the following beneficial characteristics: the site is properly zoned for industrial land use;the acreage is sufficient for siting multiple megawatts of solar generation and additional battery storage; the site is primarily clear of trees and debris; the point of interconnectionis only approximately 0.10 miles from the planned project substation and does not requireadditional land rights or permitting to access the interconnection facilities; the site is not adjacent to residential customers; and the site is owned by a landowner willing to enter into a lease agreement in support of the project and community's goals. Suitable, available sites within the Asheville region are not abundant, and these characteristics willminimize project costs and environmental impacts. Based on the evidence in the record,and the fact that no party disputed the proposed site for the project, the Commission concludes that the site selected by DEP is a reasonable location for the Hot Springs Microgrid.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 6

This finding is supported by the Application and exhibits, the direct and supplemental testimony and exhibits of DEP witness Landy, and the testimony of Public Staff witness Thomas.

The Application provided, and witness Landy testified, that the Company's 2018 IRP, filed September 5, 2018 in Docket No. E-100, Sub 157, includes the Hot Springs Microgrid in the "Integrated Systems and Operations Planning and Battery Storage" and the "WCMP" chapters. From a total system perspective, the DEP 2018 IRP identifies the need for approximately 6,300 MW of new resources to meet customers' energy needs by2033. Additionally, the 2018 IRP calls for 80 MW of energy storage and approximately 1,000 MW of incremental solar installations over the next five years. As noted in the 2018DEP IRP, grid-connected battery storage projects that provide solutions for the transmission and distribution system may also simultaneously provide benefits to the generation resource portfolio.

Public Staff witness Thomas reviewed the 2018 DEP IRP and, although he noted that the Commission has not yet accepted DEP's 2018 IRP for planning purposes, he agreed that DEP's 2018 IRP includes 140 MW of 4-hour lithium ion batteries in the basecase as placeholders for future assets to provide operational experience on the DEP system. Public Staff witness Thomas also noted that the battery resources were not economically selected by the IRP's System Optimizer model. However, the short-term plan in DEP's 2017 IRP Update called for investment in a limited number of battery storage projects to gain additional operation and technical experience with evolving utility-scale storage technologies. Based on the foregoing, the Commission concludes that the Hot Springs Microgrid project is included in, and therefore consistent with, DEP's filed 2018 IRP, although the Commission notes that it has not yet issued an order on the 2018 IRP for planning purposes in pending Docket No. E-100, Sub 157.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 7

This finding is supported by the Application and exhibits and by the direct and supplemental testimony and exhibits of DEP witness Landy.

DEP witness Landy testified that because of the unique circumstances of the Hot Springs service area and the Commission's WCMP Order requirements, DEP did not evaluate the wholesale market for alternatives to the capacity and energy to be provided by the Hot Springs Microgrid. He stated that DEP plans to competitively bid the major components and construction of the project to ensure the lowest reasonable cost for customers. In addition, he indicated that DEP intends to seek to obtain components and services from North Carolina providers where possible and effective. Because of the unique circumstances of the Hot Springs Microgrid, the Commission concludes that DEP's decision to not evaluate the existing wholesale market for alternatives, combined with the conditions set forth herein, is reasonable. In particular, the Commission takes note of the fact that the project's primary purpose is to address reliability issues arising from the Hot Springs area's dependence on a single, vulnerable distribution feeder and that purchasing additional wholesale energy supplies would not address this purpose.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 8

This finding is supported by the Application and exhibits, the direct and supplemental testimony and exhibits of DEP witness Landy, and the testimony of Public Staff witness Thomas.

According to DEP witness Landy, DEP's cost estimate for the Hot Springs Microgrid development is approximately **[BEGIN CONFIDENTIAL] [END CONFIDENTIAL]**. The estimate includes Engineering Procurement & Construction ("EPC"), major equipment, labor, and associated permitting and development costs. The annual operating cost is expected by DEP to be approximately **[BEGIN CONFIDENTIAL] [END CONFIDENTIAL]**. He indicated that any tax credits and accelerated depreciation benefits will reduce project costs for the benefit of customers.

Public Staff witness Thomas testified that the capital costs of the Hot Springs Microgrid are as presented in Table 1 below.

[BEGIN CONFIDENTIAL]

[END CONFIDENTIAL]

Witness Thomas did not dispute the reasonableness of the cost estimate for the Hot Springs Microgrid provided by DEP. However, he recommended that the Commission, in addition to finding DEP's construction cost estimate to be reasonable, establish a rebuttable presumption that any construction costs of the Hot Springs Microgrid exceeding **[BEGIN CONFIDENTIAL] [END CONFIDENTIAL]** are unreasonably or imprudently incurred and shall not be recoverable from ratepayers. This amount was derived using DEP's estimate of **[BEGIN CONFIDENTIAL] [END CONFIDENTIAL]**. Witness Thomas asserted that the Company should not be permitted to rebut this presumption and recover any construction costs for the Hot Springs Microgrid exceeding the cap except to the extent DEP demonstrates that the costs in excess of the cap were reasonably and prudently incurred by DEP as a result of an event or events directly impacting the timing or cost of construction of the Hot Springs Microgrid that was or were (1) not reasonably foreseeable at the time the CPCN is approved; (2) unavoidable through the exercise of commercially reasonable efforts and diligence consistent with prudent industry practice, and (3) outside of the reasonable control of DEP ("Force Majeure Events"). For purposes of this recommendation, "Force Majeure Events" would include (1) extreme weather events (including named storms, tornadoes, earthquakes, floods, and forest fires), war, acts of terrorism, epidemics, natural disasters, and other Acts of God, (2) discovery of latent and unknown site conditions, and (3) changes in State or federal law through judicial, legislative, or executive/administrative action or interpretation implemented, enacted, adopted or otherwise ordered after the date the CPCN is approved.

In the motion filed on February 7, 2019, DEP indicated that it agreed with this cost cap, along with the other conditions recommended by the Public Staff. Based upon all of the information in the record, and subject to the cost cap and other conditions set forth below, the Commission concludes that the cost estimate for the construction of the Hot Springs Microgrid is reasonable and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 9

This finding is supported by the Application and exhibits, the direct and supplemental testimony and exhibits of DEP witness Landy, and the testimony of Public Staff witness Thomas.

Company witness Landy testified that the solar generation facility for which DEP is seeking a CPCN is the best alternative for the specific needs to be met by the Hot Springs Microgrid and that it is consistent with the Company's commitments and the Commission's WCMP Order. According to witness Landy, the Hot Springs Microgrid supports the WCMP's goals to attempt to avoid or defer the need for a contingent natural gas combustion turbine through deliberate development of solar and battery storage projects in the Western North Carolina region of DEP's service territory.

Witness Landy testified that DEP still intends to construct solar generation and battery storage facilities at the Asheville Plant site. He stated that although construction and final plans are contingent upon completion of the ash basin work and coal plant demolition activities, at this time the Company expects to install approximately 9 to 10 MW of solar generation along with additional battery storage at the Asheville Plant site and to seek a CPCN from the Commission for the generation facilities prior to commencing construction sometime in the 2023-2024 timeframe. He testified that DEP is evaluating additional solar and storage sites in the DEP-West area and will make appropriate filings with the Commission for approval once it has made a decision on those projects. Along with furthering its commitment to site solar and storage technologies in the western region, DEP intends for the Hot Springs Microgrid and future Company facilities to support the goals and objectives of the WCMP, including efforts to avoid or defer the contingent natural gas-fired CT addressed in the WCMP Order.

Public Staff witness Thomas described the history of the WCMP and the WCMP Order in his testimony. He stated that Session Law 2015-110, commonly known as the Mountain Energy

Act, required the Commission to provide an expedited review of an application filed by DEP for the construction of a natural gas-fired generating facility at the site of the existing Asheville coal-fired generating facility. Conditions in the law required DEP to cease operation of the coal-fired facility and limit capacity of the naturalgas-fired facility to no more than twice that of the coal-fired facility.

Witness Thomas further testified that on January 15, 2016, in response to the passage of the Mountain Energy Act, DEP filed a CPCN application in Docket No. E-2, Sub 1089, to construct and operate its WCMP. The proposed WCMP was comprised of two new 280-MW combined cycle ("CC") units and one contingent 186-MW simple cycle combustion turbine ("CT") unit (to be built later). In its WCMP proposal, DEP also committed to seek a CPCN in the future to invest in a minimum of 15 MW of new solar generation in DEP's Western Region, with a portion being sited at the Asheville plant afterthe coal-fired units were demolished. In addition, DEP committed to invest in a pilot projectwith a minimum of 5 MW of utility-scale storage in DEP's Western Region.

Witness Thomas explained that on February 29, 2016, the Commission issued its Notice of Decision approving the construction and operation of the two combined cycle units. In part, the Notice of Decision also required DEP to retire the coal-fired units at theAsheville plant and file annual progress reports on: (1) construction of the combined cycleunits, (2) DEP's efforts to work with its customers in DEP's Western Region to reduce peak load through demand-side management, energy efficiency or other measures, and DEP's efforts to site solar and storage capacity in DEP's Western Region.

Witness Thomas further explained that on March 28, 2016, the Commission issued the WCMP Order. In summary, the Commission affirmed its Notice of Decision and denied without prejudice the CPCN for the combustion turbine unit. The Commission's order did not specifically approve the solar or storage components proposed by DEP, but stated that it expected DEP to file as soon as practicable the CPCN to construct at least 15 MW of solar at the Asheville plant or elsewhere in the Asheville region. The Commission further urged DEP to move forward in a timely manner with the 5 MW storageproject in the Asheville region. Finally, the Commission required DEP to include information in its annual progress reports on its efforts to site solar and storage capacityin DEP's Western Region.

Witness Thomas stated that on March 28, 2017, DEP filed its first annual progressreport on the WCMP. In it, DEP noted the creation of the Energy Innovation Task Force ("EITF"), which is working with DEP and Asheville area residents to investigate cost-effective methods of complying with the WCMP Order, including use of energy storage technologies. DEP proposed to deploy up to 10 batteries (total capacity is over 5 MW but final amount to be determined), with each installation sited and configured to serve multiple functions (e.g., frequency regulation and back-up power). DEP also discussed its proposed Mt. Sterling Microgrid Project, a 10-kW solar PV facility coupled with 95 kWh of battery storage.

Witness Thomas testified that on March 28, 2018, DEP filed its second WCMP annual progress report. The WCMP Battery Storage Deployment Plan was updated, with the total energy storage capacity target increased to 50 MW. In it, DEP stated that:

Through a cost-effective and prudent battery storage deployment plan, the Company will evaluate the impacts of deploying batteries of a significant scale on the electric system, explore the nature of new offerings desired by customers, and fill knowledge gaps. Utility-owned and operated batteries will enable the Company to leverage bulk purchases of equipment and material, build relationships with battery developers, manufacturers, and installers, and develop capabilities as an owner and operator of a battery fleet.[1]

DEP also updated the Commission on the Mt. Sterling Microgrid, stating that it is operating as intended with only a few minor issues related to control and monitoring equipment and software.

Witness Thomas concluded that construction of the Hot Springs Microgrid would be consistent with the Commission's expectation, set out in the WCMP Order, that DEP would site solar and battery storage in the Asheville region. He noted, however, the Commission did not require the siting of solar and battery storage without regard to the need or cost-effectiveness of individual projects.

The Commission concludes that the Hot Springs Microgrid is consistent with the WCMP Order. In the WCMP Order, the Commission accepted DEP's commitment to solar and storage projects and held, "As to solar and storage, the Commission expects DEP to file as soon as practicable the CPCN to construct at least 15 MW of solar at the Asheville Plant or in the Asheville region. The Commission further urges DEP to move forward in a timely manner with the 5 MW storage project in the Asheville region." WCMP Order at p. 38.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 10

This finding is supported by the Application and exhibits and the testimony and supplemental testimony of DEP witness Landy and Public Staff witness Thomas.

DEP witness Landy testified that in addition to improving reliability in the Hot Springs area, the Hot Springs Microgrid will provide bulk system benefits as well, which neither of the traditional distribution upgrades would have provided. For example, witness Landy testified that the solar array will produce approximately 4,000 MWh of annual solar generation for the benefit of all of DEP's customers. He explained that the battery components of the Hot Springs Microgrid also provide capacity value and reliability services to DEP's electric grid, such as frequency and voltage regulation and ramping support, which the distribution alternatives would not provide. Witness Landy testified that the Hot Springs Microgrid is an innovative grid solution deployed in lieu of upgrading the existing distribution feeder or constructing a new traditional distribution service. Finally, he stated that the Company anticipates increasing its reliance on these types of distributed energy technologies to reliably and cost-effectively serve its customers over time, and DEP's experience in operating the Hot Springs Microgrid will provide additional future benefits to all customers as these technologies are further deployed across DEP's grid.

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[1] DEP WCMP Second Annual Progress Report at p. 7, filed on March 28, 2018, in Docket No. E-2, Sub 1089.

Witness Thomas testified that regarding DEP's cost-benefit analysis for the Hot Springs Microgrid, the Public Staff was unable to confirm the benefits of deferring storm hardening, to verify the magnitude of the estimated bulk system benefits that would be actually realized, or to ensure that the benefits realized from the Hot Springs Microgrid will be passed on to DEP's ratepayers. For example, on a net present value ("NPV") basis, the deferral of the storm/mountain hardening alternative comprised a majority of the benefits DEP claimed. However, on a January 8, 2019 conference call, DEP's Western Region personnel indicated that due to recent service quality improvements and absent a future unfavorable trend in reliability metrics, DEP did not plan to make the storm/mountain hardening investments on the Hot Springs feeder and would instead continue with standard vegetation management on the feeder, including the Hazard Tree Assessment Program, regardless of whether the Hot Springs Microgrid were to go forward.

Witness Thomas testified that the next largest category of claimed benefits is frequency regulation, in which the Hot Springs Microgrid would provide constant up and down regulation reserves when not operating in island mode. To estimate these benefits, DEP took a multi-year average of historic market clearing prices related to the Midcontinent Independent System Operator's ("MISO") entire Regulation Reserves market. The Hot Springs Microgrid will be outfitted with a battery inverter system technically capable of providing these benefits, and as the Hot Springs Microgrid provides this service less fuel will be consumed at the thermal plants that traditionally provide regulation reserves. However, the Public Staff believes that the Regulating Reserves market clearing prices in MISO do not necessarily reflect equivalent fuel savings in DEP's system, as DEP does not participate in a regional market. Based on this information, the Public Staff concluded that although the Hot Springs Microgrid would improve reliability and service quality in the Hot Springs area, because the Public Staff was unable to verify or quantify the benefits of the project, it was unable to conclude that the Hot Springs Microgrid was the most cost- effective method of doing so.

Public Staff witness Thomas testified that, while he believes that the Hot Springs Microgrid will provide benefits to DEP ratepayers, he does not believe that DEP has enough information currently to make an accurate estimate of those benefits and thus, they are not certain enough to be relied on in this proceeding. In particular, the ancillary service benefits associated with the battery storage system – frequency and voltage regulation and ramping support – cannot be accurately quantified without actual operational data gained from experience and meticulous data collection and analysis. However, Public Staff witness Thomas testified that he recognizes the value that microgrid operational knowledge can provide to DEP, particularly as nascent energy storage technologies become more widely deployed. In his opinion, the system benefits from the Hot Springs Microgrid are material, even if they are difficult to estimate accurately without real world experience in DEP's service territory. After reviewing the application, including the costs and unique benefits, the Public Staff recommended that the Hot Springs Microgrid be treated as a pilot project and the CPCN for the solar facility be approved, subject to certain reporting requirements, a study of frequency regulation benefits, the imposition of a cap on the above-the-line capital costs of the project, and other conditions, as discussed below.

Based on the testimony of the DEP and Public Staff witnesses, and the entirety of the evidence in the record, the Commission concludes that the Hot Springs Microgrid will have the opportunity to improve the reliability of service to customers connected to the Hot Springs

22.86 kV distribution feeder, which is the single source of service for the Town of Hot Springs. The existing feeder, which extends approximately ten miles through remote and hazardous terrain in the mountainous Pisgah National Forest, incurs long-duration outage events due to its location and is expected to require high-cost equipment upgrades beginning in 2020.

Though it is undisputed that the Hot Springs Microgrid should improve reliability in the Hot Springs area, based on the testimony of the Public Staff, it is not clear that it is the most cost-effective way of doing so. However, the Commission finds and concludes that there are additional system benefits from the Hot Springs Microgrid that are material. The ancillary service benefits associated with the battery storage system – frequency and voltage regulation and ramping support – cannot be accurately quantified without actual operational data gained from experience and meticulous data collection analysis. Operation of the Hot Springs Microgrid will provide valuable operational experience as battery storage and solar technologies continue to develop and evolve.

For these reasons, and to ensure that the benefits of the Hot Springs Microgrid may be fully realized and measured, approval of the CPCN for the solar facility of the Hot Springs Microgrid should be granted, subject to the following requirements:

Reporting

DEP shall be required to do the following:

1. Within six months of Commission approval of this Application, formalize and provide its operational and learning goals in a transparent and comprehensive plan, showing how it will achieve such goals and what operational data from the Hot Springs Microgrid will be measured and recorded.
2. File with the Commission a status report on the progress of construction and actual project costs in the same format as for initial costs of construction six months after the date of the CPCN and at the completion of construction.
3. Annually report, update, and file with the Commission and provide to the Public Staff, confidentially, the results of its operational knowledge and learning goals to demonstrate the operational benefits of the Hot Springs Microgrid. At a minimum, this report should include:
   a. A detailed event summary of all instances in which the Hot Springs Microgrid operated in island mode, whether in response to an outage on the Hot Springs distribution line or otherwise. This summary should include a discussion of how outage duration and frequency were affected by the Hot Springs Microgrid, and document any instances in which an outage was not able to be mitigated completely due to the limited capacity of the energy storage system.
   b. An annual summary of Hot Springs Microgrid operations, including hourly data, with enough specificity to determine:
      i. Where solar PV energy was directed (to grid or to battery), including the percentage of energy sent to each source;

ii. How the battery was charged (from the solar PV system or the grid), including the percentage of total energy from eachsource;
iii. How the battery was discharged, and for what purpose (islanding, ancillary services, etc.), including the total number of charge/discharge cycles, typical depth of discharge, hourly state of charge, and any other recorded characteristics.
iv. Quantification of energy losses from the battery, including energy used as station power for the battery storage and anyother on-site devices that use power.

c. A discussion of how, if at all, the actual Hot Springs Microgrid operations deviated from projections made in this docket.
d. A quantification of the total ancillary services provided to the grid by the Hot Springs Microgrid (in both capacity and energy), including what types of services were provided (spinning reserve, regulation up or down, etc.) and whether these services displaced ancillary services traditionally provided by thermal plants.
e. A quantification of energy use consumed by the Hot Springs Microgrid (station power).
f. To the extent possible, an estimate of any savings realized from the energy storage system's ancillary services.
g. A summary of how the Hot Springs Microgrid enhanced economic operations and how it was beneficial to DEP's operational knowledge (i.e., lessons from design engineers regarding programming the device or maintenance personnel regarding operations and management costs; Hot Springs Microgrid behavior in light of bulk system dynamics, etc.).
h. A description of how the battery system has degraded over time to include loss of: (1) storage capacity, (2) output capacity, and (3) ability to provide ancillary services.
i. Costs of installed capital upgrades and retirements, in the same format as for initial costs of construction.
j. Operations and maintenance costs, by FERC account and with descriptive footnotes explaining purpose (ongoing maintenance, specific repairs, etc.).

Required Study

DEP shall perform a study, either by contracting with a third party or as part of its integrated systems and optimization planning initiative, to estimate the ancillary service benefits battery storage can provide DEP's system, using sub-hourly modeling techniques similar to the Astrapé Solar Integration Cost Study in Docket No. E-100, Sub 158, and use the results to help quantify the success of the Hot Springs Microgrid. In addition, the results could be used in future battery storage proposals, providing more confidence that estimated benefits used to justify battery storage projects would actually be realized by DEP ratepayers. This study should aim to quantify and value separately the various ancillary services batteries can provide, such as spinning and frequency reserves. If possible, this study should analyze different energy storage technologies of varying durations to determine the most cost-effective energy storage technology and duration for each type of ancillary service provided. The study shall be completed within 15 months after commercial operation of the Hot Springs Microgrid commences.

Cost Cap

The Commission finds DEP's construction cost estimate to be reasonable. In addition, the Commission finds that there shall be a rebuttable presumption that any construction costs of the Hot Springs Microgrid exceeding **[BEGIN CONFIDENTIAL] [END CONFIDENTIAL]** are unreasonably or imprudently incurred and shall not be recoverable from ratepayers. This amount is derived using DEP's estimate of **[BEGIN CONFIDENTIAL] [END CONFIDENTIAL]**. The Company is not permitted to rebut this presumption and recover any construction costs for the Hot Springs Microgrid exceedingthe cost cap except to the extent DEP demonstrates that the costs in excess of the cap were reasonably and prudently incurred by DEP as a result of an event, or events, directlyimpacting the timing or cost of construction of the Hot Springs Microgrid that was, or were (1) not reasonably foreseeable at the time the CPCN is approved; (2) unavoidable through the exercise of commercially reasonable efforts and diligence consistent with prudent industry practice, and (3) outside of the reasonable control of DEP ("Force Majeure Events"). For purposes of this recommendation, "Force Majeure Events" shall include (1) extreme weather events (including named storms, tornadoes, earthquakes, floods, and forest fires), war, acts of terrorism, epidemics, natural disasters, and other Acts of God, (2) discovery of latent and unknown site conditions, and (3) changes in State or federal law through judicial, legislative, or executive/administrative action or interpretation implemented, enacted, adopted or otherwise ordered after the date this CPCN is approved. The cap set forth in this paragraph shall not apply to DEP's costs incurred to meet the reporting and ancillary service benefits study required as conditions of the CPCN.

Other Conditions

1. DEP shall construct and operate the Hot Springs Microgrid in strict accordance with all applicable laws and regulations, including the provisions of all permitsissued by the North Carolina Department of Environmental Quality;

2. Issuance of the CPCN does not constitute approval of the final costs associated with the construction of the Hot Springs Microgrid for ratemaking purposes, and this order is without prejudice to the right of any party to take issue with the ratemaking treatment of the final costs in a future proceeding; and,

3. DEP shall maintain the existing radial distribution feed into Hot Springs, including vegetation management, in a manner that under normal circumstances should produce SAIDI and SAIFI indices that are at least comparable to those of the overall DEP Western Region.

The Commission finds and concludes that these reporting requirements, cost cap, and conditions, negotiated and agreed to by DEP and the Public Staff, are appropriate and provide additional protections to ensure that all of DEP's customers will benefit from the deployment of the Hot Springs Microgrid. In addition to providing renewable generation to the DEP grid, while grid-tied, the Hot Springs Microgrid will be capable of providing additional bulk system benefits for all of DEP's customers, including reliability services to the DEP electric grid, such as frequency and voltage regulation and ramping support, and capacity during system peaks. The Commission agrees with DEP and the Public Staff that the Hot Springs Microgrid will enable DEP, the Public Staff, and other interested stakeholders to gain valuable experience and lessons from the deployment of utility-scale battery storage and microgrids in North Carolina, as this technology continues to develop.

The Commission is carefully exercising it authority to ensure prudent investment by DEP in a manner that is in accord with the stated policies of Chapter 62, including the policy set forth in N.C.G.S. § 62-2(10). See N.C.G.S. § 62-2(b). North Carolina General Statute Section 62-2(10) states that one of the policies of the State is to promote the development of renewable energy, including a requirement to diversify the resources used to reliably meet the energy needs of consumers. The Commission finds, within its sound discretion, that the value of the opportunity to learn through the approval of this one, discrete project is in the public convenience and necessity. The Commission has not given DEP a blank check as demonstrated by the conditions of a cost cap and the rebuttable presumption that any construction costs exceeding the cost cap shall not be recoverable from ratepayers. The Commission's determination in the present case is based upon the unique facts presented in this application and shall not be precedent for future, even if similar, applications.

As discussed above, the Hot Springs Microgrid is also consistent with the WCMP Order and the Commission's expectation that DEP pursue solar and battery storage projects in the Asheville region. The Commission notes that seventeen (17) consumer statements of position had been filed with the Commission expressing support for the Hot Springs Microgrid, including one from the Town of Hot Springs, and no consumer statements had been filed opposing the project. Many of the supportive filings made with the Commission were from participants in DEP's collaborative stakeholder process established as part of its WCMP engagement in the Asheville region. The Commission supports the cost-effective development of solar and battery storage by DEP as provided in the WCMP Order and encourages DEP to continue to pursue such projects on behalf of its customers.

Based on the filed Application and exhibits, the testimony of Company witness Landy, the testimony of Public Staff witness Thomas, and the fact that no party opposed the proposed project, the Commission concludes that the Hot Springs Microgrid should be approved as a pilot project and that the granting of a CPCN for the solar generation-related components of the Hot Springs Microgrid is in the public interest and is required by the public convenience and necessity, subject to the enumerated conditions set forth herein.

IT IS, THEREFORE, ORDERED as follows:

1. That the Application filed in this docket should be, and the same hereby is, approved, and a Certificate of Public Convenience and Necessity for the solar generation-related components of Hot Springs Microgrid Project is hereby granted;

2. That DEP shall file with the Commission in this docket a progress report and any revisions in the cost estimates for the Hot Springs Microgrid Project, with the first report due no later than six months from the date of issuance of this CPCN and at the completion of construction;

3. That DEP shall comply with the reporting requirements, a study of frequency regulation, the imposition of a cap on the above-the-line capital costs of the project, and other conditions as enumerated in the body of this Order;

4. That for ratemaking purposes, the issuance of this Order and CPCN does not constitute approval of the final costs associated therewith, and that the approval and grant is without prejudice to the right of any party to take issue with the treatment of the final costs for ratemaking purposes in a future proceeding;

5. That the attached Attachment A shall constitute the certificate of public convenience and necessity issued to DEP for the approximately 3 MW DC / 2 MW AC solar photovoltaic ("PV") electric generator to be located in Madison County, North Carolina as part of the Hot Springs Microgrid; and

6. That the approximately 4 MW lithium-based battery storage facilities to be constructed by DEP as part of the Hot Springs Microgrid are consistent with the Commission's March 28, 2016 Order Granting Application in Part, with Conditions, and Denying Application in Part in Docket No. E-2, Sub 1089.

ISSUED BY ORDER OF THE COMMISSION.
This the 10th day of May, 2019.

NORTH CAROLINA UTILITIES COMMISSION
M. Lynn Jarvis, Chief Clerk

ATTACHMENT A

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-2, SUB 1185

Duke Energy Progress, LLC
410 South Wilmington Street
Raleigh, North Carolina 27601

is hereby issued this

CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY
PURSUANT TO G.S. 62-110.1

for construction of an approximately 3-MW direct current, 2-MW alternating current solar photovoltaic electric generation facility and associated equipment for the Hot Springs Microgrid Project

located
on property in Madison County, North Carolina

This certificate is subject to the following conditions: (a) Duke Energy Progress, LLC (DEP) shall construct and operate the Hot Springs Microgrid Project in strict accordance with all applicable laws and regulations, including any local zoning and environmental permitting requirements, including the provisions of all permits issued by the North Carolina Department of Environmental Quality; (b) DEP will obtain approval of the Commission before selling, transferring, or assigning the certificate and/or generating facility; (c) this certificate is subject to Commission Rule R8-61 and all orders, rules, regulations and conditions as are now or may hereafter be lawfully made by the Commission.

ISSUED BY ORDER OF THE COMMISSION.
This the 10th day of May, 2019.

NORTH CAROLINA UTILITIES COMMISSION
M. Lynn Jarvis, Chief Clerk

DOCKET NO. E-2, SUB 1221

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of Duke Energy Progress, LLC, for a Certificate of Environmental Compatibility and Public Convenience and Necessity and Motion for Waiver of Notice and Hearing Pursuant to N.C. Gen. Stat. §§ 62-100 <u>et seq.</u> to Construct Approximately 500 feet of New 230 kV Transmission Line in Anson County, North Carolina	)))))))))	ORDER WAIVING NOTICE AND HEARING REQUIREMENT AND ISSUING CERTIFICATE

BY THE COMMISSION: On October 31, 2019, pursuant to N.C. Gen. Stat. §§ 62-101 and 62-102, Duke Energy Progress, LLC (DEP or the Company), filed with the Commission a letter of intent to file for a waiver of the notice and hearing requirements of N.C.G.S. §§ 62-102 and 62 104. On that same date, pursuant to Commission Rule R8-62(k), DEP prefiled with the Public Staff an application for a certificate of environmental compatibility and public convenience and necessity to construct a new 230-kV transmission line approximately 500 feet in length (Line) in Anson County, North Carolina. The prefiled application stated that the Line will allow Pee Dee Electric Membership Corporation to connect the proposed Burnsville distribution substation in Anson County, North Carolina to the Lilesville – DPC Oakboro 230-kV transmission line. As detailed in DEP's prefiled certificate application, the Company will construct the Line on property for which it has purchased the right of way from the property owner, and the property owner does not object to a waiver of the hearing and notice requirements of N.C.G.S. §§ 62-102 and 62-104.

On November 21, 2019, DEP formally filed the application for a certificate and motion for waiver of notice and hearing.

N.C.G.S. § 62-101(d)(1) authorizes the Commission to waive the notice and hearing requirements of N.C.G.S. §§ 62-102 and 62-104 when it finds that the owners of the land to be crossed by the proposed transmission line do not object to the waiver and either the transmission line is less than one mile long or connects an existing transmission line to a substation, to another public utility, or to a public utility customer when any of these are in proximity to the existing transmission line. The application states that the Company will construct the Line on property for which it has acquired an easement from the property owner whose land will be crossed by the Line, the property owner does not object to the waiver of notice or hearing, and that the total length of the line is approximately 500 feet. Thus, the conditions of N.C.G.S. § 62-101(d)(1) for a waiver of notice and hearing have been met. The application is also supported by a Certificate Application Report. This report satisfies the requirements of N.C.G.S. § 62-102(a).

ELECTRIC – ELECTRIC TRANSMISSION LINE CERTIFICATE

The Public Staff presented this matter at the Commission's Regular Staff Conference on December 16, 2019. The Public Staff stated that the application meets the requirements of N.C.G.S. § 62-102 and Commission Rule R8-62 for a certificate and the conditions of N.C.G.S. § 62-101(d)(1) for waiver of the notice and hearing requirements of N.C.G.S. §§ 62-102 and 62-104. The Public Staff recommended that the Commission grant the motion for waiver and issue the requested certificate.

Based on the foregoing and the recommendation of the Public Staff, the Commission finds and concludes that the notice and hearing requirements of N.C.G.S. §§ 62-102 and 62-104 should be waived as allowed by N.C.G.S. § 62-101(d)(1) and that a certificate of environmental compatibility and public convenience and necessity should be issued for the proposed construction of a new 230-kV transmission line.

IT IS, THEREFORE, ORDERED as follows:

1. That, pursuant to N.C.G.S. § 62-101, the requirement for publication of notice and hearing is waived.

2. That, pursuant to N.C.G.S. § 62-102, a Certificate of Environmental Compatibility and Public Convenience and Necessity to construct approximately 500 feet of new 230-kV transmission line in Anson County, North Carolina, as described in DEP's application is issued, and the same is attached as Appendix A.

ISSUED BY ORDER OF THE COMMISSION.
This the 17th day of December, 2019

NORTH CAROLINA UTILITIES COMMISSION
Kimberley A. Campbell, Chief Clerk

Commissioner Jeffrey A. Hughes did not participate in this decision.

APPENDIX A

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-2, SUB 1221

DUKE ENERGY PROGRESS, LLC

is hereby issued this

CERTIFICATE OF ENVIRONMENTAL COMPATIBILITY AND PUBLIC CONVENIENCE AND NECESSITY PURSUANT TO N.C. GEN. STAT. § 62-102

to construct approximately 500 feet of new 230-kV transmission line to connect the proposed Pee Dee Electric Membership Corporation's Burnsville distribution substation to the existing Lilesville-DPC Oakboro 230-kV Transmission line in Anson County, North Carolina

subject to receipt of all federal and state permits as required by existing and future regulations prior to beginning construction and further subject to all other orders, rules, regulations, and conditions as are now or may hereafter be lawfully made by the North Carolina Utilities Commission.

ISSUED BY ORDER OF THE COMMISSION.
This the 17th day of December, 2019.

NORTH CAROLINA UTILITIES COMMISSION
Kimberley A. Campbell, Chief Clerk

DOCKET NO. E-7, SUB 487
DOCKET NO. E-7, SUB 828
DOCKET NO. E-7, SUB 1026
DOCKET NO. E-7, SUB 1146

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Duke Energy Carolinas, LLC, Existing DSM Program Rider Docket No. E-7, Subs 487, 828, 1026, and 1146	)))	ORDER APPROVING EDPR RIDER

BY THE COMMISSION: On March 29, 2019, Duke Energy Carolinas, LLC (DEC or the Company), made an initial filing proposing its annual change to the Existing DSM Program Rider (EDPR), based on the December 31, 2018, legacy demand-side management (DSM) deferral account balance. The Company requested that the EDPR be effective for the period July 1, 2019, through June 30, 2020.

An EDPR was first approved in DEC's general rate case in Docket No. E-7, Sub 828 (Sub 828 Order), and the Commission has continued to approve the EDPR mechanism in DEC's subsequent general rate cases. The EDPR reflects the inclusion in DEC's approved base rates of a per kilowatt-hour (kWh) amount specifically intended to recover the costs of certain legacy DSM and energy efficiency (EE) programs existing as of the date of the Sub 828 Order. The EDPR is adjusted annually to true up the difference between the applicable base rate amount in effect and the actual cost of the legacy DSM and EE programs incurred during the then most recent calendar year. In its March 29, 2019 filing, DEC indicated that during calendar year 2018, the applicable base rate amount was 0.0125 cents per kWh,[1] as reaffirmed pursuant to the Commission's September 24, 2013 Order in general rate case Docket No. E-7, Sub 1026.

In its March 29, 2019 filing, DEC proposed to replace the existing EDPR decrement rider amount of (0.0055) cents per kWh, which was approved effective July 1, 2018, with a new decrement rider amount of (0.0068) cents per kWh, to be effective on and after July 1, 2019.

On June 17, 2019, DEC filed a revised proposed EDPR, because DEC determined after the initial filing that the existing DSM program costs collected in base energy rates pursuant to Docket No. E-7, Sub 1146 (General Rate Case) had been reduced to 0.0067 cents per kWh. Due to a Company oversight, however, the Existing DSM Program Costs Adjustment Rider Tariff Schedule was not updated as of the date the new rates went into effect in the General Rate Case. Therefore, in this revised filing, the Company has made an adjustment to reflect the reduction in the existing DSM program costs collected in base energy rates from 0.0125 cents per kWh to 0.0067 cents per kWh, from August 1, 2018 forward. This adjustment will also reduce the calculated EDPR decrement from (0.0068) cents per kWh, as set forth above, to (0.0043) cents per kWh. The Company has filed a corrected Tariff and amended exhibits supporting the EDPR.

[1] Except as otherwise indicated, all rates are excluding the North Carolina regulatory fee.

The proposed net change to the EDPR, relative to the currently approved amount, including all rate adders, is the difference between the proposed decrement rider, including the regulatory fee, of (0.0043) cents per kWh, and the current decrement rider, including the regulatory fee, of (0.0055) cents per kWh, or a net rate increase of 0.0012 cents per kWh. The base existing DSM program cost amount of 0.0067 cents per kWh will remain in place following Commission approval of the new EDPR pursuant to the current filings. Including the North Carolina regulatory fee does not cause a change in either the base rate or EDPR amounts in this case.

This matter was presented to the Commission at its Regular Staff Conference on June 24, 2019. The Public Staff stated that it had reviewed DEC's calculation of the proposed EDPR, including the supporting workpapers submitted with the filing and information provided by DEC in response to Public Staff data requests. Based on its review, the Public Staff concluded that the proposed rate decrement is reasonable. Therefore, the Public Staff recommended that DEC's proposed EDPR be approved, effective beginning July 1, 2019.

Based on its review of DEC's filing and the recommendation of the Public Staff, the Commission concludes that the proposed EDPR is reasonable and should be approved, effective July 1, 2019.

IT IS, THEREFORE, ORDERED that the EDPR proposed by DEC in its revised filing of June 14, 2019, consisting of a rate decrement of (0.0043) cents per kWh, including the regulatory fee, is approved effective July 1, 2019, through June 30, 2020. DEC shall file with the Commission, within 10 days following the date of this order, revised tariffs showing the effective date of the tariffs.

ISSUED BY ORDER OF THE COMMISSION.
This the 25th day of June, 2019.

NORTH CAROLINA UTILITIES COMMISSION
A. Shonta Dunston, Deputy Clerk

Commissioners James G. Patterson and Daniel G. Clodfelter did not participate in this decision.

DOCKET NO. E-48, SUB 7

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application for a Certificate of Public Convenience and Necessity To Install Diesel Generator Facilities to be Owned by North Carolina Eastern Municipal Power Agency and/or Its Participants	)))))	ORDER TO EXTEND CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY AUTHORIZING INSTALLATION OF PEAK SHAVING GENERATORS

BY THE COMMISSION: On January 18, 2019, North Carolina Eastern Municipal Power Agency (NCEMPA) and its 32 member municipalities (the Participants) (collectively, Petitioners) filed a petition to extend the Certificate of Public Convenience and Necessity issued on February 7, 2017, in this docket (Current Certificate). The petition requested authority to install the approximate remaining 9.42 MW (for a total generating capacity of 40 MW) of additional generating capacity at or near customers' premises during a two-year period ending February 26, 2021.

In support of the petition, Petitioners stated that the Current Certificate authorizes Petitioners to construct and operate a maximum of 40 MW of generating capacity at or near customers' premises, so long as the capacity of each facility is 2.5 MW or less and the construction is completed on or before February 26, 2019. The Current Certificate also requires Petitioners to provide individual site information to the State Clearinghouse, obtain all necessary local, state and federal permits prior to construction and installation of any generating facility, imposes certain requirements for facilities proposed to be located at a location near, rather than at, the site of a customer, and requires the filing of annual facilities reports with the Commission. To date, Petitioners have constructed and installed pursuant to the Current Certificate generating facilities having an aggregate generating capacity of approximate 30.58 MW. The petition requested an extension of the Current Certificate for an additional two years to install the approximate remaining 9.42 MW of generating capacity.

According to the petition, the purpose of such generating facilities was and is to enable Petitioners to generate their own electricity and provide the same to the customer at the time of the monthly coincident peak with Duke Energy Progress, LLC, the time when Petitioners experience their highest costs for purchased power. As a result, Petitioners reduce purchases of electricity during peak periods and otherwise enhance their ability to obtain lower wholesale costs, and the Participants' retail customers experience lower retail costs. Petitioners believe it is advantageous to place small generators at or near the sites of customers.

Petitioners stated that extending the Current Certificate is in the public interest, as the power costs of Petitioners' customers will be reduced. Further, Petitioners stated that the generators are financed through available revenues or short-term debt repaid through the cost savings experienced. The acquisition of the generators does not increase the long-term debt of NCEMPA.

Prior to the issuance of the Current Certificate, the Commission issued and extended Certificates of Public Convenience and Necessity to Petitioners in Docket No. E-48, Subs 3, 4 and 5. During the time period of January 15, 1997, through the date of the Application, Petitioners have constructed and installed generating facilities having an aggregate output of approximately 65.14 MW pursuant to the current and prior certificates issued. (See amended 2018 Annual Report filed January 15, 2019, in Docket No. E-48, Sub 7).

The Public Staff presented this matter to the Commission at its regular Staff Conference on February 18, 2019. The Public Staff stated that it had reviewed the petition, agrees that an extension is appropriate, and recommends approval of the petition, subject to the same restrictions and requirements as the Current Certificate.

After careful consideration, based on the petition and the recommendation of the Public Staff, the Commission finds and concludes that the Current Certificate of 40 MW of generation capacity should be extended, authorizing the construction and installation of approximately 9.42 MW of generating facilities with each facility having a maximum capacity of 2.5 MW or less and located at or near the premises of customers and installed during the two-year period ending February 26, 2021. The Commission also concludes that Petitioners, at the time specific sites are selected, should be required to provide individual site information to the State Clearinghouse and obtain all necessary local, State, and federal permits prior to the construction and installation of any generating facility.

The Commission also concludes that the extension of the Current Certificate should be subject to the continuation of the previously imposed requirement that to the extent a generating facility is proposed to be constructed and installed at a location other than the site of a customer, the appropriate municipality shall make application to the municipality's City Council for approval of the installation, subject to the requirement that such installation shall not be approved until after public notice is given and an opportunity for public hearing, if requested, is provided; and that Petitioners should be required to file (a) a report within 30 days of any applications to city councils for off-site installations, including in that report or subsequent reports the location of the generating facility, whether a public hearing was requested, whether one was held, the action taken by the city council or other governing agency or board on the application, and any other relevant information, and (b) an annual report showing the initial installed location of each generator and any subsequent relocation of any generator.

IT IS, THEREFORE, ORDERED as follows:

1. That the Current Certificate should be, and hereby is, extended as limited and provided in this Order and by Appendix A attached hereto.

2. That Petitioners shall, at the time specific sites are selected, provide individual site information to the State Clearinghouse and obtain all necessary local, state, and federal permits prior to the construction and installation of any generating facility.

3. That, to the extent a Participant or NCEMPA proposes to install a generating facility at a location near, rather than at, the site of customers, such Participant or NCEMPA, as applicable, is required to make application to the appropriate City Council or appropriate

governing agency or board for approval of such installation, subject to the requirement that no such installation shall be approved until after public notice is given and an opportunity for public hearing, if requested, is provided.

4. That Petitioners shall file a report with the Commission within 30 days of every application to a City Council or other governing agency or board for approval to construct or install a generating facility at a location other than on the premises of the customer that will receive the power generated by said facility. In that report or in a subsequent report, if necessary, NCEMPA shall notify the Commission of the proposed location of the generating facility, whether a public hearing was requested, whether one was held, the action taken by the City Council on the application, and any other relevant information.

5. That Petitioners shall annually file on each January 1 a Certificate Facilities Report with the Commission showing the initial installed location of each generator and any subsequent relocations of the generators. The reporting form is attached as Appendix B.

ISSUED BY ORDER OF THE COMMISSION.
This the 19th day of February, 2019.

NORTH CAROLINA UTILITIES COMMISSION
A. Shonta Dunston, Deputy Clerk

APPENDIX A
PAGE 1 OF 2

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-48, SUB 7

North Carolina Eastern Municipal Power Agency
and Its Participants,
1427 Meadow Wood Boulevard,
Raleigh, North Carolina 27604,

are issued this extended

CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY
PURSUANT TO G.S. 62-110.1

authorizing construction and operation of a total of 40 MW
of generating capacity comprising of approximately 9.42 MW of new generating capacity
remaining to be built at or near customers'
premises for the purpose of reducing purchases
of electricity during peak periods and otherwise enhancing
NCEMPA and its Participants' ability to provide a reliable and
economic power supply, each facility with a capacity of 2.5 MW or less, and
construction completed by February 26, 2021,

and the Participants authorized to install the facilities
are the following municipalities:

Apex	Hertford	Robersonville
Ayden	Hobgood	Rocky Mount
Belhaven	Hookerton	Scotland Neck
Benson	Kinston	Selma
Clayton	LaGrange	Smithfield
Edenton	Laurinburg	Southport
Elizabeth City	Louisburg	Tarboro
Farmville	Lumberton	Wake Forest
Fremont	New Bern	Washington
Greenville	Pikeville	Wilson
Hamilton	Red Springs	

APPENDIX A
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and subject to the reporting requirements of
G.S. 62-110.1(f) and all orders, rules,
regulations and conditions now or hereafter lawfully
made by the North Carolina Utilities Commission,
and to the approval of off-site installations
by the relevant municipalities' city or town
councils after appropriate public notice
and an opportunity for a public hearing,
if requested.

ISSUED BY ORDER OF THE COMMISSION.
This the 19th day of February, 2019.

NORTH CAROLINA UTILITIES COMMISSION
A. Shonta Dunston, Deputy Clerk

APPENDIX B

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-48, SUB 7

North Carolina Eastern Municipal Power Agency
and its Participants

ANNUAL REPORT

CUSTOMER NAME	CITY & ADDRESS	SIZE (KW)	INSTALLATION DATE	OPERATION DATE

TOTAL (KW)

DOCKET NO. E-64, SUB 2
DOCKET NO. G-51, SUB 2

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Request for Exemption from Prohibition of Master Metering by The Cypress of Raleigh, LLC, Wake County, North Carolina	)))	ORDER APPROVING MASTER METERING EXEMPTION

BY THE COMMISSION: On May 1, 2019, The Cypress of Raleigh, LLC (Applicant) filed a request in the above-captioned dockets for an exemption from the master metering prohibition established in N.C. Gen. Stat. § 143-151.42. In order to promote energy conservation, the statute provides that it shall be unlawful for new residential buildings to be served by a master meter for electric or natural gas service. However, the statute includes several exceptions to the master metering prohibition, one of which is homes for the elderly.

In summary, Applicant stated that it is planning to expand its home for the elderly at 8801 Cypress Lakes Drive, Raleigh, Wake County, North Carolina, by building a new building containing 57 residential units, and that the plans for the new building include master metering for gas and electricity. Further, Applicant stated that all residents of the new building will be required to sign a Membership Agreement, and that the residents must be at least 62 years of age upon occupancy. Applicant also attached to its request a copy of the Membership Agreement that Cypress of Raleigh will use.

Based on the foregoing and the record, the Commission finds good cause to grant the request of Cypress of Raleigh, LLC, to be exempt from the master metering prohibition of N.C.G.S. § 143-151.42.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 17th day of May, 2019.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

DOCKET NO. E-7, SUB 1100B

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Duke Energy Corporation's Revised 2019 Confidential Financing Plan for the Year Ending December 31, 2019	)))	ORDER ACCEPTING REVISED 2019 FINANCING PLAN

BY THE COMMISSION: On November 18, 2019, pursuant to Regulatory Condition No. 7.6, as approved by the Order Approving Merger Subject to Regulatory Conditions and Code of Conduct in Docket Nos. E-2, Sub 1095, E-7, Sub 1100, and G-9, Sub 682, Duke Energy Corporation filed its Revised 2019 Confidential Financing Plan (the Revised Plan). Regulatory Condition No. 7.6 requires the Public Staff to file a report with the Commission with respect to whether any proposed debt issuances under the Revised Plan require Commission approval pursuant to N.C. Gen. Stat. § 62-160 through N.C. Gen. Stat. § 62-169 and Commission Rule R1-16 and to make a recommendation as to how the Commission should proceed.

On November 25, 2019, the Public Staff filed a letter stating that based on its review of the Revised Plan, the Public Staff does not believe the relevant statutes and rule require Commission approval of any of the proposed financings. Accordingly, the Public Staff recommended that the Commission issue an order, accepting the Revised Plan as being in compliance with Regulatory Condition No. 7.6 and providing that nothing in the order binds the Commission to accept any particular capital structure or cost of capital in any future proceeding or establishes any precedent in this or any other docket.

As of the date of this Order, no other filings have been made regarding the Revised Plan.

After carefully considering the filings in this matter, the Commission concludes that the Revised Plan should be accepted as being in compliance with Regulatory Condition No. 7.6 and that Commission approval pursuant to N.C. Gen. Stat. § 62-160 through N.C. Gen. Stat. § 62-169 and Commission Rule R1-16 of the debt financings described therein is not required.

IT IS, THEREFORE, ORDERED as follows:

1. That the Revised Plan is accepted as being in compliance with Regulatory Condition No. 7.6;

2. That the debt financings described in the Revised Plan do not require Commission approval pursuant to N.C. Gen. Stat. § 62-160 through N.C. Gen. Stat. § 62-169 and Commission Rule R1-6;

3. That nothing in this Order shall bind the Commission to accept any particular capital structure or cost of capital in any future proceeding; and

4. That nothing in this Order shall be considered precedent in this or any other docket.

ISSUED BY ORDER OF THE COMMISSION.
This the 4th day of December, 2019.

NORTH CAROLINA UTILITIES COMMISSION
Kimberley A. Campbell, Chief Clerk

DOCKET NO. E-2, SUB 1159
DOCKET NO. E-7, SUB 1156

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Joint Petition of Duke Energy Carolinas, LLC,	)	ORDER MODIFYING
and Duke Energy Progress, LLC, for Approval	)	AND ACCEPTING CPRE
of Competitive Procurement of	)	PROGRAM PLAN
Renewable Energy Program	)	

BY THE COMMISSION: On September 5, 2018, in Docket No. E-100, Sub 157,[1] as an attachment to their 2018 biennial integrated resource planning (IRP) reports, and pursuant to Commission Rule R8-71(g)(2), Duke Energy Carolinas, LLC (DEC), and Duke Energy Progress, LLC (DEP) (together, Duke), filed updates to their Competitive Procurement of Renewable Energy (CPRE) Program Plan (CPRE Program Plan)[2]

On October 5, 2018, in Docket No. E-100, Sub 101,[3] and in the above-captioned proceedings, the Commission issued an Order Approving Interim Modifications to North Carolina Interconnection Procedures for Tranche 1 of CPRE RFP (October Order). Among other things, the October Order allowed parties to file comments related to the timing of consideration of potential changes to the administration of the CPRE Program.

[1] Docket No. E-100, Sub 157, is the Commission's generic proceeding established to review the biennial integrated resource planning reports filed by electric public utilities.

[2] DEC and DEP submitted CPRE Program plans that are substantially similar, and contemplate the continued joint implementation of the Program between the two utilities. For convenience, the Commission will refer to the two plans together in the singular throughout this Order. In addition, capitalized terms, not otherwise defined by parentheticals in this Order, are defined as provided in Commission Rule R8-71.

[3] Docket No. E-100, Sub 101, is the Commission's generic proceeding established to consider revisions to the generator interconnection standards. Certain issues in dispute in that proceeding are relevant to the implementation of the CPRE Program, as noted in this Order.

On November 5, 2018, in Docket No. E-100, Sub 150,[1] and in the above-captioned proceedings, Duke filed a letter and the Public Staff filed comments, both in response to the October Order. In Duke's letter, Duke committed to file with the Commission interim reports on the progress of the Tranche 1 CPRE RFP Solicitation at various points during that competitive procurement process so that the Commission could gather "lessons learned" from the ongoing Tranche 1 CPRE RFP Solicitation while considering the parties' comments on the CPRE Program Plan.

On December 17, 2018, in Docket No. E-100, Sub 157, and in the above-captioned proceedings, the Commission issued an Order requiring Duke to file the interim reports regarding the status and results of the Tranche 1 CPRE RFP Solicitation on the schedule proposed in its letter filed with the Commission on November 5, 2018, authorizing Duke to implement the CPRE Program Plan on an interim basis, including the proposed schedule that would have the Tranche 2 CPRE RFP Solicitation open in July 2019, and setting out a schedule for the filing of comments on the CPRE Program Plan.

On February 1, 2019, in the above-captioned proceedings, the Commission issued an Order that revised the schedule for the filing of comments on the CPRE Program Plan by allowing all parties to file comments on or before March 22, 2019, and cancelling the filing of reply comments. These revisions were approved in response to an uncontested request by the Public Staff, in part, to accommodate the scheduling and conducting of two meetings with market participants, Duke, the Public Staff, and the Independent Administrator of the CPRE Program (IA), to discuss various issues involved in the implementation of the Tranche 2 CPRE RFP Solicitation.

On March 15, 2019, in the above-captioned proceedings, the IA filed a report on the two meetings that the IA held with the market participants, Duke, and the Public Staff, to discuss various issues involved in the implementation of the Tranche 2 CPRE RFP Solicitation. As discussed in further detail below, the IA's report lists issues where consensus was reached among the meeting attendees and lists issues where consensus was not reached.

On March 22, 2019, in the above-captioned proceedings, Duke, the North Carolina Clean Energy Business Alliance (NCCEBA), First Solar, Inc. (First Solar), and the Public Staff filed comments addressing the CPRE Program Plan.

On May 1, 2019, in the above-captioned proceedings, the Commission issued an Order postponing the opening of the Tranche 2 CPRE RFP Solicitation and scheduling this matter for a technical conference on May 23, 2019. In addition, that Order allowed the parties to file proposed amendments to Commission Rule R8-71(f)(3) related to the structuring of a "bid refresh" procedure.

[1] Docket No. E-100, Sub 150, is the Commission's rulemaking proceeding established to adopt rules implementing the CPRE Program. On November 6, 2017, in that Docket, the Commission issued an Order adopting Commission Rule R8-71, implementing the CPRE Program established pursuant to N.C. Gen. Stat. § 62-110.8.

On May 16, 2019, in the above-captioned proceedings, Duke, NCCEBA, the IA, and the Public Staff filed proposed rule amendments in response to the Commission's May 1 Order.[1]

CPRE PROGRAM PLAN AND DUKE'S COMMENTS

Pursuant to Commission Rule R8-71(g), Duke is required to annually file a CPRE Program plan that, at a minimum, addresses the following

> (i) an explanation of whether the electric public utility is jointly or individually implementing the aggregate CPRE Program requirements mandated by G.S. 62-110.8(a);
> (ii) a description of the electric public utility's planned CPRE RFP Solicitations and specific actions planned to procure renewable energy resources during the CPRE Program planning period;
> (iii) an explanation of how the electric public utility has allocated the amount of CPRE Program resources projected to be procured during the CPRE Program Procurement Period relative to the aggregate CPRE Program requirements;
> (iv) if designated by location, an explanation of how the electric public utility has determined the locational allocation within its balancing authority area;
> (v) an estimate of renewable energy generating capacity that is not subject to economic dispatch or economic curtailment that is under development and projected to have executed power purchase agreements and interconnection agreements with the electric public utility or that is otherwise projected to be installed in the electric public utility's balancing authority area within the CPRE Program planning period; and
> (vi) a copy of the electric public utility's CPRE Program guidelines then in effect as well as a pro forma power purchase agreement used in its most recent CPRE RFP Solicitation.

The CPRE Program Plan details Duke's proposed implementation of the aggregate CPRE Program requirement to procure energy and capacity from renewable energy facilities totaling 2,660 MW through RFPs during the 45-month term that began on February 21, 2018. As noted in the CPRE Program Plan, pursuant to N.C.G.S. § 62-110.8(b)(1), if prior to the end of the 45-month procurement period Duke has executed power purchase agreements (PPAs) and interconnection agreements for renewable energy capacity not subject to economic dispatch or curtailment (Transition MW Projects) that exceeds 3,500 MW, then the aggregate amount of energy and capacity required to be procured through the CPRE Program is subject to downward adjustment

[1] There are other filings that are matters of record in the above-captioned proceedings. Among them, the Commission notes that the IA has filed reports on the progress of the Tranche 1 CPRE RFP Solicitation and a report on a stakeholder meeting held to discuss both lessons learned from the Tranche 1 CPRE RFP Solicitation and to solicit feedback on the RFP documents that relate to the Tranche 2 CPRE RFP Solicitation. The Commission has found these reports to be quite helpful in approaching the issues raised in the parties' comments.

by the amount in excess of 3,500 MW. Duke projects that the total amount of Transition MW Projects will be in the range of 4,200 to 4,700 MW (approximately 1,100 in DEC and 3,600 in DEP). Thus, this range would result in a reduction of the aggregate procurement requirement by 700 to 1,200 MWs.

The CPRE Program Plan proposes to reduce the number of RFP Solicitations or Tranches from 4 to 3 in light of delays in the Tranche 1 CPRE RFP Solicitations and accounting for the potential reduction in the aggregate procurement requirement due to the total number of Transition MW Projects expected to execute PPAs and Interconnection Agreements during the 45-month procurement period. The CPRE Program Plan provides both a proposed schedule of the RFP Solicitations and an allocation of the targeted procurement amounts between DEC and DEP, which is generally consistent with the allocation proposed in Duke's initial CPRE Program plan. The CPRE Program Plan also provides discussion of the location guidance provided to market participants in the Tranche 1 CPRE RFP Solicitation, in the form of a map and table of circuits and substations, which is intended to provide market participants with information on areas that have known transmission and distribution limitations as a result of the amount of existing or approved renewable energy facilities in the area. Duke states that it is continuing to evaluate how to provide similar guidance in future tranches and that it will provide this guidance as a part of the pre-solicitation process for the Tranche 2 CPRE RFP Solicitation, or potentially earlier, to provide potential market participants as much information as possible to enable the most cost-effective proposals to be bid into the RFP.

The CPRE Program Plan also addresses the CPRE Tranche 1 RFP Documents and pro forma PPA. Duke notes in its Plan that it modified a number of PPA terms and conditions based upon feedback received, as directed by the Commission. Duke further notes that during a webinar held on August 7, 2018, Duke received "very limited" comments on the PPA itself. Duke states that it provided responses to these comments and reiterated its commitment to consider those comments in the drafting of the Tranche 2 CPRE pro forma PPA. In addition, Duke states that pursuant to the Commission's rules implementing the CPRE Program, additional comment opportunity will be allowed during the pre-solicitation process for the Tranche 2 CPRE RFP Solicitation.

In the final section of the CPRE Program Plan, Duke addresses energy storage, impacts to the transmission system from distribution connected projects, and interconnection evaluation of CPRE proposals. As to energy storage, Duke notes that the pro forma PPA includes a storage operating protocol and states that Duke intends to continue to evaluate energy storage technologies and to pursue the most effective means to deploy these resources. Duke further states that this ongoing work and the results of the Tranche 1 CPRE RFP Solicitation will inform Duke's approach to energy storage in the subsequent tranches. As to impacts to the transmission system from distribution connected projects, Duke states that North Carolina is unique in terms of the significant and growing levels of "uncontrolled third-party owned utility-scale solar connected to the distribution system." Duke states that it is continuing to monitor the impact that these projects have on the transmission system and that, as the number of these projects grows they are increasingly affecting the transmission system upgrades required to accommodate new generation. As to the process for evaluating interconnection of CPRE proposals, Duke notes that it has requested Commission approval to use a grouping study process to more efficiently evaluate CPRE proposals than the current serial review.[1] Duke provides further detail on how that process works and concludes this section by stating that in order to manage the growing challenges and complexities of the interconnection queuing and study process, it is evaluating new interconnection queue-management best practices, including fully transitioning to employing temporal cluster studies for all projects requesting interconnection, including projects requesting to bid into future CPRE RFP tranches.[2]

In its comments, Duke argues that its CPRE Program Plan sets forth a reasonable plan for implementing the CPRE Program procurement requirements in accordance with N.C.G.S. § 62-110.8 and Commission Rule R8-71. More specifically, Duke argues that its proposed timeframe for CPRE RFP Solicitations and its proposed allocation of capacity to be solicited between DEC and DEP are reasonable and should be accepted by the Commission. Duke further argues that the results of the Tranche 1 CPRE RFP Solicitation will provide a strong indication regarding whether the CPRE process is achieving the statutory objectives, and that, if the Tranche 1 CPRE RFP Solicitation satisfies the procurement targets, then such results would provide strong evidence that the CPRE Program is being reasonably implemented. Duke states that it and the IA will provide a final report on the Tranche 1 CPRE RFP Solicitation promptly after conclusion of the contracting period and provide further updates in its CPRE Program plan due to be filed on September 2, 2019.

Duke notes that because the Tranche 1 CPRE RFP Solicitation is not complete, it is not possible for Duke or the Commission to fully assess potential changes to the CPRE Program before the Tranche 2 CPRE RFP Solicitation process begins. Specifically, Duke states that only the IA and Duke's T&D Sub-Team have been involved in the Step 2 evaluation process, and, therefore, details regarding the implementation of the allocation of grid upgrade costs are not available at this time. Thus, Duke argues that a final assessment of the efficacy of the grid upgrade allocation process, along with several other issues, is premature at this time.[3]

Duke next addresses the meetings with market participants hosted by the IA. Duke states that the majority of the discussion at those meetings was focused on particular aspects of the Tranche 2 CPRE RFP Solicitation and not specifically on the CPRE Program Plan. Duke states that it and the IA will take those comments into consideration in developing the Tranche 2 CPRE RFP Solicitation documents, but its comments specifically respond to the Commission's request for comments and address the content of the meeting discussions through "high-level responses to certain issues."

Duke then notes again that the pre-solicitation process prescribed by Commission Rule R8-71(f)(1) for the Tranche 2 CPRE RFP Solicitation is currently scheduled to commence in the second quarter of 2019. Duke states that this pre-solicitation process will provide another forum for market participants to review the CPRE RFP Guidelines, including the RFP procedures,

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[1] The Commission granted this request by Order dated October 5, 2018.

[2] On June 14, 2019, the Commission issued an Order in Docket No. E-100, Sub 101 in which it required Duke to submit a report by July 31, 2019, as to the status of efforts to develop a grouping study proposal.

[3] On April 9, 2019, Accion published its Step 2 Evaluation, which provided preliminary information about grid upgrade costs for Tranche 1 bidders.

evaluation factors, credit and security obligations, the proforma PPA, and the administratively established avoided cost against which proposals will be evaluated. Therefore, Duke argues that the present comment period is the appropriate forum for in-depth consideration of issues beyond the CPRE Program Plan and those issues identified by the Commission for comment. However, Duke states that,to the extent deemed necessary by the Commission, the Companies would be willing to provide responses to any particular comments of other parties to these proceedings.

Duke then responds to the following four issues, which were identified in the October Order for further consideration in these proceedings:

1) Change the CPRE program plan to remove the ability of Duke to recover grid upgrade costs in base rates;

2) Change the CPRE program plan to require the initial bid to contain all of the Interconnection Customer's costs;

3) Revise the CPRE process to allow competitive biddersto refresh their bids based upon the assessment of grid upgrades identified in Step Two of the CPRE RFP bid evaluation process; and

4) Explore options for Duke to more specifically direct generators to locations on the system that will not involve major network upgrades.

As to the first three issues, Duke states that it is not possible to fully assess these questions because the Tranche 1 CPRE RFP Solicitation is not complete and only the T&D Sub-Team and the IA have been involved in the Step 2 evaluation process. However, Duke further states that it continues to believe that the structure under which grid upgrade costs would be recovered in base rates rather than through the CPRE rider, as a part of the PPA payment, is a reasonable approach. Duke also states that it believes that a different approach may be appropriate based on the actual experience of implementing the Step 2 evaluation in the Tranche 1 CPRE RFP Solicitation.

Duke then relates its view that the question to be answered is not whether customers will bear the costs of grid upgrades, but, instead, whether customers will pay those costs indirectly through recovery of PPA payments or directly through general rates. Under either scenario, in Duke's view, customers will ultimately pay for the grid upgradesand the total cost must meet the avoided cost cap specified in N.C.G.S. § 62-110.8(b)(2).More specifically, Duke argues that if proposals submitted in a CPRE RFP Solicitation are requiredto include grid upgradecosts, then the PPA rates will be proportionally higheras a result, and, if Duke is permitted to recover grid upgrade costs through rate base cost treatment, then the PPA would be proportionally lower as a result as the grid upgradecosts would be included in the relevant utility's rate base.

Specifically as to issue No. 3 above, Duke states that if the Commission were to conclude that the current structure for the Tranche 1 CPRE RFP Solicitation is not appropriate for future tranches, then it would be necessary to allow CPRE bidders to update bid prices during the evaluation process to allow for the required determination ofcost effectiveness. Duke further states that it is not possible for a CPRE bidder to includegrid upgrade costs in an initial bid because those costs will not be assessed until after bidsubmission, and that a bidder does not have the ability to even make a projection of gridupgrade costs. Duke recommends that if the Commission elects to adopt a structure in which grid upgrade costs are recovered through the PPA payment, then only CPRE bidders that are in the competitive tier be allowed to update their bids to avoid significant complexity in the bid evaluation process that would extend the length of time required to complete Step 2 of the evaluation process.

Finally, with respect to issue No. 4 above, Duke states that it will update and enhance its grid locational guidance like that provided in the Tranche 1 CPRE RFP Solicitation, but does not believe that it is appropriate to more specifically direct generators to specific locations on the grid, as this would deny some projects the opportunity to participate and potentially eliminate attractive proposals from consideration in the RFP.

Duke also addressed other issues raised by market participants during stakeholder meetings, as follows:

1) Grouping Study – Duke recommends that the grouping study process approved for use in the Tranche 1 CPRE RFP Solicitation be utilized for Tranche 2. Duke notes that it is pursuing more comprehensive queue reform that would allow for queue-wide grouping studies, however, those reforms will not be in place in time for use in the Tranche 2 CRPE RFP Solicitation. Finally, Duke states that late-stage proposals will not be applicable to future tranches.

2) Energy Storage – Duke expresses its support for allowing solar and co-located energy storage resources in the Tranche 2 CPRE RFP Solicitation, and for applying similar requirements related to storage equipment being located on the DC side of the inverter and to the storage equipment being charged exclusively by the co-located renewable energy facility and under the operational control of the seller. Duke states that it is continuing to assess the storage protocols included in the Tranche 1 PPA, and that, given the potential for changes in pricing periods it may be possible to reduce some of the operational constraints and limitations included in the Tranche 1 PPA. Duke states that it would release any such revisions as a part of the pre-solicitation process. Finally, Duke notes that the stakeholder meetings included discussion of "other services" that could be potentially provided by energy storage, however, Duke states that it does not believe that payment for services other than energy and capacity are appropriate at this time.

3) PPA-pre-COD Performance Assurance – Duke states that it received feedback at the stakeholder meetings that the pre-[commercial operation date] COD Performance Assurance for the CPRE PPA and the associated timing should match that historically required in the context of a negotiated PPA with qualifying facilities. For reasons detailed in its comments, Duke states that it continues to believe that the performance assurance equal to 4% of total projected revenue is a commercially reasonable requirement, taking into account the incentive this provides for completion and the risk of financial harm in the event of non-performance, as well as observed practices in similar procurement initiatives conducted by other utilities and general market requirements for long-term commodity transactions. As to the time allowed from the date the PPA is executed for a winning bidder to post the Pre-COD Performance Assurance (currently five days), Duke states that it believes that it is appropriate to require transition from the proposal

security to the Pre-COD Performance Assurance as soon as possible. Nonetheless, Duke states that it is willing to extend the current five-business day requirement to 10 business days.

4) Curtailment – Duke states that it also received feedback on the curtailment provisions included in the Tranche 1 PPA, which allow Duke to effectuate the statutory requirement that CPRE renewable energy facilities be subject to Duke's ability to dispatch, operate, and control those facilities in the same manner as Duke's own generating resources. See N.C.G.S. § 62-110.8(b). Duke describes the curtailment rights currently provided in the Tranche 1 CPRE RFP Solicitation as "broad," but of limited extent, noting that DEC is permitted to economically curtail CPRE facilities up to 5% of the facility's expected annual output and DEP is permitted to economically curtail CPRE facilities up to 10% of the facility's expected annual output. Duke further states that it is evaluating the appropriate curtailment limits to apply in Tranche 2, and that this information will be included in the updated pro forma CPRE PPA and made available for comment in the pre-solicitation process. In conclusion, Duke states that it does not support paying for curtailed energy as part of the ongoing contractual relationship under the CPRE pro forma PPA, and that, in the interest of moving expeditiously into Tranche 2, the approach of clear economic dispatch and curtailment employed in Tranche 1, with no payment for curtailed energy, should again be used in the Tranche 2 CPRE RFP Solicitation.

5) Avoided Cost Docket – Duke also addressed the subject of how the timing of the Commission's current avoided cost docket[1] will align with the initiation of the Tranche 2 CPRE RFP Solicitation. This issue, Duke states, is of importance because, pursuant to N.C.G.S. § 62-110.8(b)(2) evaluation of the cost-effectiveness of CPRE proposals is to be based on the utility's current forecast of its avoided cost and shall be consistent with the Commission-approved avoided cost methodology. Duke notes that the IA has proposed an approach where the Tranche 2 pre-solicitation documents would be released with all details finalized, except for the final avoided cost pricing periods and rates. This, Duke argues, would have the benefit of allowing the pre-solicitation process to proceed without delay, facilitating the receipt of input that would inform the finalization of all aspects of the Tranche 2 CPRE RFP Solicitation with the exception of the avoided cost threshold, and allowing market participants to begin development of proposals immediately. After the issuance of a final order in that docket, Duke states that it and the IA would then evaluate whether any changes to the 20-year forecasted avoided cost rate are required, finalize the RFP documents, and open the bidding window.

Duke further states that market participants generally commented that proceeding as expeditiously as practical toward Tranche 2 is preferred and that Duke agrees with this assessment. To that end, Duke suggested that the Commission establish a "drop dead" date for the issuance of a final order in the Sub 158 Proceeding, and, after that date, the applicable avoided cost methodology and inputs used for cost-effectiveness evaluation would be either established pursuant to the final order issued, or, if an order has not issued by that date, then the methodology approved in Docket No. E-100, Sub 148 would be used. While Duke states that it is going to discuss

[1] See In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2018, Docket No. E-100, Sub 158 (the Sub 158 Proceeding).

this issue more with the Public Staff and, potentially, will seek further guidance from the Commission, Duke also stated its belief that proceeding with Tranche 2 on a timeline that allows submission of bids in 2019 is imperative.

6) Approval of Asset Acquisition Documents – Duke states that a number of participants in the stakeholder meetings expressed a desire for the Commission to approve the various asset acquisition contracts. Noting the Commission's previous conclusion that these documents were not included in the pro forma CPRE PPA, which is expressly required to be approved by the Commission, Duke argues that there is no value "in litigating this issue for a third time."

7) Post-Term Revenue Assumptions – Duke states that one participant in the stakeholder meetings raised the issue that Duke should be required to disclose its specific post-term revenue assumptions made in connection with its own utility-sponsored proposals. Noting that the Commission previously resolved this issue, Duke again states that there is no value in re-litigating this issue.

In conclusion, Duke argues that the Commission should accept Duke's proposed CPRE Program Plan and allow the pre-solicitation process for the Tranche 2 CPRE RFP Solicitation to proceed as contemplated by Commission Rule R8-71(f)(1), and that this process is the appropriate forum for consideration of RFP-specific issues. Furthermore, Duke argues that the final Tranche 1 CPRE RFP Solicitation results will be available at that time and will provide more guidance regarding the overall RFP structure, including the treatment of grid upgrade costs. Finally, Duke requests that, to the extent that the Commission elects to consider any RFP-specific modifications, it be afforded an opportunity to respond to any recommendations made by market participants.

THE OTHER PARTIES' COMMENTS

First Solar

First Solar filed comments to supplement those comments filed by NCCEBA. First Solar's comments focus on discussion of changes to the CPRE pro forma PPA that would "shift renewables procurement from a curtailment-focused, energy-only contracting model to a dispatchable, capacity-based product." First Solar states that it has conducted extensive research on the technical capabilities, operational benefits and the economic benefits of a dispatchable renewable structure, which allows a solar power plant to be dispatched flexibly by a system operator. First Solar argues that this shift in procurement will be consistent with the legislative intent of House Bill 589 and be more cost effective for ratepayers, while also yielding operational benefits to Duke.

First Solar proposes a "dispatchable PPA" for future CPRE procurement by which market participants will bid fixed dollars per MW-month in response to future RFPs. First Solar states that by leveraging a capacity payment Duke will be able to treat a utility scale solar asset as fully dispatchable, while at the same time creating revenue certainty for the facility developer. First Solar further detailed its proposal as allowing Duke to flexibly dispatch solar assets alongside other generation assets based on optimal economic operations on a given day's forecasted insolation and customer demand; instead of delivered energy providing the key performance metric as is the case under the current pro forma PPA, renewable facilities will be required to meet dispatch availability and accuracy needs for Duke. First Solar further supports its position by citing to other jurisdictions that it views as allowing for similar contracting structures. First Solar next supports its position by detailing the technical capabilities and benefits that it believes areattainable through the use of dispatchable contracting structures, including frequency control, voltage control, ramping capability or flexible capacity, and, ultimately, cost savings for the overall system. Finally, First Solar argues that its proposal is consistent with the legislative intent of House Bill 589, will provide increased value to ratepayers andincreased operational benefits to the utility, and that North Carolina can take early and full advantage of the "operational advantages offered by dispatchable inverter-based solar resources." In conclusion, First Solar requests that the Commission approve and order the implementation of its recommended changes to the PPA, and of those recommended by NCCEBA. First Solar attached to its comments proposed changes to the CPRE pro forma PPA.

NCCEBA

In its comments, NCCEBA first notes that its comments are in addition to or in response to information provided in the IA's report filed with the Commission on March 15, 2019, and that NCCEBA is not providing comments on the information in the IA's report with which NCCEBA agrees. NCCEBA first comments regarding the liquidated damages clause in the CPRE pro forma PPA, complaining that the provision is roughly four times that allowed under PPAs that Duke previously entered into and were successfully financed by project developers. NCCEBA describes the amount as "exorbitant," the increase "astronomical," and, ultimately, argues that the liquidateddamages amount bears no relationship to Duke's actual damages should the project notbe constructed, and thus constitutes an unlawful penalty. Further, NCCEBA argues that for a CPRE bidder to post this amount in the form of cash or a cash-collateralized letter of credit is a "totally unreasonable requirement" because "very few developers havethe ability to come up with that amount of cash, especially if they receive multiple CPRE awards, and the requirement that they do so certainly increases the pricing of CPRE bids." NCCEBA recommends that the Commission require Duke to reduce the liquidated damages amount and allow the use of surety bonds for this performance security.

NCCEBA next argues that Duke should continue to be able to recover network upgrade costs assigned to winning proposals in the Tranche 2 CPRE RFP Solicitation in a future rate case. NCCEBA further argues that by continuing to allow Duke to recover network upgrade costs in base rates, there will be no adverse impact to ratepayers, because CPRE bids, including the imputed grid upgrade costs for the project, must meet the cost-effectiveness test of N.C.G.S. § 62-110.8(b)(2). In addition, NCCEBA expressesthe view that because the generating capacity added through the CPRE Program is mandated by legislative enactment it is a fortiori in the public interest, any network upgrade costs required to accommodate that generation is also in the public interest. Further, NCCEBA states that if grid upgrade costs are not recovered through base rates, CPRE bidders will increase their bid prices to cover theanticipated, but uncertain, amount of those costs. In short, NCCEBA's view is that ratepayers would be "indifferent between network upgrade costs being paid for by Duke in the first instance and ratebased and those costs being included in bids and recovered as part of higher CPRE cost recovery." Finally, NCCEBA argues that allowing Duke to recover these costs could reduce the ultimate costs of the CPRE Program because market participants who are faced with uncertain amounts of grid upgrade costs might over estimate those costs, inflating their bids unnecessarily.

NCCEBA next states that the IA incorrectly noted as an area of agreement the question of whether bids should be allowed to be refreshed if grid upgrade costs are assigned to projects. Instead, NCCEBA argues that CPRE bidders should not be allowed to refresh their bids to account for the assessment of grid upgrades in the evaluation process because it could create a disincentive for market participants to provide their best offers in their initial proposals and because allowing bids to be refreshed would complicate the evaluation process and lengthen the time required to complete Step 2 of the CPRE RFP bid evaluation process. NCCEBA suggests instead that CPRE bidders provide an adjustment factor to account for unknown network upgrade costs that become known through the cluster study process while avoiding the problems associated with submission of a new bid. In the alternative, if a bid refresh is allowed, NCCEBA argues that it should be available to all bidders and not just those in the competitive tier.

NCCEBA next argues that the CPRE Program Plan should not require the inclusion of interconnection costs in a bid proposal because these costs are paid by the winning bidders as required by the North Carolina Interconnection Procedures (NCIP). Thus, NCCEBA equates interconnection costs with construction costs that are reflected within the bid price and argues that these costs should play no role in bid evaluation.

NCCEBA next requests that the Commission require Duke to provide updated information for locations on Duke's system where major upgrades will not be required as expeditiously as possible. NCCEBA argues that this updated information is necessary for market participants to submit the most cost-effective proposals in locations that do not require substantial network upgrades. While arguing for this requirement, NCCEBA also states that the guidance should not limit projects to specific areas, as overly specific detail could drive up land prices for market participants, resulting in higher bids.

NCCEBA next argues that the CPRE PPA should not include "problematic" energy storage requirements that would act as a barrier to energy storage in the CPRE Program. NCCEBA notes having raised this issue in these proceedings previously, and states that its concerns have been demonstrated by the results of the Tranche 1 CPRE RFP solicitation, where four of a total 78 projects were proposed to include an energy storage component. For the Tranche 2 CPRE RFP Solicitation, NCCEBA argues that there should be no operational restrictions on energy storage in the PPA, except for grid reliability, and unless there is a stakeholder process and the Commission determines that the restrictions are in fact necessary for grid reliability. NCCEBA then details the provisions of the CPRE PPA energy storage protocol that it views as problematic, focusing on the "ramp rate limitations" that NCCEBA believes would unnecessarily reduce the amount of energy storage facilities installed and energy storage protocol number nine that NCCEBA views as providing Duke with the "unfettered right" to add additional operating restrictions.

In the final sections of its comments NCCEBA argues that CPRE proposals should continue to be required to meet an in-service date of January 1, 2021, as an eligibility requirement and that this requirement should be enforced, that the curtailment provisions should be revised, and that certain documents used in the execution of self-developed facilities and asset acquisition proposals be subject to Commission approval. In conclusion, NCCEBA requests that the Commission consider the issues raised in its comments.

The Public Staff

In its comments, the Public Staff provides a detailed background on the implementation of the CPRE Program, including the market participant meetings held February 22, 2019, and March 6, 2019, and the IA's report filed with the Commission on March 15, 2019, which details the discussions held at those meetings. The Public Staff then addresses several discrete issues related to the CPRE Program Plan and raised by the Commission or by market participants. With regard to the four issues that the Commission noted in its October Order, the Public Staff first states that changing the CPRE construct to not allow for Duke's recovery of grid upgrade costs through general rates may create additional challenges for implementing the CPRE Program. The Public Staff states that while it shares the Commission's concern regarding potential increases in upgrade costs in the future, to require bidders to include these costs may result in additional complexity as a "bid refresh" would be needed. That, the Public Staff states, would require a Commission rulemaking proceeding that would add additional delay in Tranche 2.

Aside from concerns about delaying Tranche 2, the Public Staff notes that it is unknown at this time whether Tranche 1 was successful in identifying and screening for projects with little to no upgrade costs. The Public Staff states that if imputed costs of system upgrades resulted in certain projects not being cost effective in Tranche 1, and projects with no upgrade costs were most competitive, then the RFP is working as anticipated. In addition, the Public Staff states that better location guidance can guide market participants towards projects that will require little to no upgrade costs in Tranche 2. In addition, the Public Staff states that the IA has identified an additional concern with a bid refresh procedure: the potential that such a procedure would result in an endless loop as allocated costs change and projects are eliminated and others added as part of that process. The Public Staff details the reasons that it shares these concerns and relates the concerns voiced by the market participants on this issue. The Public Staff concludes this section by arguing that "whether winning bidders pay for grid upgrades in their project price or the utility pays for grid upgrades and includes them in base rates, the difference to ratepayers is minimal." Thus, the Public Staff states that there may be benefit in choosing the methodology that results in a simpler RFP and evaluation process, which would be socialization of the grid upgrade costs for winning bidders and no bid refresh, as utilized in Tranche 1. Finally, on this issue, the Public Staff states that while there is risk to the ratepayers of grid upgrade costs being underestimated in the evaluation phase of the RFP, better locational guidance may mitigate that risk.

As to grid locational guidance, the Public Staff states that Duke indicated at the February IA-hosted stakeholder meeting that it will continue to refine the maps used for grid locational guidance ahead of the Tranche 2 process. The Public Staff states that it supports more detailed maps or guidance to direct market participants to areas where there is existing capacity and where projects are not likely to trigger significant upgrade costs. However, the Public Staff notes that some market participants voiced concerns that locational guidance that is too specific might lead to inflated land prices and burdensome local regulatory activity in anticipation of solar facility development, while others indicated that more specific data would aid in business planning. Thus, the Public Staff states that it believes that it is appropriate for Duke to develop and publicize revised locational guidance that improves on that provided in Tranche 1, reflecting, to the extent possible, the impacts of projects that will be interconnected as a result of Tranche 1 and other developments in the interconnection queues.

As to energy storage, the Public Staff states that the IA has indicated that four competitive tier projects have an energy storage component. These projects have proposed to use storage devices to maximize revenue by discharging during on-peak hours and charging during off-peak hours. However, the Public Staff notes that using the broad on-peak hours defined in the Option B rate tariffs based upon the methodology established pursuant to the Commission's Sub 148 Avoided Cost Order, which do not accurately reflect Duke's current highest production cost hours, makes it unlikely that energy storage operation using those on- and off-peak hours will maximize the benefits to ratepayers.

Turning to the discussion of energy storage at the stakeholder meetings, the Public Staff states that this discussion was "robust and informative." First, the Public Staff further states that market participants and Duke generally agree that energy storage can provide many grid benefits, such as frequency regulation, operational reserves, and firm capacity; however, there is no mechanism to pay market participants for these services. Instead, the Public Staff states, the only way for a market participant to utilize energy storage in Tranche 1 was to either use it to capture curtailed energy or to engage in energy arbitrage by charging during off-peak hours and discharging during on-peak hours. In short, the Public Staff's view is that energy storage promises many grid benefits but if future CPRE Tranches do not attempt to quantify their value and compensate developers for them, they will never be realized by ratepayers. Second, the Public Staff relates the stakeholders' discussion of issues related to what party has operational control and dispatch rights over the energy storage. The Public Staff identifies this issue as one related to ancillary services in this regard: Duke would need operational control over the energy storage in order to maximize ancillary services, yet this could result in reduced value of these resources to the market participant by changing the energy output profile to no longer align with the on-peak hours, operating at reduced energy output to maximize frequency regulation benefits or other ancillary reserves, or, potentially, operating the energy storage system in a way that reduces its operational life. The Public Staff describes this issue as "complex and challenging" and states that its resolution may require significant modifications to the pro forma PPA. The Public Staff also states that no solutions to this issue were presented or discussed at the stakeholder meeting. Third, the Public Staff states that market participants expressed concerns about obtaining financing of projects in light of the energy storage protocol provisions. In particular, market participants were concerned about the requirement for Duke to provide the next day's bulk discharge window by 4:00 p.m. of the current day, the tail end of a solar facility's daily output profile. No specific recommendations to improve the energy storage protocol were presented at the stakeholder meetings. The Public Staff relates some areas of agreement related to energy storage, namely, market participants expressed a desire for more granular pricing and for more transparency into the IA's evaluation methodology. Finally, the Public Staff recommended that a technical conference or separate stakeholder process focusing on energy storage may help resolve some of the complex technical issues related to the operation and compensation of energy storage.

The Public Staff next addresses the issue of transparency, as it relates to evaluation of proposals, post-Step One project rankings, and how winning and losing bids are treated in the interconnection queue. The Public Staff believes that the CPRE RFP process should be as transparent as possible, particularly with respect to the evaluation methodology. The Public Staff further explains the evaluation process and relates that some participants requested that the project rankings be released after the Step One process. However, the Public Staff states that it agrees with the IA that such a ranking would be of limited value prior to the winning proposals being announced, but also states that it would be appropriate and helpful for the IA to release an anonymized post-Step One project ranking along with winning bids, so that market participants and other interested parties can understand how imputed project costs affected the proposal rankings.

The Public Staff next addresses issues related to the curtailment provisions in the CPRE pro forma PPA. The Public Staff states that there was general agreement that the 5% and 10% curtailment provisions resulted in bid prices that are higher than they otherwise would be, as market participants factored into their pricing assumptions that they will be curtailed up to those maximums, which would be reflected in each bid. The Public Staff further explains that the concern raised was that these provisions could cost ratepayers more if the facilities were not curtailed to the maximum, and, at the same time, the maximums were based on limits initially established in negotiated QF PPAs to provide flexibility to Duke to address system reliability events, not to facilitate an efficient level of curtailment for economic dispatch purposes. In addition, the Public Staff states that as solar penetration increases over time, the curtailment maximums may not accurately reflect the most cost-effective amount of dispatch control that Duke needs to operate its electric systems in a cost-effective fashion, and the 20-year terms do not provide flexibility to adjust these levels. Consensus on a resolution was not reached during the stakeholder meetings. However, several conceptual solutions were raised, including, incorporating the system emergency limits on curtailment that exists for QFs under PURPA, providing "full payment" for every MWh that is curtailed, providing "partial payment" for every MWh that is curtailed, and providing a fixed monthly payment with unlimited curtailment. The Public Staff concludes by stating that it would like to explore the option of a fixed monthly payment, and that it believes that the Commission should carefully consider this issue in the context of any potential changes to the pro forma PPA.

The Public Staff next addresses the potential of modifications to the RFP documents to be used in Tranche 2. Noting the Commission's direction to Duke to continue its discussions with other parties about this subject, and Duke's incorporation of revisions prior to the Tranche 1 CPRE RFP Solicitation, the Public Staff believes that it is appropriate for the Commission to review and approve the pro forma PPA for Tranche 2. The Public Staff also notes that market participants requested that the Commission approve the asset acquisition agreements, but the Public Staff states that it continues to maintain the position that only the pro forma PPA is required to be approved by the Commission. The Public Staff also expressed its hope that the IA will work to identify and facilitate agreement between the market participants and Duke to revise terms and conditions in the pro forma PPA that may be perceived as commercially unreasonable.

The Public Staff next addresses the RFP Solicitation schedule, stating that the timeline presented in the CPRE Program Plan is reasonable and will result in procurement within the statutorily required timeframe of 45 months. Nonetheless, the Public Staff states that it may also be prudent to consider delaying Tranche 2 and the entire CPRE Program Plan until the avoided cost rates proposed in the Sub 158 Proceeding are approved by the Commission. In that proceeding, the Public Staff is proposing more granular peak pricing periods that will allow more compensation in hours when capacity need is greatest and when energy storage is most valuable. The market participants also agreed that more pricing periods would be preferable for Tranche 2. The Public Staff further states that the elimination of Tranche 4, as proposed in the CPRE Program Plan, allows more flexibility to delay Tranche 2, if there is a compelling reason to do so. The Public Staff seems to suggest that the benefit of having updated avoided cost rates based on the methodology approved by the Commission in the Sub 158 Proceeding would be a compelling reason. The Public Staff relates that market participants indicated an openness to a modest delay, but overall opposed any substantial delay due to cost factors. Finally, the Public Staff states that it believes that evaluating CPRE projects based on the most current avoided cost methodology is in the best interest of ratepayers and may resolve other challenges, including proper compensation for energy storage in Tranche 2. However, the Public Staff further states that if the Commission determines that the delay required to resolve all issues in the Sub 158 proceeding would result in too significant a delay for market participants, it may be possible to incorporate some components of the proposed changes if agreement can be reach in a reasonable timeframe.

In conclusion, the Public Staff makes the following recommendations: (1) it is appropriate to allow Duke to continue to recover the grid upgrade costs allocated to winning bids through base rates and not modify the CPRE Program to include a bid refresh process; (2) Duke should provide more detailed and updated grid locational guidance, reflecting the addition of Tranche 1 resources and other changes in its interconnection queues, which will direct market participants to areas of the grid with capacity to accommodate new facilities and that are less likely to require major grid upgrades; (3) in the interest of transparency, it is appropriate to require the IA to release a suitably anonymized post-Step One project ranking along with the winning bids; (4) It is appropriate to require Duke and the IA to provide a more full and complete description of the bid evaluation methodology prior to Tranche 2; (5) it is appropriate that additional changes to the pro forma PPA should be presented to the Commission for approval prior to Tranche 2. Changes proposed by Duke and commented on by intervenors should address the energy storage protocol and curtailment procedures, limits, and compensation; (6) a technical conference or stakeholder process focusing on energy storage has merit and should be considered; and (7) it is appropriate to utilize the avoided cost rates and methodology from the Sub 158 Proceeding for Tranche 2 purposes, even if this potentially results in a delay of Tranche 2 and successive tranches of the CPRE Program. In the alternative, if certain elements of the Sub 158 Proceeding, such as the more granular pricing periods can be agreed to by the interested parties and approved by the Commission prior to the issuance of Tranche 2, those elements should be used for Tranche 2 purposes.

THE TECHNICAL CONFERENCE

On May 23, 2019, this matter came on for technical conference as scheduled. The parties participating in the technical conference detailed their views on the issues identified by the Commission for discussion at the technical conference and responded to questions from the Commission. The Commission appreciates the efforts that the parties and the IA made to prepare for and participate in the technical conference.

DISCUSSION AND CONCLUSIONS

Based upon the foregoing and the entire record herein, including the CPRE Program Plan, the parties' comments, and the statements and arguments made at the technical conference, the Commission concludes that the CPRE Program Plan is reasonable for planning purposes and meets the requirements of Commission Rule R8-71. Therefore, the Commission further concludes that with the modifications discussed herein the CPRE Program Plan should be accepted. Most significantly, the Commission will direct Duke to revise the timeline for the Tranche 2 CPRE RFP Solicitation as follows: the 60-day pre-solicitation document review period will open on August 15, 2019, the acceptance of proposals shall open on October 15, 2019, and close on December 15, 2019, subject to adjustment depending upon the timing of the issuance of a final order or notice of decision in the Sub 158 Proceeding, as discussed further below. In addition, the Commission will resolve those issues that were the subject of the technical conference and address the appropriate treatment of interconnection cost overruns. The Commission is prepared to address those issues not specifically discussed in this Order during the 60-day pre-solicitation document review period ahead of the Tranche 2 CPRE RFP Solicitation. To facilitate a more efficient review process, the Commission will require Duke to host monthly meetings with the IA and market participants and to make corresponding monthly reports to the Commission on these discussions.

As to those issues identified in the Commission's October Order, the parties' written comments and the statements made at the technical conference confirmed for the Commission that the general structure of the CPRE Program used in the Tranche 1 CPRE RFP Solicitation was appropriate. In addition, except as to those issues addressed herein or reserved for consideration within the Tranche 2 pre-solicitation period, the Commission determines that it is appropriate to continue this structure in the Tranche 2 CPRE RFP Solicitation. Therefore, the Commission concludes that (1) it is unnecessary to amend Commission Rule R8-71(f)(3) to allow for a bid refresh procedure; (2) Duke should be required to update the grid locational guidance used in the Tranche 1 CPRE RFP Solicitation and publish that guidance to the market participants as soon as reasonably practical; (3) it is appropriate to require Duke to continue to evaluate the operational restrictions in the energy storage protocol that is a part of the CPRE PPA for the Tranche 1 CPRE RFP Solicitation and to continue discussions with the market participants regarding the energy storage protocol; and (4) approval of the use of the dispatchable PPA proposed by First Solar is premature at this time.

In reaching these conclusions, the Commission relies on the discretion delegated to it through the enactment of N.C.G.S. § 62-110.8 to implement the CPRE Program in a reasonable manner consistent with the plan language of the statute. To a great extent, the parties' comments on the contested issues are based upon their preferences for implementation of the Program and not on the provisions of that statute. Many of these comments include assertions of "commercial unreasonableness" that lack support. In short, the Commission determines that reasonable progress is being made toward achieving the goals of the CPRE Program and that the CPRE Program Plan is a reasonable plan for achieving those goals in the future. With the additional requirements for meetings among the interested stakeholders and reporting to the Commission about those meetings, the Commission is prepared to advance to the Tranche 2 CPRE RFP Solicitation on the schedule detailed in this Order.

As to the question of what avoided cost rates and rate methodologies should be incorporated into the Program Methodology and used to evaluate proposals submitted in the Tranche 2 CPRE RFP Solicitation, the Commission concludes that a delay in the opening of Tranche 2 to establish updated avoided cost rates and rate methodologies is justified by the policy supporting the enactment of House Bill 589 and the policy goals embodied in N.C.G.S. § 62-110.8. Therefore, the Commission will direct Duke and the IA to proceed toward the opening of the Tranche 2 CPRE RFP Solicitation on the schedule provided above, including the preparation and publication of all relevant documents during the 60-day pre-solicitation period, with a "placeholder" for the relevant avoided cost rate information. It is the Commission's intent to issue a notice of decision or final order in the Sub 158 Proceeding with sufficient time for Duke to make a compliance filing in response to that notice or order, and the rates and rate methodologies established pursuant thereto to be incorporated into the CPRE Program Methodology. Thus, the Commission will further direct Duke and the IA to schedule the proposal submission period for at least 60 days (approximately October 15—December 15), subject to automatic extension up to and including the 45th day after the Commission issues a notice of decision or final order in the Sub 158 Proceeding.

The parties' written comments and the statements made at the technical conference focused the Commission's attention on the potential that network upgrade costs exceed the estimates developed within the proposal evaluation process and used to evaluate cost-effectiveness. The Commission's emphasis in resolving this issue is on the importance that all network upgrade costs be appropriately assigned to a proposal for evaluating cost-effectiveness pursuant to N.C.G.S. § 62-110.8(b)(2). In addition, the Commission recognizes that the potential for actual costs to exceed projected costs is presently without an effective regulatory limit. The Commission agrees with the Public Staff that it is appropriate to apply such a limit in the nature of a presumption that costs in excess of 25% of the estimated costs, are unreasonably incurred and not recoverable. In a general rate case where a Duke utility seeks to recover these costs, the utility may rebut this presumption by competent, material, and substantial evidence.

At the technical conference, the IA detailed for the Commission the development of a "base case" for the purposes of evaluating the potential costs of accommodating the renewable energy facilities that are the subject of proposals submitted into a CPRE RFP Solicitation. In summary, the discussion of this issue, which was not a topic expressly included in the scope of the technical conference, centered around recognition that Duke's interconnection queue includes a significant number of pending requests, representing a significant amount of generation capacity, some of which may never progress to commercial operation. Thus, assuming that 100% of these facilities will become operational results in the "bloated base case" that the IA described. The Commission recognizes that this issue involves a myriad of considerations that are not fully developed in the record here. In addition, as noted in the Commission's June 14, 2019 Order in Docket No. E-100, Sub 101, Duke is working to develop a proposal for overall queue reform and required to report to the Commission regarding that proposal on or before July 31, 2019. The Commission, therefore, determines that this issue is not ripe for decision, but nonetheless merits monitoring and, potentially, further consideration after the filing of the report, but prior to the opening of the Tranche 3 CPRE RFP Solicitation.

To the extent that issues raised by the parties were not specifically addressed in this Order, those issues should be the subject of ongoing discussions between Duke, the IA, the Public Staff, and the market participants. The Commission will require Duke to host monthly meetings with interested stakeholders and to report to the Commission on these meetings. These reports shall indicate the attendees at these meetings, provide a detailed and substantive summary of the subjects discussed at the meetings, and indicate areas of agreement and disagreement among the attendees. This requirement to meet and report will provide a measure of relief to those parties who have requested more transparency and information about Duke's preparation of the CPRE Program documents and the solicitation process. In particular, the Commission notes that Duke's representatives at the technical conference represented that consideration of the operational restrictions included in the energy storage protocol is ongoing in advance of the Tranche 2 CPRE RFP Solicitation. See Tr. Vol. 2, p. 57-59, 63-64, and 78. The Commission will require these meetings to begin prior to the 60-day pre-solicitation period with the goal of reaching consensus on the documents relevant to the Tranche 2 CPRE RFP Solicitation and to continue through the close of the proposal submission period with the goal of providing a forum for market participants to gain more detailed information about the solicitation process.

The Commission is prepared to address issues that cannot be resolved informally among the parties within the established pre-solicitation document review process. However, the Commission is not inclined to revisit its conclusions that the Self-developed and Asset Acquisition Contracts are not subject to Commission review and approval pursuant to N.C.G.S. § 62-110.8(b)(3),[1] and that Duke has proposed a reasonable means of meeting the disclosure requirements of Commission Rule R8-71(l) with regard to assumptions related to post-term revenue for Duke-developed facilities. The Commission reiterates again its expectations that all parties and other participants in the CPRE Program meetings and discussions participate in good faith, seeking to resolve issues and reach consensus on the details of the structure of the Tranche 2 CPRE RFP Solicitation, including potential for revisions to the CPRE pro forma PPA.

IT IS, THEREFORE, ORDERED as follows:

1. That Duke shall modify its CPRE Program Plan to reflect the adjusted timeline for implementation of the Tranche 2 CPRE RFP Solicitation and, as necessary, to reflect the other conclusions reached in this Order;

2. That the CPRE Program Plan, as modified in compliance with this Order shall be, and is hereby, accepted; and

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[1] See Order Approving CPRE PPA, p. 6-7, Docket Nos. E-2, Sub 1159, and E-7, Sub 1160 (June 25, 2018).

3. That Duke shall meet monthly with interested stakeholders to continue discussions with the IA, the Public Staff, and the market participants with the goal of reaching consensus on the documents that will be used in the Tranche 2 CPRE RFP Solicitation and of providing a forum for market participants to gain more detailed information about the solicitation process. Duke shall file reports detailing the status of these discussions on or before July 15, 2019, and every 30 days thereafter untilDecember 15, 2019, as further described in this Order.

ISSUED BY ORDER OF THE COMMISSION.
This the 2nd day of July, 2019.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

DOCKET NO. E-2, SUB 1159
DOCKET NO. E-7, SUB 1156

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Joint Petition of Duke Energy Carolinas, LLC	)	ORDER EXTENDING
and Duke Energy Progress, LLC, for Approval	)	TRANCHE 2 CPRE RFP
of Competitive Procurement of Renewable	)	SOLICITATION RESPONSE
Energy Program	)	DEADLINE AND RESCHEDULING
	)	STAKEHOLDER MEETING

BY THE CHAIR: On July 2, 2019, the Commission issued an Order modifying and accepting the Competitive Procurement of Renewable Energy (CPRE) Program Plan filed by Duke Energy Progress, LLC and Duke Energy Carolinas, LLC (together, Duke). In that Order, the Commission directed Duke and the Independent Administrator of the CPRE Program to adjust the schedule of Tranche 2 CPRE RFP Solicitation so that acceptance of proposals would open on October 15, 2019, and close on December 15, 2019. In addition, that Order required Duke to host monthly stakeholder meetings leading up to the opening of the Tranche 2 CPRE RFP Solicitation, with the final meeting scheduled for December 15, 2019.

On October 7, 2019, the Commission issued an Order requesting that the parties herein provide comments as to certain discrete issues related to the application of the solar integration services charge (SISC) to this program. The SISC is among the issues that the Commission resolved through issuance of a Notice of Decision and Supplemental Notice of Decision in the 2018 biennial avoided cost proceeding (Docket No. E-100, Sub 158). Importantly, the Notice of Decision and Supplemental Notice of Decision were issued in Docket No. E-100, Sub 158, to allow for the calculation of avoided cost rates and determination of the cost-effectiveness limitation with respect to proposals submitted in the Tranche 2 CPRE RFP Solicitation and as part of the Commission's effort to facilitate the timely continuance of the Trance 2 CPRE RFP Solicitation.

On or after October 18, 2019, Duke, North Carolina Sustainable Energy Association (NCSEA) and North Carolina Clean Energy Business Alliance (NCCEBA), First Solar, Inc. (First Solar), and the Public Staff filed comments and reply comments in response to the Commission's October 7 Order.

On November 22, 2019, NCCEBA, NCSEA, Duke, and the Public Staff filed a joint motion requesting that the Commission extend the deadline for the submission of proposals in the Tranche 2 CPRE RFP Solicitation through February 15, 2020 (or 45 days after the Commission issues an order resolving the issues related to the SISC), and to reschedule the stakeholder meeting previously scheduled for December 15, 2019, to January 15, 2019 (or 30 days prior to the deadline for submission of proposals in the Tranche 2 CPRE RFP Solicitation).[1]

Based upon the foregoing and the entire record herein, the Chair finds good cause to direct the Independent Administrator to extend the deadline for the receipt of responses to the Tranche 2 CPRE RFP Solicitation to allow market participants and the Proposal Team to submit proposals on or before February 17, 2020,[2] and to reschedule the stakeholder meeting previously scheduled for December 15, 2019, to a date convenient to the Independent Administrator of the CPRE Program, Duke, and the interested stakeholders, but no later than January 17, 2020.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 2nd day of December, 2019.

NORTH CAROLINA UTILITIES COMMISSION
Kimberley A. Campbell, Chief Clerk

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[1] Although not a party to this proceeding, the Independent Administrator of the CPRE Program joined the joint motion.

[2] February 17, 2020, is the next day following February 15, 2020 (a Saturday), on which the Commission's offices will be open for business.

DOCKET NO. E-2, SUB 1169
DOCKET NO. E-7, SUB 1168

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Petition of Duke Energy Progress, LLC, and	)	
Duke Energy Carolinas, LLC, Requesting	)	ORDER APPROVING REVISED
Approval of Community Solar Program Plan	)	COMMUNITY SOLAR PROGRAM
Pursuant to N.C.G.S. § 62-126.8	)	PLAN AND RIDERS

BY THE COMMISSION: On July 27, 2017, the Governor signed into law House Bill 589 (S.L. 2017-192). Part VI of House Bill 589, added a new article 6B to Chapter 62 of the General Statutes, the Distributed Resources Access Act (Act). Part of the Act, codified at N.C. Gen. Stat. § 62-126.8, requires Duke Energy Progress, LLC (DEP), and Duke Energy Carolinas, LLC (DEC) (together, Duke), to file for Commission approval a plan to offer a Community Solar Energy Program, through which Duke's retail customers could voluntarily participate in and receive benefits from distributed solar photovoltaic (PV) resources without having to install, own, or maintain a PV system of their own. Pursuant to N.C. Gen. Stat. § 62-126.10, the Commission is directed to adopt rules to implement the provisions of the Act, including the following requirements applicable to the Community Solar Program:

(1) Establish uniform standards and processes for the community solar energy facilities that allow the electric public utility to recover reasonable interconnection costs, administrative costs, fixed costs, and variable costs associated with each community solar energy facility, including purchase expenses if a power purchase agreement is elected as the method of energy procurement by the offering utility;

(2) Be consistent with the public interest;

(3) Identify the information that must be provided to potential subscribers to ensure fair disclosure of future costs and benefits of subscriptions;

(4) Include a program implementation schedule;

(5) Identify all proposed rules and charges;

(6) Describe how the program will be promoted;

(7) Hold harmless customers of the electric public utility who do not subscribe to a community solar energy facility; and

(8) Allow subscribers to have the option to own the renewable energy certificates produced by the community solar energy facility.

N.C.G.S. § 62-126.8(e)(1)-(8).

On December 19, 2017, in Docket No. E-100, Sub 155, after receiving comments and proposed rules from Duke, the Public Staff, and other parties, the Commission issued an Order adopting Commission Rule R8-72. That Rule sets out the filing, reporting, and other program requirements, provides for a mechanism through which the Commission can annually review the program's success or evaluate potential program changes, and clarifies that Program participants will be able to avail themselves of the Commission's existing consumer complaint process in the event that a dispute arises over billing, service, or program administration.

On January 23, 2018, Duke filed a petition for approval of its Community Solar Program Plan, DEC's Shared Solar Rider SSR, and DEP's Shared Solar Rider SSR-3. Included in the petition are examples of communication materials intended for use by Duke in marketing the Community Solar Program.

On January 26, 2018, the Commission issued an Order establishing these proceedings to review Duke's proposed Community Solar Program Plan, allowing for intervention by interested persons, and setting a schedule for the filing of comments and reply comments.

The following filed petitions to intervene, which were granted by orders subsequently issued in these proceedings: North Carolina Sustainable Energy Association (NCSEA), the Sierra Club, and North Carolina Waste Awareness and Reduction Network (NC WARN).

On April 13, 2018, the Public Staff, NC WARN, NCSEA, and the Sierra Club filed comments.

On June 4, 2018, Duke filed its reply comments.

Also on June 4, 2018, the Public Staff filed a Motion requesting leave for the parties to file additional reply comments, which was granted by Commission Order issued on June 5, 2018.

On June 25, 2018, the Public Staff, NCSEA, NC WARN, and the Sierra Club filed additional reply comments.[1]

On or after June 26, 2018, the Commission received three consumer statements of position, expressing the view that Duke's Community Solar Program Plan, as proposed, will not be successful due to its design as a premium product for consumers, rather than one that presented opportunities for cost savings.

On July 16, 2018, Duke filed its additional reply comments.

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[1] On July 23, 2018, the Sierra Club filed a letter of clarification, stating that its recommendation contained in its reply comments that Duke "not accept bids above the...avoided cost rate" was "intended to recommend capping only the PPA price at avoided cost" (emphasis in original).

DUKE'S PETITION FOR APPROVAL OF COMMUNITY SOLAR PROGRAM PLAN

In its petition, Duke argues that its proposed Community Solar Program and Shared Solar Rider,[1] satisfy the objectives and requirements of N.C.G.S. § 62-126.8. In support of its petition, Duke states that it "diligently researched the best practices of other community solar programs, discussed the scope of the Program with and solicited input from interested parties ... and surveyed Duke Energy customers to gauge potential interest in participation" prior to filing its proposed Program. Duke asserts that the Program's purpose as a means by which "to expand the access to solar power to those retail customers that want to support the development and integration of solar power in North Carolina, but who have been unable or do not wish to do so because they cannot host on-site PV systems on their roofs." Duke contends that it designed its Program in a manner that minimizes costs, while maximizing the benefits, of subscription. Included with its petition is Duke's request that the Commission grant an exemption to the requirement of N.C.G.S. § 62-126.8(c) that community solar energy facilities in both DEC and DEP service be located in the same county, or a contiguous county, as the subscribers to that community solar energy facility. The Commission is granted authority pursuant to N.C.G.S. § 62-126.8(c) to allow such an exemption for facilities located within 75 miles from the county where subscribers are located. Also included as attachments to Duke's petition are radio advertisements and website images that Duke proses to use in marketing the Program.

In its petition, Duke argues that due to the statutory prohibition against subsidization of Program costs by non-participating ratepayers, partnerships with interested local communities and organizations will be critical to minimizing program costs. Although Duke's customer survey research indicates that "certain customers are inclined to support developing shared solar resources" by participating in the program, Duke states that it remains to be seen whether the Program "is attractive to a sufficient number of customers if the Program does not guarantee any savings over time." For this reason, Duke proposes a gradual rollout of its Program in tranches involving relatively small facilities, in order to allow the Company to implement lessons learned, and to modify the Program accordingly, depending on the success of prior tranches. To that end, Duke's petition contains only the proposed design for Tranche 1 of the Program.

The following summarizes the key components of Duke's proposed design for Tranche 1 of the Program, as detailed in Duke's petition:

- <u>Tranche 1 Procurement and Implementation Plan</u>: Duke intends to procure solar energy for Tranche 1 of the Program through power purchase agreements (PPAs) with "qualifying

[1] There appear to be no substantive differences between DEC's Shared Solar Rider SSR and DEP's Shared Solar Rider SSR-3. The Commission will, therefore, refer singularly to those Riders in this Order.

small power production facilities,"[1] totaling approximately 1 MW of capacity[2] each for DEC and DEP, with the goal of achieving commercial operation for Tranche 1 facilities in 2020 or 2021. Prior to entering into a PPA, Duke states that it will engage with internal and external stakeholder channels in an effort to identify a viable project, to include "locations that could facilitate both lower solar costs and, potentially, subscribers willing to commit to larger subscriptions as a way to lower projected marketing expenses." Next, Duke proposes to conduct a request for proposal (RFP) and finalize and launch the marketing effort for the program. Within sixty to ninety days following the marketing launch, Duke will make a determination regarding sufficiency of apparent consumer interest in the program. If Duke determines interest to be insufficient, it states that it may petition the Commission to authorize a delay, suspension, or closure of the program. If Duke determine interest to be sufficient, on the other hand, the Companies will proceed with processing initial subscriber payments and executing the PPA(s) during the ninety to one hundred and twenty days following the launch of the program marketing efforts.

- Availability and Participation: Duke proposes that the program be available for voluntary participation on a first-come, first-served basis for DEC or DEP residential and nonresidential retail customers who are not served under a net metering rider or power purchase agreement, and who are located in a geographic area 1) within 75 miles from the from the solar energy facility (or 75 miles from the county in which the solar energy facility is located, if the Commission allows Duke's request for an exemption of the Same/Contiguous County Requirement set forth in N.C.G.S. § 62-126.8(c)); wherein Duke has pre-determined sufficient customer interest in the Program exists; and 3) where at least 4 additional and otherwise-eligible subscribing customers are located. No subscriber will be eligible to subscribe to greater than 100% of the maximum annual peak demand of electricity at the subscriber's premises. In addition, no single subscriber will be eligible to subscribe to greater than 40% of the total capacity of the subscription blocks available at any one community solar energy facility, with each subscription block representing 220 watts (W) of solar energy capacity and projected to produce a fixed amount of 35 kilowatt hours (kWh) of energy for the duration of the Program.

- Program Costs and Cost Recovery: Duke proposes that the solar PV facility (QF) with which Duke will execute PPAs to implement Tranche 1 of the Program pay for all reasonable interconnection costs through interconnection fees. Duke further proposes that subscribers pay administrative costs, such as marketing, billing, and program management expenses, through the subscription fee. In addition, Duke proposes that subscribers pay for the renewable energy credits

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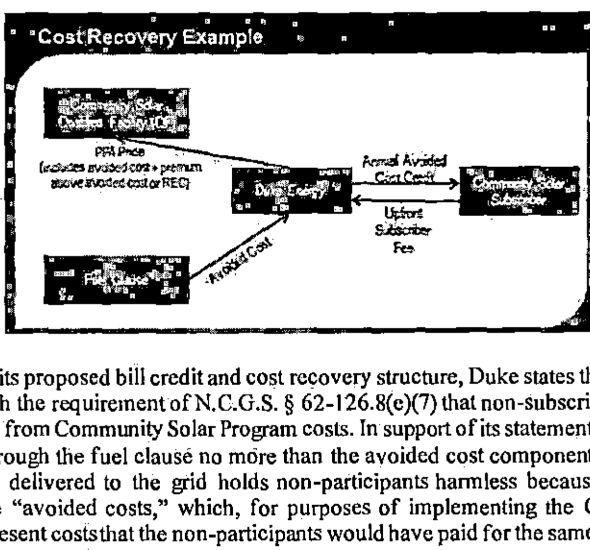
[1] Although Duke proposes to procure solar energy for the Program through PPAs with "qualifying small power production facilities, as defined in 16 U.S.C. § 796," Joint Petition of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC, at 5, In re: Petition for Approval of Community Solar Program, Docket Nos. E-2, Sub 1169 and E-7, Sub 1168 (N.C.U.C. filed Jan. 23, 2018), Duke does not otherwise suggest or imply that the electric generating facilities involved in the Community Solar Program would use a technology other than solar photovoltaic (PV) to generate electricity. The Commission, therefore, will disregard the reference to the term "qualifying small power production facilities," which includes many technologies other than solar PV that can be used to generate electricity, and proceed to review Duke's petition and comments as embracing the deployment of only "community solar energy facilities," as that term is defined in N.C.G.S. § 62-126.3(3), within the Community Solar Program.

[2] Duke will consider a facility's nameplate capacity to be its continuous rated power output, meaning "the facility's designed and intended maximum continuous output capability, measured in watts, at the facility's point of interconnection with the distribution or transmission system."

(RECs) from the program's purchased power through the subscription fee. In return, Duke proposes that subscribers receive an bill credit that is based on each utility's avoided cost rates utilizing the methodology most recently approved by the Commission at such time as the Program is open to subscriptions. Finally, Duke proposes that the energy generated by the community solar energy facility be put to the grid and that the total delivered costs, including capacity and non-capacity costs associated with the purchased power, be recovered pursuant to N.C.G.S. § 62-133.2(a1)(10) from all customers utilizing the same methodology applied to other [QF] purchases." However, in the event that the amount of subscriptions are insufficient to cover Program costs, and the Commission consequently allows Duke to cancel the Program, Duke plans to seek recovery of administrative costs incurred in promoting and developing the Program in its next general base rate case. In support of this contingency plan, Duke argues that such course of action would be appropriate given the statutory mandate that the Companies develop the program. In addition, the Companies point out that such a request would be subject to a reasonableness and prudence review by the Commission, as would be the case with other costs recovered pursuant to N.C.G.S. 62-133.

Duke provides the following diagram to illustrate the bill credit and cost recovery structure of its proposed Community Solar Program:



In support of its proposed bill credit and cost recovery structure, Duke states that the proposal is compliant with the requirement of N.C.G.S. § 62-126.8(e)(7) that non-subscribing customers be held harmless from Community Solar Program costs. In support of its statement, Duke argues that recovering through the fuel clause no more than the avoided cost component of the purchased power that is delivered to the grid holds non-participants harmless because the costs being recovered are "avoided costs," which, for purposes of implementing the Community Solar Program, represent costs that the non-participants would have paid for the same amount of power in the absence of the PPA.

Duke states that, to make the program viable, each MW of community solar capacity, will require 4300 subscription blocks to be subscribed within the location parameters mandated by N.C.G.S. § 62-126.8(c) (subject to modification if the Commission allows Duke's request for an exemption from the location requirement of § 62-126.8(e)). Duke argues that due to the statutory requirement that non-subscribing customers be held harmless, it may be challenging to attract "a sufficient number of customers who will be both (i) committed to paying a premium for their electric power to promote the development of solar energy and (ii) located within one county, a contiguous county or within 75 miles of the facility." Duke, therefore, opines that "a robust marketing effort will be necessary," and projects marketing costs for the implementation of Tranche 1 at $860,000 for DEC and DEP combined. Duke states that it intends to use a combination of the following methods, to market the Program: digital and printed communications through the Duke Energy website, email, press releases, newsletters, social media, direct mail, webinars, [and] internal and external stakeholders.

In its comments, Duke also provides a number of ways in which they will seek to minimize Program costs, including 1) encouraging solar developers to partner with entities that may donate brownfields or other land for the facilities; 2) engaging and educating customers about the program; 3) employing lessons learned from Tranche 1 of the Community Solar Program to decrease costs of future tranches; and 4) utilizing partnerships with external organizations. Duke also observes that projected PPA and marketing expenses are the most variable program costs, and make up the majority of the program costs. As a result, if Duke is able to successfully lessen some Program costs as described herein, particularly with regard to PPA and marketing costs, then the subscription fee should decrease accordingly.

• <u>Subscription Fee, Terms, and Bill Credit</u>: The Companies propose to charge an upfront subscription fee for Tranche I, arguing that an upfront charge lowers administrative costs, simplifies Duke's management and oversight of the Program, and "mitigates the administrative burden and costs of having DEC and DEP employees receiving, accounting for, and tracking multiple and ongoing subscriber payments and cash transactions." Payment of the upfront subscription fee entitles the subscriber to one subscription block of community solar, with an energy amount of 35 kWh per month, for a 20-year term.

The Companies state that they do not as of yet know the exact amount of the subscription fee because "[e]ach solar energy facility may present varying circumstances, and, therefore, the Companies cannot precisely project the amount of the costs that will make up the subscription fee at this time." However, the Companies estimate that a reasonable PPA price for a project with the characteristics of a Tranche 1 community solar energy facility is $65/MWh. Consequently, and assuming a PPA price of $65/MWh, the Companies project an upfront subscription fee in the amount of $500 per subscription block of community solar. The Companies provide the following as a breakdown of projected estimated costs comprising the subscription fee charge:

Cost Category	Projected Estimated Costs
PPA @ approximately $65/MWh	$284
Marketing and Customer Engagement	$131
Enrollment / Billing / Credit	$37
Call Center	$9
Program Management	$39
TOTAL	$500

Assuming a bill credit to the subscriber based upon current avoided cost rates at the time the program is opened to subscriptions, the subscriber's credit would amount to $420 over the duration of the 20-year subscription term, meaning that the Program will involve payment of a premium in addition to a subscriber's normal retail rates. Duke further proposes that the bill credit will consist of a fixed annual payment for the duration of the program. In addition to the annual bill credit, "subscribers to Tranche 1 will have the ability to indicate they are participating in a renewable energy program through the retirement of the associated REC." Under Duke's proposal, neither the payment of the subscription fee, nor the annual fixed payment bill credit, will appear on a subscriber's bill. Instead, Duke proposes to manage "credits and charges outside of the billing system" in order to allow "quicker implementation of the Program at a lower overall cost." Similarly, the Companies "also do not intend to offer 'on-bill' financing of subscription costs to subscribers at this time," on the grounds that on-bill financing would increase administrative costs, in turn increasing the subscription fee.

As proposed, subscribers would pay the cost of the RECs produced by the community solar facilities through their subscription fees. Duke states that this has been described as a "best practice" in community solar programs, and cites to decision of the Michigan Public Service Commission in support thereof.[1] In addition, Duke argues that this practice would result in lower administrative costs and is otherwise appropriate "given that it will take more than two years for one subscription block of the community solar energy facility to produce a REC, which results in the block's REC value being immaterial for the majority of subscribers for the first few years" of the Community Solar Program.

If a customer moves from the premises first used to establish Program eligibility, Duke proposes to continue provide annual fixed payments to the customer, regardless of the location of the customer's new premises. In support of this plan, Duke states that this would result in no additional administrative costs and that it will help make the Program more attractive "[c]onsidering that customers rarely live in one place for 20 years." As for subscription transferability, the Companies point out that they must be "mindful of the potential risk that the subscription fee could be characterized as an investment in a common enterprise and therefore subject to federal or state securities regulation." However, given the length of the subscription term, Duke proposes to allow each subscriber the option of designating a beneficiary of the subscription and to permit transfer of a subscription from the original subscriber to their designated beneficiary only in cases where an unforeseen event, such as death or divorce, adversely impacts the original subscriber's ability to receive payments under the Program.

Duke notes that it will be the subscriber's responsibility to designate a beneficiary at the time of subscription, and that this information will be provided to subscribers when they apply to participate in the program. In addition, Duke will provide subscribers, at the time of program subscription, with information about 1) how to access a copy of Commission Rule R8-72 via the Commission's website; and 2) the process through which they may file a consumer complaint with the Commission pursuant to N.C.G.S. § 62-73 and Commission Rule R1-9.

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[1] See Opinion and Order, Case No. U-17752, Mich. Pub. Serv. Comm'n., issued on June 9, 2016, at 1-2.

- Process for Subscribing: Throughout all steps of the process, Duke states that it will provide "status updates by email regarding the status of the Program project, including the date of the solar facility site's energization and ribbon cutting." Once the community solar energy facility comes online, subscribers also "will be able to track their Project's output through an online portal." The Companies contemplate the following subscription process:

    - Step 1 – Prospective subscriber learns about the Program as a result of the Companies' customer engagement and marketing efforts.

    - Step 2 – Prospective subscriber visits Duke's website or otherwise makes contact with Duke to learn more about the Program.

    - Step 3 – Once a decision has been made to subscribe, the prospective subscriber completes and submits an online form and provides payment information.

    - Step 4 – If the Companies already have determined that sufficient subscriber interest exists to move forward with the community solar energy facility for which the prospective subscriber has applied, Duke will collect from the subscriber $200 as payment for the first of two installments of the upfront subscription fee. If the Companies have not yet determined that sufficient subscriber interest exists to move forward with the community solar energy facility for which the prospective subscriber has applied, the prospective subscriber will receive notice at such time as Duke decides to proceed with the facility; the subscriber then will have one week from the notification date to cancel their application at no charge before Duke collects the $200 first installment of the upfront subscription fee from the payment information provided by the subscriber at the time of application.

    - Step 5 – After Duke executes the PPAs for the community solar facilities in each service territory, the Companies will charge each subscriber the second installment of the upfront subscription fee.

    - Step 6 – Once annually after the applicable solar energy facility comes online, each subscriber will receive a fixed payment in lieu of an on-bill credit, based on the utility's avoided cost rates using the methodology most recently approved by the Commission at the time the Program is opened for subscriptions.

In addition to requesting approval of its proposed Community Solar Program Plan, Duke also requests that the Commission allow an exemption from the Same/Contiguous County Requirement codified as N.C.G.S. § 62-126.8(c). In support of this request, Duke argues that "the Program has the best chance of success if it is marketed in or near urban areas, where more potential subscribers are located, while having the flexibility to site projects within a large enough area nearby to those urban locations to permit lower development costs." The Companies further argue that such exemption is in the public interest because "customer participation is vital to the Program's success," and the requested exemption would allow the Companies to "target their Program marketing efforts at the widest possible audience, and seek development opportunities in locations that minimize upfront cost of subscription, thereby attracting more subscribers and increasing the Program's chances of success." Pursuant to N.C.G.S. § 62-126.8(c) and

Commission Rule R8-72(e)(4), the Companies, therefore, request that the Commission approve an exemption from the Same/Contiguous County Requirement, such that a community solar energy facility may be located up to 75 miles from the county in which a subscriber lives.

SUMMARY OF THE OTHER PARTIES' COMMENTS

NCSEA

In response to Duke's proposal of a cost-premium rather than cost-savings program, NCSEA states that Duke did not explore "whether either shorter (i.e., 10 or 15-year) or longer (i.e., 25-year) subscriptions would be more cost effective, or generate a return on investment, or program participants." Because Commission Rule R8-72(c)(1)(x) requires Duke to provide, in part, the "estimated time period for a subscriber to receive a return on investment," NCSEA contends that "[b]y not presenting an analysis of longer or shorter subscription lengths, it is unclear if Duke fully explored the time period necessary for participants to receive a return on investment." Similarly, NCSEA contends that Duke provided no explanation for its selection of 1-MW facilities and whether or not it explored smaller or larger facilities instead.

While NCSEA supports the Companies' request for an exemption from the same-county/contiguous requirement, it recommends that if the Commission grants such exemption, "the Commission should require Duke to include a summary of how the exemption did or did not minimize costs to program participants" in its annual reports to the Commission.

Although NCSEA supports Duke's proposal to collect subscription fees in two installment payments, it expresses concern that "the lack of clarity about the full subscription fee" in Duke's proposed tariffs "could discourage customer participation due to the uncertainty around how much the full subscription fee will ultimately cost." To alleviate this concern, NCSEA suggests that the Commission require Duke to state a maximum

Sierra Club

The Sierra Club contends that there are a number of deficiencies in Duke's proposed Program Plan. First, the Sierra Club notes that although Duke projects that Tranche 1's community solar energy facilities could achieve commercial operation by 2020-2021, Duke's Program Plan "fails to provide an adequate [Community Solar Program] implementation schedule as required by H.B. 589 and Commission Rule R8-72." The Sierra Club states that its concern regarding "Duke's potential delay of the community solar program is amplified by the delay Sierra Club observed in South Carolina, where Duke has delayed multiple times a community solar program established through state legislation."

Also of particular concern, according to the Sierra Club, are (1) the high upfront subscription fee instead of ongoing monthly payment plans or financing options; (2) the fact that Duke's Program Plan does not forecast any economic benefit to subscribing customers over a 20-year period; (3) Duke's proposed bill credit is on an off-bill, annual basis, which the Sierra Club contends may "inadvertently trigger federal or state securities laws and/or ... create taxable income for participants"; and (4) that Duke "has failed to adequately evaluate opportunities for low-to-moderate income customer participation."

The Sierra Club contends that one way to reduce the upfront subscription fee would be for Duke "to substantially reduce both the PPA price and proposed marketing and administrative costs," which the Sierra Club contends are higher than similar costs for other community solar programs. To illustrate this point, the Sierra Club states that Duke's proposed marketing and administrative cost budgets together amount to over 43% of the total subscription price. In addition, the Sierra Club contends that Duke's marketing analysis "fails to account for customers who may subscribe to multiple community solar blocks, thereby decreasing the customer acquisition cost per block, and it does not consider the present value of marketing efforts that may reach customers who subscribes to the community solar program in future Tranches." Along those lines, the Sierra Club states that it is likely that Tranche 1 customers may ultimately "subsidize future community solar subscribers whose subscription (sic) costs are lower due to decreased marketing needs." The Sierra Club argues that "[a] lower-cost community solar program that minimized costs and maximized benefits would provide a net benefit to subscribers, would be more attractive to customers, and would be easier to market." Finally, the Sierra Club pledges that if Duke's program offering is one that the Sierra Club can support, it "would consider assisting Duke in the promotion of the community solar program in hopes of decreasing program costs for subscribers."

The Sierra Club contends that one way to improve economies of scale, and, thus, improve the program's economics for subscribers, would be to procure energy as a carve- out of a larger project, allocating only a percentage of a larger facility's output to use as a community solar energy facility. In addition, the Sierra Club suggests that Duke should "thoroughly evaluate opportunities to contract with a solar energy facility that is already in the interconnection queue and that will achieve commercial operation earlier than Duke's estimated date of 2020 or 2021."

To address its concerns as enumerated above, the Sierra Club requests that Duke be required to submit a revised Program Plan after obtaining stakeholder input; Duke "be required to demonstrate that it has diligently sought out the lowest feasible PPA price"; (3) Duke "be required to demonstrate to the Commission that its PPA procurement plan will minimize costs and maximize benefits for community solar subscribers, and receive Commission approval, before signing its Tranche 1 PPAs;[1] (4) Duke "be required to establish a marketing plan that will minimize costs and that will more closely align with community solar marketing costs of other community solar offerings;" (5) Duke be required to provide an on-bill credit mechanism for Tranche 1; and (6) initially include a 5% carve-out of the program for LMI customers,[2] "consider ways to coordinate LMI community solar efforts with low-income energy efficiency programs," be required "to further evaluate additional LMI program components" such as solar developer donations, non-LMI subscriber donations, federal funding opportunities, and applying for revenue from voluntary utility bill roundup programs to assist LMI customers who may be otherwise unable to participate in the program.

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[1] To that end, the Sierra Club requests that the Commission provide an expedited review of the proposed PPA in order to ensure that the implementation of Tranche 1 is not delayed.

[2] Any portion of the carve-out not subscribed would be eligible for reallocation into the general community solar program, according to the Sierra Club.

While the Sierra Club does not object to Duke's proposed avoided cost credit, it notes that future circumstances could arise in which reconsideration of Duke's proposed avoided cost methodology may be warranted. In addition, while the Sierra Club does not necessarily disagree with the reasoning underlying Duke's request for an exemption from the location requirements of N.C.G.S. § 62-126.8(c), it contends that such request is "premature" and "recommends that Duke be required to demonstrate that the exemption will result in a net decrease in subscription costs" before the Commission approves such a request. Furthermore, while the Sierra Club generally does not oppose Duke's proposed program provisions regarding portability and transferability, it "recommends that customers moving outside of Duke's service territory also have the option to transfer their subscription to another customer."

NC WARN

NC WARN argues that while some provisions of the Companies' proposal satisfy some of "the most important criteria for successful community solar programs," as published by the Interstate Renewable Energy Council and the Southern Environmental Law Center,[1] many components do not. First, NC WARN contends that Duke's Community Solar Program should ensure through minimization of program costs that customers earn a return on investment by way of savings on future electric bills. To minimize Duke's projected marketing costs, for example, NC WARN recommends that "the Companies should be limited to using existing lines of communication with customers (bill inserts, website, social media) for which the incremental cost of adding community solar promotion would be minimal," and further that "[m]ore expensive marketing such as television, radio, and newspaper advertising should be allowed only if the costs can be absorbed under existing advertising budgets that may be recovered from rates or shareholders." In addition, NC WARN suggests that the Companies partner with clean energy NGOs, local government agencies, and faith organizations to promote the program.

NC WARN further argues that the Companies' proposal should be modified as follows: (1) the first upfront subscription fee installment payment should be lowered from $200 to $75; (2) flexible payment plans should be offered to accommodate participation by low- and moderate-income customers;[2] (3) Duke "should not be permitted to discontinue the community solar program nor recover costs in a rate case;" and, further, if Tranche 1 is not fully subscribed, Duke "should instead seek approval to amend the Program in a way that increases the benefit to participants so that more subscribers are attracted to the Program;" (4) Duke should provide a program implementation schedule beyond that which they have provided from Tranche 1 only; (5) on-bill credits, rather than separate off-bill payments to program participants, should be required; (6) bill credits should be increased, but not decreased, over time as the avoided cost rate changes; and (7) low-cost sites for community energy solar facilities should be selected.

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[1] See "Shared Renewable Energy Scorecard," Interstate Renewable Energy Council, available at https://sharedrenewablesscorecard.org/ (last accessed on January 8, 2019); "Community Solar: Best Practices for Utilities in the South," Southern Environmental Law Center, available at https://www.southernenvironment.org/uploads/publications/CommSolar_Utility_Best_Practices.PDF (last accessed on January 8, 2019).

[2] NC WARN lists Tucson Electric Power's Bright Tucson Community Solar Program and the community solar program offered by South Carolina Gas & Electric as two examples of community solar programs who have successfully implemented this practice.

Finally, NC WARN agrees with the Companies' request for an exemption from the same-county/contiguous requirement.

The Public Staff

By its reply comments, the Public Staff states that it reviewed Duke's petition for approval of the Companies' proposed Community Solar Program, in addition to the requirements of N.C.G.S. § 62-126.8 and Commission Rule R8-72. The Public Staff highlights the following issues for the Commission's attention:

- Upfront subscription fees: The Public Staff states that Duke's proposed Community Solar Program involves an upfront fee of $500 per 220 W subscription block, in exchange for an estimated off-bill credit of $21 annually. The Public Staff states that while it "recognizes that Community Solar programs are generally available at a cost premium to subscribers, this particular model of a high upfront fee coupled with off-bill annual credits seems designed to shift all risk from the Companies to the subscribers, at a cost of potentially depressing the levels of customer interest," which, in turn, could jeopardize the program's success. In support of its position, the Public Staff notes that the upfront subscription fee consists of the present value of both all program administrative and overhead costs and the PPA payments to the facility for the entire 20-year contract term. In short, the Public Staff argues that it would not be fair or in the public interest to require subscribers to prepay the costs of energy from the community solar energy facility for 20 years, when Duke will spread these payments to the community solar energy facility out over the 20 year PPA duration.

- Proposed advertising and administrative costs: The Public Staff states that, based on information exchanged during discovery, Duke estimates that the Community Solar Program's first-year marketing costs will amount to $537,500 for each 1 MW community solar energy facility, a large portion of which Duke proposes to spend on direct mail advertisements. The Public Staff further states that this proposed marketing budget equates to approximately $135 per subscriber and $538 per kW. The Public Staff argues that Duke should prioritize their direct marketing expenditures to emphasize those that may be more effective per dollar spent than direct mail, for example, email blasts or radio adverts. The Public Staff also notes that "multiple intervenors have expressed interest in partnering with the Companies" to market the Community Solar Program, and, therefore, recommends that Duke pursue such partnership opportunities in an effort to reduce advertising and administrative costs, thereby also reducing the individual subscription fee proportionately.

- Off-bill credits and charges; lack of on-bill financing: The Public Staff next takes issue with the off-bill credits and charges proposed by Duke, stating that Duke has not provided a compelling reason for such proposal. Specifically, the Public Staff argues that Duke's "inability ... to manage on-bill financing or on-bill payments and credits" of Community Solar Program fees does not justify the off-bill payments and credits suggested by the Companies. The Public Staff further contends that off-bill credits are inconsistent with statutory intent as expressed in N.C.G.S. 62-126.3(15); namely, that the statutory definition of "subscription," in part, "allows a subscriber to receive a bill credit." In addition, the Public Staff opposes the Companies' plan not to offer on-bill financing of subscription costs, arguing that allowing customers to avoid the high upfront fees through on-bill financing, or eliminating the upfront fee entirely in favor of monthly, on-bill charges and credits reflecting energy produced by the community solar energy facility and overhead fees, is likely to increase subscriber interest in the program. In further support of its position that on-bill financing would increase the likelihood of program success, the Public Staff provides several examples of successful community solar programs that are structured to include on-bill charges and credits,[1] contending that this program characteristic "is more likely to encourage subscriber interest and to keep the subscriber committed for the full contract term."

- Transferability of subscriptions: Although the Public Staff states that it generally agrees with Duke's program design with regard to the proposed transferability and portability of a Community Solar subscription, the Public Staff states that the following additional steps "could be taken to design the program to reduce the risk that the subscriptions will be deemed a security and subject to securities regulation," including "monthly or quarterly payments; making payments due after electricity is generated; and marketing the program in a way that emphasizes that the subscriber's primary interest in the shared community solar project is the energy generated and not in producing a profit by investing in the subscription."

- Portability of subscriptions: In response to the Company's proposal regarding portability of community solar subscriptions, the Public Staff argues that "it is inconsistent with the plain language of the Act to allow community solar subscribers to continue to receive credits if they move outside the State or outside the county or a county contiguous to a community solar energy facility." Instead, the Public Staff "supports a mechanism to allow for a subscriber to cancel the subscription and receive a pro rata share of any fee returned based on the size of the subscription or to transfer the subscription to another eligible subscriber." The Public Staff further recommends that the program be designed such that Duke will take steps to remarket unsubscribed or cancelled subscription shares of each community solar energy facility.

- Treatment of RECs: While the Public Staff acknowledges that the value of RECs associated with a single community solar subscription "is essentially immaterial" and reporting fees that would be owed if a subscriber elected to own the RECs produced likely would be cost-prohibitive as a result, it notes that Commission Rules R8-65(g)(iii)(h) and R8-72(c)(1)(ix) "specifically require that subscribers to the community solar program be allowed the option of owning the RECs produced by the community solar energy facility." The Public Staff, therefore, recommends that "the Commission require that the Companies modify their SSR tariff to indicate that the subscriber may elect to own any RECs produced by their subscription, provided that the subscriber initiate all necessary applications and pay all applicable fees to create a REC tracking account with a system such as NC Renewable Energy Tracking System (NC-RETS)." Under such a scenario, the Public Staff states that a "subscriber should also be responsible to pay any fees required to transfer the RECs from the [community solar energy facility's] NC-RETS account to the subscriber's chosen REC tracking account."

[1] Including Roanoke Electric Cooperative, Cape Hatteras Electric Cooperative, Pee Dee Electric Cooperative, and the following electric membership corporations (EMCs): Blue Ridge EMC, Piedmont EMC, Randolph EMC, Brunswick EMC, Central EMC, and Walton EMC (Georgia).

• Locational exemption: The Public Staff agrees with Duke's request for an exemption from the same/contiguous county requirement of N.C.G.S. § 62-126.8(c). The Public Staff further recommends that this exemption be limited to the initial community solar offering only, with any such future requests to be evaluated by the Commission at that time.

• Program cancellation: The Public Staff disagrees with Duke's plan to discontinue the program "if subscriptions are insufficient to cover the costs of the Program in either or both [of DEC and DEP's respective] service territories," on the grounds that such a provision "may be contrary to G.S. 62-126.8(a), which mandates that each offering utility shall make its [community solar] program available until total nameplate generating capacity equals 20 MW." However, the Public Staff states that it would not oppose a delay in program implementation "if a specific and reasonable target for subscriber interest is not met in tranche 1 and the Companies have attempted to [appropriately] scale the project."

• Project scalability: The Public Staff states that "it may be in the public interest to scale the projects to the appropriate sizes to meet demand, either by increasing or decreasing the capacity, after the initial marketing period," as opposed to the Companies' proposal to offer one facility in each service territory with a pre-determined capacity of 1-MW.

• Recovery of costs: In response to the Companies' plan "to seek recovery of administrative costs incurred in promoting and developing the Program in its next general base rate case," the Public Staff contends that it would be "premature to determine cost recovery for the program in this proceeding."

In conclusion, the Public Staff requests that the Commission consider the issues raised in its comments, and states that it will continue to work with Duke to resolve the concerns that the Public Staff has raised in its comments.

DUKE'S REPLY COMMENTS AND MODIFIED
COMMUNITY SOLAR PROGRAM PLAN

Along with its reply comments, Duke filed an amended program plan that Duke contends addresses many of the intervenors' concerns. In addition to the program changes summarized below, Duke restated and reiterated many of the positions taken in its petition for approval of the Community Solar Program, including, its request that the Commission grant an exemption from the facility location requirement of N.C.G.S. § 62-126.8(c).

First, Duke states that the revised plan now would align the launch of the Community Solar Program with Duke's new billing system, Customer Connect, which currently is scheduled for implementation in DEP's service territory in 2021 and in DEC's service territory in early 2022. In addition, Duke argues that aligning the launch dates of both Customer Connect and the Community Solar Program will make feasible billing features that otherwise would have been cost-prohibitive. For example, Duke states that it would have the functionality to implement on-bill charges and credits (on a monthly rather than annual basis, as was initially proposed by Duke), thus reducing the upfront subscription fee. Duke states that during the lead-up to the availability of Customer Connect, the Companies plan to continue working on Program implementation, including running the RFP, and potentially entering into PPAs and marketing the Program. In addition, Duke states that the Public Staff supports its proposal to launch the Community Solar Program in alignment with the implementation of Customer Connect.

Second, Duke states it will allow projects sized up to 5 MW (rather than 1 MW as Duke initially proposed) to bid into the Community Solar Program RFP process. Duke also proposes an increase in the subscription block size, from 200 watts as initially proposed, to 1 kilowatt (kW). In addition, Duke's amended program plan would permit subscribers to own the renewable energy certificates (RECs) generated from each subscription block.

Third, Duke states that it intends to contract with the Clean Energy Collective "to deploy a real time application, a customer portal and program administration software," which Duke also uses for its South Carolina Shared Solar Program. The Companies contend that the use of the Clean Energy Collective will "help ensure full subscription through real time reporting of subscription levels and wait list functionality," which will "facilitate enrollment and avoid administrative costs of using a call center for those purposes."

Fourth, as it pertains to transferability and portability, the Companies' revised proposal provides that "portability within each utility service area will remain permissible," regardless of "whether or not a customer in that location would otherwise be eligible to subscribe." The Companies, on the other hand, provide that "customers will not be able to carry a subscription with them if they move between or outside of the DEC and DEP service areas, and no transfers of subscriptions will be permitted." While silent as to the issue of whether a customer would receive a full or partial refund, the Companies do provide that a cancelled subscription will be offered "to the next customer on the Program wait list in order to keep each community solar energy facility fully subscribed."

SUMMARY OF THE PARTIES' ADDITIONAL REPLY COMMENTS

NCSEA

By its sur-reply comments, NCSEA takes issue with Duke's proposed implementation schedule whereby the launch of the Community Solar Program would be aligned with the roll out of the Customer Connect Program. NCSEA argues that this proposed implementation program is unacceptable, lacks statutory support, and fails to substantiate a reduction in costs as compared to the costs as originally proposed by Duke. Further, NCSEA argues that Duke fails to provide a model for comparison where on-bill credits and monthly payments are implemented immediately, such as a third-party solution offering service of on-bill credits and monthly payment repository or some other cost-neutral or cost-beneficial method to implement the new program immediately. NCSEA, therefore, recommends that the Commission reject any such delay in the program implementation schedule.

NCSEA next takes issue with the overall program costs. NCSEA contends that gross subscription costs under Duke's revised program represent an increase of $3,440.80 from the initial $500.00 proposed fee over the life of the subscription. Based on what NCSEA estimates to be "a more than twenty-five-fold increase in costs for the program," combined with the delayed implementation schedule, NCSEA contends that Duke's revised program plan is a significantly worse program than the initial program despite the additions Duke has made to acquiesce the intervenors' initial comments.

NCSEA specifically objects to Duke's proposed 20-year PPA cost rate, which significantly exceeds the proposed bill credit at the avoided cost rate and which NCSEA contends "is not supported by evidence or statute." NCSEA recommends, therefore, that "Duke analyze its potential costs and then submit to the Commission a revised proposed PPA contract with more specific prices and fees and only upon review of more concrete evidence of the costs and fees should the Commission approve Duke's proposed PPA, likely at a price point much closer to the avoided cost rate." To that end, NCSEA states that it "is amenable to a recurring Commission approval process wherein Duke's proposed PPAs can be resubmitted on a yearly basis." In addition, NCSEA expresses concerns "that under the proposed tranche-based program, Tranche 1 customers may be unfairly burdened with additional costs that later tranches may not have to incur," and, as a result, "will render the program difficult to get off the ground."

Finally, NCSEA contends that Duke's revised program plan contains insufficient incentives to stimulate LMI customer participation. While NCSEA "is generally supportive of Duke continuing to consider potential alterations to the program to make it more cost-effective and financially reasonable for more customer classes, including" LMI customers, it has several recommendations for how Duke can achieve a more LMI-friendly program. First, NCSEA states that it supports the "Sierra Club's proposed modification to allow for third parties to provide independent funding assistance to low income subscribers who wish to subscribe to the program." Second, NCSEA "requests that Duke provide its customers with an ability to make donations to support LMI customer access to" the Community Solar Program "via an online portal for donations or, alternatively, a request to customers to be a recurring monthly donor to low-income solar projects, including projects that would fall under the Community Solar Program."

<u>Sierra Club</u>

By its sur-reply comments, the Sierra Club acknowledges that Duke made some improvements to the program through its revised plan, but expresses lingering concerns regarding program costs, the timeline of Tranche 1 implementation, LMI customer participation incentives, and certain transferability and portability provisions. Despite these remaining concerns, the Sierra Club notes that it agrees with Duke's proposal on a number of issues, including monthly on-bill credits, increased project scalability from 1 MW to 5 MW, permitting subscribers to own the RECs associated with their subscription block, and Duke's request for an exemption from the locational requirement outlined in N.C.G.S. § 62-126.8(c).

As it pertains to program costs, the Sierra Club contends that "overall program costs are too high and fail to minimize costs and maximize benefits to subscribers, and a number of the administrative costs in the revised program appear to be duplicative of services provided by Customer Connect or the Clean Energy Collective's community solar services." The Sierra Club recommends that Duke be proscribed from accepting bids above the then-projected 20-year avoided cost rate. The Sierra Club further recommends that, after the conclusion of Duke's RFP to solicit bids for community solar projects, the Commission require Duke "to finalize administrative costs, including coordinating with the Sierra Club and other interested stakeholders regarding potential marketing partnership commitments or other assistance to reduce program costs, and . . . file final numbers with the Commission for comment and Commission approval." The Sierra Club states that "it cannot support the program unless the overall program costs are substantially reduced." In order to reduce projected IT costs, the Sierra Club requests that only those costs which are essential for program implementation be allowed, and that to the extent allowed, such costs be divided and allocated evenly between Tranche 1 and future tranches. In order to reduce projected marketing costs, the Sierra Club requests that Duke collaborate with it "and other interested intervenors on a potential marketing partnership after Duke completes the RFP and sets the PPA price." As for the projected costs related to labor, the call center and customer engagement, the Sierra Club contends that additional justification is needed and that Duke should be required to provide a more detailed accounting of the cost projections, with the possibility of certain budget caps and true-up mechanisms to ensure actual spending is properly managed. In addition, the Sierra Club recommends that Duke's annual reporting requirement should include information regarding "actual administrative costs, actual marketing costs, a calculation of any excess revenue and supporting evidence for the calculation. In addition, annual reporting should include the number of customers participating, enrollments and de-enrollments (attrition), the average length of customer participation term (to-date), levels of participation (percentage of average annual usage), and other pertinent facts."

The Sierra Club opposes Duke's proposed timeline for Tranche 1, specifically its proposal to align the implementation of Tranche 1 with Customer Connect, on the grounds that this proposal "creates a substantial—and ultimately unknown—delay." The Sierra Club proposes as a possible solution that "Duke evaluate whether the third-party community solar company Clean Energy Collective could feasibly provide billing services for Tranche 1 without waiting for Customer Connect implementation." In support of this position, the Sierra Club argues that the "implementation of a large program like Customer Connect, estimated to cost up to $295 million in DEC territory, could foreseeably expect delays in one or both of Duke's service territories." Further, the Sierra Club points out that "[i]f the Companies operate under the Customer Connect timeline and wait to enter into a PPA until after the end of 2019, customers will lose the benefit of the federal Investment Tax Credit ('ITC') which will decline after 2019 from 30% to 26% and again after 2020 from 26% to 22%. In 2023 the ITC will be reduced permanently to 10%." The Sierra Club argues that "[b]ecause these tax credit reductions may increase PPA costs, and therefore increase costs for subscribers, Duke should plan to enter into Tranche 1 PPAs before the respective ITC step-downs."

While the "Sierra Club does not object to monthly subscription credits that are based on the actual production of the community solar project," it argues that "if customer credits are based on the actual production, monthly PPA payments – capped at avoided cost – should also be linked to the project's actual production," rather than the fixed monthly payments (PPA price + monthly administrative costs) as presently proposed.

As it pertains to LMI participation, the Sierra Club "requests that Duke make a firm commitment to evaluate opportunities to leverage any available third-party funding for an LMI program during a post-PPA review and determination of final program costs and, depending on final program costs, evaluate the feasibility of the donation-based model Sierra Club proposed in its initial comments. The Companies also should include LMI program updates in their annual reports that provide an analysis of progress towards an LMI program, including potential program designs that could more readily incorporate an LMI component."

As it pertains to transferability and portability, the Sierra Club "recommends that subscribers maintain the ability to designate a beneficiary under [certain] limited circumstances, which would include acknowledgement by the beneficiary of the monthly payment obligation associated with the subscription." On a related note, the Sierra Club notes that "the revised plan does not describe when a customer may cancel a subscription for reasons other than discontinuing electric service. The Sierra Club recommends that subscribers also be permitted to cancel a Shared Solar subscription if the program waitlist has customers that are willing to purchase the current subscriptions at that time." While the Sierra Club "agrees that customers who cancel a subscription should receive a pro rata share of their one-time fee based on the number of months they were enrolled in the program, and the waitlisted customer should pay the same pro rata one-time fee to subscribe to the program," such language "could be included on page 2 of Riders SSR and SSR-3, 'General Provisions.'"

NC WARN

By its sur-reply comments, NC WARN argues that the Commission should reject Duke's revised proposal and report to the Legislature "on the Companies' noncompliance." In addition, NC WARN argues that the Commission "must require the Companies to submit a third proposal that actually has a chance to succeed by meeting the requirements of G.S. 62-126.8 and Commission Rule R8-72, correcting the problems outlined [below], and containing the basic qualities of a reasonable community solar program: portability and transferability, provision for low-to-moderate income ('LMI') customer participation, on-bill payments and credits, the option to make payments over time, and creation of value for the subscriber."

In support of its position, NC WARN contends that (1) Duke's proposal fails to comply with the requirements of Commission Rule R8-72; (2) Duke's proposal "is unacceptable because customers would lose half their investment, [and] thus be unwilling to participate;" (3) Duke's proposal "imposes an unreasonable 5-year delay" through its intended implementation alignment with Customer Connect; (4) Duke's proposal "falls short because the Companies do not plan to increase the avoided cost rate over the 20-year contract period;" (5) Duke's proposal to increase the subscription block size from 200 watts to 1 kilowatt "puts participation out of reach for most customers;" (6) "a reasonable community solar program would not introduce the delay, complication and inequity of multiple tranches, but would instead offer all 40 MW simultaneously from the outset;" and (7) Duke's proposal "leaves subscribers responsible for excessive marketing expenses."

Additionally, NC WARN argues that the Commission "should not allow the Companies to recover expenditures in a future rate case" due to the prohibition against cross-subsidization of program costs as outlined in N.C.G.S. § 62-126.8.

Duke

By its sur-reply comments, Duke argues in response to multiple intervenors' concerns regarding the proposed timeframe for Program implementation that the "technological and administrative benefits...outweigh extending the implementation timeframe" by aligning the Program with Customer Connect. The Companies further note that the Public Staff supports this modification, and reiterate that "there is no required statutory timeline to implement the Program, unlike other new programs being implemented under House Bill 589." In addition, Duke points out that the revised proposal to implement the Program in alignment with Customer Connect only results in a one-year delay beyond when the Companies projected to launch the Program without Customer Connect. In response to the intervenors' recommendation that Duke consider using a third party to do what Customer Connect will accomplish, thus potentially allowing for program implementation to occur sooner, Duke argues that its proposal "avoids additional costs that would be incurred by using a third party" to do what Customer Connect will be able to do. In an attempt to address some of these concerns, Duke agrees that "[t]o the extent developments in the Customer Connect program are relevant to the development of the Community Solar program and are not already covered by the comprehensive annual reports filed for Customer Connect, the Companies will include that information in their annual Community Solar reports." In response to the Public Staff's suggestion that Duke evaluate whether Customer Connect software could be used to implement the Program before full deployment of the billing system, the Companies note that they remain dedicated to launching the monthly subscription process for customers as soon as is feasible with Customer Connect. The Community Solar Program as proposed, however, requires the complete functions of a customer servicing system: customer set-up, move in/move out, billing, payment processing, collections, etc. As it pertains to some of the Program administration services to be provided by a third party, Duke confirms that the "Companies' work will not overlap with" work provided or costs incurred by the third party.

In response to multiple intervenors' concerns regarding its projected cost estimates, Duke reiterates "that precise cost estimates cannot be determined until the RFP is run." In addition, Duke states that "the Companies are not requesting approval of any estimates of Program costs or any estimated upfront or monthly charges or credits." Rather, "[s]ubsequent to the conclusion of the RFP, consistent with the recommendations of the Public Staff and Sierra Club, and in recognition of the lingering cost concerns, the Companies commit to share and discuss the RFP results and status with current intervenors, seek feedback on those results, and seek other opportunities to reduce Program costs through partnerships with intervenors or other interested parties." Furthermore, Duke offers that "[a]fter this period of stakeholder engagement, the Companies will make a filing with the Commission in these dockets reporting on the outcome of the RFP and those discussions and requesting Commission approval of the final cost and charge/credit amounts resulting from the RFP as well as any relevant schedule or process information."

If allowed to proceed with the program structure as revised, the Companies assert that they then will be in a position to move forward with the RFP solicitation process and determine more precise program costs and a timeframe for implementation based on the RFP results. To that end, the Companies "agree with the Public Staff's suggestion to include more precise cost information in their annual reports on the Program," and further that "this post-RFP request for approval may be filed independent of the annual reporting schedule in order to provide transparency as to costs and charges as soon as those are determined." On a related note, "in addition to committing to stakeholder discussions on and filing for Commission approval of Program charges and credits following the RFP, the Companies propose to use those post-RFP discussions to address any lingering questions about timing and procedure that can be addressed at that point in time, and to request Commission approval of a further developed Program implementation schedule consistent with R7-72(c)(1)(xiv) together with the request for approval of charges and credits."

In response to the Intervenors' view that Duke should spread program costs across multiple tranches, Duke disagrees and contends that it would be premature to require such because the scope of future Program tranches is not yet known or approved. At the least, as the Public Staff has supported, a delay in Program implementation may be necessary if there is not sufficient interest to support Tranche 1. It would therefore be inappropriate and present unnecessary risk to the Companies to require at this time that the costs to implement Tranche 1 be spread over future tranches. In the alternative, the Companies propose that "[o]nce the Tranche 1 RFP bids have been received and analyzed, if the Companies determine that based on projected costs they can fully subscribe more than one project in both service areas, the Companies will consider how the Tranche 1 costs might be spread across future tranches."

In response to certain of the Intervenors' suggestion that the Companies should specify in the RFP that they will not accept bids greater than the avoided cost, the Companies point out that while a bid by itself may be less than the avoided cost, the total price could exceed avoided costs when "costs relating to marketing and project management for a particular project" are included in the project's final cost. However, in order to address the Intervenors' concerns as they relate to this issue, the Companies state that they are "willing to specify in the RFP that they will not accept projects for which the total costs are greater than avoided cost."

In response to several of the Intervenors' suggestion that the Companies have not included a sufficient LMI component in the Program, Duke contends that these Intervenors have not offered a feasible way to incorporate such a component without also increasing Program costs or violating the statutory prohibition against cross-subsidization of Program costs. The Companies reiterate, however, their position that they "do not object to third parties donating funds to assist in subscription."

Finally, Duke highlights the areas of agreement among the Companies and at least several of the intervenors, including (1) project size and selection; (2) increased size of subscription block; (3) subscribers having the option to own RECs associated with their subscriptions; and (4) the Companies' request for exemption from the facility location requirement of N.C.G.S. § 62-126.8(c).

<u>The Public Staff</u>

By its additional reply comments, the Public Staff explains that it supports the launching of the Community Solar Program with Customer Connect, in part, because "Duke has indicated that until Customer Connect is deployed in each service territory, on-bill credits would have to be added to each customer bill manually, which would add significant cost to the Program." Further, the Public Staff states that it believes that the benefits of launching the Program with Customer

Connect, which may make the Program more attractive to potential subscribers are, on balance, worth a one to two year delay in Program implementation. Notwithstanding this support, however, the Public Staff "recommends that the Commission encourage Duke to look for potential avenues to accelerate implementation of the Program where possible." Further, the Public Staff "recommends that the Commission require Duke to include in its annual filing, as required by Rule R8-72(c)(2), an update on the deployment of Customer Connect and any progress in the Companies' ability to use the software to issue monthly on-bill credits and charges for the Program."

In addition, the Public Staff states that it also supports Duke's proposed increased subscription block size and project size, both of which consequently should reduce the initial upfront subscription fee to subscribers. As it pertains to project scalability, however, the Public Staff "recommends that the Commission require the Companies provide a summary in its annual reports of the subscription thresholds reached in the South Carolina community solar program and a description of the project sizes and PPA prices achieved in that program and whether North Carolina can expect to achieve similar prices and interest in participation."

The Public Staff further supports Duke's efforts "to find a lower PPA price through competitive solicitation methods, including the consideration of bids submitted to the CPRE Tranche 1 that are not selected." To this end, however, the Public Staff opines "that Duke will most likely be able to obtain a PPA price much closer, or perhaps even below, the avoided cost," and recommends that the Commission require the Companies to provide more information than is required by Commission Rule R8-72(c)(1)(xiii); specifically, information "regarding any alternative methods of procurement to a community solar RFP in order to provide transparency and assurance that the Companies are making reasonable efforts to achieve cost-effective PPA prices for all community solar energy facilities."

As it pertains to Duke's revisions to its proposed portability and transferability provisions, the Public Staff states that it also is supportive of these revisions, specifically as it pertains to Duke's elimination of the customer's option to transfer subscriptions to a beneficiary. In addition, the Public Staff supports the customer's "ability to cancel [his or her subscription] and Duke's proposal to provide for a waitlist for the next customer to subscribe." However, the Public Staff "recommends that the Commission require the Companies either (i) refund a pro rata share of the upfront fee to the departing customer as originally suggested, or (ii) similarly discount a replacement subscriber's upfront fee."

The Public Staff states that it supports Duke's revised approach to allow subscribers "a path to own the RECs associated with its subscription block if the subscriber pays all fees and applies with NC-RETS to create a REC tracking account." The Public Staff also continues to support Duke's request for a locational exemption to the same/contiguous county requirement set forth in N.C.G.S. § 62-126.8(c), subject to the Public Staff's continued recommendation "that the exemption request be granted for Tranche 1 and that future exemption requests be evaluated on an individual basis."

As it pertains to program costs, the Public Staff states that Duke's revised program remains a cost premium program and has "significantly increased administrative costs instead of reducing them," contrary to the Companies' claim that aligning the launch of the Community Solar Program with Customer Connect will reduce overall costs. In addition, the Public Staff takes issue with the fact that Duke's cost estimates "do not appear to spread fixed costs for the Program, such as program management and IT, over the entire 40 MW of community solar that is statutorily authorized." Accordingly, the Public Staff contends that the "Tranche 1 offering should reflect only a fraction of the total costs of setting up and managing the Program." In an effort "to make the Programs more economically attractive to potential subscribers, the Public Staff recommends that the Commission encourage the Companies to pursue the larger 3 or 5 MW programs and allocate fixed costs beyond Tranche 1 of the Program." In addition, the Public Staff recommends that the Commission require Duke "to incorporate revised overhead costs in future Program annual reports as those cost estimates become more accurate" and "to provide further details on the implementation schedule for the full 20 MW in each service territory and how costs will be allocated among tranches of the Program." Finally, as it pertains to cost recovery, the Public Staff states that it "continues to believe that it is premature to consider cost recovery for the Program in this proceeding."

While the Public Staff acknowledges that an LMI option "may result in cost shifting," which is prohibited by statute, it nonetheless "recommends that the Commission require Duke to provide in its annual reports a description of any LMI options it has considered and the feasibility of those options in the structure of the Program and in compliance with the requirements to hold non-participating customers harmless."

While the Public Staff states that it continues to believe that Program cancellation for lack of prospective subscriber interest may be contrary to the statutory mandate to offer the Program until both DEC and DEP's respective nameplate generating capacity equals 20 MW, the Public Staff opines "that the statute does not prohibit its cancellation or at least delay" and that the Public Staff "continues to support Duke's option to seek a delay in the implementation of the Program if a specific and reasonable target for subscriber interest is not met in Tranche 1."

DISCUSSION AND CONCLUSIONS

The Commission carefully reviewed Duke's petition, proposed Community Solar Program Plan, the accompanying rider leaflets and related documents, all of the other parties' comments, the consumer statements of position, and the entire record in these proceedings. Based upon this review, the Commission determines that Duke's revised Community Solar Program Plan and accompanying rider tariffs comply with the requirements of N.C.G.S. § 62-126.8 and Commission Rule R8-72. Therefore, the Commission concludes that Duke's revised Community Solar Program Plan and accompanying rider tariffs should be approved. In addition, for the reasons stated by Duke and the other parties to these proceedings, the Commission determines that allowing Duke's requested exemption from the facility location requirement of N.C.G.S. § 62-126.8(c) is in the public interest, and, therefore, concludes that this request should be granted.

In approving the revised Community Solar Program Plan and accompanying riders, the Commission acknowledges that it is deferring to Duke's business judgment and the Public Staff's expertise and recommendations to a greater extent than the Commission has in other proceedings established to review programs established under House Bill 589. The Commission finds this approach to be appropriate for the following reasons.

First, the structure of the Community Solar Program, as established pursuant to N.C.G.S. § 62-126.8, is materially different than those other programs in at least one key aspect: the Community Solar Program is not limited in time, but exists into perpetuity, subject to the Commission's oversight. Thus, the Commission will have the opportunity to monitor and adjust the terms of participation in the Community Solar Program based upon the results of offering of subscriptions in Tranche 1 of the program. For that reason, the Commission would look with disfavor upon Duke's request to cancel the program before improvements have been implemented.

Second, the comments filed by Duke and the Public Staff demonstrate that the Public Staff has diligently and effectively performed its role as the consumer advocate in these proceedings. The Public Staff resolved many of its differences with Duke over the structure of the Community Solar Program and Duke incorporated many of the Public Staff's recommendations into its revised program. The Public Staff also recommended that the Commission require Duke to consider or implement certain refinements to the Community Solar Program. The Commission agrees with the Public Staff. The Commission will, therefore, require Duke to consider those issues raised by the Public Staff in its implementation of the program, and to address each of the issues raised by the Public Staff in the first annual report on the implementation of the Community Solar Program, in addition to those matters required to be addressed in the annual report pursuant to Commission Rule R8-72(c)(2).

More specifically, the Commission is concerned that Duke has placed too little emphasis on implementing aspects of the program prior to the "full deployment" of Customer Connect.[1] Therefore, consistent with the recommendation of the Public Staff, the Commission will direct Duke to undertake efforts to implement the Community Solar Program, where possible, prior to Customer Connect being deployed across the Duke electric systems. In doing so, the Commission will also require Duke to file an interim report on this specific aspect of the implementation of the Community Solar Program and addressing the concerns raised by the Public Staff, including whether and how Duke decided to address those issues in implementing the program. In addition, the Commission determines that the Public Staff should continue to monitor the program implementation so that the Public Staff will be prepared to respond to Duke's interim and annual reports with recommendations for speedier implementation of, or improvements to, the Community Solar Program. Any adjustments in the Community Solar Program that the Commission undertakes will be considered and decided in the context of the review of these reports, with appropriate opportunity for all parties to provide comments.

Third, while the Commission notes many parties' ongoing objections to the revised program, the Commission finds that many of these arguments lack support in the provisions of N.C.G.S. § 62-126.8. Instead, the Commission concludes that N.C.G.S. § 62-126.8 delegates to

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[1] On April 1, 2019, in Docket No. E-7, Sub 1146, DEC filed a revised AMI rate design work plan and proposed dynamic pricing pilots. In that filing, DEC states that it has revised the timeline for this work to reflect accelerated implementation of the Customer Connect billing system in spring of 2021. The Commission understands and expects that certain functions of the Customer Connect billing system may be available to facilitate the implementation of the Community Solar Program.

the Commission discretion to implement the Community Solar Program consistent with the public interest and subject to the express provisions of that statute. After careful review, the Commission finds nothing in the revised Community Solar Program Plan and accompanying rider tariffs that is inconsistent with the provisions of N.C.G.S. § 62-126.8.

Finally, the Commission agrees with the Public Staff that it is premature to address issues related to recovery of costs incurred to implement the Community Solar Program. The Commission will reserve consideration of those issues until the question is squarely before the Commission in an appropriate proceeding.

IT IS, THEREFORE, ORDERED as follows:

1. That the Community Solar Program filed by Duke Energy Carolinas, LLC and Duke Energy Progress, LLC, as revised consistent with the conclusions reached in this Order, including the revised Schedule SSR and SSR-3, shall be, and is hereby, approved;

2. That the requested exemption from the location requirements of N.C.G.S. § 62-126.8(c) made by Duke Energy Carolinas, LLC and Duke Energy Progress, LLC shall be, and is hereby, granted;

3. That Duke Energy Carolinas, LLC and Duke Energy Progress, LLC shall implement the Community Solar Program in the manner and on the timeline described in their reply comments filed in these proceedings, taking into account the conclusions reached herein and the comments of the Public Staff, and shall continue to cooperate with the Public Staff in the implementation of the Community Solar Program, including, considering the issues raised by the Public Staff in these proceedings and addressing those issues in its first annual report required by Commission Rule R8-72;

4. That, within 180 days of the date of this Order, Duke Energy Carolinas, LLC and Duke Energy Progress, LLC shall file an interim report addressing the following issues:

a. What avenues to accelerate the implementation of the Community Solar Program did Duke consider and what conclusions were reached as a result of this consideration;

b. Provide an update on Customer Connect and the progress made to use the software to issue monthly on-bill credits and charges within the Community Solar Program;

c. A summary of subscription thresholds reached in the South Carolina community solar program, the project sizes and PPA prices, and whether the experience in implementing the Community Solar Program will be similar

d. What alternative methods of procurement, other than a community solar RFP, is Duke considering and what is Duke's view on whether any of those alternative methods might result in lower costs of implementing the Community Solar Program;

e. Whether Duke has considered alternative arrangements for the refunding of a pro rata portion of the upfront fee, or a discount on a replacement subscriber's fee, and what conclusions were reached as a result of this consideration;

f. Whether Duke has changed its views on the size of facilities or the allocation of fixed costs across the Program;

g. Whether revisions to the estimated overhead costs of the Community Solar Program are available;

h. Whether Duke considered LMI options and, if so, what conclusions were reached as a result of this consideration; and

i. The results of the RFP, if available, and the result of the post-RFP discussions that Duke committed to undertake at an appropriate time.

5. That the Public Staff shall maintain an appropriate level of involvement in the implementation of the Community Solar Program so that it can provide the Commission with an informed response to the filing of the interim report required by this Order and the first annual report required by Commission Rule R8-72(c)(2); and

6. That in addition to those matters required to be addressed in the annual report required pursuant to Commission Rule R8-72(c)(2), Duke Energy Carolinas, LLC and Duke Energy Progress, LLC shall update the Commission on the issues enumerated in Ordering Paragraph No. 4 of this Order.

ISSUED BY ORDER OF THE COMMISSION.
This the 4th day of April, 2019.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

DOCKET NO. E-7, SUB 1146

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Duke Energy Carolinas,	)	ORDER DECLINING TO
LLC for Adjustment of Rates and Charges	)	ACCEPT RATE DESIGN PLAN,
Applicable to Electric Utility Service in	)	REQUIRING COMPLIANCE
North Carolina	)	FILING, SCHEDULING HEARING,
	)	AND REQUIRING COORDINATION
	)	WITH PUBLIC STAFF

BY THE COMMISSION: On June 22, 2018, the Commission issued an Order Accepting Stipulation, Deciding Contested Issues and Requiring Revenue Reduction (Rate Order) in the above-captioned docket. In Finding of Fact No. 39 of the Rate Order, the Commission found:

> DEC should be required to design and propose new rate structures to capture the full benefits of AMI [advanced metering infrastructure].

Rate Order, at 19.

In the Evidence and Conclusions section for Finding of Fact No. 39, the Commission discussed, among other things, the testimony of Public Staff witness Floyd that DEC's customers will not be able to use AMI data to save energy and money unless DEC provides new rate designs, such as time-of-use (TOU) rates, and new payment options, including prepay. Id. at 89-90. In addition, the Commission noted that the North Carolina League of Municipalities (NCLM), in its post-hearing brief, stated that full deployment of AMI is not necessary prior to DEC's initiation of customer discussions on new rate designs, and that DEC should be required to develop proposals for TOU and critical peak pricing rate designs and prepayment options before its next rate case. Id. at 121.

The Commission made the following statement in the Rate Order section on AMI entitled Discussions and Conclusions.

> The Commission gives substantial weight to the above evidence. The AMI benefits, current and future, identified by DEC are substantial. It was reasonable and prudent for DEC to rely on these AMI benefits in deciding to deploy AMI on a full scale.
>
> However, the Commission also agrees with NCLM, EDF and others that DEC should be required to follow through on designing and proposing new rate structures that will capture the full benefits of AMI. Therefore, the Commission finds and concludes that DEC should within six months of the date of this Order file in this docket the details of proposed new time-of-use, peak pricing, and other dynamic rate structures that will, among other things, allow ratepayers in all customer classes to use the information provided by AMI to reduce their peak time usage and to save energy. The Commission's goal is to require DEC to develop rate

> structures now that will enable DEC to deliver on its promise that there are "additional customer products and services that this solution [AMI] can enable" no later than DEC's next general rate case. Further, the Commission hereby gives DEC notice that DEC's success, or lack thereof, in developing new rate structures that enable AMI energy usage benefits will be one of the factors used by the Commission in determining the prudence and reasonableness of DEC's costs incurred in deploying AMI following the present rate case.

Id. at 124.

In Ordering Paragraph No. 29, the Commission directed:

> That within six months of the date of this Order, DEC shall file in this docket the details of proposed new time-of-use, peak pricing, and other dynamic rate structures that will, among other things, allow ratepayers in all customer classes to use the information provided by AMI to reduce their peak-time usage and to save energy.

Id. at 331.

On Dec. 21, 2018, DEC filed its Report on Plans for AMI and Customer Connect Enabled Rate Design. The report includes a background section that cites testimony of DEC's witnesses about AMI and Customer Connect. For example:

> Company witness Pirro responded that the Company will consider new rate designs after full AMI deployment, which is expected by mid-2019. Tr. Vol. 19, p. 87. As the Company continues deployment of AMI and begins implementation of new billing infrastructures, the Company will evaluate all potential future rate designs, including dynamic rate designs, and will assess the approach or combination of approaches that cost-effectively meets customer interests and demand response objectives.

Rate Order, at 88.

DEC further stated in its report that it anticipates full deployment of Customer Connect by September 2022, and that Customer Connect is more than a billing system. DEC stated that Customer Connect will provide a website that allows customers to access their meter data, make bill comparisons, and select a rate schedule most suited to their needs. DEC also cited the following segment of the Commission's Rate Order discussion on rate design:

> The Commission agrees that it is premature to offer specific AMI-enabled rate designs in this proceeding since the infrastructure underlying such rate design is not yet available. The Commission concludes, however, that it is appropriate for DEC to evaluate new rate designs that will, among other things, allow ratepayers in all customer classes to use the information provided by AMI to reduce their peak time usage and to save energy.

Id. at 90.

Moreover, DEC stated that load research data is available for all customer classes. DEC noted that this data has been used for developing cost allocations among customer classes, and it could be used to create new rate designs, but that it is preferable to also have two years of AMI data.

DEC provided a summary of its existing TOU and demand response offerings, including:

- Residential Rate RT – On and off-peak rates for distinct summer and winter periods.
- Residential Power Manager - Bill credits in return for allowing DEC to manage the customer's air conditioning load.
- Industrial OPT Rates - On and off-peak rates for distinct summer and winter periods.
- Industrial Power Share - Demand response option that allows DEC to reduce the customer's usage during peak periods.
- Schedule HP – Offers larger customers variable hourly rates that reflect DEC's cost based on a day-ahead forecast. DEC noted that this program "is complex and difficult to administer with less sophisticated small load customers."

In addition, DEC stated that it will focus on several factors in developing new rate designs, including customer choices, appropriate pricing signals, support of customer technology options, and preparation for the future. In addition, DEC noted that it is working with EPRI to study rate design features through a multi-utility research project. DEC stated that in nine months, or in its next general rate case, whichever comes first, DEC will propose "at least two new pilot rate designs – one applicable to residential service and the other to small general service." In addition, DEC provided a time line for its rate design work plan. The time line shows the following components of DEC's rate design work and the date that each step will be finalized.

Installation of meters	-	July 2, 2019
Review and update of TOU	-	July 2, 2019
Preparation of analytical tools	-	Dec. 29, 2019
Data collection and analysis	-	June 21, 2021
Initial rate designs	-	Sept. 19, 2021
Collaborative discussions	-	Dec. 18, 2021
Final designs for deployment	-	Mar. 18, 2022
Approval by NCUC	-	July 16, 2022

Discussion and Conclusions

In the Rate Order, the Commission ordered DEC to file "the details of proposed new time-of-use, peak pricing, and other dynamic rate structures" within six months. Instead of complying with the Commission's Rate Order, DEC filed a report outlining its proposed plan for compliance with the Rate Order. In essence, DEC attempted in its report to persuade the Commission that the Rate Order's directive to file new rate designs in six months was premature, and that DEC needs more time to accomplish that task. The Commission is not persuaded. In addition, if that was the situation, DEC should not have waited six months to inform the Commission that it needed an additional nine months to comply with the Commission's Rate Order.

DEC's report and plan do not comply with the Commission's Rate Order and, therefore, are not accepted by the Commission. Rather, the Commission finds and concludes that DEC should be required to comply with the Commission's Rate Order within sixty days of the date of this Order. On a preliminary basis, subject to the Commission's review of DEC's proposed pilot programs, the Commission will accept as compliance with the present order a filing by DEC containing its proposed two new AMI pilot rate designs – one applicable to residential service and the other to small general service.

Further, the Commission is not persuaded that it is reasonable for DEC to take until March 2022 to propose final AMI rate designs. That would be almost three years after DEC completes its deployment of AMI. As the Commission detailed in the Rate Order:

> [D]EC has followed a studied and deliberate plan for installing AMI, including the AMI Phase 1 and Phase 2 projects, and the AMI Expansion 2015 project...As of September 2016 DEC had cumulatively installed about 527,391 AMI meters. After gaining substantial knowledge about AMI provided by the installation of more than 500,000 AMI meters, DEC made a decision in late 2016 to begin full scale deployment of AMI in North Carolina, and began implementing that decision in early 2017.
>
> The Commission gives substantial weight to the above evidence. AMI is a new technology. Maintaining adequate and reliable electric service includes staying abreast of the latest developments in equipment and technology. Indeed, advances in technology can provide efficiencies and other benefits that justify retiring present equipment. After having deployed AMI on a project-by-project basis for several years, it was reasonable and prudent for DEC to use that experience to decide to deploy AMI on a full scale.

Rate Order, at 123.

DEC having deployed AMI for several years, it should currently possess a large amount of information about AMI's capabilities and its customers' usage profiles. As a result, it is reasonable for the Commission to require DEC to use that information now to design new AMI rate structures on a faster schedule than the time line proposed by DEC in its report.

In particular, the Commission does not accept DEC's proposal to take until June 2021 to complete its data collection and analysis, until December 2021 to complete its collaborative discussions, and until March 2022 to complete its final rate designs. Rather, the Commission concludes that DEC should be required to significantly accelerate its rate design plan. To assist DEC in doing so, the Commission concludes that DEC should be required to work with the Public

Staff to develop a revised work plan that accelerates the deployment of new rate structures, and to file its revised work plan within 60 days of the date of this order. The plan shall include a proposal for informing customers about the potential energy and cost savings that can be achieved by making changes in their energy usage.

In addition, the Commission finds good cause to schedule a hearing in this docket to review DEC's progress in complying with the present order. At that hearing, DEC shall have available a witness or witnesses who can provide information and answer in detail the Commission's questions about innovative AMI rate structures, including questions on the following subjects.

1. DEC's present TOU, peak and non-peak, and real time pricing rate structures, and how these rate structures can be made available to other customers and customer classes.

2. AMI data collection, information processing, understanding of capabilities, time constraints or other challenges that DEC must address in designing AMI rate structures.

3. AMI data collection, information processing, and understanding of capabilities that DEC has accomplished since beginning its AMI deployment in 2013.

4. New lessons on AMI data collection, information processing, and understanding of capabilities that DEC expects to learn from the EPRI study.

5. The start date, anticipated completion date, objectives and cost of the EPRI study.

6. The reason(s) that DEC maintains that it is preferable to have two years of AMI data in addition to DEC's presently available load research data for all customer classes.

7. The relationship of Customer Connect to DEC's design of AMI rate structures.

8. The details of the TOU, peak and non-peak, and real time pricing rate structures available to the customers of Duke Energy's electric operating subsidiaries in Florida, Kentucky, Indiana and Ohio.

Finally, the Commission is not requesting that the Public Staff or intervenors provide witnesses or testimony at the hearing. The Commission will, however, provide the Public Staff and intervenors a reasonable opportunity to ask questions on the Commission's questions.

IT IS, THEREFORE, ORDERED as follows:

1. That DEC's Report on Plans for AMI and Customer Connect Enabled Rate Design is not accepted.

2. That DEC shall file its two proposed AMI rate design pilot programs within sixty (60) days of the date of this Order.

3. That DEC shall work with the Public Staff to develop a revised AMI rate design work plan that accelerates the deployment of new AMI rate structures, and shall file its revised work plan within sixty (60) days of the date of this Order.

4. That DEC shall provide a witness or witnesses at a hearing before the Commission on February 26, 2019, at 9:30 a.m., in Commission Hearing Room 2115, Dobbs Building, 430 N Salisbury Street, Raleigh, North Carolina, to answer the Commission's questions and provide additional details on DEC's AMI rate design plan.

ISSUED BY ORDER OF THE COMMISSION.
This the 30th day of January, 2019.

NORTH CAROLINA UTILITIES COMMISSION
A. Shonta Dunston, Deputy Clerk

DOCKET NO. E-7, SUB 1146

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of Duke Energy Carolinas, LLC for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina	)))))	ORDER DECLINING TO ACCEPT ANNUAL VEGETATION MANAGEMENT REPORT AND REQUIRING COMPLIANCE FILING

BY THE COMMISSION: On June 22, 2018, the Commission issued an Order Accepting Stipulation, Deciding Contested Issues and Requiring Revenue Reduction (Rate Order) in the above-captioned docket. Among other things, the Rate Order accepted an Agreement and Stipulation of Partial Settlement (Stipulation) entered into by Duke Energy Carolinas, LLC (DEC) and the Public Staff that settled several contested issues. One of the contested issues was that DEC was behind on its vegetation management plan, which had resulted in a 13,467-mile tree-trimming backlog on DEC's distribution system. In the Rate Order, the Commission stated:

> The Stipulation provides that the Company should be allowed to recover distribution vegetation management costs in an annual amount of $62.6 million on a total system basis. Stipulation, § III.A. For the purpose of complying with the Company's current vegetation management program, the Company committed to eliminate completely the 13,467 miles of Existing Backlog as of December 31, 2017 within five years after the date rates go into effect in this proceeding, and the Company additionally committed to spending the necessary amount on an annual basis to trim its annual target distribution miles under its 5/7/9 Plan. In addition, DEC agreed to provide a report annually to the Commission with the following information: (1) actual 5/7/9 and Existing Backlog miles maintained in the previous calendar year; (2) current level of Existing Backlog miles; (3) vegetation

> management maintenance dollars budgeted for the previous calendar year for 5/7/9 and Existing Backlog; and (4) vegetation management maintenance dollars expended in the previous calendar year for 5/7/9 and Existing Backlog.

Rate Order, at 104.

On January 7, 2019, the Commission issued an Order Requiring Tree-Trimming Backlog Updates and Other Information (Update Order), in Docket Nos. E-7, Sub 1146 and E-7, Sub 1182. The Update Order referenced a report that DEC had been required to file to explain reliability problems that had been experienced by GKN Driveline (GKN), a retail customer in Maiden, North Carolina, stating:

> The report states that a primary cause of outages for GKN was tree contact with the feeder serving GKN, and that the Company had not trimmed trees along that feeder since 2007. The report also acknowledges that under DEC's vegetation management methodology, introduced in DEC's 2013 General Rate Case (Docket No. E-7, Sub 1026), this distribution circuit (Startown 1203) should have been trimmed in 2016.
>
> ...
>
> The Commission is concerned that other DEC customers might be experiencing service quality issues due to the Company's tree-trimming backlog.

Update Order, at 1-2.

In order to more closely monitor DEC's tree-trimming expenditures and activities, the Update Order clarified that DEC should file its annual vegetation management reports on March 1, with the first report to be filed on March 1, 2019. In addition, the Update Order requested that the Public Staff file an analysis of DEC's vegetation management report within 45 days of DEC's filing of its report.

On March 1, 2019, DEC filed its first Annual Vegetation Management Report (Report). In addition to an introductory paragraph, the Report consisted of three tables entitled Actual 5/7/9 and Existing Backlog Miles, Backlog Miles as of December 31, 2018, and Vegetation Management Maintenance Budget and Actuals.

After two extensions of time were granted by the Commission, on May 22, 2019, the Public Staff filed its analysis of DEC's Report. In summary, the Public Staff stated that it requested and received from DEC its current work plan mileage forecast for the next five years, and its current work plan budget forecast for the next five years, with both sets of information distinguishing between On-Cycle and Off-Cycle. The Public Staff stated that DEC uses the following two definitions:

> On-Cycle: refers to circuits that have been trimmed within a 5, 7, or 9-year timeframe based on the identified circuit category (old urban, mountain, or other, respectively). The total miles reported as on-cycle are not considered to be part of the existing backlog.

Off-Cycle: refers to circuits that have a last trim date greater than the 5, 7, or 9-year timeframe based on the identified circuit category. The total miles reported as off-cycle are the miles considered to be part of the existing backlog.

The Public Staff attached appendices A and B to its analysis. It stated that Appendix A is a breakdown of the mileage that was trimmed by DEC during calendar year 2018, as well as DEC's forecast for miles to be trimmed through 2023, and Appendix B is a breakdown of the expenditures that were billed during calendar year 2018, as well as DEC's forecast of expenses through 2023.

The Public Staff stated that in developing its vegetation management plan DEC decided to focus on the "oldest" miles first, those being the miles that have gone the longest period without proper cyclical vegetation management. Further, the Public Staff stated that this has resulted in a delay in DEC's trimming of some of the miles that ordinarily would be trimmed under the 5/7/9 Plan. The Public Staff stated that in the Sub 1146 rate case it established with DEC the following annual 5/7/9 Plan targets for vegetation management trim cycles:

Circuit Category	Total miles for each category	Cycle (years)	Miles per year – target
Old Urban Miles	2,180	5	436
Mountain Miles	7,831	7	1,119
Other Miles	41,603	9	4,623
Total	**51,614**	-	**6,177**

The Public Staff stated that in discussions with DEC and in data responses DEC made clear to the Public Staff that by focusing on the "oldest" circuit miles first, "new" backlog miles will result, at least in the immediate future. In addition, the Public Staff stated that its Appendix A shows that by concentrating on the oldest miles first, DEC currently is not achieving its annual 5/7/9 Plan target miles. However, the Public Staff stated that notwithstanding that "new" backlog miles are being created, DEC emphasized that it has included the newly created backlog into its trimming calculations, and that by the end of the five-year period, December 31, 2023, the 13,467 Stipulation backlog miles and the newly created backlog miles will both be eliminated as agreed to in the Stipulation. In conclusion, the Public staff stated that this approach is reasonable because it first addresses the miles of distribution line that are at greatest risk of vegetation related outages.

The Public Staff also provided responses to two Commission questions, and requested that the Commission require DEC to file future vegetation management reports in the formats shown in the Public Staff's appendices A and B. The Public Staff stated that having DEC provide data in those formats should reduce the need for multiple data requests and allow for more expedited reviews of DEC's annual filings.

Discussion and Conclusion

The Commission appreciates the Public Staff's extra effort in obtaining from DEC the information necessary to supplement and fully understand DEC's Report. The Commission does not take issue with DEC's decision to focus its tree trimming efforts on the oldest miles first. However, the Commission does not understand why that strategy necessarily results in DEC falling behind on its regularly scheduled non-backlog miles of tree trimming under the 5/7/9 Plan. The Stipulation stated:

> For the purpose of complying with the Company's current vegetation management program, the Company commits to eliminate completely the 13,467 miles of existing back-log as of December 31, 2017 (as identified in the testimony of Public Staff witness Williamson (Existing Backlog), within five years after the date rates go into effect in this proceeding, and the Company additionally commits to spending the necessary amount on an annual basis to trim its annual target distribution miles under its 5/7/9 Plan.

Stipulation, at 6. The Stipulation was accepted by the Commission and became a part of the Rate Order. DEC has neither asked for nor received authority to deviate from the terms of the Rate Order. As a result, the Commission does not accept DEC's proposal to unilaterally amend the Rate Order by failing to trim its annual target distribution miles under its 5/7/9 Plan.

In addition, the Commission notes that DEC's total miles trimmed in 2018 was 5,559 miles, while its annual target miles was approximately 10% more, 6,177. This appears contrary to the Company's commitment to spend "the necessary amount on an annual basis to trim its annual target distribution miles." According to the Public Staff's Appendix A, DEC intends to trim 6,368 miles in 2019, and more miles per year in subsequent years. In the event that the Commission approves such revisions, the Commission seeks DEC's confirmation that it intends to spend the necessary funds to implement the miles-per-year plan reflected in the Public Staff's Appendix A.

Based on the foregoing and the record, the Commission finds good cause to reject DEC's March 1, 2019 Vegetation Management Report, and to require DEC to file a revised Report showing that DEC intends to comply with the Rate Order. Further, the Commission finds good cause to direct that if DEC's revised Report does not show that DEC intends to trim its annual target distribution miles to meet the target under the 5/7/9 Plan, then DEC should be required to file a motion to alter or amend the Rate Order, and include with its motion an affidavit or affidavits in support of its motion.

Finally, the Commission finds good cause to require that DEC file its future Annual Vegetation Management Reports in the formats shown in the Public Staff's appendices A and B, and, in addition, to expressly state in each Report: (a) whether it met its annual target miles for eliminating back-log miles, and, if not, the number of miles by which it missed the target, and the reason(s) why it missed the target; and (b) whether it met its annual target miles to be maintained under the 5/7/9 Plan, and, if not, the number of miles by which it missed the target in the Urban, Mountain and Other categories, and the reason(s) why it missed the target.

IT IS, THEREFORE, ORDERED as follows:

1. That DEC's March 1, 2019 Vegetation Management Report is not accepted.

2. That within 30 days after the date of this Order DEC shall file a revision to its March 1, 2019 Vegetation Management Report showing for each of the Urban, Mountain and Other categories under the 5/7/9 Plan: (a) the number of miles of tree trimming required annually from 2019 through 2023 to comply with the annual target under the 5/7/9 Plan, and (b) the number of miles of tree trimming that DEC plans to accomplish annually from 2019 through 2023 under the 5/7/9 Plan.

3. That if DEC's revision to its March 1, 2019, Vegetation Report does not show that DEC intends to trim its annual target distribution miles to meet the target under each category of the 5/7/9 Plan, then DEC shall, simultaneously with the filing of its revised Report, file a motion to alter or amend the Rate Order, and include with its motion a verified affidavit or affidavits in support of its motion.

4. That DEC's future Annual Vegetation Management Reports shall be filed in the formats shown in the Public Staff's appendices A and B. In addition, DEC shall expressly state in each Report: (a) whether it met its annual target miles for eliminating back-log miles, and, if not, the number of miles by which it missed the target, and the reason(s) why it missed the target; and (b) whether it met its annual target miles to be maintained under the 5/7/9 Plan, and, if not, the number of miles by which it missed the target in the Urban, Mountain and Other categories, and the reason(s) why it missed the target.

ISSUED BY ORDER OF THE COMMISSION.
This the 18th day of June, 2019.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

DOCKET NO. E-7, SUB 1146

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Duke Energy Carolinas,	)	
LLC, for Adjustment of Rates and	)	ORDER ACCEPTING REVISED
Charges Applicable to Electric Utility	)	VEGETATION MANAGEMENT PLAN
Service in North Carolina	)	

BY THE COMMISSION: On June 18, 2019, the Commission issued an Order Declining to Accept Annual Vegetation Management Report and Requiring Compliance Filing (Compliance Order) in the above-captioned docket. The Commission's Compliance Order rejected the Vegetation Management Report (Report) filed by Duke Energy Carolinas, LLC (DEC) on March 1, 2019. As discussed in the Compliance Order, the Commission rejected the Report because it showed that DEC had not met its 2018 target for on-cycle tree-trimming miles under its 5/7/9 Vegetation Management Plan (5/7/9 Plan), which Plan had previously been approved by the Commission. Further, the Compliance Order directed DEC to either revise the Report to explain how DEC intended to comply with the Plan, or file a request to amend the Plan.

On July 25, 2019, DEC filed a Revised Vegetation Management Plan (Revised Plan) covering the years 2019 through 2023. In summary, DEC stated that its Revised Plan substantially increases the number of on-cycle miles DEC will trim through the remainder of 2019, and ensures that all on-cycle miles due to be trimmed in 2020, 2021, 2022, and 2023 will be trimmed in the year due. In addition, DEC stated that the Revised Plan confirms its commitment to spend the amount needed to trim its annual on-cycle distribution miles under the 5/7/9 Plan. Further, DEC explained that it missed its 2018 target for on-cycle tree-trimming miles primarily due to Hurricanes Florence and Michael and Winter Storm Diego.

On August 15, 2019, the Commission issued an Order on Revised Vegetation Management Plan (August 15 Order) that, among other things, concluded that Hurricanes Florence and Michael and Winter Storm Diego were a change of circumstances that prevented DEC from complying with its 5/7/9 Plan in 2018. In addition, the Commission requested that DEC provide confirmation by October 1, 2019, that its Revised Plan includes sufficient resources to enable DEC to maintain its tree-trimming schedule even if it experiences a major storm.

On September 26, 2019, DEC filed its response to the Commission's August 15 Order. In summary, DEC stated that it is committed to meeting the tree-trimming goals of its Revised Plan. Further, DEC stated that it will notify the Commission promptly, and submit a revised schedule, if major storms disrupt its ability to meet its tree-trimming goals. In addition, DEC discussed several contingency planning points that it utilizes to anticipate and address the disruptive effects of major storms, including:

1. As a means of getting ahead before storm season, DEC's weekly trimming plans target more than 50% of the workplan in the first six months of the year.

2. Adherence to the trimming schedule is tracked weekly.

3. In areas not meeting targets, DEC works with the contractor to add resources and/or schedule overtime.

4. For major storm response, DEC can leverage vegetation management resources from its Midwest and Florida operations.

Based on the foregoing and the record, the Commission finds good cause to accept DEC's Revised Vegetation Management Plan. In addition, the Commission finds good cause to increase the frequency of DEC's vegetation management reports from annually to every six months. Finally, the Commission reminds DEC of its obligation to promptly inform the Commission if a major storm disrupts DEC's vegetation management schedule, and that if a disruption occurs DEC shall propose a revised schedule for meeting its vegetation management commitments as soon as reasonably possible.

IT IS, THEREFORE, ORDERED as follows:

1. That DEC's Revised Vegetation Management Plan shall be, and is hereby, accepted.

2. That DEC shall file semi-annual Vegetation Management Reports each year, beginning in 2020, with reports due on January 2 and July 1.

ISSUED BY ORDER OF THE COMMISSION.
This the 4th day of November, 2019.

NORTH CAROLINA UTILITIES COMMISSION
Kimberley A. Campbell, Chief Clerk

ELECTRIC – RATE SCHEDULES/RIDERS/SERVICE RULES AND REGULATIONS

DOCKET NO. E-7, SUB 1190

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of

Application of Duke Energy Carolinas, LLC Pursuant to N.C.G.S. § 62-133.2 and NCUC Rule R8-55 Relating to Fuel and Fuel-Related Charge Adjustments for Electric Utilities	))))	ORDER APPROVING FUEL CHARGE ADJUSTMENT

HEARD: Tuesday, June 11, 2019, at 9:30 a.m. in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Chair Charlotte A. Mitchell, Presiding; Commissioner ToNola D. Brown-Bland, Commissioner Jerry C. Dockham, Commissioner James G. Patterson, Commissioner Lyons Gray, and Commissioner Daniel G. Clodfelter[1]

APPEARANCES:

For Duke Energy Carolinas, LLC:

Jack Jirak, Associate General Counsel, Duke Energy Corporation, NCRH 20/P.O. Box 1551, Raleigh, North Carolina 27602-1551

Robert W. Kaylor, Law Office of Robert W. Kaylor, P.A., 353 Six Forks Road, Suite 260, Raleigh, North Carolina 27609

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

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

For Sierra Club:

Gudrun Thompson, Senior Attorney, Southern Environmental Law Center, 601 West Rosemary Street, Suite 220, Chapel Hill, North Carolina 27516

For North Carolina Sustainable Energy Association (NCSEA):

Benjamin Smith, Regulatory Counsel, 4600 Six Forks Road, Suite 300, Raleigh, North Carolina 27609

[1] Commissioner Jerry C. Dockham and Commissioner James G. Patterson retired from the Commission on June 30, 2019, and did not participate in the decision in this matter.

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

Warren K. Hicks, Bailey & Dixon, 434 Fayetteville Street, Suite 2500, Raleigh, North Carolina 27601

For the Using and Consuming Public:

Dianna Downey, Staff Attorney, Public Staff - North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4300

BY THE COMMISSION: On February 26, 2019, Duke Energy Carolinas, LLC (Duke Energy Carolinas, DEC, or the Company) filed an application pursuant to N.C. Gen. Stat. § 62-133.2 and Commission Rule R8-55 regarding fuel and fuel-related cost adjustments for electric utilities, along with the testimony and exhibits of Kimberly D. McGee, Eric S. Grant, Regis T. Repko, Steven D. Capps, and Kevin Y. Houston.

Petitions to intervene were filed by CIGFUR on February 28, 2019; by CUCA on March 6, 2019; by NCSEA on March 19, 2019; and by the Sierra Club on May 20, 2019. The Commission granted CUCA's petition to intervene on March 7, 2019, CIGFUR's petition to intervene on March 8, 2019, NCSEA's petition to intervene on March 20, 2019, and the Sierra Club's petition on May 29, 2019.

On March 8, 2019, the Commission issued an Order Scheduling Hearing, Requiring Filing of Testimony, Establishing Discovery Guidelines, and Requiring Public Notice, in which the Commission set this matter for hearing; established deadlines for the submission of intervention petitions, intervenor testimony, and DEC rebuttal testimony; required the provision of appropriate public notice; and mandated compliance with certain discovery guidelines.

On March 18, 2019, the Commission entered an Order Rescheduling Hearing, Intervention and filing of Testimony dates, and Revising Public Notice. That Order provided that the direct testimony of the Public Staff and other intervenors should be filed on May 20, 2019, that rebuttal testimony should be filed on May 30, 2019, and that a hearing on this matter would be held on June 11, 2019.

The intervention of the Public Staff is recognized pursuant to N.C. Gen. Stat. § 62-15(d) and Commission Rule R1-19(e).

On April 30, 2019, DEC filed the supplemental testimony, exhibits and work papers of Kimberly D. McGee, in which she presented revised rates reflecting the impacts related to six updates to numbers presented in her direct exhibits and workpapers, which resulted in an overall increase in the amount requested in the original application.

On May 2, 2019, the Commission issued an Order Requiring Publication of Second Public Notice.

On May 15, 2019, DEC filed the second supplemental testimony and exhibits of Kimberly D. McGee, presenting revised rates reflecting the correction of the (over)/under-collection balance for the months of September 2018-December 2018, which resulted in an increase in the amount requested in the original application. In order to mitigate the increase in customers' rates, the Company elected to withdraw its prior request (made in witness McGee's first supplemental filing) to include the update period of January 2019-March 2019.

On May 20, 2019, the Public Staff filed a notice of affidavits and the affidavits of Jenny X. Li and Jay B. Lucas.

On June 3, 2019, DEC filed a motion to excuse all Company and Public Staff witnesses. On June 6, 2019, Sierra Club filed a response to DEC's motion, stating that Sierra Club did not object, given that DEC indicated that it would not object to certain responses to data requests being entered into evidence at the hearing. On June 7, 2019, the Commission granted the motion and excused all DEC and Public Staff witnesses from appearing at the expert witness hearing.

On May 14, 2019, DEC filed affidavits of publication indicating that the initial public notice had been provided in accordance with the Commission's March 8, 2019 Order. On June 4, 2019, DEC filed affidavits of publication indicating that the second public notice had been provided in accordance with the Commission's May 2, 2019 Order.

The case came on for hearing as scheduled on June 11, 2019. The prefiled direct and supplemental testimonies of DEC's witnesses, the prefiled affidavits of the Public Staff's witnesses, and Confidential Sierra Club Exhibit 1 were received into evidence. No other party presented witnesses or exhibits, and no public witnesses appeared at the hearing.

On July 29, 2019, DEC and the Public Staff filed a Joint Proposed Order.

Also on July 29, 2019, Sierra Club filed a post-hearing Brief.

Based upon the Company's verified application, the testimony, affidavits, and exhibits received into evidence at the hearing and the record as a whole, the Commission makes the following:

FINDINGS OF FACT

1. Duke Energy Carolinas is a duly organized corporation existing under the laws of the State of North Carolina, is engaged in the business of developing, generating, transmitting, distributing, and selling electric power to the public in North Carolina, and is subject to the jurisdiction of the Commission as a public utility. Duke Energy Carolinas is lawfully before this Commission based upon its application filed pursuant to N.C. Gen. Stat. § 62-133.2.

2. The test period for purposes of this proceeding is the 12 months ended December31,2018 (test period).

3. In its application and direct, supplemental, and second supplemental testimony including exhibits in this proceeding, DEC requested a total increase of $68.6 million to its North Carolina retail revenue requirement associated with fuel and fuel-related costs, excluding the regulatory fee. The fuel and fuel-related cost factors requested by DEC included Experience Modification Factor (EMF) riders to take into account fuel and fuel-related cost under-recoveries and over-recoveries experienced during the test period, with an overall under-recovery of $78.2 million.

4. The Company's baseload plants were managed prudently and efficiently during the test period so as to minimize fuel and fuel-related costs.

5. The Company's fuel and reagent procurement and power purchasing practices during the test period were reasonable and prudent. However, given DEC's increased reliance on natural gas and the resulting increased risk of under-recoveries if natural gas prices are not forecasted as accurately as possible, the Company should evaluate historic price fluctuations and whether its current method of forecasting and hedging programs should be adjusted to mitigate the risk of significant under-recovery of fuel costs. The Company shall report the results of this evaluation in the next fuel proceeding.

6. The test period per book system sales are 90,487,628 megawatt-hours (MWh). The test period per book system generation (net of auxiliary use and joint owner generation) and purchased power is 97,045,431 MWh and is categorized as follows:

Net Generation Type	MWh
Coal	22,653,740
Natural Gas, Oil and Biomass	16,236,067
Nuclear	44,770,657
Hydro – Conventional	2,877,050
Hydro Pumped Storage	(529,226)
Solar DG	130,018
Purchased Power – subject to economic dispatch or curtailment	8,564,915
Other Purchased Power	2,551,485
Interchange In/Out	(209,275)
Total Net Generation	97,045,431

7. The appropriate nuclear capacity factor for use in this proceeding is 92.95%.

8. The North Carolina retail test period sales, adjusted for customer growth and weather, for use in calculating the EMF are 58,074,054 MWh. The adjusted North Carolina retail customer class MWh sales are as follows:

N.C. Retail Customer Class	Adjusted MWh Sales
Residential	22,043,791
General Service/Lighting	23,564,462
Industrial	12,465,801
Total	58,074,054

9. The projected billing period (September 2019-August 2020) sales for use in this proceeding are 87,243,844 MWh on a system basis and 57,717,997 MWh on a North Carolina retail basis. The projected billing period North Carolina retail customer class MWh sales are as follows:

N.C. Retail Customer Class	Projected MWh Sales
Residential	21,397,068
General Service/Lighting	23,381,644
Industrial	12,939,285
Total	57,717,997

10. The projected billing period system generation and purchased power for use in this proceeding in accordance with projected billing period system sales is 92,298,568 MWh and is categorized as follows:

Generation Type		MWh
Coal		18,355,203
Gas Combustion Turbine (CT) and Combined Cycle (CC)		19,943,217
Nuclear		43,570,151
Hydro		4,839,425
Net Pumped Storage Hydro		(3,874,211)
Solar Distributed Generation (DG)	184,444	
Purchased Power		9,280,339
Total		92,298,568

11. The appropriate fuel and fuel-related prices and expenses for use in this proceeding to determine projected system fuel expense are as follows:

a. The coal fuel price is $31.06/MWh.
b. The gas CT and CC fuel price is $24.17/MWh.
c. The appropriate expense for ammonia, lime, limestone, urea, dibasic acid, sorbents, and catalysts consumed in reducing or treating emissions (collectively, Reagents) is $24,959,649.
d. The total nuclear fuel price (including Catawba Joint Owners generation) is $6.12/MWh.

e. The total system purchased power cost (including the impact of Joint Dispatch Agreement (JDA) Savings Shared) is $314,814,153.
f. System fuel expense recovered through intersystem sales is $16,986,301.

12. The projected fuel and fuel-related costs for the North Carolina retail jurisdiction for use in this proceeding are $1,090,922,448.

13. The Company's North Carolina retail jurisdictional fuel and fuel-related expense under-collection for purposes of the EMF was $78.2 million, consisting of an under-recovery for the residential, general service/lighting, and industrial classes of $30.3 million, $21.9 million and $26.0 million respectively.

14. The increase in customer class fuel and fuel-related cost factors from the amounts approved in Docket No. E-7, Sub 1163 should be allocated among the rate classes on a uniform percentage basis, using the uniform bill adjustment methodology that was approved by the Commission in that docket.

15. The appropriate prospective fuel and fuel-related cost factors for this proceeding for each of DEC's rate classes, excluding the regulatory fee, are as follows: 1.8126 cents/kilowatt-hour (kWh) for the Residential class; 1.9561 cents/kWh for the General Service/Lighting class; and 1.8934 cents/kWh for the Industrial class.

16. The appropriate EMF increments established in this proceeding, excluding the regulatory fee, are as follows: 0.1375 cents/kWh for the Residential class; 0.0927 cents/kWh for the General Service/Lighting class; and 0.2089 cents/kWh for the Industrial class.

17. The total net fuel and fuel-related costs factors for this proceeding for each of DEC's rate classes, excluding the regulatory fee, are as follows: 1.9501 cents/kWh for the Residential class; 2.0488 cents/kWh for the General Service/Lighting class; and 2.1023 cents/kWh for the Industrial class.

18. The base fuel and fuel-related costs as approved in Docket No. E-7, Sub 1146 of 1.7828 cents/kWh, 1.9163 cents/kWh, and 2.0207 cents/kWh for the Residential, General Service/Lighting, and Industrial customer classes, respectively will be adjusted by amounts equal to 0.0298 cents/kWh, 0.0398 cents/kWh, and (0.1273) cents/kWh for the Residential, General Service/Lighting, and Industrial customer classes, respectively. The resulting approved fuel and fuel-related costs will be further adjusted by EMF increments totaling 0.1375 cents/kWh, 0.0927 cents/kWh, and 0.2089 cents/kWh for the Residential, General Service/Lighting, and Industrial customer classes, respectively.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 1

This finding of fact is essentially informational, procedural, and jurisdictional in nature and is uncontroverted.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 2

North Carolina General Statute § 62-133.2(c) sets out the verified, annualized information that each electric utility is required to furnish to the Commission in an annual fuel and fuel-related cost adjustment proceeding for a historical 12-month test period. Commission Rule R8-55(b) prescribes the 12 months ending December 31 as the test period for DEC. The Company's filing in this proceeding was based on the 12 months ended December 31, 2018.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 3

The evidence for this finding of fact is contained in the application, the direct, supplemental, and second supplemental testimony of Company witness McGee, and the entire record in this proceeding. This finding is not contested by any party.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 4

The evidence for this finding of fact is contained in the direct testimony of Company witnesses Capps and Repko.

Commission Rule R8-55(d)(1) provides that capacity factors for nuclear production facilities will be normalized based generally on the national average for nuclear production facilities as reflected in the most recent North American Electric Reliability Corporation (NERC) Generating Availability Report, adjusted to reflect the unique, inherent characteristics of the utility facilities and unusual events. Company witness Capps testified that the Company's seven nuclear units operated at a system average capacity factor of 95.29% during the test period. This capacity factor, as well as the Company's 2-year average capacity factor of 95.58%, exceeded the five-year industry weighted average capacity factor of 90.21% for the period 2013-2017 for average comparable units on a capacity-rated basis, as reported by NERC in its latest Generating Availability Report.

Witness Capps testified that for the 19th consecutive year, DEC's seven nuclear units achieved a system average capacity factor exceeding 90%, which included five refueling outages. McGuire Unit 1 established a new net generation record during 2018, and McGuire Unit 2 operated continuously during the operating cycle leading up to the September 2018 refueling outage. Catawba Unit 1 operated continuously during the cycle leading into the November 2018 refueling outage, and established a new record for the highest net generation for nine months during the year. Catawba Unit 2 also achieved a continuous cycle run leading into that unit's March 2018 refueling outage, which represented the second shortest refueling outage for the unit. During the peak summer demand, the Oconee station achieved the highest 3rd quarter output in the station's history, and, over the course of the entire year, recorded the third best annual generation performance.

Company witness Repko testified concerning the performance of DEC's fossil, hydro, and solar assets. He stated that the primary objective of the Company's fossil, hydro, and solar generation department is to provide safe, reliable and cost-effective electricity to DEC's customers. Witness Repko further stated that DEC complies with all applicable environmental regulations and maintains station equipment and systems in a cost-effective manner to ensure reliability. The Company also takes action in a timely manner to implement work plans and projects that enhance the safety and performance of systems, equipment, and personnel, consistent with providing low-cost power for its customers.

Company witness Repko testified that the Company's generating units operated efficiently and reliably during the test period. He explained that several key measures are used to evaluate operational performance, depending on the generator type: (1) equivalent availability factor (EAF), which refers to the percent of a given time period a facility was available to operate at full power, if needed (EAF is not affected by the manner in which the unit is dispatched or by the system demands; it is impacted, however, by planned and unplanned (i.e., forced outage time)); (2) net capacity factor (NCF), which measures the generation that a facility actually produces against the amount of generation that theoretically could be produced in a given time period, based upon its maximum dependable capacity (NCF is affected by the dispatch of the unit to serve customer needs); (3) equivalent forced outage rate (EFOR), which represents the percentage of unit failure (unplanned outage hours and equivalent unplanned derated hours); a low EFOR represents fewer unplanned outage and derated hours, which equates to a higher reliability measure; and, (4) starting reliability (SR), which represents the percentage of successful starts.

Company witness Repko presented the following chart, which shows operation results, as well as results from the most recently published NERC Generating Availability Brochure for the period 2013 through 2017, and is categorized by generator type:

Generator Type	Measure	Review Period DEC Operational Results	2013-2017 NERC Average	Nbr of Units
Coal-Fired Test Period	EAF	79.5%	78.4%	752
	NCF	38.3%	56.4%	
	EFOR	7.5%	8.7%	
Coal-Fired Summer Peak	EAF	95.8%	n/a	n/a
Total CC Average	EAF	86.2%	85.0%	338
	NCF	76.7%	52.7%	
	EFOR	3.32%	5.3%	
Total CT Average	EAF	83.3%	87.8%	776
	SR	99.4%	98.1%	
Hydro	EAF	76.3%	80.4%	1,113

Concerning significant planned outages occurring at the Company's fossil and hydroelectric facilities during the test period, Company witness Repko testified that in general, planned maintenance outages for all fossil and larger hydroelectric units are scheduled for the spring and fall to maximize unit availability during periods of peak demand. During the test period, most of these units had at least one small planned outage to inspect and maintain plant equipment.

Witness Repko testified that Bad Creek hydro completed a major outage in Spring 2018, which included spherical valve overhauls and inspections of the intake and penstock to prepare for the Bad Creek uprate project, which will begin in Fall 2019. Lincoln CT Unit 1 and Unit 2 completed an outage in Spring 2018 to upgrade the turbine control system. The CC fleet performed planned outages at Dan River CC and Buck CC in Spring 2018. The primary purpose of the Dan River CC outage was to perform a CT borescope inspection and a heat recovery steam generator inspection. The primary purpose of the Buck CC outage was to perform a borescope inspection on each combustion turbine. In Fall 2018, Belews Creek Unit 2 preformed a boiler outage. The primary purpose of the outage was to replace the secondary superheater in the boiler and rewind the LP generator. Marshall Unit 2 completed an outage in Fall 2018. The primary purpose of this outage was to replace the HP and LP turbine rotors. Cliffside Unit 5 and Unit 6 completed an outage for the dual fuel conversion to allow the units to burn coal and natural gas. Lincoln CT Units 3-8 completed an outage in Fall 2018 to upgrade the turbine control systems.

Based on a preponderance of the evidence in the record, the Commission concludes that the Company managed its baseload plants during the test period prudently and efficiently so as to minimize fuel and fuel-related costs.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 5

Commission Rule R8-52(b) requires each electric utility to file a Fuel Procurement Practices Report at least once every 10 years and each time the utility's fuel procurement practices change. The Company's updated fuel procurement practices were filed with the Commission in Docket No. E-100, Sub 47A in December 2014, and were in effect throughout the 12 months ending December 31, 2018. In addition, the Company files monthly reports of its fuel and fuel-related costs pursuant to Commission Rule R8-52(a). Further evidence for this finding of fact is contained in the testimony of Company witnesses McGee, Grant, Repko, and Houston and the affidavit of Public Staff witness Lucas.

Company witness McGee testified that key factors in DEC's ability to maintain lower fuel and fuel-related rates for the benefit of customers include its diverse generating portfolio mix of nuclear, coal, natural gas, and hydro; lower natural gas prices; the capacity factors of its nuclear fleet; and fuel procurement strategies that mitigate volatility in supply costs. Other key factors include the combination of Duke Energy Progress, LLC's (DEP) and DEC's respective skills in procuring, transporting, managing and blending fuels and procuring reagents; the increased and broader purchasing ability of the combined companies; and the joint dispatch of DEP's and DEC's generation resources.

Company witness Grant described DEC's fossil fuel procurement practices, set forth in Grant Exhibit 1. Those practices include computing near and long-term consumption forecasts, determining and designing inventory targets, inviting proposals from all qualified suppliers, awarding contracts based on the lowest evaluated offer, monitoring delivered coal volume and quality against contract commitments, conducting short-term and spot purchases to supplement term natural gas supply, and obtaining natural gas transportation for the generation fleet through a mix of long term firm transportation agreements and shorter term pipeline capacity purchases.

According to witness Grant, the Company's average delivered cost of coal per ton for the test period was $78.71 per ton, compared to $74.90 per ton in the prior test period, representing an increase of approximately 5%. This includes an average transportation cost of $29.58 per ton in the test period, compared to $26.46 per ton in the prior test period, representing an increase of approximately 12%. Witness Grant further testified that the Company's average price of gas purchased for the test period was $3.84 per Million British Thermal Units (MMBtu), compared to $3.65 per MMBtu in the prior test period, representing an increase of approximately 5%.

Witness Grant stated that DEC's coal burn for the test period was 8.7 million tons, compared to a coal burn of 9.7 million tons in the prior test period, representing a decrease of approximately 10%. The Company's natural gas burn for the test period was 128.8 MMBtu, compared to a gas burn of 80.8 MMBtu in the prior test period, representing an increase of approximately 59%. The net increase in DEC's overall natural gas burn was primarily driven by the addition of the new Lee combined cycle facility, which became commercially available in April 2018. An additional contributing factor to changes in coal and natural gas burns were commodity prices.

Witness Grant stated that coal markets continue to be in a state of flux due to a number of factors, including: (1) uncertainty around proposed, imposed, and stayed U.S. Environmental Protection Agency (EPA) regulations for power plants; (2) continued abundant natural gas supply and storage resulting in lower natural gas prices, which has lowered overall domestic coal demand; (3) strong global market demand for both steam and metallurgical coal; (4) uncertainty surrounding regulations for mining operations; and (5) tightening supply as bankruptcies, consolidations and company reorganizations have allowed coal suppliers to restructure and settle into new, lower on-going production levels.

Witness Grant also testified that with respect to natural gas, the nation's natural gas supply has grown significantly over the last several years, and producers continue to enhance production techniques, enhance efficiencies, and lower production costs. Natural gas prices are reflective of the dynamics between supply and demand factors, and in the short term, such dynamics are influenced primarily by seasonal weather demand and overall storage inventory balances. Over the longer term planning horizon, natural gas supply is projected to continue to increase along with the needed pipeline infrastructure to move the growing supply to meet demand related to power generation, liquefied natural gas exports and pipeline exports to Mexico.

Witness Grant stated that DEC's current coal burn projection for the billing period is 6.5 million tons, compared to 8.7 million tons consumed during the test period. DEC's billing period projections for coal generation may be impacted due to changes from, but not limited to, the following factors: (1) delivered natural gas prices versus the average delivered cost of coal; (2) volatile power prices; and (3) electric demand. Combining coal and transportation costs, DEC projects average delivered coal costs of approximately $66.80 per ton for the billing period compared to $77.13 per ton in the test period.

Witness Grant testified that this cost, however, is subject to change based on, but not limited to, the following factors: (1) exposure to market prices and their impact on open coal positions; (2) the amount of non-Central Appalachian coal DEC is able to consume;

(3) performance of contract deliveries by suppliers and railroads which may not occur despite DEC's strong contract compliance monitoring process; (4) changes in transportation rates; and (5) potential additional costs associated with suppliers' compliance with legal and statutory changes, the effects of which can be passed on through coal contracts.

Witness Grant further testified that DEC's current natural gas burn projection for the billing period is approximately 147.2 MMBtu, which is an increase from the 128.8 MMBtu consumed during the test period. The net increase in DEC's overall natural gas burn projections for the billing period versus the test period is driven by the inclusion of natural gas generation at Cliffside, Belews Creek, and Marshall Units 3 and 4 as a result of the dual fuel conversions being commercial available over the course of the billing period. The current average forward Henry Hub price for the billing period is $2.75 per MMBtu, compared to $3.09 per MMBtu in the test period. Projected natural gas burn volumes will vary based on factors such as, but not limited to, changes in actual delivered fuel costs and weather driven demand.

According to witness Grant, DEC continues to maintain a comprehensive coal and natural gas procurement strategy that has proven successful over the years in limiting average annual fuel price changes while actively managing the dynamic demands of its fossil fuel generation fleet in a reliable and cost effective manner. Aspects of this procurement strategy include having an appropriate mix of contract and spot purchases for coal, staggering coal contract expirations which thereby limit exposure to market price changes, diversifying coal sourcing as economics warrant, as well as working with coal suppliers to incorporate additional flexibility into their supply contracts. The Company expects to address any spot and long-term coal requirements throughout this year with any potential competitively bid purchases, if made, taking into account projected coal burns, as well as coal inventory levels.

Witness Grant also testified that the Company has implemented natural gas procurement practices that include periodic Request for Proposals and shorter-term market engagement activities to procure and actively manage a reliable, flexible, diverse, and competitively priced natural gas supply that includes contracting for volumetric optionality in order to provide flexibility in responding to changes in forecasted fuel consumption.

According to witness Grant, DEC continues to maintain a short-term financial natural gas hedging plan to manage fuel cost risk for customers via a disciplined, structured execution approach.

Public Staff witness Lucas testified that of particular concern to the Public Staff in its investigation of the test year fuel costs was the significant under-recovery that took place due to the Company's greater than expected fuel costs in January 2018. He stated that after reviewing discovery and discussing the issue with DEC employees, the Public Staff is satisfied that the January 2018 fuel costs were reasonable and prudently incurred. However, DEC, like other utilities, has increased its reliance on natural gas to produce electricity and serve load. Witness Lucas explained that as utilities have significantly increased their reliance on a fuel with greater price variances (compared to nuclear and coal) in order to more economically serve their customers, these same customers are exposed to greater risk of fuel cost under- and over-recoveries despite the overall decreasing cost of natural gas. Increased natural gas consumption, coupled with recent winter weather events of the last few years, have caused exposure to higher than anticipated short-term natural gas prices. Witness Lucas stated that given the increased risk of under-recoveries if natural gas prices are not forecasted as accurately as possible, the Public Staff believes that the Company should evaluate historic price fluctuations and whether its current method of forecasting and hedging programs should be adjusted to mitigate the risk of significant under-recovery of fuel costs.

North Carolina General Statute § 62-133.2(a1)(3) permits DEC to recover the cost of "ammonia, lime, limestone, urea, dibasic acid, sorbents, and catalysts consumed in reducing or treating emissions." Company witness Repko testified that the Company has installed pollution control equipment in order to meet various current federal, state, and local reduction requirements for nitrogen oxide (NO_x) and sulphur oxide (SO_X) emissions. The selective non-catalytic reduction technology (SCR or SNCR) that DEC currently operates on the coal-fired units uses ammonia or urea for NO_x removal. The SNCR technology employed at Allen station and Marshall Units 1, 2 and 4 injects urea into the boiler for NO_x removal. All DEC coal units have wet scrubbers installed which use crushed limestone for sulfur dioxide (SO_2) removal. Cliffside Unit 6 has a state-of-the-art SO_2 reduction system which couples a wet scrubber (e.g., limestone) and dry scrubber (e.g., quicklime). SCR equipment is also an integral part of the design of the Buck, Dan River and Lee CC stations, in which aqueous ammonia (19% solution of NH_3) is introduced for NO_x removal.

Company witness Repko further testified that overall, the type and quantity of chemicals used to reduce emissions at the Company's plants varies depending on the generation output of the unit, the chemical constituents in the fuel burned, and the level of emissions reduction required. He stated that the Company is managing the impacts, favorable or unfavorable, as a result of changes to the fuel mix and/or changes in coal burn due to competing fuels and utilization of non-traditional coals. He also stated that the goal is to effectively comply with emissions regulations and provide the most efficient total-cost solution for operation of the unit.

Company witness Houston testified as to DEC's nuclear fuel procurement practices, which include computing near and long-term consumption forecasts, establishing nuclear system inventory levels, projecting required annual fuel purchases, requesting proposals from qualified suppliers, negotiating a portfolio of long-term contracts from diverse sources of supply, and monitoring deliveries against contract commitments. Witness Houston explained that for uranium concentrates as well as conversion and enrichment services, long-term contracts are used extensively in the industry to cover forward requirements and ensure security of supply. He also stated that throughout the industry, the initial delivery under new long-term contracts commonly occurs several years after contract execution. For this reason, DEC relies extensively on long-term contracts to cover the largest portion of its forward requirements. By staggering long-term contracts over time for these components of the nuclear fuel cycle, DEC's purchases within a given year consist of a blend of contract prices negotiated at many different periods in the markets, which has the effect of smoothing out the Company's exposure to price volatility. He further stated that diversifying fuel suppliers reduces the Company's exposure to possible disruptions from any single source of supply. Due to the technical complexities of changing fabrication services suppliers, DEC generally sources these services to a single domestic supplier on a plant-by-plant basis, using multi-year contracts.

North Carolina General Statute §§ 62-133.2(a1)(4), (5), (6), and (7) permit the recovery of the cost of non-capacity power purchases subject to economic dispatch or economic curtailment; capacity costs of power purchases associated with qualifying facilities subject to economic dispatch; certain costs associated with power purchases from renewable energy facilities; and the fuel costs of other power purchases. Company witness Grant testified that DEP and DEC consider the latest forecasted fuel prices, transportation rates, planned maintenance and refueling outages at generating units, estimated forced outages at generating units based on historical trends, generating unit performance parameters, and expected market conditions associated with power purchases and off-system sales opportunities in order to determine the most economic and reliable means of serving their respective customers.

In its post-hearing Brief, the Sierra Club uses DEC's response to a data request to illustrate that a projected increase in fixed gas costs at numerous DEC units in the future appears to be attributable, at least in part, to DEC passing on a portion of the multi-billion-dollar cost of the Atlantic Coast Pipeline (ACP) through the fuel clause. The Sierra Club submits that if this occurs, DEC's ratepayers will be paying significantly more in fuel costs after the ACP goes into service than they currently pay for gas shipped via the Transco pipeline. The Sierra Club recognizes that DEC is not attempting to recover any ACP costs in this proceeding. However, the Sierra Club states that after the ACP comes online, the Commission should be concerned with the large increases in the fuel costs that DEC will seek to recover from its captive retail ratepayers. The Sierra Club advises that, in light of this projected cost differential, any future requests to recover the cost of gas shipped on the ACP should be viewed with skepticism, and the reasonableness of those costs should be subjected to careful scrutiny. The Commission notes the concerns of the Sierra Club.

Based upon the fuel procurement practices report and the evidence in the record, the Commission concludes that the Company's fuel procurement and power purchasing practices were reasonable and prudent during the test period. However, the Commission agrees with the Public Staff that given the Company's increased reliance on natural gas to produce electricity and serve load, and the possible exposure of customers to greater risk of fuel cost under- and over-recoveries, the Company should evaluate historic price fluctuations and whether its current method of forecasting and hedging programs should be adjusted to mitigate the risk of significant under-recovery of fuel costs, and report the results of that evaluation in the Company's next fuel proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 6

The evidence supporting this finding of fact is contained in the testimony and exhibits of Company witness McGee.

According to the exhibits sponsored by Company witness McGee, the test period per book system sales were 90,487,628 MWh, and test period per book system generation and purchased power amounted to 97,045,431 MWh (net of auxiliary use and joint owner generation). The test period per book system generation and purchased power are categorized as follows (Revised McGee Exhibit 6):

Net Generation Type	MWh
Coal	22,653,740
Natural Gas, Oil and Biomass	16,236,067
Nuclear	44,770,657
Hydro – Conventional	2,877,050
Hydro Pumped Storage	(529,226)
Solar DG	130,018
Purchased Power – subject to economic dispatch or curtailment	8,564,915
Other Purchased Power	2,551,485
Interchange In/Out	(209,275)
Total Net Generation	97,045,431

The evidence presented regarding the operation and performance of the Company's generation facilities is discussed in the Evidence and Conclusions for Finding of Fact No. 4.

No party took issue with the portions of witness McGee's exhibits setting forth per books system sales, generation by fuel type, and purchased power. Therefore, based on the evidence presented and noting the absence of evidence presented to the contrary, the Commission concludes that the per books levels of test period system sales of 90,487,628 MWh and system generation and purchased power of 97,045,431 MWh are reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 7

The evidence supporting this finding of fact is contained in the direct testimony and exhibits of Company witness Capps.

Commission Rule R8-55(d)(1) provides that capacity factors for nuclear production facilities will be normalized based generally on the national average for nuclear production facilities as reflected in the most recent NERC Generating Availability Report, adjusted to reflect the unique, inherent characteristics of the utility's facilities and unusual events. The Company proposed using a 92.95% capacity factor in this proceeding based on the operational history of the Company's nuclear units and the number of planned outage days scheduled during the billing period. This proposed capacity factor exceeds the five-year industry weighted average capacity factor of 90.21% for the period 2013-2017 as reported in the NERC Brochure during the period of 2013 to 2017.

Based upon the requirements of Commission Rule R8-55(d)(1), the historical and reasonably expected performance of the DEC system, and the fact that the Public Staff did not dispute the Company's proposed nuclear capacity factor, the Commission concludes that the 92.95% nuclear capacity factor, and its associated generation of 58,459,031 MWh, are reasonable and appropriate for determining the appropriate fuel and fuel-related costs in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 8 - 10

The evidence supporting these findings of fact is contained in the testimony and exhibits of Company witness McGee.

On her Revised Exhibit 4, Company witness McGee set forth the test year per books North Carolina retail sales, adjusted for weather and customer growth, of 58,074,054 MWh, comprised of Residential class sales of 22,043,791 MWh, General Service/Lighting class sales of 23,564,462 MWh, and Industrial class sales of 12,465,801 MWh.

Witness McGee used projected billing period system sales, generation, and purchased power to calculate the proposed prospective component of the fuel and fuel-related cost rate. The projected system sales level used, as set forth on Revised McGee Exhibit 2, Schedule 1, is 87,243,844 MWh. The projected level of generation and purchased power used was 92,298,568 MWh (calculated using the 92.95% capacity factor found reasonable and appropriate above), and was broken down by witness McGee as follows, as set forth on that same schedule:

Generation Type	MWh
Coal	18,355,203
Gas Combustion Turbine (CT) and Combined Cycle (CC)	19,943,217
Nuclear	43,570,151
Hydro	4,839,425
Net Pumped Storage Hydro	(3,874,211)
Solar Distributed Generation (DG)	184,444
Purchased Power	9,280,339
Total	92,298,568

As part of her Workpaper 7, Company witness McGee also presented an estimate of the projected billing period North Carolina retail Residential, General Service/Lighting, and Industrial MWh sales. The Company estimates billing period North Carolina retail MWh sales to be as follows:

N.C. Retail Customer Class	Projected MWh Sales
Residential	21,397,068
General Service/Lighting	23,381,644
Industrial	12,939,285
Total	57,717,997

These class totals were used in Revised McGee Exhibit 2, Schedule 1, in calculating the total fuel and fuel-related cost factors by customer class.

Based on the evidence presented by the Company, the Public Staff's acceptance of the amounts presented by the Company, and the absence of evidence presented to the contrary, the Commission concludes that the projected North Carolina retail levels of sales set forth in the

Company's exhibits (normalized for customer growth and weather), as well as the projected levels of generation and purchased power, are reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSION FOR FINDING OF FACT NO. 11

The evidence supporting this finding of fact is contained in the testimony and exhibits of Company witnesses McGee and Grant and the affidavit of Public Staff witness Lucas.

Company witness McGee recommended fuel and fuel-related prices and expenses, for purposes of determining projected system fuel expense, as follows:

A. The coal fuel price is $31.06/MWh.
B. The gas CT and CC fuel price is $24.17/MWh.
C. The appropriate expense for ammonia, lime, limestone, urea, dibasic acid, sorbents, and catalysts consumed in reducing or treating emissions (collectively, Reagents) is $24,959,649.
D. The total nuclear fuel price (including Catawba Joint Owners generation) is $6.12/MWh.
E. The total system purchased power cost (including the impact of Joint Dispatch Agreement (JDA) Savings Shared) is $314,814,153.
F. System fuel expense recovered through intersystem sales is $16,986,301.

These amounts are set forth on or derived from Revised McGee Exhibit 2, Schedule 1. The total adjusted system fuel and fuel-related expense, based in part on the use of these amounts, is utilized to calculate the prospective fuel and fuel-related cost factors recommended by the Company and the Public Staff.

In his affidavit, Public Staff witness Lucas stated that, based on upon his review, it appears that the projected fuel and reagent costs set forth in DEC's testimony, and the prospective components of the total fuel factor, have been calculated in accordance with the requirements of N.C. Gen. Stat. § 62-133.2.

No other party presented evidence on the level of DEC's fuel and fuel-related prices and expenses.

Based upon the evidence in the record as to the appropriate fuel and fuel-related prices and expenses, the Commission concludes that the fuel and fuel-related prices recommended by Company witness McGee and accepted by the Public Staff for purposes of determining projected system fuel expense are reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 12

The evidence supporting this finding of fact is contained in the testimony and exhibits of Company witness McGee and the affidavit of Public Staff witness Lucas.

Consistent with N.C. Gen. Stat. § 62-133.2(a2), witness McGee testified that the annual increase in the aggregate amount of purchased power costs under the relevant sections of N.C. Gen. Stat. §62-133.2(a1) does not exceed 2.5% of DEC's total North Carolina jurisdictional gross revenues for 2018.

According to Revised McGee Exhibit 2, Schedule 1, the projected fuel and fuel-related costs for the North Carolina retail jurisdiction for use in this proceeding are $1,090,922,448. Public Staff witness Lucas did not take issue with her calculation.

Aside from the Company and the Public Staff, no other party presented or elicited testimony contesting the Company's projected fuel and fuel-related costs for the North Carolina retail jurisdiction. Based upon the evidence in the record and the absence of any direct testimony to the contrary, the Commission concludes that the Company's projected total fuel and fuel-related cost for the North Carolina retail jurisdiction of $1,090,922,448 is reasonable.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 13-17

The evidence supporting these findings of fact is contained in the testimony and exhibits of Company witness McGee and the affidavits of Public Staff witnesses Lucas and Li.

Company witness McGee presented DEC's original fuel and fuel-related expense under-collection and prospective fuel and fuel-related cost factors. Company witness McGee's supplemental testimony and revised exhibits set forth the projected fuel and fuel-related costs, the amount of over/(under) collection for purposes of the EMF, the method for allocating the increase in fuel and fuel-related costs, the composite fuel and fuel-related cost factors, and the EMFs along with exhibits and workpapers reflecting the following adjustments: (1) correction to the Company's weather normalization adjustment, (2) correction of the Company's customer growth adjustment, (3) correction of an inadvertent scrivener's error in the company's over/under recovery exhibit, and (4) inclusion of the over/under collection balances for the update period January – March 2019 in the over/under calculation. Company witness McGee's second supplemental testimony and revised exhibits set forth the projected fuel and fuel-related costs, the amount of over/ (under) collection for purposes of the EMF reflecting the following adjustments: (1) correction of Exhibit 3 under/(over) recovery balances due to an error found in the Schedule 4 monthly fuel reports filed with the Commission and (2) the removal of the update period January – March 2019. Public Staff witness Lucas recommended the approval of the prospective and EMF components and total fuel factors (excluding regulatory fee) set forth in Company witness McGee's second supplemental testimony.

Public Staff witness Li testified that the EMF riders proposed by DEC are based on DEC's calculated and reported North Carolina retail fuel and fuel-related cost under-recoveries of $30,299,742, $21,853,594, and $26,041,062 for the Residential, General Service/Lighting, and

Industrial classes, respectively. She recommended that DEC's EMF riders for each customer class be based on these net fuel and fuel-related cost under-recovery amounts and on the Company's proposed normalized North Carolina retail sales of 22,043,791 MWh for the residential class, 23,564,462 MWh for the general service/lighting class, and 12,465,801 MWh for the industrial class, as proposed by the Company. She stated that these amounts produce EMF increment riders for each North Carolina retail customer class as follows (excluding the regulatory fee):

Residential	0.1375 cents per kWh
General Service/Lighting	0.0927 cents per kWh
Industrial	0.2089 cents per kWh

Company witness McGee calculated the Company's proposed fuel and fuel-related cost factors for which there are no specific guidelines in N.C. Gen. Stat. § 62-133.2(a2) using a uniform bill adjustment method. She stated that DEC proposes to use the same uniform percentage average bill adjustment methodology to adjust its fuel rates to reflect a proposed increase in fuel and fuel-related costs as it did in its 2018 fuel and fuel-related cost recovery proceeding in Docket No. E-7, Sub 1163. No party opposed the use of this allocation method. Public Staff witness Lucas recommended the approval of the prospective and total fuel and fuel-related cost factors (excluding regulatory fee) set forth in Company witness McGee's second supplemental testimony and revised exhibits.

Based upon the testimony and exhibits in the record, the Commission concludes that DEC's projected fuel and fuel-related cost of $1,090,922,448 for the North Carolina retail jurisdiction for use in this proceeding is reasonable. The Commission also concludes that (1) DEC's EMFs proposed in this proceeding, excluding the regulatory fee, and (2) DEC's prospective fuel and fuel-related cost factors proposed in this proceeding for each of DEC's rate classes are appropriate. Additionally, the Commission concludes that DEC's increase in fuel and fuel-related costs from the amounts approved in Docket No. E-7, Sub 1163, other than those costs allocated pursuant to N.C. Gen. Stat. § 62-133.2(a2), should be allocated between the rate classes on a uniform percentage basis, using the uniform bill adjustment methodology approved by the Commission in DEC's past fuel cases.

The following tables summarize the impact of the rates approved in this case and the rates approved in Docket No. E-7, Sub 1163 (excluding regulatory fee).

E-7 Sub 1163			
Description	Residential cents/kWh	General Service Lighting cents/kWh	Industrial cents/kWh
Base Fuel	1.7828	1.9163	2.0207
Prospective Component	(0.0825)	(0.0849)	(0.2187)
EMF Component	0.0980	0.1068	0.2213
Total Fuel Factor	1.7983	1.9382	2.0233

E-7 Sub 1190			
Description	Residential cents/kWh	General Service Lighting cents/kWh	Industrial cents/kWh
Base Fuel	1.7828	1.9163	2.0207
Prospective Component	0.0298	0.0398	(0.1273)
EMF Component	0.1375	0.0927	0.2089
Total Fuel Factor	1.9501	2.0488	2.1023

Summary of Differences Sub 1190 — 1163 (excluding regulatory fee):

Change in Fuel Rates			
Description	Residential cents/kWh	General Service Lighting cents/kWh	Industrial cents/kWh
Base Fuel	-	-	-
Prospective Component	0.1123	0.1247	0.0914
EMF Component	0.0395	(0.0141)	(0.0124)
Total Fuel Factor	0.1518	0.1106	0.0790

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 18

The evidence for this finding of fact is contained in the testimony of Company witness McGee and in the affidavits of Public Staff witnesses Li and Lucas, and is discussed in more detail in Evidence and Conclusions for Finding of Fact No. 5.

The Commission has carefully reviewed the evidence and record in this proceeding. The test period and projected fuel and fuel-related costs, and the proposed factors, including the EMF, are not opposed by any party. Accordingly, the overall fuel and fuel-related cost calculations, incorporating the conclusions reached herein, results in net fuel and fuel-related cost factors of 1.9501 cents/kWh for the Residential class, 2.0488 cents/ kWh for the General Service/Lighting class, and 2.1023 cents/kWh for the Industrial class, excluding regulatory fee, consisting of the prospective fuel and fuel-related cost factors of 1.8126 cents/kWh, 1.9561 cents/kWh, and 1.8934 cents/kWh, EMF increments of 0.1375 cents/kWh, 0.0927 cents/kWh, and 0.2089 cents/kWh, all respectively, excluding the regulatory fee.

IT IS, THEREFORE, ORDERED as follows:

1. That effective for service rendered on and after September 1, 2019, DEC shall adjust the base fuel and fuel-related costs in its North Carolina retail rates of 1.7828 cents/kWh, 1.9163 cents/kWh, and 2.0207 cents/kWh for the Residential, General Service/Lighting, and Industrial classes, respectively as approved in Docket No. E-7, Sub 1146, by amounts equal to 0.0298 cents/kWh, 0.0398 cents/kWh, and (0.1273) cents/kWh for the Residential, General

Service/Lighting, and Industrial classes, respectively, and further, that DEC shall adjust the resulting approved fuel and fuel-related costs by EMF increments of 0.1375 cents/kWh for the Residential class, 0.0927 cents/kWh for the General Service/Lighting class, and 0.2089 cents/kWh for the Industrial class (excluding the regulatory fee). The EMF increments are to remain in effect for service rendered through August 31, 2020.

2. That DEC shall file appropriate rate schedules and riders with the Commission in order to implement these approved rate adjustments as soon as practicable.

3. That DEC shall work with the Public Staff to prepare a notice to customers of the rate changes ordered by the Commission in this docket, as well as in Docket No. E-7, Sub 1191, and the Company shall file such notice for Commission approval as soon as practicable, but not later than ten (10) days after the Commission issues orders in both dockets.

4. That the Company shall evaluate historic price fluctuations and whether its current method of forecasting and hedging programs should be adjusted to mitigate the risk of significant under-recovery of fuel costs and report the results of that evaluation in the Company's next fuel proceeding

ISSUED BY ORDER OF THE COMMISSION.
This the 7th day of August, 2019.

NORTH CAROLINA UTILITIES COMMISSION
A. Shonta Dunston, Deputy Clerk

DOCKET NO. E-2, SUB 936
DOCKET NO. E-2, SUB 1174

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 936 In the Matter of Application of Duke Energy Progress, LLC, for Approval of Modifications to Residential Smart $aver Energy Efficiency Program DOCKET NO. E-2, SUB 1174 In the Matter of Application of Duke Energy Progress, LLC, for Approval of Demand-Side Management and Energy Efficiency Cost Recovery Rider Pursuant to Gen. Stat. § 62-133.9 and Commission Rule R8-69	)	ORDER APPROVING PROGRAM MODIFICATIONS

BY THE COMMISSION: On December 18, 2018, Duke Energy Progress, LLC (DEP or Company), filed a request seeking approval to modify its Residential Smart $aver Energy Efficiency Program (Program).

The proposed modifications were filed in response to the Commission's *Order Approving DSM/EE Rider and Requiring Filing of Customer Notice* issued on November 29, 2018, in Docket No. E-2, Sub 1174, where the Commission ordered the Company to propose modifications to the Program no later than December 31, 2018, with the goal of restoring the TRC score to 1.0 or greater. In its application, DEP indicated that the modifications to the Program are intended to increase its overall cost-effectiveness. DEP's proposed modifications to the Program include: acknowledging lower actual incremental customer costs; improving trade ally participation to make it more streamlined and less costly; reducing program administration costs; implementing a three-year transition period to a referral-only channel; and introducing an online channel. The Company also proposed to eliminate from the tariff the listing of the maximum incentives for the measures, as well as to reduce the maximum incentive for HVAC (Heating, Ventilation, and Air Conditioning) equipment from $600 to $400.

DEP's application indicated that the effect of these proposed modifications would be a Total Resource Cost Test (TRC) score of 1.35.

DEP's application requested that the Commission: (1) approve the Program and tariff as modified; (2) find that the Program continues to meet the requirements of a "new" energy efficiency program pursuant to Commission Rule R8-69; (3) find that all costs of the Program will be eligible for cost recovery; and (4) approve the proposed utility incentives for inclusion in the annual DSM/EE rider.

The Public Staff filed comments on February 4, 2019, regarding the Company's proposal. The Public Staff did not oppose the first four modifications as proposed. However, the Public Staff recommended that the online channel be separate and distinct from the HVAC-related measures and that the performance of the Program be accounted for separately in the Company's annual rider proceedings. The Public Staff stated that if the compliance tariff is amended, it is not opposed to the approval of the online channel for the Program. The Public Staff also recommended that the Commission request that the parties address the issue of what measures are appropriate for inclusion in a particular program during the upcoming review of the Company's cost recovery mechanism.

On February 13, 2019, the Company filed a letter stating that while the Company did not necessarily agree that the inclusion of the online channel within the Program is inappropriate, for purposes of this proceeding, the Company agreed with the Public Staff's recommendation that the Commission approve the first four modifications as part of the Residential Smart $aver Program and require the Company to file a separate compliance tariff for the online channel. The Company also agreed to report the performance of the HVAC-related measures and the online channel-related measures separately in the Company's annual rider proceedings.

The Public Staff presented this matter to the Commission at its Regular Staff Conference on February 25, 2019. The Public Staff summarized its filed comments and recommended that the Commission issue its proposed order on the Company's request.

Based on the foregoing, the Commission is of the opinion that the proposed modifications to the Program should be approved, the Company should be directed to file a separate compliance tariff for the online channel, and the Company should report the performance of the HVAC-related measures and the online channel-related measures separately in the Company's annual rider proceedings.

IT IS, THEREFORE, ORDERED:

1. That DEP's proposed modifications to the Residential Smart $aver Energy Efficiency Program are hereby approved.

2. That DEP shall file a separate compliance tariff for the online channel.

3. That DEP shall report the performance of the HVAC-related measures and the online channel-related measures separately in the Company's annual rider proceedings.

4. That the Residential Smart $aver Energy Efficiency Program continues to be eligible for recovery of program costs and incentives, in accordance with N.C. Gen. Stat. § 62-133.9 and Commission Rule R8-69.

5. That DEP shall file with the Commission, within 10 days following the date of this order, a revised tariff showing the effective date of the tariff.

6. That the parties shall address the issues of what measures are appropriate for inclusion in a particular program during the upcoming review of the Company's cost recovery mechanism.

ISSUED BY ORDER OF THE COMMISSION.
This the 27th day of February, 2019.

NORTH CAROLINA UTILITIES COMMISSION
A. Shonta Dunston, Deputy Clerk

Commissioners James G. Patterson and Lyons Gray did not participate in this decision.

DOCKET NO. E-2, SUB 1085

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application by Duke Energy Progress, LLC, for Approval to Terminate the Residential Save Energy and Water Kit Program	))))	ORDER TERMINATING PROGRAM

BY THE COMMISSION: On April 2, 2019, Duke Energy Progress, LLC (DEP or the Company), filed an application seeking approval to terminate its Residential Save Energy and Water Kit Program (SEWK Program).

The SEWK Program was originally approved as an energy efficiency (EE) program on October 6, 2015 to provide participants with free energy efficient water heating savings kits, consisting of a combination of low flow showerheads, kitchen and bathroom faucet aerators, and pipe wrap insulation.

On February 27, 2019, the Commission approved modifications to DEP's Residential Energy Efficient Appliances and Devices (REEAD) Program. Those modifications included incorporating the water reduction and efficiency measures offered by the SEWK Program into the REEAD Program. DEP stated that with the approval of the REEAD Program modifications, the SEWK Program is now redundant.

The Public Staff presented this matter at the Commission's Regular Staff Conference on May 6, 2019, and recommended approval of the Company's request to terminate the SEWK Program.

Based on the foregoing and the entire record in this proceeding, the Commission finds good cause to approve DEP's request to terminate the SEWK Program.

IT IS, THEREFORE, ORDERED as follows:

1. That the SEWK Program is hereby terminated effective as of the date of this Order; and

2. That the Commission shall determine the appropriate ratemaking treatment for the SEWK Program, including program costs, net lost revenues, and incentives, in DEP's annual cost recovery rider, in accordance with N.C. Gen. Stat. § 62-133.9 and Commission Rule R8-69.

ISSUED BY ORDER OF THE COMMISSION.
This the 6th day of May, 2019.

NORTH CAROLINA UTILITIES COMMISSION
A. Shonta Dunston, Deputy Clerk

Chairman Edward S. Finley, Jr., and Commissioner James G. Patterson did not participate in this decision.

DOCKET NO. E-2, SUB 1153
DOCKET NO. E-2, SUB 1142

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1153	)	
	)	
In the Matter of	)	
Petition of Duke Energy Progress, LLC,	)	
for an Order Approving a Job Retention Rider	)	ORDER APPROVING
	)	END OF JOB RETENTION
DOCKET NO. E-2, SUB 1142	)	PILOT PROGRAM AND
In the Matter of	)	APPROVING CUSTOMER NOTICE
Application by Duke Energy Progress, LLC,	)	
for Adjustment of Rates and Charges	)	
Applicable to Electric Utility Service in	)	
North Carolina	)	

ELECTRIC -- RATE SCHEDULES/RIDERS/SERVICE RULES AND REGULATIONS

BY THE COMMISSION: On February 23, 2018, the Commission issued an Order Accepting Stipulation, Deciding Contested Issues and Granting Partial Rate Increase (Rate Order), in the above-captioned dockets authorizing Duke Energy Progress, LLC (DEP) to adjust its rates and charges for retail electric service in North Carolina. In addition, the Rate Order approved a Job Retention Pilot Program (JRPP) for the purpose of retaining industrial jobs in North Carolina. The JRPP was approved for one year, with the option to renew the JRPP for a second year, upon a showing that the JRPP is achieving its intended results. Further, the Rate Order approved a Job Retention Rider (JRR) as the revenue source that funds the JRPP.

On July 22, 2019, DEP filed a letter and supporting tariffs notifying the Commission that DEP has elected not to renew the JRPP for a second year. In addition, DEP provided a proposed Customer Notice to be used as a bill insert to inform all customers of the end of the JRPP and JRR. Further, DEP stated that once all activity related to the JRPP concludes, DEP anticipates filing a request by mid-November 2019 to address via a true-up rider the revenue differences between the amount received under the JRR and the cost of the JRPP. DEP stated that the true-up rider would be in effect for 12 months, beginning on January 1, 2020, which will coincide with other rate rider changes. Moreover, DEP stated that interest will accrue on any over-collected JRPP balance. Finally, DEP stated that it has discussed this proposal with the Public Staff, and that the Public Staff supports this approach.

Based on the foregoing and the record in these dockets, the Commission finds good cause to grant DEP's request to exercise the option not to renew the Job Retention Pilot Program, to revise its tariffs to reflect the end of the Job Retention Rider as of September 1, 2019, and to send all customers its proposed Customer Notice by bill insert.

IT IS, THEREFORE, ORDERED as follows:

1. That DEP's request to not renew the Job Retention Pilot Program, and to revise its tariffs to reflect the end of the Job Retention Rider as of September 1, 2019, is hereby approved.

2. That DEP's proposed Customer Notice, to be provided to all DEP customers by bill insert, is hereby approved.

ISSUED BY ORDER OF THE COMMISSION.
This the 22 day of August, 2019.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

ONE-HUNDRED NINTH REPORT

OF THE

NORTH CAROLINA

UTILITIES COMMISSION

ORDERS AND DECISIONS

Volume II

ISSUED FROM
JANUARY 1, 2019 THROUGH DECEMBER 31, 2019

ONE-HUNDRED NINTH REPORT
of the
NORTH CAROLINA UTILITIES COMMISSION

ORDERS AND DECISIONS

Issued from

January 1, 2019, through December 31, 2019

*Edward S. Finley, Jr., Chairman

ToNola D. Brown-Bland, Commissioner

**Jerry C. Dockham, Commissioner

**James G. Patterson, Commissioner

Lyons Gray, Commissioner

Daniel G. Clodfelter, Commissioner

*Charlotte A. Mitchell, Commissioner

*Kimberly W. Duffley, Commissioner

*Jeffrey A. Hughes, Commissioner

North Carolina Utilities Commission
Office of the Chief Clerk
Kimberley A. Campbell
4325 Mail Service Center
Raleigh, North Carolina 27699-4300

The Statistical and Analytical Report of the North Carolina Utilities Commission is printed separately from the volume of Orders and Decisions and will be available from the Office of the Chief Clerk of the North Carolina Utilities Commission upon order.

* Chairman Finley retired May 31, 2019.
** Commissioners Dockham and Patterson retired June 30, 2019.

* Commissioner Mitchell, appointed Chair June 4, 2019.
* Commissioner Duffley, seated November 12, 2019.
* Commissioner Hughes, seated November 17, 2019.

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BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Petition of Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC, Requesting Approval of Green Source Advantage Program and Rider GSA to Implement N.C.G.S. § 62-159.2	)))))	ORDER MODIFYING AND APPROVING GREEN SOURCE ADVANTAGE PROGRAM, REQUIRING COMPLIANCE FILING, AND ALLOWING COMMENTS

BY THE COMMISSION: On January 23, 2018, Duke Energy Carolinas, LLC (DEC), and Duke Energy Progress, LLC (DEP), (together, Duke), jointly filed a petition for approval of the Green Source Advantage Program (GSA Program) and the corresponding Rider GSA (for DEC) and Rider GSA-1 (for DEP). In its petition, Duke argues that the proposed GSA Program is designed to implement the requirements of N.C.G.S. § 62-159.2, as enacted by Part III of S.L. 2017-192 (House Bill 589), and to cost-effectively facilitate Duke's direct procurement of new renewable energy resources on behalf of North Carolina's major military installations, the University of North Carolina system, and large nonresidential customers that are retail electric customers of DEC or DEP.

On January 26, 2018, the Commission issued an Order establishing this proceeding to review Duke's proposed GSA Program, rider tariffs, and associated program design features. That Order also set out a schedule for the filing of petitions to intervene, initial comments, and reply comments in this proceeding.

On or after January 30, 2018, the Commission issued orders allowing the following to intervene in this proceeding: the North Carolina Sustainable Energy Association (NCSEA), the North Carolina Clean Energy Business Alliance (NCCEBA), Wal-Mart Stores East, LP, and Sam's East, Inc. (together, Walmart), North Carolina Electric Membership Corporation (NCEMC), the United States Department of Defense and all other Federal Executive Agencies (DoD/FEA), the University of North Carolina at Chapel Hill (UNC-CH), Apple, Inc., and Google, LLC, (together, Apple and Google), and the Southern Alliance for Clean Energy (SACE).

On February 19, 2018, the North Carolina Attorney General's Office (AGO) filed a notice of intervention pursuant to N.C.G.S. § 62-20.

The participation of the Public Staff is recognized pursuant to N.C.G.S. § 62-15(d).

On February 22 and 23, 2018, DoD/FEA, NCCEBA, NCSEA, Apple and Google, SACE, Walmart, and the Public Staff filed initial comments.

Also on February 23, 2018, the following corporations filed a joint consumer statement of position: New Belgium Brewing, SAS Institute, Inc., Sierra Nevada Brewing Co., Unilever, and VF Corporation.

On April 20, 2018, Duke, NCCEBA, NCEMC, NCSEA, SACE, UNC-CH, the AGO, and the Public Staff filed reply comments.

On May 4, 2018, NCCEBA, NCSEA, UNC-Chapel Hill, and DoD/FEA filed a joint motion for leave to file sur-reply comments. On May 15, 2018, Duke filed a response to that joint motion, stating that it is not opposed to allowing the motion, but requesting an opportunity to respond and otherwise disputing some statements included in that joint motion.

On July 16, 2018, the Commission issued an Order Scheduling Oral Argument, setting this matter for oral argument on September 4, 2018. In addition to scheduling this matter for oral argument, that Order states that "it is premature to allow comments addressing the proposed contracts filed in this proceeding at this time." However, that Order further expressed encouragement to the parties to continue to discussions in an effort to reach agreement on the disputed issues in this proceeding.

On September 4, 2018, this matter came on for oral argument as scheduled.

On September 5, 2018, Duke filed a consumer statement of position on behalf of Wells Fargo Bank, N.A. (Wells Fargo). In its statement of position, Wells Fargo expresses support for three proposals for calculating the GSA Bill Credit: the bill credit based on administratively-determined 5-year avoided cost, the bill credit calculated on an hourly, day-ahead projection similar to that proposed in the Walmart settlement, and the GSA customer negotiating a levelized $/MWh price with the third-party renewable developer that becomes the GSA Product Charge and the GSA customer being permitted to allocate the total capacity (and the associated GSA Product Charge and Bill Credit) between various of the GSA customer's accounts.

On September 19, 2018, NCSEA and NCCEBA filed post hearing comments.

On September 26, 2018, Duke filed a motion to strike certain statements from the post-hearing comments of NCSEA and NCCEBA.

On October 8, 2018, Duke filed a response to the Commission's questions raised at oral argument.

On October 11, 2018, the Commission issued an Order on Post Oral Argument Filings. In that Order the Commission determined that NCSEA and NCCEBA's post-hearing comments contained statements that were appropriately responsive to the Commission's questions and statements that were inappropriately argumentative. Therefore, that Order granted Duke's motion to strike, in part, and denied the motion, in part.

On October 24, 2018, NCCEBA, UNC-Chapel Hill, and SACE filed an agreement and partial settlement. In this filing, these parties detail their agreement to a bill credit that would be fixed for 10 years and thereafter be "refreshed" based on updated cost data, if the customer is participating under an agreement that extends beyond 10 years.

On October 25, 2018, the AGO filed a response to the NCCEBA, UNC-Chapel Hill, and SACE agreement and partial settlement, expressing support for Commission approval of that agreement.

RENEWABLE ENERGY PROCUREMENT FOR MAJOR MILITARY INSTALLATIONS, PUBLIC UNIVERSITIES, AND OTHER LARGE CUSTOMERS

On July 27, 2017, House Bill 589 (Session Law 2017-192) was enacted into law. Part III of House Bill 589, enacted as N.C.G.S. § 62-159.2 (GSA Statute), requires DEC and DEP to file with the Commission an application requesting approval of a new program to procure renewable energy resources on behalf of North Carolina's major military installations, the University of North Carolina system, and large nonresidential customers served by the offering utility. Subsection N.C.G.S. § 62-159(a) provides that the term "major military installation" is defined as provided in N.C.G.S. § 143-215.115(1),[1] that the University of North Carolina is the public, multi-campus university encompassing 16 constituent institutions as established by Article 1 of Chapter 116 of the General Statutes (UNC System), and that the other new and existing nonresidential customers to whom this program applies are those nonresidential customers with either a contract demand (i) equal to or greater than one megawatt (MW), or (ii) at multiple service locations that, in aggregate, is equal to or greater than five MW.

Pursuant to N.C.G.S. § 62-159.2(b), the program application shall provide standard contract terms and conditions for participating customers and for renewable energy suppliers from which the electric public utility procures energy and capacity on behalf of the participating customer. Further, that subsection provides that eligible customers shall be allowed to select the new renewable energy facility from which the electric public utility shall procure energy and capacity under the proposed program. In addition, that subsection provides that the standard terms and conditions available to renewable energy suppliers shall provide a range of terms, between two years and 20 years, from which the participating customer may elect. Finally, that subsection provides that the eligible customers shall be allowed to negotiate with the renewable energy suppliers regarding price terms.

Pursuant to N.C.G.S. § 62-159.2(c), each contracted amount of capacity under the program shall be limited to no more than 125% of the maximum annual peak demand experienced at the

[1] Pursuant to N.C.G.S. § 143-215.115(1), the term "major military installation" means Fort Bragg, Pope Army Airfield, Marine Corps Base Camp Lejeune, New River Marine Corps Air Station, Cherry Point Marine Corps Air Station, Military Ocean Terminal at Sunny Point, the United States Coast Guard Air Station at Elizabeth City, Naval Support Activity Northwest, Air Route Surveillance Radar (ARSR-4) at Fort Fisher, and Seymour Johnson Air Force Base, in its own right and as the responsible entity for the Dare County Bombing Range, and any facility located within the State that is subject to the installations' oversight and control.

eligible customer's premises. In addition, this subsection provides that DEC and DEP shall establish reasonable credit requirements for financial assurance for eligible customers that are consistent with the Uniform Commercial Code of North Carolina[1] However, this subsection further provides that major military installations and the UNC System are exempt from the financial assurance requirements.

Pursuant to N.C.G.S. § 62-159.2(d), the program shall be offered by DEC and DEP for a period of five years, or until December 31, 2022, whichever is later, and shall not exceed a combined 600 MW of total capacity. That subsection provides that 100 MW of new renewable energy facility capacity shall be reserved for participation by major military installations, and that 250 MW of new renewable energy facility capacity shall be reserved for participation by the UNC System. That subsection further provides that major military installations and the UNC System must fully subscribe to these reserved capacity amounts prior to December 31, 2020, or three years after Commission-approval of the program, whichever is later. Any of these reserved capacities not subscribed to by the applicable deadline, shall be reallocated for use by any eligible program participant. Finally, any of the total GSA Program capacity not subscribed to by the end of the Program shall be reallocated to and included in a competitive procurement of renewable energy as provided in N.C.G.S. § 62-110.8(a).

Pursuant to N.C.G.S. § 62-159.2(e), in addition to the participating customer's "normal retail bill," the total cost of any renewable energy and capacity procured by or provided by the electric public utility for the benefit of the program customer shall be paid by that customer. Further, that subsection provides that DEC or DEP shall pay the owner of the renewable energy facility which provided the electricity. In addition, that subsection provides that the participating customer shall receive a bill credit for the energy as determined by the Commission; provided that, the bill credit shall not exceed the utility's avoided cost. Finally, that subsection provides that the Commission shall ensure that all other customers are held neutral, neither advantaged nor disadvantaged, from the impact of the renewable electricity procured on behalf of the program customer.

DUKE'S PETITION FOR APPROVAL OF THE
GREEN SOURCE ADVANTAGE PROGRAM AND GSA RIDER TARIFFS

Duke's petition provides a detailed review of the proposed GSA Program and the program design. In its overview, Duke first sets the proposed GSA Program in the context of the existing renewable energy and energy efficiency portfolio standard (REPS)[2] requirements and the recently approved program for the competitive procurement of renewable energy (CPRE Program).[3] Duke states that North Carolina has been a national leader in promoting the development of renewable energy generation since the enactment of the REPS in 2007, and that the CPRE Program, and its requirement to procure 2,660 MW of new renewable energy capacity over a 45-month period as

[1] Codified at Chapter 25 of the General Statutes.

[2] Codified at N.C.G.S. § 62-133.8.

[3] Codified at N.C.G.S. § 62-110.8. See also Commission Rule R8-71, and Order Modifying and Approving Joint CPRE Program, Docket No. E-2, Sub 1159, and E-7, Sub 1156 (issued Feb. 21, 2018).

"another major policy step forward." Duke describes N.C.G.S. § 62-159.2 as an additional mandate for the direct procurement of up to 600 MW of new renewable energy capacity for GSA Program-eligible customers over the next five years. After the conclusion of the GSA Program, Duke states that N.C.G.S. § 62-110.8(a) requires that the remaining GSA Program capacity be transitioned to the general renewable energy competitive procurement as an expansion of the CPRE Program. Thus, Duke states, House Bill 589 positions the state to continue to significantly expand Duke's procurement of cost effective renewable energy resources through both direct procurement, on behalf of participating GSA Program customers, and through the CPRE Program, on behalf of all customers.

Duke then argues that its proposed GSA Program meets the requirements of House Bill 589 to develop a customer-directed program for eligible customers to increase their commitment to renewable energy, while ensuring that non-participating customers are held neutral, neither advantaged nor disadvantaged, from the procurement requirements of N.C.G.S. § 62-159.2. Duke proposes to satisfy these mandates by offering two options under the GSA Program: (1) a "standard offer" GSA procurement option, where an eligible GSA Program customer would direct DEC or DEP to procure new renewable energy facilities dedicated to the GSA Program on behalf of the customer; and (2) a "self-supply option" that would allow customers to negotiate with renewable energy suppliers regarding price terms and select the new renewable energy facility from which DEC or DEP shall procure energy and capacity. Duke proposes that the standard offer option would be integrated with the CPRE Program request for proposal (RFP) process to ensure that the cost of the renewable power procured at the direction of the GSA Program customer is comparably cost-effective to that of new renewable energy resources procured under the CPRE Program for all customers. Duke states that, under both options, all retail customers receive the benefit of cost-effective energy and capacity, while each customer participating in the GSA Program will receive the renewable energy certificates (RECs) earned by the new renewable energy facilities participating in the GSA Program.

Duke next addresses in detail the following aspects of its proposed GSA Program design:

(1) <u>GSA Program availability and customer eligibility:</u> Duke states that it has designed the GSA Program's availability and customer eligibility requirements to meet the requirements of N.C.G.S. § 62-159.2, as further addressed in DEC and DEP's respective GSA Program tariffs attached to its petition. Duke proposes a three-year reserve period, during which 250 MW of the total 600 MW of GSA Program capacity will be reserved for the UNC System customers and 100 MW of the total 600 MW of GSA Program capacity will be reserved for major military installation customers. Duke further proposes that, at the end of the reserve period, any unsubscribed capacity will become available to any customer eligible to participate in the GSA Program, subject to Duke's proposed allocation of GSA Program capacity between DEC and DEP's service territories.

Duke proposes to allocate the 250 MW of unreserved GSA Program capacity between DEC and DEP's service territories based upon the load-ratio share of DEC and DEP's commercial and industrial customer classes. Therefore, proposed Rider GSA and Rider GSA-1 provide that 160 MW shall be allocated and available to DEC customers eligible for participation in the GSA Program and 90 MW shall be allocated and available to DEP customers eligible for participation in the GSA Program. Duke states that it will review and potentially update this proposed allocation after the expiration of the three-year reserve period.

Duke also proposes that customer eligibility for the GSA Program be limited to North Carolina retail customers receiving concurrent service from DEC or DEP who elect to contract for the RECs associated with renewable energy generated by a new renewable energy facilities dedicated to the GSA Program. Further, Duke proposes that large nonresidential customers seeking to participate in the GSA Program must have a contract demand that is equal to one MW or an aggregate demand at multiple service locations that is equal to or greater than five MW. In addition, Duke proposes that for a customer whose eligibility is based on aggregation of accounts to meet the five MW minimum, the aggregated accounts must be located within the same utility's service territory. Finally, Duke proposes that the customer participating in the GSA Program be required to be located in the same utility's service territory, in either North Carolina or South Carolina, as the new renewable energy facility or facilities dedicated to the GSA Program.

(2) The standard offer and self-supply options: Duke proposes two options for eligible customers to participate in the GSA Program: a standard offer option and a self-supply option. Under the proposed standard offer option, Duke states that DEC or DEP will procure renewable energy from a portfolio of new renewable energy facilities dedicated to the GSA Program, based upon customer interest expressed prior to each GSA Program RFP Solicitation. Duke states that this is intended to incorporate the GSA Program standard offer option into future CPRE RFPs as an "integrated component of the CPRE RFP process," and that any GSA Program standard offer capacity would be included in the CPRE RFP solicitation issued by the Independent Administrator of the CPRE Program and required to be consistent with the CPRE Program Guidelines. Evaluation of proposals would be managed by the Independent Administrator as provided in Commission Rule R8-71(f)(3) and future CPRE Program Plans would identify GSA Program capacity forecasted to be procured by DEC and DEP under the Standard Offer option. Under the proposed self-supply option, Duke states that customers eligible to participate in the GSA Program would be allowed to negotiate with renewable energy suppliers regarding price terms, select from contract terms of 2, 5, and 20 years, and select the renewable energy facility from which DEC or DEP shall procure energy and capacity.

Included in this section of Duke's petition is a planned GSA Program enrollment and implementation timeline. This timeline anticipates Commission approval of the proposed GSA Program in summer 2018, and marketing of the program to eligible customers during the remainder of 2018. As proposed by Duke, the initial enrollment window for eligible customers to apply to reserve capacity under either the standard offer or the self-supply option will open January 1, 2019, and close prior to the initiation of the CPRE Tranche 2 RFP Solicitation, which is scheduled for February 2019.[1] After the close of this first enrollment window, Duke will announce the aggregate GSA capacity that has been applied for and procure the capacity applied for as part of the Tranche 2 RFP Solicitation, in addition to the required CPRE Program capacity for Tranche 2. After the close of each CPRE RFP Solicitation bid evaluation, Duke will establish the

[1] On September 5, 2018, in Docket No. E-100, Sub 157, DEC and DEP filed updated CPRE Program plans as part of their 2018 integrated resource planning filings.

applicable GSA bill credit and enter into power purchase agreements (PPAs) with the new renewable energy facilities dedicated to the GSA Program. Any remaining GSA Program capacity will then be made available to customers eligible to participate in the GSA Program through a subsequent enrollment window, which would be open until the issuance of the CPRE Tranche 3 RFP Solicitation. This iterative enrollment and capacity allocation process would repeat until the total GSA Program capacity is subscribed, and, at the end of the GSA Program, any amount of unsubscribed capacity would be transitioned to the CPRE Program, as required by N.C.G.S. § 62-110.8(a).

(3) <u>The GSA customer application and enrollment process:</u> As proposed by Duke, a customer eligible to participate in the GSA Program must first submit an application form through the GSA Program web platform on Duke's website. These applications would be accepted during an open enrollment period based upon Duke's proposed GSA Program implementation timeline. The customer application will identify an annual amount of capacity to be procured from one or more new renewable energy facility(ies) dedicated to the GSA Program, up to 125% of the customer's maximum annual peak demand at the customer's premises, and identify whether the eligible customer is seeking to participate in the standard offer procurement process or is seeking to negotiate independently with one or more new renewable energy facilities dedicated to the GSA Program under the self-supply option. Additionally, the customer must identify the term of the GSA Program service agreement from the 2-, 5-, and 20-year options available. The standard offer would only be available under a 20-year term, consistent with the CPRE Program procurement term. An eligible customer would be required to submit a $2,000 application fee, which would be refunded only in the event that there is insufficient capacity available under the GSA Program.

An eligible customer seeking the self-supply option must have identified and negotiated price terms with the new renewable energy facility dedicated to the GSA Program and executed a standard form GSA term sheet prior to submitting the customer application for the GSA Program. The customer will be required to submit information about its selected new renewable energy facility by attaching the executed GSA term sheet to the application. In addition, the GSA term sheet will require the new renewable energy facilities dedicated to the GSA Program to attest that the facility will have corresponding supply that is exclusively dedicated to the GSA Program and that the renewable energy capacity is reserved on behalf of the customer-applicant. The facility supplying the renewable energy under the self-supply option will also be required to pay a GSA reservation fee calculated in a manner substantially similar to the bid bond established in the CPRE Program Guidelines.

Upon receipt of the completed application and the applicable fees, DEC or DEP will assign GSA capacity to the eligible customer on a first come, first served basis in the appropriate queue depending upon the reserved capacity sought (major military installations, UNC System, or unreserved). Duke states that this process will apply to both the standard offer option and the self-supply option and is designed to provide queueing parity among eligible customers of the same class. After accepting the completed application, DEC or DEP will deliver a standard GSA Service Agreement to the customer. Duke states that the GSA Service Agreement will describe the general terms and conditions, identify the material terms of the arrangement, and, for customers enrolling in the self-supply option, address the terms for pricing, tracking, and depositing RECs. Although the GSA Service Agreement for the self-supply option will address the handling of RECs, Duke further states that it will not take title to RECs under this option; rather, title to the RECs will transfer directly to the customer from the renewable energy facility owner. The GSA Service Agreement will also set forth the financial security required. Finally, Duke proposes that a GSA customer be required to execute the GSA Service Agreement within 30 calendar days of delivery, and additionally, under the self-supply option, that the renewable energy facility owner would be required to execute a GSA PPA within 30 calendar days of delivery. Failure to meet these deadlines would result in termination of the customer application.

(4) The GSA Product under the standard offer and self-supply options: In Duke's view, the GSA Program is "integrally tied to HB589's broader renewable energy procurement mandate" because any unsubscribed capacity under the GSA Program transitions into the CPRE Program pursuant to N.C.G.S. § 62-159.2(d). Thus, Duke proposes that the "GSA renewable energy product" procured under the GSA standard offer will be the same as the CPRE Program product, including requiring the new renewable energy facilities dedicated to the GSA Program to transfer contractual rights to the renewable energy, capacity, and environmental and renewable attributes as well as the rights to dispatch, operate, and control the renewable energy facility in the same manner as the utility's own generating resources. Thus, under Duke's proposed standard offer option, DEC or DEP will enter into a bundled PPA that is materially similar to the CPRE Program PPA, and the RECs associated with the PPA will be transferred from DEC or DEP to the NC-RETS account designated by the GSA customer. Under Duke's proposed self-supply option, DEC or DEP will enter into an unbundled GSA PPA with the owner of the new renewable energy facilities dedicated to the GSA Program for the energy and capacity, but not the RECs. Under the self-supply option, the RECs generated by the new renewable energy facilities dedicated to the GSA Program will be the subject of separate negotiations and agreements between GSA customers and the owner of the new renewable energy facilities dedicated to the GSA Program.

(5) The methodology for establishing the GSA bill credit: Duke states that its proposed methodology for determining the billing credit that a customer participating in the GSA Program will receive "was designed to meet the unique requirements of" N.C.G.S. § 62-159.2. Under Duke's proposed methodology, the customer participating in the GSA Program will remain a full requirements retail customer of DEC or DEP, and the new renewable energy facilities dedicated to the GSA Program will be a system asset providing energy and capacity to serve all of Duke's native load customers. Duke argues that the proposed GSA Program will facilitate eligible customers directing the procurement of renewable energy from the new renewable energy facilities dedicated to the GSA Program, but the participating customer will not be responsible for the cost and risk associated with directly procuring its own energy and capacity solely from the facility. As examples, Duke states that in the event of default by the owner of the new renewable energy facility dedicated to the GSA Program, DEC or DEP would continue to serve the customer's full electric requirements from other system resources, and, in the event of default by a customer participating in the GSA Program, DEC or DEP would have recourse to recover any outstanding costs of RECs (under the standard offer) and administrative costs, including the claim to any posted security, but DEC or DEP would otherwise continue to supply the customer's retail electric service and would continue to perform under the GSA PPA.

Duke proposes that the bill credit applicable to both the standard offer and the 20-year self-supply option will be equal to the capacity-weighted average price of all proposals selected in the most recently concluded CPRE RFP Solicitation, minus the forecasted cost of RECs that will be received by the participating customer.[1] The forecasted cost of RECs will be determined by Duke prior to each GSA Program enrollment period based on a national, voluntary market index for procuring RECs. Duke argues that calculating the bill credit in this manner appropriately recognizes that the bundled renewable energy product procured through the CPRE Program represents the current market price of renewable energy capacity available to serve customers not participating in the GSA Program, who will be served by, and pay for, the energy and capacity generated by the new renewable energy facilities dedicated to the GSA Program. Duke further argues that because the CPRE Program is initially procuring bundled renewable energy to serve the electric requirements of all native load customers, reducing the bill credit by the cost of RECs appropriately allocates the cost of renewable energy attributes to the customer participating in the GSA Program. This arrangement, Duke concludes, meets the requirements of N.C.G.S. § 62-159.2 by ensuring that customers not participating in the GSA Program are held neutral from the impact of the procurement obligations arising under the GSA Program, and that the bill credit does not exceed DEC or DEP's forecasted avoided cost rate. Finally, for customers participating in the GSA Program that select the 2- or 5-year contract terms under the self-supply option, the bill credit will be the lesser of the negotiated GSA PPA contract price, or the forecasted avoided cost rate for the applicable contract term.

(6) Rider GSA Rate Design: Duke proposes rate designs for the options available to customers participating in the GSA Program, and detailed the charges and credits that would take place between Duke, the customer participating GSA Program, and, if applicable, the new renewable energy facilities dedicated to the GSA Program, as selected by the GSA Program customer under the self-supply option. These proposed charges and credits are depicted in figures 2 and 3 in Duke's petition, and summarized in the following tables.

[1] Duke included a graphical representation of the timeline for GSA Program enrollment and implementation that also shows the timing of the CPRE RFP Solicitations as Figure 1 in its petition. The same figure is included as Attachment 2 to its petition for ease of reference.

Table 1. Summary of Duke's Proposed Standard Offer Option Rate Design

	Proposed Charges or Credits		
GSA Customer Pays Duke:	**Retail** charges under existing rate schedule	**GSA Product Charge** = quantity of energy delivered by the new renewable energy facility dedicated to the GSA Program (in kWh) during the prior billing month, multiplied by the weighted average price of the most recently concluded CPRE RFP Solicitation (in $/kWh)	**GSA Administrative Charges** = $375/month, plus $50/month for each billed account. As discussed further below, Duke states that this charge is intended to recover costs for manual billing, labor, program management and support costs.
Duke pays GSA renewable energy facility:	**Bundled renewable energy product PPA price** = the facility owner's as-bid RFP price (in $/MWh), divided by 1,000, and multiplied by the quantity of energy delivered by that facility (in kWh) during the prior billing month.		
Duke pays GSA Customer:	**GSA Bill Credit** = the weighted average price of the most recent CPRE RFP Solicitation (in $/kWh), minus the GSA REC value (in $/MWh) divided by 1,000, and multiplied by the quantity of energy delivered by the facility(ies) (in kWh) during the prior billing month.		

Note: the **GSA Product Charge** – **the GSA Bill Credit** = **value of RECs** procured. The net effect on the GSA Customer's bill is the sum of the **value of RECs procured, GSA Administrative Charges,** and the customer's **retail charges** under its existing rate schedule.

Table 2. Summary of Duke's Proposed Self-Supply Option Rate Design

	Proposed Charges or Credits		
GSA Customer Pays Duke:	**Retail** charges under its existing rate schedule	**GSA Product Charge** = For 20-year term: weighted average price of the most recent CPRE RFP Solicitation (in $/MWh), minus GSA REC value (in $/MWh) divided by 1,000, and then multiplied by the quantity of energy delivered to DEC or DEP by the designated new renewable energy facility in the previous billing month. For 2- and 5-year term: lesser of forecasted avoided cost rate or negotiated unbundled PPA price. Note: This **Product Charge** is equal to the **negotiated unbundled PPA price** paid by Duke to the GSA renewable energy facility owner. This **Product Charge** is also equal to the **GSA Bill Credit.**	**GSA Administrative Charges** = $375/month, plus $50/month for each billed account.
Duke pays GSA renewable energy facility owner	**The negotiated, unbundled self-supply PPA price under the GSA self-supply PPA** (which is limited to the lesser of the unbundled self-supply PPA price or the avoided cost rate)		
GSA Customer pays renewable energy facility owner	An **agreed-to price for the RECs** earned by the facility, which reflects the difference between the bundled, negotiated PPA price, and the negotiated, unbundled self-supply PPA price.		
Duke pays GSA Customer	**GSA Bill Credit** = For 20-year term: weighted average price of the most recent CPRE RFP Solicitation (in $/MWh), divided by 1,000, multiplied by the quantity of energy delivered to DEC or DEP by the designated new renewable energy facility. For 2- and 5-year term: lesser of forecasted avoided cost rate or negotiated unbundled PPA price. Note: This **GSA Bill Credit** = **GSA Product Charge.**		

Note: the net effect on the GSA Customer's bill is the sum of the **GSA Administrative Charges** and the customer's **retail charges** under its existing rate schedule. The self-supply customer will separately pay the GSA renewable energy facility owner an **agreed-to price for the RECs** earned by the facility, which would reflect the difference between the negotiated, bundled PPA price and the negotiated, unbundled self-supply PPA price.

Duke also proposes that under the self-supply option all self-supply customers that enroll during the same enrollment period will receive the same fixed GSA bill credit for the monthly energy produced, which would be equal to the CRPE Tranche weighed average price minus the

GSA REC value. Similarly, Duke proposes that all standard offer customers that enroll during the same enrollment period will receive the same fixed GSA bill credit for monthly energy produced, which would be equal to the CPRE Tranche weighted average price minus the GSA REC value. Finally, Duke proposes that, under the 2- and 5-year terms available under the self-supply option, the GSA bill credit would be calculated according to the corresponding avoided cost rates, and limited to the unbundled self-supply PPA price.

(7) Billing and administrative charges: Duke proposes to continue billing customers that participate in the GSA Program under the applicable rate schedule for retail electric service. Duke's proposed GSA Riders would be a companion tariff to an applicable primary rate schedule, and, therefore, Duke states that the participating customer's billing statement will look much as it does today, but also reflect charges for the costs associated with the renewable energy delivered by the new renewable energy facility dedicated to the GSA Program (either the standard offer renewable energy product charge or the unbundled GSA product charge), net of the GSA Program bill credit (calculated as described above) and the GSA Program administrative charge. Duke proposes that the GSA administrative charge be equal to $375/month, plus $50/month for each billed account, and states that this charge is intended to recover costs for manual billing, labor, program management and support costs.

(8) Requirements for GSA Program new renewable energy facilities: Duke proposes a number of requirements for new renewable energy facilities dedicated to the GSA Program. First, Duke proposes that these facilities be required to be located within DEC or DEP's respective North Carolina and South Carolina assigned service territories, and be located in the same utility's service territory as the premises associated with the eligible customer's accounts for retail electric service. Second, for facilities that are participating in a standard offer process, Duke proposes applying the same requirements as apply under the CPRE Program. For facilities that are participating in a self-supply option, Duke proposes that additional eligibility requirements may be identified and included in the term sheet that is submitted by the customer participating in the GSA Program as part of the customer application, and that, at a minimum, these facilities be required to have completed the system impact study under the North Carolina Interconnection Procedures (NCIP) or the South Carolina Generator Interconnection Procedures (SCGIP) to provide an initial indication of viability. In addition, Duke proposes that a customer participating in the self-supply option be required to submit all facility documentation at the time the customer makes its application to participate in the program and that, for facilities located in North Carolina, the facility have obtained a certificate of public convenience and necessity (CPCN) prior to construction, but not prior to application.

(9) Reasonable credit requirements: For nonresidential customers eligible to participate in the GSA Program, Duke proposes required compliance with the credit requirements as set forth in Duke's proposed GSA Service Agreement.[1] Pursuant to the GSA Service Agreement, customers that have a minimum acceptable credit rating from either Standard and Poor's Global Ratings, Inc. (S&P) or Moody's Investor Service will be assigned an unsecured credit limit based on the customer's rating. For eligible customers that do not have such a credit rating, Duke proposes

[1] The GSA Service Agreement was not included with the filing of Duke's petition and proposed GSA riders; however, as is addressed further below, was included with the filing of Duke's reply comments.

allowing these customers to provide a guarantee from a parent entity that does have such a credit rating, or, alternatively, to submit financial statements for Duke's review and determination of an appropriate rating on a commercially reasonable basis. Duke proposes that customers that are unable to demonstrate at least a BB- rating on the S&P rating scale be ineligible for participation in the GSA Program.

Duke further proposes that the amount of performance security be sufficient to cover the early termination payment as determined under the schedule attached to the GSA Service Agreement for each year of the term of the agreement. If the customer does not have an unsecured credit limit, or if the performance security amount exceeds the customers unsecured credit limit, then Duke proposes that the customer be required to provide further credit support in the form of a guarantee from some credit-worthy entity, a letter of credit acceptable to Duke, or a cash deposit. Duke states that these proposed credit support requirements are intended to protect Duke and its customers that are not participating in the GSA Program from the cost impacts in the event that a GSA Program customer fails to perform on the GSA Service Agreement, including the cost of RECs and the unrecovered administrative costs. Finally, Duke proposes an adjustment in the unsecured credit limit if the credit rating of the customer participating in the GSA Program changes, and proposes procedures for aggregating the security requirement to allow a customer to enter into multiple GSA Service Agreements, and for allowing an entity to act as guarantor for multiple GSA Service Agreements.

(10) <u>Cost recovery and impacts to cost of service:</u> Duke states that it has designed the GSA Program such that all administrative costs and REC costs will be recovered from or, in the case of the self-supply option, paid directly by the customer participating in the GSA Program. Further, Duke states that the costs of energy and capacity attributable to Duke-owned and third-party facilities under the GSA Program will be recovered from all native load customers, as these facilities will be "system supply resources" that deliver energy and capacity to Duke's electric systems to serve all North Carolina retail, South Carolina retail, and wholesale jurisdictional customers. Accordingly, Duke argues that the cost of energy and capacity generated by these facilities should also be recovered from all jurisdictions and customers, and that this cost is required to be at or below DEC or DEP's respective forecasted avoided costs.

Therefore, Duke states that it plans to annually petition the Commission for the recovery of the costs of energy and capacity attributable to Duke-owned and third-party facilities under the GSA Program, pursuant to newly enacted N.C.G.S. § 62-133.2(a1)(11).[1] Duke further states that the "non-administrative/non-REC costs for energy and capacity to be recovered through the fuel factor [G.S. 62-133.2] will be equal to the GSA bill credit provided to the GSA customer multiplied by the megawatt-hours generated by the GSA Facility during the annual fuel factor test period." Finally, Duke states that because the GSA bill credit is equal to or below DEC and DEP's respective forecasted avoided costs, Duke customers not participating in the GSA Program will be held

[1] N.C.G.S. § 62-133.2(a1)(11) provides that, "cost of fuel and fuel-related costs" means, among other things, "all nonadministrative costs related to the renewable energy procurement pursuant to N.C.G.S. § 62-159.2 not recovered from program participants."

neutral, neither advantaged nor disadvantaged, from the impact of the GSA Program, as is required pursuant to N.C.G.S. § 62-159.2(e).

(11) Continued market based revenues after the GSA Program service agreement concludes: Duke proposes that if a DEC- or DEP-owned proposal is selected through the CPRE RFP Solicitation as a new renewable energy facility dedicated to the GSA Program, or if DEC or DEP enters into an arrangement to facilitate a customer's self-supply option under the GSA Program, then annualized recovery of Duke's expenses incurred would be a "market-based recovery similar to the market-based recovery mechanism contemplated for utility-owned CPRE assets" pursuant to N.C.G.S. § 62-110.8(g). Duke states that it has similar concerns as those that were addressed by the Commission in adopting Commission Rule R8-71 (l)(4), and Duke will seek to ensure that its companies will have an equal opportunity to continue recovering revenues based upon an updated market based mechanism after the initial term of the GSA Service Agreement expires. In other words, Duke argues that both third-party-owned facilities recovering their costs through a PPA under the GSA Program and utility-owned facilities recovering their costs on a market basis through the fuel factor, if authorized by the Commission, should be given an equal opportunity to recover market-based revenues after the 20-year GSA Service Agreement expires at a rate that does not exceed the then-prevailing avoided cost rate established pursuant to N.C.G.S. § 62-156.

Duke concludes its petition by arguing that the proposed GSA Program, including the respective Rider GSA tariffs, were developed to achieve the mandates and objectives of N.C.G.S. § 62-159.2 and to facilitate cost-effective, direct renewable energy procurement on behalf of North Carolina's major military installations, the UNC System, and large nonresidential customers, while ensuring that non-participating customers are held neutral. Duke therefore requests that the Commission issue an order approving the proposed GSA Program and respective Rider GSA tariffs, authorizing Duke to integrate the GSA standard offer procurement as part of the CPRE Program RFP process, authorizing DEC and DEP to seek future recovery of costs attributable to DEC- or DEP-owned and third-party-owned facilities that are dedicated to the GSA Program on a market-basis pursuant to N.C.G.S. § 62-133.2(a)(11), and providing DEC and DEP an equal opportunity to continue recovering revenues based upon an updated market based mechanism after the initial term of the GSA Service Agreement expires, similar to the process provided for in Commission Rule R8-71(l)(4).

THE INTERVENOR-PARTIES' INITIAL COMMENTS

DoD/FEA's Initial Comments

In its initial comments DoD/FEA states that it is still reviewing the proposed GSA Program riders and analyzing the options potentially available under the proposed riders. DoD/FEA further states that its two major concerns with regard to energy procurement on military installations are cost and energy resiliency. As to cost DoD/FEA states that it is unclear what the cost of energy under the proposed rider would be in comparison to energy purchased through current tariffs, when taking into account the administrative costs, application fees, and potential costs related to capacity bonds under the proposed GSA Program. DoD/FEA also states that its military installations can provide land for use to site renewable energy facilities and that access to this land is usually given in exchange for increased energy resiliency and costs savings. In addition, DoD/FEA states that the Federal Acquisition Regulations and the Defense Federal Acquisition Regulations require some contract terms that may conflict with the standard contract developed for the CPRE Program. As to energy resiliency DoD/FEA expressed its goal of providing stronger infrastructure to its military installations, including providing on-site generation resources that can power critical operations during times of crisis, including when the broader electric system is inoperable. DoD/FEA further states that under the proposed standard offer and self-supply options, it appears that the energy generated at a new renewable energy facility dedicated to the GSA Program will serve Duke's customers and the projects may not be able to be constructed in a manner that would strengthen installation resiliency. In conclusion, DoD/FEA states that its participation in the GSA Program will depend upon achieving the dual goals of energy resiliency and costs savings, and reiterates its desire for GSA Program offerings that would accommodate siting new renewable energy projects at DoD/FEA's military installations in exchange for cost savings and increased resiliency.

NCCEBA's Initial Comments

In its initial comments, NCCEBA provides a history of this proceeding, a background on the enactment of House Bill 589, and argues that Duke's proposed GSA Program is in substantial violation of N.C.G.S. § 62-159.2. In addition, NCCEBA proposes an alternative GSA Program design that it argues fully complies with the requirements of N.C.G.S. § 62-159.2.

NCCEBA states that it was an active participant in the negotiations that led to the enactment of House Bill 589 as a representative of companies that intend to sell renewable energy for the benefit of customers participating in the GSA Program. NCCEBA argues that the proposed GSA Program fails to meet the needs and expectations of both renewable energy suppliers and customers eligible to participate in the GSA Program. As background to the enactment of House Bill 589, NCCEBA cites the Commission's approval of the green source rider pilot program in 2013 (Docket No. E-7, Sub 1043). NCCEBA states that the pilot program had numerous flaws and experienced only limited participation, which prompted large electric customers to seek a new program that would promote the growth of renewable energy and economic development, enable the achievement of sustainability goals, and provide for predictability of electricity costs through long-term contracts for electricity, among other goals. NCCEBA further states that the General Assembly enacted N.C.G.S. § 62-159.2 in response to the interest in an improved program that would allow these customers to achieve these goals. Therefore, NCCEBA argues that it is critical that the GSA Program approved by the Commission effectuate the intent of the statute.

In arguing that Duke's proposed GSA Program is in substantial violation of N.C.G.S. § 62-159.2, NCCEBA first alleges that the proposed GSA Program is unlawfully integrated into the CPRE Program. Specifically, NCCEBA argues that Duke's proposed procurement of energy and capacity for the GSA Program through the CPRE RFP Solicitations ties the GSA Program to the CPRE Program in a manner that the General Assembly never intended. Second, NCCEBA argues that Duke's proposed program fails to allow customers eligible to participate in the GSA Program to negotiate with renewable energy suppliers regarding the price term, because under Duke's proposal the price term is established based on the results of RFPs issued under the CPRE Program. On this point, NCCEBA criticizes both the proposed standard offer, as allowing no opportunity for participating customers to realize energy savings, and spreading savings to Duke's shareholders and other customers, and the proposed self-supply option, as being tantamount to a REC deal with the added costs of an administrative fee paid to Duke and with no opportunity for energy savings or for consummating transactions outside of the CPRE Program timeline. As an alternative design, which NCCEBA argues is compliant with N.C.G.S. § 62-159.2, NCCEBA suggests setting the bill credit at or near avoided cost. Third, NCCEBA argues that Duke's proposed GSA Program fails to meet two requirements of N.C.G.S.§ 62-159.2(b): (1) to provide the "standard contract terms and conditions for participating renewable energy suppliers from which" Duke will procure energy and capacity on behalf of customers participating in the GSA Program, and (2) to provide the "range of terms, between two years and 20 years, from which a participating customer may elect."[1] Fourth, NCCEBA argues that Duke's proposed GSA Program wrongfully affords Duke the authority to control and dispatch new renewable energy facilities dedicated to the GSA Program in the same manner that is provided under the CPRE Program. Fifth, NCCEBA argues that Duke's proposed GSA Program is inconsistent with N.C.G.S. § 62-159.2, because it is "essentially a REC purchase program" and not a program for the procurement of unbundled RECs. Sixth, NCCEBA objects to two additional features of Duke's proposed GSA Program: that the proposed self-supply option would not open until January 1, 2019, and that Duke has proposed to allocate the 250 MW of capacity that is not reserved for major military installations or the UNC System between DEC and DEP's respective service territories (160 MW to DEC and 90 MW to DEP).

Next, NCCEBA cites the provision of N.C.G.S. § 62-159.2(e) that requires "all other customers to be held neutral, neither advantaged nor disadvantaged, from the impact of the renewable energy procured on behalf of the program customer," and argues that the proposed GSA Program would unfairly advantage nonparticipating customers and disadvantage customers participating in the GSA Program. NCCEBA argues that requiring renewable energy to be procured at a price lower than Duke's avoided cost, as Duke has proposed, would result in savings being passed on to nonparticipating customers and to Duke's shareholders in violation of the intent and the plain language of the statute. In addition, NCCEBA argues that the proposed GSA Program creates "substantial disincentives" for eligible customers to participate in the GSA Program, because participating customers would, "in all cases pay more to participate in the program due to the costs that Duke would impose." Further, NCCEBA argues that the limited contract terms and conditions proposed by Duke would present practical limitations to participation by eligible customers.

NCCEBA proposes an alternative GSA Program that it believes fully complies with the law. NCCEBA's proposed GSA Program addresses various aspects of the program in detail. The critical point of disagreement between Duke's proposed GSA Program and NCCEBA's is the calculation of the bill credit that the customer participating in the GSA Program receives from Duke (other differences are not insignificant, and these differences will be discussed further below). Under NCCEBA's proposed GSA Program, the bill credit would be computed using the applicable

[1] NCCEBA observes that Duke, in its petition, makes reference to the CPRE pro forma PPA and suggests that the CPRE pro forma PPA would be used for the GSA Program. However, NCCEBA argues that this does not satisfy Duke's obligation to file a proposed agreement in this proceeding, and that there are a number of respects in which the CPRE pro forma PPA is not suitable for the GSA Program.

avoided cost rates (in $/kWh) multiplied by the quantity of energy delivered to DEC or DEP by the designated facility during the billing period. Under its proposed GSA Program, NCCEBA argues that there will be no "nonadministrative costs" related to the GSA Program that are recoverable under N.C.G.S. § 62-133.2(a)(11) because DEC and DEP will recover the full cost of payments under PPA with the owner of the renewable energy facility dedicated to the GSA Program. NCCEBA further argues that, because the bill credit is equal to DEC or DEP's forecasted avoided cost, non-participating customers will be held neutral from the impact of other customers' participation in the GSA Program.

NCSEA's Initial Comments

In its initial comments, NCSEA argues that Duke's proposed GSA Program fails to comply with the requirements N.C.G.S. § 62-159.2, and, therefore, requests that the Commission reject Duke's proposed GSA Program and direct Duke to engage stakeholders to craft a green tariff that complies with the language and intent of that statute.[1] NCSEA's fundamental objection to Duke's proposed GSA Program is that instead of providing for DEC and DEP's procurement "of energy and capacity on behalf of the participating customer," as stated in N.C.G.S. § 62-159.2(b), Duke's proposed GSA Program provides participating customers with only RECs, and not energy and capacity. NCSEA also objects on the basis that Duke's proposed GSA Program does not provide "a range of terms, between two years and 20 years, from which the participating customer may elect," as stated in N.C.G.S. § 62-159.2(b), where Duke's proposed GSA Program provides for only a 20-year term under the standard offer and a two-, five-, or 20-year term under the self-supply option. NCSEA states that an eligible customer or renewable energy project developer may prefer to enter into a 10- or 15-year contract. NCSEA further argues that Duke's proposed GSA Program would benefit non-participating customers by capping the bill credit for certain participants at the lesser of the PPA price or avoided cost, resulting in a cross-subsidization by transferring benefits from participants to all other customers. Under NCSEA's view when a customer participating in the GSA Program negotiates a PPA price that is below DEC or DEP's avoided cost, then the difference between avoided cost and the PPA price represents a benefit to either Duke or to non-participating customers at the expense of program participants. This, NCSEA argues, violates the provision of N.C.G.S. § 62-159.2 requiring that non-participating customers be held neutral from the impact of the GSA Program. NCSEA next argues that Duke's petition and proposed GSA Program omitted the standard contract terms and conditions for participating customers and for renewable energy suppliers from which Duke procures energy and capacity that is required by N.C.G.S. § 62-159.2(b). While NCSEA acknowledges that Duke proposes that the GSA PPA will be the same in all material respects as the CPRE PPA, NCSEA argues that this is insufficient to comply with the requirement of N.C.G.S. § 62-159.2(b).

[1] Attached to NCSEA's initial comments was the consumer statement of position letter filed in this docket on February 23, 2018, and a separate letter from Davidson College, Duke University, and Wake Forest University that was not filed in this docket. NCSEA includes these two letters to support its general argument that Duke's proposed GSA Program falls short of meeting the needs or expectations of the customers that are eligible to participate in the program.

NCSEA also argues that Duke has introduced elements into the proposed GSA Program that are unnecessarily complicated or restrictive and inconsistent with the provisions of N.C.G.S. § 62-159.2. NCSEA argues that Duke has inappropriately linked the GSA Program to the CPRE Program, and, as a result, the proposed GSA Program fails to comply with the requirements of N.C.G.S. § 62-159.2 by (1) allowing Duke the rights to dispatch a renewable energy facility under the GSA Program, (2) requiring evaluation of GSA Program procurement to be evaluated by the Independent Administrator of the CPRE Program, (3) failing to set out all standard terms and conditions for participating customers and renewable energy providers (as discussed above), (4) including restrictions on eligibility of new renewable energy facilities to participate in the GSA Program such as a reservation fee established in the same manner as the bid bond under the CPRE Program and requiring that the renewable energy facility participating in the GSA Program have completed the system impact study under the NCIP. NCSEA next argues that Duke has inappropriately linked the GSA Program to utility service territories by proposing an allocation of capacity under the GSA Program between the DEC and DEP service territories, by proposing to allow new renewable energy facilities located in the DEC and DEP balancing areas in South Carolina to participate in the GSA Program, and by proposing to require that the aggregated customer load be located in the same utility service territory. NCSEA further argues that Duke has inappropriately proposed other additional features in the GSA Program that are not supported by N.C.G.S. § 62-159.2 by allowing utility-owned facilities to participate in the GSA Program, and artificially restricting the times at which eligible participants may enroll in the GSA Program.

NCSEA then offered some criticisms of the structure provided for in N.C.G.S. § 62-159.2, describing the statute as "flawed." NCSEA concludes its initial comments by stating its interest in continued discussion, and by requesting that the Commission reject Duke's proposed GSA Program and instead direct Duke to engage stakeholders to craft a program that complies with the language and the intent of N.C.G.S. § 62-159.2.

SACE's Initial Comments

In its initial comments SACE provides an introduction that included discussion of the growing interest in "green tariffs" among utilities' large commercial and industrial customers across the country, including a list of principles that these customers view as the marker of a well-designed green tariff.[1] SACE then provides a summary of the background that led to the enactment of N.C.G.S. § 62-159.2 and of Duke's proposed GSA Program.

SACE next addresses the substance of Duke's proposed GSA Program, and argues that the proposed GSA Program fails to comply with the requirements of N.C.G.S. § 62-159.2 for several reasons. First, SACE argues that N.C.G.S. § 62-159.2 does not contemplate a REC-purchase program, stating that Duke's customers that wish to purchase RECs were able to do so without the

[1] SACE included as attachments to its comments a publication titled Corporate Renewable Energy Buyers' Principles: Increasing Access to Renewable Energy and a letter from a number of corporations that have a presence in the state to the General Assembly that identifies the GSA Statute as a provision of House Bill 589 that is "in need of further improvement during implementation."

enactment of N.C.G.S. § 62-159.2, and that, while a REC-purchase program provides a simple option for customers to obtain renewable energy attributes, it does not provide an opportunity to benefit economically from the fixed cost of power purchased directly from a renewable energy project. In support of its argument SACE cites to N.C.G.S. § 62-159.2(e) stating that this subsection describes multiple transactions involving payments and credits for energy and capacity, not a REC-purchase program. Second, SACE argues that the proposed GSA Program does not allow customers to negotiate with renewable energy suppliers regarding price terms as provided in N.C.G.S. § 62-159.2(b). In support of this argument SACE criticizes the proposed standard option as providing no opportunity to negotiate any price terms, where the price is established based on the weighted average price of the most recent CPRE RFP Solicitation and the REC value is based on a national voluntary market, and criticizes the self-supply option as providing an opportunity to negotiate only the REC price, where the bill credit is based on either the weighted average price of the most recent CPRE RFP Solicitation, DEC or DEP's forecasted avoided cost rate, or the negotiated self-supply price. Third, SACE argues that the proposed GSA Program does not ensure that all other customers are held neutral as required by N.C.G.S. § 62-159.2(e). In support of this argument, SACE states that the proposed GSA Program would advantage non-participating customers because the customers participating in the GSA Program will continue to pay their normal retail bill, in addition to the GSA Program charges, and the savings resulting from the energy and capacity purchased through the GSA Program, at or below the utility's avoided cost, will be passed to Duke's general customer base. SACE suggests that a bill credit at DEC or DEP's avoided cost rate is more appropriate than linking the GSA Program bill credit to the CPRE Program prices, and that this would allow customers participating in the GSA Program to realize electric bill savings if they are able to negotiate price terms below the avoided cost rates. Fourth, SACE argues that the proposed GSA Program does not provide an adequate range of terms from which customers may select as required by N.C.G.S. § 62-159.2(b). Rather than the proposed terms of 2, 5, and 20 years, SACE suggests that Duke should be required to offer a 15-year term, because eligible customers will benefit from a wider range of terms that provide price certainty and facilitate long-term business planning. Fifth, SACE argues that the proposed GSA Program should allow participants to hedge against future energy price increases or realize energy bill savings over a particular term. In support of this argument, SACE states that, although the proposed GSA Program contemplates fixed prices over the contract term, participating customers will see no benefit from the program as proposed, because the customer will continue to be required to pay its retail electric charges in addition to the GSA Program charges. Instead, SACE recommends that the Commission require Duke to allow customers participating in the GSA Program to negotiate a rate with the renewable energy supplier and capture the economic benefit of a price that is below DEC or DEP's avoided cost.

In conclusion SACE again argues that the proposed GSA Program fails to comply with the requirements of N.C.G.S. § 62-159.2 in that it fails to establish a green tariff that will provide meaningful access to renewable energy for customers eligible to participate in the program. Therefore, SACE requests that the Commission declare that Duke's proposed GSA Program does not comply with N.C.G.S. § 62-159.2 and instruct Duke to revise its program to comply with the statute and to reflect the arguments discussed in its comments.

Apple and Google's Initial Comments

In their initial comments Apple and Google provide a background on the enactment of House Bill 589 and state that, through their respective affiliates, they own and operate one or more data centers and related infrastructure in DEC's assigned service territory for retail electric service. They further state that the ability to invest in green energy is a "primary and essential" consideration in their business planning as they seek to save money, hedge against volatile fossil fuel prices, and lock in cost-effective, fixed energy rates. Apple and Google also express their support for fair, cost-competitive options for sourcing renewable energy, but argue that the proposed GSA Program fails to implement the requirements of N.C.G.S. § 62-159.2 and falls short of creating a viable program that is attractive to intensive users of energy in Duke's service territory, who are eligible to participate in the GSA Program.

Apple and Google then outline their principal concerns with Duke's proposed GSA Program. First, they argue that the proposed GSA Program does not provide the "range of terms" required by N.C.G.S. § 62-159.2(b), where the proposed GSA Program allows only a standard term of 20 years, and self-supply options of 2, 5, and 20 years. Apple and Google argue that this fails to satisfy both the plain language and the intent of the statute, and suggests that the addition of 10- and 15-year terms would be appropriate. Second, Apple and Google argue that the economic terms of the proposed GSA Program are not transparent or predictable, where the "overall net economic impact on participating customers is not readily apparent." They further argue that the pricing and credit mechanisms as proposed are confusing and fail to provide the level of certainty for participants to decide whether to participate in the GSA Program. Third, Apple and Google argue that Duke's proposed GSA Program does not identify the standard contract terms and conditions applicable to the underlying commercial arrangements required by N.C.G.S. § 62-159.2(b). Based upon these concerns, Apple and Google conclude their comments by arguing that the Commission should reject Duke's proposed GSA Program and that "a truly impactful program" would ensure that customers have access to flexible contract terms, transparent pricing and standard terms and conditions, the ability for a participating customer to achieve 100% renewable targets, and additional flexibility in their procurement options.

UNC-Chapel Hill's Initial Comments

In its initial comments, UNC-Chapel Hill states that it does not believe that Duke's proposed GSA Program meets the requirements of N.C.G.S. § 62-159.2, and that, as a result, the 250 MW of renewable energy reserved for the UNC System will not be provided in a manner consistent with the intent and language of the statute unless the Program is modified. UNC-Chapel Hill then provided additional background on its interest in this proceeding, as a significant consumer of electric power and as a participant in the legislative process that lead to the enactment of House Bill 589. UNC-Chapel Hill further states that, under a program that is consistent with N.C.G.S. § 62-159.2, it could purchase as much as 112.5 MW of electricity from renewable energy facilities, saving up to $1.7 million annually and reducing carbon dioxide emissions from the electric power it consumes by up to 10%. However, UNC-Chapel Hill further states that under Duke's proposed GSA Program, UNC-Chapel Hill would not realize any savings by purchasing renewable energy through the program, and would have to pay additional amounts for RECs, plus administrative fees, to achieve a similar reduction in carbon dioxide emissions.

UNC-Chapel Hill then states that its principal objection to Duke's proposed GSA Program is that it will not allow the procurement of energy from renewable energy facilities at fair and competitive rates. UNC-Chapel Hill also expressed its concern that the benefits of the program as proposed would be passed on to Duke's other customers, in violation of N.C.G.S. § 62-159.2, because the bill credit available to a participating customer is below Duke's avoided cost. In addition, UNC-Chapel Hill argues that Duke's proposed GSA Program does not meet the requirements of N.C.G.S. § 62-159.2 in that a compliant program would offer greater flexibility in contact length, provide for direct and full negotiating rights between renewable energy facility developers and the participating customers, and allow more options to meet diverse and changing customer needs. Further, UNC-Chapel Hill argues that Duke's proposed GSA Program would benefit from standardized contract terms addressing default, early termination, financial assurances, and other provisions approved by the Commission.

In conclusion UNC-Chapel Hill states that procuring electricity at fair and competitive rates assists UNC-Chapel Hill in overall cost management and frees up resources to focus on its core mission of education, research, and service. Further, UNC-Chapel Hill argues that any proposed program that unfairly inflates the cost of renewable energy, so that it is not competitive from a pricing standpoint, frustrates the legislative intent underlying N.C.G.S. § 62-159.2 and makes the program economically unattractive. Finally, UNC-Chapel Hill argues that the proposed GSA Program would not allow it to reduce its power costs, hedge against future increases in the cost of energy, or reduce carbon emissions.

Walmart's Initial Comments

In its initial comments, Walmart provides a statement of its interest in this proceeding, including, its having established "aggressive and significant renewable energy goals" such as an aspirational goal to be supplied by 100% renewable energy and to be supplied by 50% renewable energy by 2025. In addition, Walmart states that it has set "a science-based target" to reduce emissions in its operations by 18% by 2025 through implementation of energy efficiency measures and consumption of renewable energy. Further, Walmart states that it currently takes electricity from one or more renewable energy resources in 19 states and Puerto Rico, but North Carolina is not among those states.

Walmart next states that it seeks renewable energy resources that deliver "industry leading value," including RECs, within a structure that allows the customer to receive any potential benefits associated with the risk of being served by that resource rather than, or in addition to, the otherwise applicable resource portfolio. Walmart further states that it does not, as a general rule, enter into premium structures or programs that only result in additional costs to its facilities or enter into programs with a term in excess of 15 years. In addition, Walmart states that it utilizes three channels to secure renewable energy resources to meet its goals: (1) contracting for off-site resources; (2) contacting for on-site resources; and (3) utility partnerships.[1]

[1] With regard to utility partnerships Walmart provided the example of its partnership with Alabama Power to off-take a portion of the output from a 72-MW solar-powered electric generating facility. Walmart also provided citations to proceedings before the respective public utility regulatory agencies in Missouri, Virginia, and Georgia, as

Walmart then argues that the Commission should reject Duke's proposed Program as incomplete based on the omission of a "GSA Service Agreement" and a "standard form term sheet" that were referenced in Duke's petition, but not included with its filing. This omission, Walmart argues, precludes parties from evaluating the proposed GSA Program because certain key terms are not defined in the proposed tariff or in the other documents filed with Duke's petition.

Turning to the substance of the proposed GSA Program, Walmart states that neither the proposed standard offer nor the self-supply option is attractive to Walmart. With regard to the standard offer Walmart states that this option is essentially a cost-additive REC purchase program, and that the 20-year term of the contract is also problematic for Walmart. In short, Walmart states that it would not participate in the standard offer under the proposed GSA Program, and suggests that if it is appropriate for Duke to establish a REC purchase program it should be established outside of the limited capacity required to be made available under N.C.G.S. § 62-159.2. With regard to the self-supply option Walmart states that this option "boils down to nothing more than a cost-additive REC purchase program with significant administrative costs," including the "added burden of additional transaction costs associated with negotiating a REC price with the supplier." Again, Walmart states that this option is not an attractive option for Walmart. Nonetheless, Walmart argues that if the Commission approves the self-supply option, it should require the following modifications: (1) require more options in the length of a contract than the proposed 2-, 5-, and 20-year terms to comply with the requirement of N.C.G.S. § 62-159.2(b) that the program "provide a range of terms, between two and 20 years;" (2) establish a bill credit based on the avoided costs of DEC and DEP, rather than based upon the weighted average cost of the most recent CPRE RFP Solicitation; and (3) provide clarification regarding the applicability of the proposed GSA Program administrative charges.

THE PUBLIC STAFF'S INITIAL COMMENTS

In its initial comments the Public Staff provides a background on House Bill 589 and a summary of the requirements of N.C.G.S. § 62-159.2. The Public Staff then states that it has reviewed Duke's proposed GSA Program and, based upon this review, the Public Staff agrees that the proposed GSA Program was designed to implement the program in an efficient manner and generally includes the necessary components called for in N.C.G.S. § 62-159.2. However, the Public Staff further states that it takes exception to several aspects of Duke's proposed implementation of the GSA Program as further detailed in its comments.

The Public Staff first addresses the linkage between the proposed GSA Program and the CPRE Program by summarizing the proposed standard offer and self-supply options, and stating that the Public Staff generally supports the structure of the self-supply option as proposed, but disagrees with the standard offer option because it is linked to the CPRE Program in a manner that is "counter to the timeframes and purposes called for in each statute." While recognizing that N.C.G.S. § 62-110.8 (the CPRE Program) and N.C.G.S. § 62-159.2 (the GSA Program) were both enacted as part of House Bill 589, the Public Staff argues that the plain language of the statutes "clearly and unambiguously" delineates separate goals and purposes of each program with specific

examples of proceedings where it is "actively engaged with a number of utilities nationwide to develop and seek regulatory approval for similar programs."

operating parameters and timeframes that reflect the independent nature of the two programs. The Public Staff cites N.C.G.S. § 62-159.2(d) in support of its view that the GSA Program should operate independently from the CPRE Program for its five-year eligibility period, and cites N.C.G.S. § 62-110.8(a) as reinforcing this conclusion. In short, under the Public Staff's interpretation, the only linkage between the CPRE Program and the GSA Program is that after the conclusion of the five-year availability period required under GSA Program, any unsubscribed capacity under the GSA Program would be "reallocated" to competitive procurements that are additional to the 2,660 MW required under the CPRE Program. In addition the Public Staff argues that the goals for each program clearly support different desired outcomes under the two programs on the part of the General Assembly and notes several differences between the two statutory provisions. The Public Staff then notes the similarities between the program required by N.C.G.S. § 62-159.2 and the Green Source voluntary pilot program approved by the Commission in its Order issued on December 19, 2013, in Docket No. E-7, Sub 1043, and offered by DEC from December 2013 to December 2016. In conclusion the Public Staff reiterates its view that the self-supply option generally conforms more to the voluntary nature of N.C.G.S. § 62-159.2 and that the standard offer option does not align with the independent implementation of the GSA Program and the CPRE Program.

Next, the Public Staff addresses the issues of interconnection costs and application status under Duke's proposed GSA Program, in light of the linkage between the GSA Program and the CPRE Program. The Public Staff states that these issues, in addition to the implementation timeframes, operational limitations, and mandatory versus voluntary nature of the programs, also weigh against the integration of the two programs as proposed by Duke. The Public Staff first notes that under the CPRE Program, the Commission has approved a cost recovery methodology that departs from the traditional cost-causation approach (where all interconnection costs would be assigned to and recovered from the interconnection customer through Commission-approved interconnection fees) to allow the use of a grouping study process to evaluate grid upgrade costs, assignment of the costs to the proposal for evaluation purposes, and recovery of those costs through general rates. On this background the Public Staff states that Duke's use of the CPRE Program to identify and select projects for the standard offer under the GSA Program would further expand the departure from traditional cost-causation principles and make it more difficult to ensure that non-participating customers are neither advantaged nor disadvantaged as required by N.C.G.S. § 62-159.2. In addition, the Public Staff argues that it is critical to ensure that eligibility for the two programs is not biased in favor of one program over the other. As an example, the Public Staff states that the use of interconnection status as a part of the eligibility requirements should not be different under the two programs. However, the Public Staff further states that, under Duke's proposed standard offer, the fact that network upgrade costs identified under the CPRE grouping study may not be assigned to specific projects, along with the requirement that renewable energy suppliers have completed the system impact study to be selected under the self-supply option, has the potential to bias participation in favor of the standard option through the externalization of costs or faster implementation.

The Public Staff then addresses the basis for determining the bill credit to be received by the customer participating in the GSA Program, citing N.C.G.S. § 62-159.2(e) as providing the Commission the authority to determine the appropriate basis for the bill credit subject to two requirements: non-participating customers be held neutral and the bill credit not exceed the utility's avoided cost. The Public Staff states that it is considering various bill credit options and may provide additional recommendations in its reply comments. However, the Public Staff further states that at this time it does not agree with Duke's proposed utilization of the CPRE Tranche weighted average price to form the basis of the bill credit under the self-supply option for the initial GSA Program offering period. While recognizing that the CRPE Tranche weighted average price reflects the market-based price for renewable energy resources, the Public Staff argues that the unknown nature of that price at this time makes participation in the GSA Program impractical and that waiting until that price is determined unduly delays implementation of the GSA Program and would result in further congestion of the CPRE Tranche 2 RFP Solicitation. Finally, the Public Staff notes that if the Commission determines that the negotiated unbundled PPA price should form the basis for determining the bill credit, the Public Staff believes that any REC price negotiated between the GSA Program customer and the renewable energy supplier should be a positive value to prevent potential gaming of the bill credit mechanism.

The Public Staff next turns to the requirement of N.C.G.S. § 62-159.2(b) that Duke provide standard contract terms and conditions for participating customers and for renewable energy suppliers, noting that Duke included copies of its proposed GSA rider tariffs, but did not include a standard PPA in its filing. The Public Staff acknowledges that Duke noted its expectation that the commercial terms of the GSA PPA would be the same as the pro forma PPA approved by the Commission for use in the CPRE Tranche 1 RFP Solicitation. However, the Public Staff further notes that, in approving the pro forma PPA for use in the CPRE Program, the Commission directed Duke to continue discussions regarding potential revisions to that PPA to address the issues raised by the parties to that proceeding. On this background the Public Staff states that it agrees that the use of the CPRE pro forma PPA as the basis for the GSA PPA, subject to the following modifications: (1) incorporation of any modifications made to the pro forma PPA; (2) elimination of the provisions dealing with the transfer of RECs and environmental attributes; and (3) modification of the curtailment and control instruction provisions. With regard to the provisions dealing with the transfer of RECs and environmental attributes, the Public Staff states that these provisions are not necessary under the self-supply option because the REC transaction is unbundled from the PPA and is handled in a separate transaction between the GSA customer and the GSA renewable energy supplier. With regard to the provisions related to curtailment and control instructions, the Public Staff cites N.C.G.S. § 62-110.8(b) as expressly providing that a CPRE Program renewable energy supplier allow dispatch, operation, and control of its renewable energy facility in the same manner as the utility's own generation resources, but similar language is not found in N.C.G.S. § 62-159.2. However, the Public Staff further states that, consistent with its positions expressed in the Commission's 2016 Biennial Avoided Cost Proceeding (Docket No. E-100, Sub 148), it continues to support reasonable control instructions and system emergency instructions similar to what would apply in the negotiated contract setting between the utility and a qualifying facility. The Public Staff, therefore, requests that the Commission require Duke to include information on the curtailment of any renewable energy resource under the GSA Program in the quarterly curtailment reports that are required pursuant to the Commission's October 11, 2017 Order issued in Docket No. E-100, Sub 148, as modified in the Commission's Order that approved the modified joint CPRE Program (issued in Docket Nos. E-2, Sub 1159, and E-7, Sub 1156).

Finally, the Public Staff addressed issues related to the length of term of the contracts under the proposed GSA Program, the proposed administrative fees and costs, and allocation among customers, queueing, and aggregation. The Public Staff believes that additional contract term lengths between the two and 20 year terms proposed for the standard option and between the two, five, and 20-year terms as proposed for the self-supply option are required under N.C.G.S. § 62-159.2(b). The Public Staff further states that it does not take exception to the administrative fees and charges as proposed, but it has requested additional information from Duke and may comment further in its reply comments. Finally, the Public Staff agrees with Duke's proposed allocation of undesignated capacity between DEC and DEP based on load ratio share, does not take exception with Duke's proposed queuing process for each of the specific allocation categories, and supports Duke's requirement that projects that seek to aggregate their accounts for participation in the GSA be located in the same utility service territory and that the renewable energy facility also be located in the same utility service territory.

THE INTERVENOR-PARTIES' REPLY COMMENTS

NCCEBA's Reply Comments

In its reply comments, NCCEBA provides a background of this proceeding and summarizes the comments of the other intervenor-parties, which generally express concern that the proposed GSA Program will not allow cost savings to participating customers, and, that very few, if any, large customers will participate in the program as proposed because they believe it is unworkable.

NCCEBA then argues that the "most fundamental problem" with the proposed GSA Program is that the proposed bill credit mechanism precludes participating customers from realizing any savings through participation in the program. While NCCEBA acknowledges that Duke's proposed GSA Program appropriately envisions that the participating customer paying its full retail bill, reimbursing Duke for amounts paid to a renewable energy supplier selected by the customer, and paying an administrative charge, NCCEBA argues that a bill credit equal to the PPA price, as Duke has proposed, means that the reimbursed amount and the PPA price cancel each other out and the participating customer has no potential for savings, even if the participating customer negotiated a PPA price below DEC or DEP's respective avoided cost rate. NCCEBA further argues, as it did in its initial comments, that any savings resulting from the GSA PPA price below avoided cost would be realized by Duke's other ratepayers or its shareholders and not by the customer participating in the GSA Program, who negotiated the PPA price below the utility's avoided cost rate. Therefore, NCCEBA urges the Commission to require Duke to implement the GSA Program in a manner that allows the participating customer to realize savings resulting from negotiating a GSA PPA price below the utility's avoided cost rate. This, NCCEBA concludes, is the only way to incentivize participation in the GSA Program within North Carolina's regulated monopoly framework.

NCCEBA then summarizes the comments of other intervenor-parties and the Public Staff which express objections to Duke's proposed GSA Program on the grounds that the standard offer option is unlawfully linked to the CPRE Program, that the proposed bill credit would penalize

GSA Program participants,[1] that the proposed standard contract fails to provide the terms and conditions required by N.C.G.S. § 62-159.2(b), and that Duke improperly included curtailment rights in the GSA PPA. NCCEBA then addressed the linkage between the proposed GSA Program and the CPRE Program in further detail, again arguing that this proposed feature of the GSA Program is contrary to the plain language of N.C.G.S. § 62-159.2, and expressing concerns about the delay of the Tranche 1 CPRE RFP Solicitation and about the potential for any further delays in implementing the two programs that might result from the Commission allowing the proposed linkage between the two programs. Finally, NCCEBA argues that renewable energy suppliers bidding into the Tranche 1 CPRE RFP Solicitation should be allowed to withdraw a bid without penalty if they intend to supply energy and capacity under the GSA Program, because the timing of the first RFP Solicitation vis-à-vis the implementation of the GSA Program may not allow for the reservation of capacity prior to the Tranche 1 CPRE RFP Solicitation opening. In other words NCCEBA is concerned that renewable energy suppliers will be forced to make "premature decisions" about whether to bid projects into the CPRE Tranche 1 RFP Solicitation or not submit a proposal in the hope of being selected as a supplier under the GSA Program.

In conclusion NCCEBA argues that the structure and implementation of the GSA Program are crucial to the success of the overall goals of the program for both customers and suppliers. Based on its view that Duke has made "significant deviations from the law and the underlying policy" of N.C.G.S. § 62-159.2, NCCEBA requests that the Commission order Duke to adopt NCCEBA's proposed alternative program outlined in its initial comments. Finally, in light of the complexity of these issues, NCCEBA requests that the Commission order oral arguments in this proceeding.

<u>NCEMC's Reply Comments</u>

In its reply comments, NCEMC states that its interest in this proceeding is to ensure that the implementation of the GSA Program comports with the agreements reached among the stakeholders and the legislative direction in N.C.G.S. § 62-159.2(e) to ensure that all non-participating customers be "held neutral, neither advantaged nor disadvantaged, from the impact of the renewable electricity procured on behalf of the program customer." NCEMC focuses the remainder of its reply comments on the calculation of the bill credit under the program, first emphasizing that N.C.G.S. § 62-159.2 does not require that the bill credit be set at the utility's avoided cost, but provides the Commission discretion to set the bill credit at a lower level to ensure that non-participating customers are held neutral. NCEMC then argues that setting the bill credit at the avoided cost rate does not hold non-participating customers neutral, as illustrated by the following simplified example:

[1] While NCCEBA agrees with the Public Staff that it would be appropriate to use the utility's avoided cost to establish the bill credit, and that it would be reasonable to "refresh" the bill credit for subsequent 5- or 10-year terms to accurately reflect the utility's current avoided costs, NCCEBA "strongly opposes" the Public Staff's alternative proposals to allow for an energy-only based bill credit, to utilize a competitive bidding process specific to the GSA Program, or to establish the bill credit based on actual incremental generation costs. These alternatives proposed by the Public Staff in its reply comments are discussed in further detail below.

The GSA Program bill credit is equal to the utility's avoided cost (as determined under the Commission-approved methodology in Docket No. E-100, Sub 148)	=	\$60/MWh over a 20-year term
The GSA Program customer procures renewable energy at a negotiated levelized cost	=	\$50/MWh over a 20-year term
The difference, NCEMC argues, is socialized to the utility's non-participating customers	=	\$10/MWh

NCEMC further argues that the Public Staff's suggestion to update or refresh the avoided cost data does not achieve indifference for non-participating customers because it does not take into account "solar integration costs," as NCEMC argued in the 2016 Biennial Avoided Cost Proceeding.[1]

On this background, NCEMC recommends that the bill credit for a program customer be set at the exact amount that the electric utility pays the owner of the renewable energy facility, which amount shall not exceed the utility's avoided cost, and should "be calculated on a PPA-by-PPA basis to reflect the utility's then-current true avoided costs." NCEMC further states that it believes that Duke's proposed CPRE-derived market proxy for its "true avoided costs" is more accurate than the other proposals advocated for in this proceeding, and that this methodology will hold non-participating customers neutral as required by N.C.G.S. § 62-159.2(e) by minimizing the potential for socialized costs. Finally, NCEMC reiterates its opposition to setting the bill credit based upon the utility's avoided cost rates determined under the E-100, Sub 148 methodology and its further opposition to setting the bill credit at an updated or refreshed rate based upon the E-100, Sub 148 methodology, unless that update or refresh reflects solar integration costs. In conclusion, NCEMC recommends that if the Commission does not approve Duke's proposed bill credit methodology, the Commission should require Duke to publicly file an annual report detailing the difference between the amount DEC and DEP paid, in the aggregate, for renewable energy procurement under the GSA Program and the amount each operating company credited program customers via bill credits, in the aggregate, to add a measure of transparency and accountability to the program.

NCSEA's Reply Comments

In its reply comments NCSEA states that it largely agrees with the comments and concerns set forth by the other intervenors in their respective initial comments. In support of its view that Duke's proposed GSA Program fails to provide a workable option for large energy consumers to procure clean energy through Duke NCSEA cites the initial comments of Walmart, NCCEBA, Apple and Google, and UNC-Chapel Hill. NCSEA then expresses its strong disagreement with the Public Staff's assertion that Duke's proposed GSA Program implements N.C.G.S. § 62-159.2 in an efficient manner and includes the components required by that statute.

[1] Included as an attachment to NCEMC's reply comments, is Duke's response to a data request of the Public Staff, wherein Duke states that solar integration costs are not included in its model.

NCSEA next argues that the proposed GSA Program provides no economic benefit to participating customers. In support of its argument, NCSEA cites comments of the other intervenor-parties to demonstrate that the proposed GSA Program does not provide participants an opportunity to procure clean energy in a cost-effective manner, nor an opportunity to lock-in rates and hedge against the volatility of fossil fuel prices, or even to determine in advance the overall economics of participation in the GSA Program. NCSEA further argues that Duke's proposed GSA Program does not provide an appropriate bill credit to participants. In support of this argument NCSEA agrees with the other intervenor-parties' arguments that the bill credit should reflect the costs that Duke avoids by purchasing power from the renewable energy resource under the GSA Program rather than from the system portfolio resources. In short NCSEA agrees with the other parties that the bill credit should be at, or very near to, the utility's avoided cost, and any difference between the bill credit and the utility's avoided cost would result in financial benefit to the utility or its shareholders. In addition NCSEA agrees with the Public Staff's view that the most up-to-date information and avoided cost calculations should be used when establishing the bill credit, but further argues that the bill credit should be fixed throughout the duration of the GSA Program contract rather than allowing the bill credit to adjust.

NCSEA also reiterated its arguments that the proposed GSA Program fails to meet the statutory requirements of N.C.G.S. § 62-159.2 in the following respects: by failing to allow negotiation of pricing, by failing to provide rate certainty, by failing to provide for the required range of contract term lengths or terms and conditions, and by unfairly advantaging non-participating customers. In addition NCSEA reiterates its arguments that Duke's proposed GSA Program is inconsistent with N.C.G.S. § 62-159.2 and frustrates the legislative intent underlying that statute by tying the GSA Program to the CPRE Program, by unreasonably delaying the implementation of the GSA Program, and by procuring RECs rather than energy and capacity. In conclusion, NCSEA states its support for NCCEBA's proposed alternative GSA Program, with some modifications, and, therefore, requests that the Commission reject Duke's proposed GSA Program and direct Duke to engage in discussions with the stakeholders to craft a green tariff that complies with the language and intent of N.C.G.S. § 62-159.2.

<u>SACE's Reply Comments</u>

In its reply comments SACE states that, overall, it agrees with the initial comments asserting that Duke's proposed GSA Program fails to properly implement N.C.G.S. § 62-159.2 and requesting that the Commission require Duke to revise its GSA Program. SACE further states that it supports the creation of a stakeholder process to develop a GSA Program that is consistent with N.C.G.S. § 62-159.2 and that meets the needs of the eligible customers. SACE then addresses more specifically issues raised by other intervenor-parties that support its broader view that the proposed GSA Program fails to comply with N.C.G.S. § 62-159.2. In particular, SACE expressed its agreement with NCCEBA that the alternative GSA Program proposed in NCCEBA's initial comments complies with N.C.G.S. § 62-159.2 and is more aligned with the type of renewable energy procurement program that would accommodate the clean energy procurement goals of eligible non-residential customers.

SACE next addresses the Public Staff's initial comments. SACE states its general agreement with the Public Staff's assertion that linking the proposed GSA Program to the

CPRE Program is inappropriate. More specifically, SACE agrees with the Public Staff that eligibility for the CPRE and GSA Programs should not be biased in favor of one program over the other, that the bill credit should not be based upon the CPRE Tranche weighted average price under the self-supply option,[1] and that Duke should be required to offer additional length of term options beyond the proposed two, five, and 20-year terms as proposed.

UNC-Chapel Hill's Reply Comments

In its reply comments UNC-Chapel Hill states that N.C.G.S. § 62-159.2 was incorporated into House Bill 589 at the request of the eligible customers, including UNC-Chapel Hill, and that the General Assembly intended these customers to benefit from the program. UNC-Chapel Hill further states that these eligible customers, through their comments filed in this proceeding, "have consistently, uniformly, and unequivocally stated" that Duke's proposed GSA Program does not create a program that would be subscribed to by these customers or achieve the intent of the legislation. UNC-Chapel Hill cites the initial comments of several of these parties for support of this view. Finally, UNC-Chapel Hill argues that customers eligible to participate in the GSA Program can be afforded the flexibility in the procurement of energy and capacity from renewable energy resources, at prices that they have negotiated, without disadvantaging Duke's non-participating customers, as required by N.C.G.S. § 62-159.2.

THE AGO AND PUBLIC STAFF'S REPLY COMMENTS

The AGO's Reply Comments

In its reply comments the AGO states that there is broad consensus among the intervenor parties that Duke's proposed GSA Program violates the "spirit and letter" of House Bill 589 by inappropriately merging the CPRE Program and the GSA Program, by requiring GSA Program participants to subsidize other customers, by denying customers participating in the GSA Program the benefit of having negotiated price terms with a renewable energy supplier, by providing only a five-year term instead of a range of term lengths between two and 20-years, and by omitting the standard contract terms from the filing in this proceeding. The AGO then states that it concurs with these critiques and concludes that these features of Duke's proposed GSA Program are materially noncompliant with Part III of House Bill 589. The AGO then cites a number of intervenor-parties' comments to demonstrate that the eligible customers that the General Assembly "envisioned would participate in the program have stated that their participation would conflict with their obligation to minimize costs in their operations." In conclusion the AGO expresses agreement with the intervenor-parties' argument that the bill credit under the GSA Program should be "tied to Duke's avoided cost, with periodic resets to ensure that the credit reasonably matches Duke's actual avoided costs." This, the AGO argues, would comply with the mandate of N.C.G.S. § 62-159.2

[1] While SACE and the Public Staff agree that the bill credit should not be based upon the CPRE Tranche weighted average price under the self-supply option for the initial GSA offering period, the Public Staff indicated an openness to use of the tranche weighted average price as "a reflection of the market-based price for renewable energy resources" in future GSA offerings. SACE states that it does not agree with this view, and again argues that the use of the utility's avoided costs to form the basis of the bill credit complies with the requirement of N.C.G.S. § 62-159.2 that non-participating customers be held neutral.

that the program be cost-neutral for nonparticipating customers, while allowing the GSA Program participants to achieve energy savings by negotiating PPA prices below Duke's avoided cost.

The Public Staff's Reply Comments

In its reply comments the Public Staff notes that the intervenor-parties generally took issue with features of Duke's proposed GSA Program that link the GSA Program to the CPRE Program. These parties argue that the two programs were intended to serve different roles and purposes, with the only link being that any unsubscribed GSA Program capacity would be added to the required procurement under the CPRE Program. The Public Staff states that this argument and those comments are generally consistent with the Public Staff's position on this point. In particular the Public Staff notes its having taken exception to the proposed bill credit calculation based on the weighted average price of the CPRE Tranche 1 RFP under the self-supply option for the initial GSA offering period, as counter to the timeframes and purposes of the statutory sections authorizing each program. The Public Staff further states that N.C.G.S. § 62-159.2(e) authorizes the Commission to determine the appropriate basis for the bill credit to be received by the GSA Program customer, ensuring that all nonparticipating customers are held neutral, with the only limitation being that the bill credit may not exceed the utility's avoided cost. The Public Staff then summarizes and compares the comments of NCCEBA, SACE, UNC-Chapel Hill, and Walmart that addressed the method for determining the bill credit.

On this background the Public Staff frames the issue in this proceeding as centered on the legislative intent behind the enactment of N.C.G.S. § 62-159.2 in this way:

> Was it [G.S. 62-159.2] designed to establish a voluntary program for customers to choose to participate in solely for the purposes of procuring new renewable energy resources in North Carolina, or was it also intended to provide participating customers with an opportunity to negotiate a renewable energy procurement at a cost below their bill credit, thereby establishing an additional financial incentive for participation? If it is the latter, then how do you reconcile the financial incentive provided to GSA participating customers while holding non-participating customers harmless?

The Public Staff then argues that N.C.G.S. § 62-159.2(b) clearly indicates that participating customers are allowed to "select the renewable energy facility from which the public utility shall procure energy and capacity" as well as to "negotiate with renewable energy suppliers regarding price terms." Public Staff's Reply Comments at 5, quoting N.C.G.S. § 62-159.2(b). These provisions, the Public Staff further argues, support the concept that the program established by N.C.G.S. § 62-159.2 "was intended to be more than simply a generic purchase of renewable energy attributes from facilities, instead establishing a process by which participating customers could identify projects and negotiate prices directly for the procurement of not only the renewable energy attributes, but also the energy and capacity component of the purchase." The Public Staff notes that several intervenor-parties stated their view that the proposed GSA Program is little more than a cost-additive REC buying program.

Turning to the intervenor-parties' proposal to set the bill credit at avoided cost, the Public Staff first provides a background on the Commission's final Order issued in the 2016 Biennial Avoided Cost Proceeding (Docket No. E-100, Sub 148). The Public Staff then draws a comparison between the concept that avoided cost rates, when properly established, make the purchasing utility indifferent to the source of electric output (purchases from qualifying facilities or from another source, including, the utility building and owning its own generation facility) and the provision of N.C.G.S. § 62-159.2(e) that customers not participating in the GSA Program be held neutral. Thus, the Public Staff argues that if the GSA bill credit is properly established, non-participating customers should be indifferent to the source of the purchased electric output, whether from a utility-owned generation facility, a PURPA[1] qualifying facility (QF), or other purchased power. Continuing the comparison between the Commission's implementation of PURPA and the program established in N.C.G.S. § 62-159.2, the Public Staff notes that the implementation of Part I of House Bill 589 resulted in the Commission establishing the maximum term for a standard contract at 10 years, providing that the standard contract would be available to QFs with a generating capacity of 1 MW or less, and providing that, for QFs with a generating capacity greater than 1 MW, who are not eligible for the standard contract, the maximum term of the contract shall be 5 years. The Public Staff states that this is relevant to its analysis of Duke's proposed GSA Program in that N.C.G.S. § 62-159.2 requires that a range of terms between two years and 20 years be available, it does not require the Commission to fix the bill credit for the same length of time as the contract term. The Public Staff states that it believes that a contract term under the GSA Program, along with a fixed bill credit of equivalent length, would result in non-participating customers facing overpayment and underpayment risk for the same reasons articulated in the Commission's final Order in the 2016 Avoided Cost Proceeding, thereby violating the neutrality concept required by N.C.G.S. § 62-159.2(e). Finally, the Public Staff notes that the Commission acknowledged other potential costs and benefits associated with the different supply characteristics of intermittent resources in that Order, and directed the utilities to consider and study these issues and to make proposals in the next avoided cost proceeding reflecting of those efforts.

Based upon its consideration of these concepts, the Public Staff believes that if the Commission chooses to use administratively determined avoided costs to establish a bill credit for GSA purposes, the credit should be fixed for a limited duration to reflect the risk that would otherwise be borne by non-participating customers. Therefore, the Public Staff recommends that the bill credit available under the GSA Program be fixed for a time period that is equal in length to the term of the PPA signed between the renewable energy supplier and the utility, up to 10 years. If the term of the PPA is longer than 10 years, then the Public Staff recommends that the bill credit be "refreshed" to reflect the then-current avoided cost rates for the balance of the term of the PPA (which is itself limited to 20 years). The Public Staff notes that this would provide a bill credit that is available for a time period that is equal to the maximum length of term available under the PURPA standard offer contract and that is five years longer than the maximum length of term available under a PURPA negotiated contract. The Public Staff further explained that the latter part of the duration of the GSA Program bill credit, the "refresh period," would allow for changes in market conditions, such as updates to natural gas price forecasts or costs and benefits based on the supply characteristics of intermittent resources, to be incorporated into the determination of the GSA Program bill credit. The Public Staff acknowledges that this introduces some risk to the

[1] The Public Utility Regulatory Policies Act of 1978.

GSA customer that the bill credit will decrease in the later part of the GSA Program PPA, the Public Staff also argues that the refresh could result in significant savings, if avoided costs rise in 10 years. This, the Public Staff concludes, provides the type of hedge against increases in electricity rates and in price volatility in fuel markets that several intervenor-parties addressed in their comments.

The Public Staff then suggests that the Commission consider the following options, if the Commission determines that avoided costs do not provide an appropriate basis for the GSA bill credit:

1. Bill credit based on energy-only: Citing N.C.G.S. § 62-159.2(e), which provides that the "the program customer shall receive a bill credit for the energy as determined by the Commission," the Public Staff states that, tracking this language and utilizing the energy-only component of avoided costs would remove the capacity portion of the avoided costs from the bill credit, allowing that reduction to serve as a proxy for the potential costs associated with long-term forecast risk and the integration costs associated with distributed generation.

2. GSA-specific solicitation: The Public Staff also suggests that the Commission consider directing Duke to conduct a GSA-specific market solicitation separate from its CPRE solicitation, with the market clearing price providing the basis for the bill credit for both market participants and self-supply options, assuming sufficient levels of participation. The Public Staff states that, under this option, customers participating in the GSA Program would receive a financial benefit if the bundled price they negotiated was below the GSA-specific market clearing price.

3. Actual Incremental Generation Costs: In this option, the Public Staff suggests consideration of an approach similar to that taken by Georgia Power with its REDI C&I initiative, in which the bill credit provided to participants is based on Georgia Power's actual hourly running cost of incremental generation per kWh, calculated on a monthly basis. There is no fixed rate, but the fixed formula applies for the entire term of the contract (up to 30 years). The Public Staff notes that the initial offering under the Georgia REDI C&I initiative was fully subscribed.

Finally, the Public Staff addresses comments of Apple and Google that emphasized the need for transparency or predictability to encourage market participants to participate in the program, including the ability to determine in advance the overall economics of a particular proposal. The Public Staff notes that the joint consumer statement of position filed by New Belgium Brewing, SAS Institute, Inc., Sierra Nevada Brewing Co., Unilever, and VF Corporation expresses a similar concern. The Public Staff acknowledges these concerns, but states that to the extent the certainty provided to potential GSA Program participants comes by increasing the risk to non-participating customers, the Public Staff does not believe that would be consistent with the statutory requirement that non-participating customers remain neutral as to the impact of the GSA Program.

In conclusion the Public Staff suggests that the Commission may wish to evaluate the levels of participation or feedback received from the market after the initial GSA Program offering and requests that the Commission consider the issues and other considerations raised in its comments.

DUKE'S REPLY COMMENTS, REVISED GSA RIDER TARIFFS, PROPOSED GSA SERVICE AGREEMENTS, AND PROPOSED GSA TERM SHEET

In its reply comments Duke first states that it designed the GSA Program to meet the express requirements of N.C.G.S. § 62-159.2, while also reflecting the State's broader renewable energy procurement framework enacted through House Bill 589. Duke states that it is fully supportive of delivering a GSA Program that meets the needs and goals of eligible customers, and have proposed "certain incremental modifications" in the proposed GSA Program in its reply comments to address recommendations made by the Public Staff and the intervenor-parties. More specifically, Duke proposes to "partially open" the GSA Program within 60 days of Commission approval (prior to January 1, 2019, as originally proposed) to offer 10 and 15-year GSA service agreement options in addition to the two, five, and 20-year options initially proposed, and to modify the standard offer option to address the Public Staff's concerns related to the participation requirements that are different under the self-supply option. In addition Duke includes as an attachment to its reply comments a pro forma GSA Service Agreement and certain other documents that it states are designed to more fully inform interested GSA Program customers regarding participation requirements.

Duke then states that while it is taking these steps to modify the proposed GSA Program, it is also apparent from the comments filed in this proceeding that "a fundamental misalignment of expectations exists in terms of the purpose of the GSA Program." While Duke describes its proposed GSA Program as a "customer-directed sustainability program to procure incremental renewable energy," it views the intervenor-parties as seeking a cost-savings program that would allow large, sophisticated electric customers to "fix zero-risk long-term 'hedges' of their energy supply at rates above" Duke's anticipated cost of procurement through the CPRE Program and based upon a bill credit "to be subsidized by nonparticipating customers." Duke states that it disagrees with this altered approach to implementation of the program and that it continues to support its proposed GSA Program as consistent with N.C.G.S. § 62-159.2, in particular, the requirement that nonparticipating customers be held neutral. Therefore, Duke requests that the Commission approve the GSA Program and associated tariffs as modified in its reply comments.

Duke then argues that the Commission must decide whether the GSA Program is a "sustainability program or a subsidy program." Duke views the comments submitted by the intervenor-parties as an argument that the proposed GSA Program "should be fundamentally restructured to facilitate hedging and arbitrage activities that deliver artificially-derived savings to" customers participating in the GSA Program and "above-market profits to" suppliers of renewable energy under the program. Duke further argues that because these benefits will necessarily be funded by nonparticipating customers, the threshold question, as described by Duke, for the Commission to resolve is one of legislative intent between two alternative views of the program:

> (1) to provide eligible GSA Customers with an opportunity to increase their commitments to renewable energy procurement without adversely impacting nonparticipating customers (as [Duke] proposes), or
>
> (2) to require nonparticipating customers to subsidize Eligible GSA Customers' hedging strategies based on an administratively-calculated, long-term fixed forecast of avoided cost up to 20 years in the future (as the [intervenor-parties] argue).

Expanding on its argument that the former view is the appropriate interpretation of the legislative intent underlying N.C.G.S. § 62-159.2, Duke argues that its approach to implementing the GSA Program is grounded in N.C.G.S. § 62-2(3a), providing that Duke plan for their customers' energy needs and operate their system to deliver reliable and affordable energy utilizing the "least cost mix of generation and demand-reduction measures." Duke then acknowledges that the General Assembly departed from this mandate in the enactment of the REPS in 2007, which contemplates charging Duke's North Carolina customers with the "incremental costs" of compliance above the utility's avoided cost, and costs below avoided costs treated as system supply costs used to serve all customers. Further, Duke argues that the establishment of the CPRE Program and the GSA Program with the passage of House Bill 589, and the subsequent implementation of these programs, represent an "integrated" approach to expansion of Duke's procurement of cost effective renewable energy resources. In addition Duke states that, like the REPS, the CPRE Program and the GSA Program contain "critical cost containment protections" in that N.C.G.S. § 62-110.8(b)(2) limits the CPRE Program procurement price at the utility's avoided cost and that N.C.G.S. § 62-159.2(e) requires that Duke's customers that are not participating in the GSA Program be held neutral from the impact of those who do participate. Duke then repeats many of the arguments made in its initial comments to support its view that the proposed GSA Program is compliant with the requirements of N.C.G.S. § 62-159.2, including holding nonparticipating customers neutral and allowing participating customers to negotiate pricing.

Duke next addresses the method for determining the bill credit paid to a customer participating in the GSA Program. Duke argues that the intervenor-parties' view that the bill credit should be established at or just below the utility's avoided costs and fixed throughout the term of the PPA seeks to transform the statute's cap on the bill credit amount into the bill credit itself, and ignores the competitively-established market data and price of renewable energy that is contemporaneously being procured by Duke through the CPRE Program. Duke further argues that establishing the bill credit in this manner creates an artificial price to beat and will allow for gaming of the program to provide participants guaranteed cost-savings. Duke uses the following example to illustrate its point:

20 Year Avoided Cost	$57/MWh
GSA Bill Credit	$57/MWh
Negotiated PPA Price	$45/MWh
GSA Product Charge	$45/MWh
GSA Weighted Avg. Price	$42/MWh

From this example, Duke concludes that, because the GSA bill credit is recovered from all nonparticipating customers through the adjustment in rates authorized by N.C.G.S. § 62-133.2, the utility's nonparticipating customers pay the $12 difference between the bill credit and the negotiated PPA price. Further, Duke concludes that the renewable energy supplier would benefit from selling at $45/MWh rather than at a price established through the CPRE RFP Solicitation (represented in this example by the GSA weighted avg. price of $42/MWh). Extending this example over 20 years and assuming that it applies across the full 600 MW available under the GSA Program, Duke further concludes that the "over-payment by nonparticipating customers compared to the CPRE Program-procured solar could approach $350 million over the 20-year term."

Duke then argues that the statutory framework established by the enactment of House Bill 589 does not support the use of a 20-year forecast of avoided cost rates to set the bill credit, in light of the changes made to N.C.G.S. § 62-156 (reducing the maximum term of the standard contract to 10-years for QFs with a generating capacity of 1 MW or less and reducing the maximum term of negotiated contracts to 5 years), and the enactment of the CPRE Program, which relies on competitive bidding rather than the traditional, administratively established avoided cost rates. In addition, Duke argues that the Commission's recent avoided cost orders likewise reject the use of a 20-year term in PURPA contracts. Finally, Duke again argues that establishing the GSA Program bill credit in a manner that is not based on the results of the CPRE RFP Solicitations would disadvantage nonparticipating customers in violation of N.C.G.S. § 62-159.2(e).

Duke next responds to NCCEBA's comments related to cost recovery for energy delivered under the GSA Program. Duke argues that NCCEBA's proposed alternative GSA Program would "effectively guarantee" that DEC and DEP would not recover the costs of implementing the GSA Program. Duke states that under NCCEBA's alternative program design, the bill credit paid to the GSA Program participant would equal the utility's avoided cost over the contracting period of the GSA PPA, while the bundled GSA PPA price would equal the price negotiated between the GSA Program participant and the renewable energy supplier. Duke then responds to NCCEBA's argument that its proposed alternative obviates the need to recover costs through the fuel factor because the GSA Program participant pays the full cost of the PPA. Duke argues that NCCEBA's view fails to recognize that the Bill Credit paid to the GSA Customer must be, and is authorized to be, recovered under amended N.C.G.S. § 62-133.2. Under Duke's proposed GSA Program, the "non-administrative/non-REC costs for energy and capacity to be recovered through N.C.G.S. § 62-133.2(a1)(11) will be equal to the GSA bill credit provided to the GSA Customer multiplied by the megawatt-hours generated by the GSA Facility during the annual fuel factor test period." Otherwise, Duke argues, the bill credit will go unrecovered.

Duke further argues that NCCEBA fails to recognize that the renewable energy facilities dedicated to the GSA Program will be system supply resources, delivering energy and capacity to serve Duke's North Carolina and South Carolina retail customers and wholesale customers. Under this arrangement, Duke intends to allocate the cost of the energy and capacity procured through the GSA Program, minus the standard offer REC value assigned to and recovered from the GSA Program customer, for recovery from all jurisdictions and customers. Duke further states that this approach is consistent with the manner in which Duke recovers all other purchased power expense today, including purchases made to comply with the REPS and purchases that were made under the Green Source Rider pilot in effect from 2013-2016. Duke then emphasizes that the provision included at N.C.G.S. § 62-133.2(a1)(11), authorizing Duke to recover "all nonadministrative costs related to the renewable energy procurement" under the GSA Program that is not recovered from the GSA Program participants, is unique to North Carolina. In contrast Duke states that in South Carolina, Duke is authorized to recover only the equivalent to its purchased power costs from retail and wholesale jurisdictions. In conclusion, Duke states that it designed the bill credit under the proposed GSA Program to be equal to the unbundled GSA PPA price (under the self-supply option) or to the bundled renewable energy product price minus the REC value (under the standard option), to ensure "full cost recovery" and to ensure that customers not participating in the GSA Program are held neutral.

Duke next addresses the comments of the intervenor-parties and of the Public Staff related to its standard offer option under the proposed GSA Program. Duke's comments largely repeat and emphasize arguments made in its petition, describing the standard offer option as a "turnkey participation option." Duke argues that this option should be preserved as it accommodates eligible customers' varied preferences and resources. Duke further argues that nothing in N.C.G.S. § 62-159 prohibits linking the GSA Program to the CPRE Program. In response to concerns expressed by the Public Staff, Duke states that it has agreed to modify the standard option in two ways: first, to require that renewable suppliers under the standard option be required to separately bid the full cost of delivering their potential project (including grid upgrade costs) in addition to offering a proposal under the CPRE Program (where grid upgrade costs are not included in the initial proposal), and, second, by eliminating the requirement that self-supply option renewable energy facilities have completed a system impact study before an eligible customer can submit an application to participate in the GSA Program.

Duke then addresses arguments and concerns raised in the comments of the intervenor-parties and of the Public Staff related to the timing in the opening of the enrollment period for the proposed GSA Program. Duke first states that NCCEBA's concerns stem from a misreading of the proposed program design in that the restrictions NCCEBA perceived do not exist because once the self-supply option opens, it remains continuously open for the duration of the five-year GSA Program. Duke also states, in response to the Public Staff's comments, that it proposed January 1, 2019, as the opening of the enrollment window because it is after the completion of the Tranche 1 CRPE RFP Solicitation and to allow Duke to undertake "proper administrative and technical support for the Program." However, Duke further states that, if the Commission determines that January 1, 2019 is an undue delay in the opening of the GSA Program enrollment period, then Duke would support opening the enrollment period 60 days after the Commission approves the program, with a 5-year avoided cost rate serving as the bill credit for all customers participating in the GSA Program.

Finally, Duke explains its offer to include additional contract terms of 10 and 15 years under the self-supply option, and addresses various issues raised in the comments of the other parties. As modified, Duke proposes that the self-supply option offer customers two-, five-, ten-, fifteen-, and twenty-year contract terms, with the bill credit under the five-, ten-, and fifteen-year terms be set at the lesser of the negotiated PPA price or the five-year administratively-determined avoided cost rate, fixed for the duration of the service agreement. For the two-year term, the bill credit would be the lesser of the negotiated PPA price or the Commission-approved two-year forecasted avoided cost rate, and, for the twenty-year term, the bill credit would be the GSA tranche weighted average price, minus the GSA REC value. Duke then addresses the other parties' comments related to bill credits and charges, and other features of the program design. These arguments are summarized above, and Duke's responses recited and emphasized arguments made in its petition, therefore, these comments will not be summarized again here. Lastly, the Commission notes that Duke included with its reply comments revised rider tariffs, service agreements, and a term sheet for the self-supply option.

AGREEMENTS AND STIPULATIONS AMONG THE PARTIES

On August 16, 2018, Duke filed its agreement and stipulation of partial settlement reached with Walmart. Duke states that its settlement memorializes its agreement with Walmart providing for an alternative self-supply bill credit mechanism based on the Duke utilities' marginal energy costs. Duke proposes that this bill credit mechanism "would be available to participating customers in addition to the Bill Credit options proposed in the Company's initial filing and reply comments." Duke further states that the concept behind this bill credit mechanism was mentioned by the Public Staff as a potential compromise solution and is substantially similar to the credit provided under Georgia Power's REDI C&I initiative.

On October 24, 2018, NCCEBA, UNC-Chapel Hill, and SACE filed an agreement and stipulation of partial settlement reached among these parties. These parties agreed among themselves to an "alternative bill credit" that would be fixed for a period up to ten years, and then "refreshed" based upon updated data for any GSA agreement that lasts longer than ten years. These parties agree that this alternative bill credit "strikes an appropriate balance between providing reasonable certainty to the participating customer regarding their electricity costs and ensuring that the projection of costs is accurate." These parties also identified the following other parties who did not join the agreement and stipulation, but who also do not object to the use of the alternative bill credit proposed therein: the Public Staff, NCSEA, and DoD/FEA.

ORAL ARGUMENT

On September 4, 2018, pursuant to the Commission's Order issued in these proceedings on July 16, 2018, this matter came on for oral argument. The parties reiterated and detailed their positions on the issues in controversy, consistent with the foregoing summary of the parties' comments. In addition counsel for Duke stated that it held discussions with the relevant stakeholders and agreed to the use of the Commission-approved five-year avoided cost rate, consistent with the five-year rate made available to QFs not eligible for the standard rate pursuant to N.C.G.S. § 62-156(c), with a "re-fresh," or recalculation of the rate based on updated data occurring at the end of every five-year period. Further, there was general agreement among the parties that the Commission is not required to, nor prohibited from, using a bill credit methodology based on the results of the CPRE RFP Solicitations, as proposed by Duke, or from using a bill credit methodology based on the Commission-approved avoided cost rates established pursuant to N.C.G.S. § 62-156(b) (the standard contract under PURPA). The Commission found the session of oral argument helpful to resolving the disputed issues in these proceedings and appreciates the efforts that the parties undertook to participate in the oral argument.

DISCUSSION AND CONCLUSIONS

The Commission has carefully reviewed Duke's petition, Duke's proposed rider tariffs and related documents, the parties' comments, the transcript of the oral argument held on September 4, 2018, and the entire record in these proceedings. Based upon this review, the Commission recognizes that the parties have substantial disagreement over how nearly every aspect of how this program should be implemented. Their disagreement extends to issues that are fundamental to the structure of the program, and is of a tenor that makes any further discussions among the parties unlikely to be fruitful. Therefore, the Commission will deny the pending requests to require a stakeholder process for discussion of a redesigned program. Further, because the Commission determines that there is sufficient information and arguments before it to define the issues in these proceedings, and because the Commission will require Duke to make significant revisions to its GSA Program filings, the Commission will deny NCCEBA's request to allow sur-reply comments or additional oral arguments in this matter. In short, it is left to the Commission to resolve the disputed issues and determine the appropriate means of implementing the GSA Program in a manner consistent with the requirements of N.C.G.S. § 62-159.2.

The Commission is an administrative agency created by statute, and has no regulatory authority except such as is conferred upon it by statute. State ex. rel. Utils. Comm'n. v. Edmisten, 291 N.C. 451, 232 S.E.2d 184 (1977). In enacting N.C.G.S. § 62-159.2, the General Assembly directed DEC and DEP to seek Commission approval of a program that complies with the provisions of that section. This requires the Commission to undertake an effort to discern the meaning of the provisions of N.C.G.S. § 62-159.2 through application of the rules of statutory interpretation. The cardinal principle of statutory interpretation is to ensure that the legislative intent is accomplished. Harris v. Nationwide Mut. Ins. Co., 332 N.C. 184, 191, 420 S.E.2d 124, 128 (1992). Statutory interpretation properly begins with an examination of the plain words of the statute, and if the statute is clear and unambiguous, the Commission must conclude that the Legislature intended the statute to be implemented according to the plain meaning of its terms. Three Guys Real Estate v. Harnett County, 345 N.C. 468, 472, 480 S.E.2d 681, 683 (1997). The fundamental issue before the Commission is what program structure and features best effectuate the legislative intent underlying the enactment of N.C.G.S. § 62-159.2.

In addressing this question, the Commission finds it helpful to make reference to the evolution of the State's energy policy, as cited by Duke in its reply comments. The policy of this State is for electric public utilities to produce and deliver energy using the "least cost mix of generation and demand-reduction measures." N.C.G.S. § 62-2(3a). Historically, utilities' obligations to purchase renewable resource-supplied energy was an exception to this general policy. For example, in 2007, the General Assembly enacted the REPS, requiring Duke, among others, to meet an escalating percentage of their North Carolina retail electric sales from renewable energy sources or to reduce energy demand through the implementation of demand-side management or energy efficiency programs. See N.C.G.S. § 62-133.8. At the time, electricity generated from renewable resources was more expensive than the costs a utility would otherwise incur under the least-cost mandate, and, therefore, the REPS authorized the recovery of "incremental costs" to comply with the REPS; that is, costs that are in excess of the utility's avoided costs. N.C.G.S. § 62-133.8(h)(1)(a). As with the GSA Statute, the REPS did not define "avoided costs," leaving the resolution of that question to the Commission. See Order Adopting Final Rules, pp. 37-42, Docket No. E-100, Sub 113 (2008).

In November 2017, in Docket No. E-100, Sub 148, Duke filed cost data and proposed changes to the rates, terms, and conditions for the purchase of electricity from QFs. These filings demonstrated that 60% of all QF projects in the nation were located in North Carolina, and alleged a significant risk of overpayment for electric power supplied by renewable energy facilities based on the position that there is an inherent risk of inaccuracy in avoided cost rates based on forecasted cost data over long-term periods.[1] The Commission presumes that the General Assembly was aware of these filings and of the Commission's order in Docket No. E-100, Sub 140 during its deliberations on House Bill 589. The Commission recognizes that House Bill 589 was enacted as a response to this perceived imbalance in the market for QF-supplied power and to changing customer attitudes toward renewable energy, intended to (1) introduce measures of market forces to set the rates, terms, and conditions for Duke's purchases of energy and capacity supplied by renewable energy facilities and to reduce reliance on Commission-established rates; (2) establish programs that require Duke to continue procuring energy and capacity supplied by renewable energy facilities beyond what they would be required to do pursuant to the REPS requirements; and (3) allow Duke's customers to have more choice about how Duke procures the energy it needs to serve these customers. In addition, and indicative of the intended meaning of "avoided cost" for purposes of the GSA Statute, it is now understood that it is possible for Duke to procure such energy below the price established by the "Commission-approved avoided cost methodology." See N.C.G.S. § 62-110.8(b)(2).

The Commission concludes that the GSA Statute was enacted to further these goals, with an emphasis on Duke's additional obligations to purchase renewable energy and capacity, and on the eligible customers' ability to choose how Duke procures that energy and capacity. Thus, the Commission generally agrees with Duke's argument that House Bill 589 was intended to evolve the State's energy policy. In addition, the Commission finds it appropriate to incorporate features of market forces into the GSA Program, where practicable, and of the Commission's PURPA implementation, where necessary, to further the broad intent underlying the enactment of House Bill 589. Further, the Commission concludes that the appropriate structure of the GSA Program should attract participation from the eligible customers, because, as many of the parties have argued, the General Assembly did not intend to establish a program that would be unsuccessful in attracting participation from eligible customers.

At the outset, the Commission acknowledges that many parties support their contentions by arguing what they maintain the General Assembly intended by authorizing the GSA Program. The Commission finds many of these arguments unpersuasive. While the Commission understands that the GSA Program and House Bill 589 resulted from a collaborative process, it is apparent to the Commission that the stakeholders have come away from the process with widely disparate views of what the General Assembly intended. Consequently, unless the General Assembly's intentions found their way into the wording of the statute, the Commission cannot rely on stakeholders' representations of what these intentions are. Likewise, parties make many assertions

[1] See Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC's Joint Initial Statement and Exhibit, at 27, Docket No. E-100, Sub 148 (Nov. 15, 2016).

that what Duke has proposed is inconsistent with the statute or even unlawful.[1] Most of the assertions of "inconsistency" or "unlawfulness" lack support. For example, Duke has requested certain tie-ins in integrating the GSA Program into the CPRE Program addressed elsewhere in House Bill 589. The Commission finds nothing unlawful or fundamentally inconsistent in what Duke proposes. The requested tie-in is neither prohibited nor authorized. Rather, it is for the Commission, in its discretion, to approve or disapprove these recommendations.

Fundamentally, many parties argue that the terms of the GSA Statute require the ability of the subscribing customers to have the ability to "hedge" or to enhance profitability by participating. The Commission finds no explicit language in the statute containing such a requirement. The Commission's willingness to authorize implementation of the statute to facilitate this result must be based on the General Assembly's "implied" intent that customers subscribe and the fact that the previously available green source mechanism failed to attract sufficient customers.[2] At the same time, the Commission must be mindful of the express provisions of the GSA Statute that "avoided costs" are the ceiling for the subscribing customers' bill credit, and not the floor; and that Duke's non-participating customers are to be neither advantaged nor disadvantaged by participation of eligible customers. When, hypothetically, the renewable generator sells renewable power to Duke under the must buy provisions of the GSA Program at \$X when Duke has no intent to build new generation or enter into contracts to purchase additional wholesale power and when the credit Duke provides the subscribing customer is \$X + 10, Duke and NCEMC make a forceful and persuasive argument that non-subscribing customers will have to bear responsibility for the "\$ 10."[3]

The Commission finds the provisions of the GSA Statute difficult to reconcile, the arguments of the parties in many respects less than helpful, and, consequently, seeks to exercise its discretion to implement its Order in compliance with the statute to the best of its ability. Thus, after careful consideration of the entire record in this proceeding, the Commission concludes that the General Assembly has delegated to the Commission the discretion to structure the GSA Program in a manner consistent with the intent supporting House Bill 589 and the specific mandates of the GSA Statute by striking an appropriate balance between the risks and benefits to participating customers, renewable energy facility owners, and the utility enterprises. The Commission exercises this discretion subject to two specific directives that have broad implications for implementing a GSA Program that complies with the GSA Statute. First, all nonparticipating customers are to be held "neutral, neither advantaged nor disadvantaged, from the impact of the renewable electricity procured on behalf of the program customer." N.C.G.S. § 62-159.2(e).

[1] See, e.g., NCCEBA April 20, 2018 Reply Comments, p. 7, footnote 3, "As noted by NCCEBA, the Public Staff, and others, Duke's proposed Standard Offer GSA Option blatantly violates the GSA Program Statute . . . ."

[2] See Final Report on Implementation of Pilot Program, p. 2, Docket No. E-7, Sub 1043 (filed Mar. 20, 2017) (stating that DEC entered into agreements with three customers, for a total of 192,868 MWh and that an additional project will come online in July 2017 with approximately 10,500 MWh, and that this represents 20% of the annual aggregate cap (1,000,000 MWh) for customer participation.

[3] The provisions of HB 589 authorizing the GSA cannot be divorced from other provisions of the legislation limiting the "must take" provisions under PURPA. The standard offer entitlement is circumscribed, and the term of negotiated PPAs is limited to five years. Were the Commission to authorize long-term must take PPAs into the GSA Program at fixed rates, these actions would be inconsistent with HB 589 viewed in totality.

Second, the bill credit received by participating customers "shall not exceed [the] utility's avoided cost." Id. As reflected in the following, other specific directives included in the GSA Statute guide the Commission's resolution of discrete issues in controversy. In doing so, absent specific direction included in the plain language of the statute, the Commission's approval of the modifications to the GSA Program rely upon the sound discretion of the Commission, informed by its expert judgement and its experience in the regulation of electric public utilities.

With this background, the Commission now addresses two disputed issues related to the broad legislative intent of the GSA Statute: (1) the extent to which the GSA Program and the CPRE Program are integrated, if at all; and (2) the establishment of an appropriate proxy for the value of the energy and capacity procured through the GSA Program. At the oral argument, no party argued that any other party's proposals for implementation of the statute is unlawful.

Duke argues that the GSA Program and the CPRE Program are part of an "integrated renewable energy procurement plan," citing the provision of N.C.G.S. § 62-159.2(d), whereby unsubscribed capacity available under the GSA Program will be reallocated to the CPRE Program if any portion of the 600 MW available under the GSA Program is unsubscribed. The other parties disagree with Duke's view, arguing that the GSA Program stands on its own, separate and apart from the CPRE Program, notwithstanding this reallocation provision. These parties argue that the GSA Program should not incorporate the features of the CPRE Program, and instead advocate for the incorporation of features akin to the Commission's implementation of PURPA, such as long-term rates that are based on the Commission-established avoided cost rates.

The Commission concludes that neither interpretation of the provisions of the GSA Statute is prohibited in light of the express language of the GSA Statute, which neither requires, nor forbids, the use of features of the CPRE Program or of PURPA implementation, in the administration of the GSA Program. However, the Commission, in its discretion, does not agree that Duke's proposed integration of the CPRE Program should be authorized. Consistent with the comments of the Public Staff, the Commission concludes that as the General Assembly did not require the two programs to be implemented complimentarily, and as implementation in this fashion poses difficulties in administration, the Commission declines to approve it. The Commission's determination is supported by several considerations. First, the provision of N.C.G.S. § 62-159.2(d) that would reallocate the capacity available under the GSA Program to the CPRE Program did not expressly create the linkage Duke sees, but provides some measure of certainty that Duke would achieve the legislative goal of procuring an additional 3,300 MW of renewable energy-supplied energy and capacity through the following programs established by the enactment of House Bill 589: CPRE Program (2,660 MW), GSA Program (600 MW), and Community Solar (40 MW). Second, the GSA Program and the CPRE Program both are established by statutes that provide for robust administrative structures and include features unique to each program. Third, as the Public Staff argues, the CPRE Program and the GSA Program have different timeframes and purposes, a consideration that takes on additional import in light of the delays experienced in implementing the CPRE Program and the present uncertainty about the results of the Tranche 1 CPRE RFP Solicitation. In short, the Commission determines that building the GSA Program into the CPRE Program framework in the way Duke proposes, while not expressly prohibited under the GSA Statute, is (1) difficult to administer for practical and administrative reasons related to the timing of the CPRE RFP Solicitations; unnecessary given the structure of the GSA Program set out in the GSA Statute; and unjustified by the provisions that reallocate unused GSA Program capacity to the CPRE Program at the end of the 5-year GSA Program. Therefore, the Commission will direct Duke to revise its proposed GSA Program to remove the program features that relied on the integrated implementation of the GSA Program and the CPRE Program.

The most complex and contested issue in this proceeding is how to establish a bill credit that serves as a proxy for the value of the energy and capacity procured through the GSA Program. The Commission's determination of the appropriate bill credit to be received by participating customers is at the heart of implementing the General Assembly's directive that all customers not participating in the GSA Program be "held neutral, neither advantaged nor disadvantaged, from the impact of the renewable electricity procured on behalf of the program customer." N.C.G.S. § 62-159.2(e). The bill credit is also the mechanism through which a participating customer is compensated for the energy and capacity procured on its behalf. Thus, properly established, the bill credit should provide an economic incentive for eligible customers to participate in the GSA Program. While not burdening non-participating customers with costs that they otherwise would not incur, Duke's proposed bill credit for the longer-term agreements is based on the results of the CPRE RFP Solicitations. The other parties have generally argued for the use of Commission-established avoided cost rates, fixed over a long-term period, as the basis for the bill credit. In addition, the Public Staff presents three alternative recommendations for establishing the bill credit: (1) a bill credit based on energy only; (2) establishment of the bill credit based on a competitive solicitation specific to the GSA Program; and (3) the use of actual incremental generation costs, similar to the approach taken by Georgia Power with its REDI C&I Initiative. Further, the Walmart Settlement proposes an additional alternative, using a bill credit based on hourly incremental generation costs, as determined on a day-ahead basis. This, as Duke explained at the oral argument, differs from the Georgia Power's REDI C&I Initiative in that the Georgia Power initiative is based on actual cost data on a day-behind basis. After the oral argument and in response to Commission questions, Duke filed an explanation that the day-ahead basis aligns with Duke's real-time pricing tariffs and is administratively less burdensome because the data used are already generated for the purposes of those tariffs. All of the parties generally agree that each bill credit methodology proposed in this proceeding is permissible under the GSA Statute.

The Commission agrees with the Public Staff that N.C.G.S. § 62-159.2(e) authorizes the Commission to determine the appropriate basis for the bill credit to be received by the GSA Customer, while also ensuring that all other (non-participating) customers are held neutral, neither advantaged nor disadvantaged from the impact of the GSA Program, the only specific limitation being that the bill credit may not exceed the utility's avoided costs. As noted above, the avoided costs are a ceiling, not a floor. The Commission weighed several factors in determining the appropriate bill credit, including: how the bill credit reduces reliance on the long-term fixed rates based on forecasted costs, as is consistent with the broad intent of House Bill 589; (2) that the bill credit does not exceed the utility's avoided cost, and is an accurate proxy for the value of the energy procured through the GSA Program, thereby holding non-participating customers harmless; and (3) whether the bill credit has the potential to attract participation from eligible customers. The latter factor weighed heavy in the Commission's consideration of these issues, particularly in light of some parties' predictions that unless the bill credit is calculated in a certain manner, the GSA Program, as proposed by Duke, would be largely un-subscribed or under-subscribed. The Walmart Settlement and the Wells Fargo consumer statement of position demonstrate that Duke's proposed bill credit methodologies would be accepted by some eligible customers. The remaining questions are whether Duke's proposed bill credit methodology would exceed the relevant utility's avoided cost and hold nonparticipating customers neutral, as required by N.C.G.S. § 62-159.2(e).

In these proceedings and in others, much time and effort have been devoted to discussing the Commission's administratively-established avoided cost rates. The two alternative views are that these rates are inherently inaccurate over the long-term, and that administratively established avoided cost rates are, as a matter of law under PURPA, assumed to be the point where the utility is indifferent to purchasing power from a QF or another source, or generating power itself.[1] The Commission recognizes that both arguments have support; however, the Commission need not resolve this debate to establish a GSA Program that will comply with both the express requirement of the GSA Statute to hold nonparticipating customers neutral and the implied requirement to attract participation from eligible customers. It is sufficient that the Commission strike an appropriate balance between the risk of inaccurate price forecasting that is inherent in the administratively-established avoided cost rates that are fixed for the long-term, and the risk inherent in a rate based upon cost data that cannot be fully known today.

The Commission first determines that the General Assembly did not define the words "avoided cost" in the GSA Statute, but in this Order the Commission will use the term as it is understood and implemented through N.C.G.S. § 62-156(c). Thus, for the bill credit options based on the Commission's implementation of PURPA, the Commission expects the utility to "design [the bill credit] rates consistent with the most recent Commission-approved avoided cost methodology" and to use "up-to-date data in determining the inputs for negotiated avoided cost rates," updated at the time of the submission of the GSA Service Agreement.[2]

The Commission, in its discretion, determines that two bill credit methodologies proposed in this proceeding strike the appropriate balance called for in the GSA Statute: 1) Duke's proposal to use an avoided cost rate methodology that would apply to contracts made pursuant to N.C.G.S. § 62-156(c) and make such rate available for two- and five-year term GSA Service Agreements, with a refresh of that rate every five years thereafter under longer-term GSA Service Agreements; and 2) the use of hourly, marginal cost data to determine the bill credit, under a formula that is fixed for the term of the GSA Service Agreement, as proposed under the Walmart Settlement.

The following considerations support the Commission's conclusion that the use of a 2-year avoided cost rate methodology that would be available under contracts made pursuant to N.C.G.S. § 62-156(c) is appropriate for use in determining the GSA bill credit. First, this bill credit

[1] See, generally, Order Establishing Standard Rates and Contract Terms for Qualifying Facilities, pp. 16-18, Docket No. E-100, Sub 148 (2017). However, the Commission, as addressed above, recognizes that House Bill 589, including the GSA Statute, display an intent on the part of the General Assembly to introduce an element of competitive pricing into the procurement of renewable energy and to reduce reliance on PURPA, which contains a "must purchase" requirement for investor-owned utilities in purchasing a QF's electric output.

[2] See N.C.G.S. § 62-156(c) and Order of Clarification, Docket No. E-100, Sub 140 (2015).

determination mitigates almost entirely the risk of inaccurate price forecasts, because the data that produces this rate are relatively current, in the sense that there is minimal lag time between the utility submits the cost data and proposed rate methodology to the Commission for review and approval, and updating of that cost data at the time of the establishment of the rate through the execution of the GSA Service Agreement and PPA. Second, the 2-year rate roughly coincides with the timing of the Commission's biennial avoided cost proceedings, meaning the rate methodology would reflect the Commission's evolving implementation of PURPA. Third, the 2-year rate is shorter in duration than the period the General Assembly concluded is appropriate for a negotiated contract under PURPA. See N.C.G.S. § 62-156(c) (allowing for a negotiated PURPA contract up to 5 years). While not dispositive, the Commission finds persuasive the parties' arguments that this congruence is appropriate based on the recent amendments to N.C.G.S. § 62-156(c), which are generally understood to be an attempt to mitigate the risk of inaccuracy of long-term avoided cost rates. Therefore, the Commission will approve the use of the 2-year avoided cost rate, as agreed to by Duke and as supported by the Public Staff, as a basis for calculating the GSA Bill Credit. In the compliance filing required by this Order, the Commission will require Duke to address with specificity the timing of the establishment of the rate in light of the need to use updated cost data as inputs to the Commission-approved rate methodology.

Similar considerations support the determination that use of a 5-year avoided cost rate methodology that would be available under contracts made pursuant to N.C.G.S. § 62-156(c) is appropriate for use in determining the GSA bill credit. While a 5-year term slightly increases the risk of "staleness" in cost data (because there is a longer lag time between the update to the cost data that are inputs to the rate methodology at the time of the execution of the PPA or GSA Service Agreement and the conclusion of the term of the fixed rate), the Commission concludes that the congruency with the 5-year term provided for in recently amended N.C.G.S. § 62-156(c) supports use of a 5-year term. In addition, the approval of this five-year term is supported by the comments submitted by Duke and the Public Staff. Further, the Commission will approve the use of Duke's proposed five-year reset under the ten-, 15-, and 20-year terms to be made available under the GSA Program. This five-year reset will mitigate the impact of the staleness of long-term fixed rates, consistent with the intent supporting House Bill 589.

The Commission also determines that the GSA Program should include an alternative option for calculating the bill credit based on the utility's marginal hourly cost data, as proposed in the Walmart Settlement. The Commission recognizes the arguments made by a number of the parties in favor of a long-term, fixed bill credit amount based on the Commission-established avoided cost rates, as providing a measure of certainty for participating customers and renewable energy facility owners. However, the Commission determines that such a bill credit would be inconsistent with the broad legislative intent supporting the enactment of House Bill 589, including the reduced emphasis on long-term fixed rates. Moreover, to the extent that these arguments rest on PURPA's mandate to provide QFs a reasonable opportunity to obtain financing, these arguments are misplaced because there is no similar mandate under the GSA Statute. Furthermore, the GSA Statute is part of House Bill 589, which expressly reduces both the availability and the maximum term of the standard offer contract under PURPA and limits the term of negotiated PPAs under PURPA to five years. Walmart's commitment to avail itself of such a program through its settlement with Duke is sufficient to rebut the arguments that structuring the bill credit based on hourly cost data would result in a significantly lower level of participation in the GSA Program than the 600 MW authorized through the GSA Statute. Finally, the Commission is persuaded by the additional information provided in Duke's response to Commission questions that this bill credit option should be forward-looking, rather than retrospective. Therefore, the Commission will approve the Walmart Settlement and require Duke to make this bill credit option generally available to eligible customers.

The Commission bases its approval of the Walmart Settlement on the following understanding of the explanation included with the filing accompanying the Walmart Settlement: (1) that the GSA Service Agreement is a three-party agreement between (a) DEC or DEP, (b) the GSA Customer, and (c) the GSA renewable energy facility; that the GSA customer will negotiate a levelized $/MWh price with the GSA renewable energy facility to set the GSA Product Charge; (3) that the PPA between DEC or DEP and the GSA renewable energy facility will include a price term that reflects the applicable marginal hourly rate formula set out in the Walmart Settlement; (4) that Duke will assign to the GSA renewable energy facility its right to receive the GSA Product Charge payment from the GSA customer; (5) that the GSA renewable energy facility will assign to the GSA Customer its right to receive payment under the PPA, which payment is determined by the applicable hourly marginal rate formula and shall be equal to the GSA Bill Credit. In this manner, the GSA Bill Credit payment is passed-through Duke from the GSA renewable energy facility to the GSA Customer, and the GSA Product Charge is passed-through Duke from the GSA Customer to the GSA renewable energy facility. As discussed throughout this Order, this arrangement complies with the requirements of N.C.G.S. § 62-159.2, and will be required under both bill credit options. Although the Walmart Settlement then contemplates "additional amounts" that may be payable by Duke to the GSA renewable energy facility, during period when the PPA price (the price based on the applicable marginal hourly rate formula) is less than the GSA Product Charge (the price negotiated by the GSA Customer with the GSA renewable energy facility), it is not clear to the Commission that this additional payment is permissible under the GSA Statute. To the extent that this provision creates ambiguity as it is inconsistent with the explanation Duke provided, the Commission resolves this ambiguity on the basis of the foregoing understanding of Duke's explanation, because the Commission assumes that the parties would not have proposed an additional, but undefined, payment that would call into question whether the Walmart Settlement complies with the GSA Statute.

Finally, and as further discussed below, the Commission notes that a number of the parties have argued in favor of the availability of a bill credit option that is fixed up to ten years, and which is based upon Commission-approved avoided cost rates. As with other proposed bill credit methodologies that the Commission has declined to approve, the Commission chooses not to authorize this option. While this option is not strictly prohibited by the GSA Statute, the Commission finds it to place the non-participating customers at too great a risk of overpayment in contradiction of the express requirement that they be held "neutral, neither advantaged, nor disadvantaged." Upon examination of the evolution of state energy policy, including the advent of the GSA Program and the other changes enacted through House Bill 589, the Commission is unwilling to require the availability of a bill credit that is fixed for a term that is longer than the five years authorized in the implementation of PURPA for QFs not eligible for the standard contract. The rationale for making available a ten-year fixed rate for the GSA credit, as the Commission understands it, is to support the opportunity to obtain financing of the renewable energy facility project, which supports PURPA's mandate to encourage QFs.[1] While the bill credit is the item at issue, the term of the credit is inextricably tied to the term of the PPA entered into by the renewable generator with respect to which the credit is offered. Historically, in its implementation of PURPA, the Commission has implemented the requirement of a term length enabling favorable financing terms by requiring the relevant utilities to offer standard contracts that include long-term levelized rates that are fixed for five, ten, or 15 years.[2] This Commission determination, among others, has been criticized by some as imposing unreasonable costs on ratepayers. In House Bill 589, the General Assembly reduced the maximum length of the standard offer contract available pursuant to the State's implementation of PURPA to ten years (eliminating the availability of the 15-year term), limited the availability of the standard offer contract to projects with a generating capacity of 1 MW or less (reducing the Commission-established threshold from 5 MWs) and limited the maximum length of the negotiated contracts available to those projects that do not qualifying for standard offer to five years.[3] While one objective of limiting the term of negotiated PURPA eligible PPAs to five years arguably was to drive QF developers into the CPRE Program, that fact in no way undercuts the conclusion that the General Assembly viewed with disfavor long-term fixed rates based on administratively-determined avoided costs. The CPRE Program is itself an alternative that reduces the risk to ratepayers that is inherent in long-term fixed rates that are based on forecasted price data. The theory behind the CPRE Program is that competition will drive down the price paid to QFs below the administratively determined avoided costs. Moreover, participation in CPRE Program is limited in MWs eligible and duration of the program, and includes the right to dispatch and control the electric output from facilities participating in the CPRE Program. In contract, the five-year limit for negotiated QF PPAs is unlimited in capacity available, exists into perpetuity (absent a change in federal law), and requires the utility to take and purchase the electric output from the QF without regard to the traditional least-cost, economic dispatch model.

As explained above, the Commission understands the use of the term "avoided cost" in the GSA Statute as it is understood and implemented through N.C.G.S. § 62-156(c), the PURPA negotiated contract. It would be inconsistent with the recent amendments to N.C. Gen. Stat. § 62-156(c) to require the availability of a bill credit under the GSA Program (a non-PURPA context) that is longer than five years, when the Commission understands that House Bill 589 is a departure from the traditional implementation of PURPA, which includes the express requirement to provide a reasonable opportunity to obtain financing of QF projects. Therefore, the Commission chooses not to approve the availability of a bill credit under the GSA Program that is fixed for longer than five years.

PURPA, enacted in 1978, requires the incumbent electric utility to buy power generated by a QF at a price based on the costs incurred to build and operate a unit the utility would build and operate but for its purchase from the QF. Such purchases are required whether or not the utility

[1] See Windham Solar LLC & Allco Fin. Ltd., 157 FERC ¶ 61,134 (Nov. 22, 2016).

[2] See Order Setting Avoided Cost Input Parameters, pp. 19-22, Docket No. E-100, Sub 140 (2014).

[3] See N.C. Gen. Stat. § 62-156(b)(1) and (c).

actually would build that unit or not. PURPA is a must purchase statute. According to FERC, the PPA with the QF under PURPA should be of sufficient length to enable the QF to obtain reasonable financing. Historically, one difficulty with PURPA has been that the long-term fixed rates established at the time the QF obtains a legally enforceable obligation seldom equals the actual price a utility would pay for procurement of electric power 10 years later. Often this results in the utility paying too much to the detriment of its ratepayers. In North Carolina, the proxy plant upon which administratively determined avoided costs are based has been a natural gas burning combustion turbine. Subsequent to the availability of shale gas, the price of natural gas has dropped precipitately. This result, from what was then an unanticipated and unknowable development in the marketplace, typifies the type of risk inherent in establishing long-term, fixed rates based on estimated avoided costs, and likely resulted in utilities purchasing power at rates substantially in excess of their actual avoided costs.[1]

Moreover, unlike the combustion turbine, solar QFs have no fuel costs, so the PURPA theoretical proxy fails to measure the solar QF's actual costs. Also, unlike the combustion turbine, historically solar generation output is dependent on sunshine, making it intermittent, largely non-dispatchable, and unlikely to generate on system peak.

Consequently, historically long-term fixed administratively-determined PURPA avoided costs rates have posed substantial risks to ratepayers. The longer the required PPA term under PURPA or the GSA Program, the greater the likelihood that the payments will be out of line with the subsequently experienced avoided costs and the greater the risk to ratepayers. The fundamental requirement of the GSA Statute is that the credit be structured to "ensure that all other customers are held neutral, neither advantaged, nor disadvantaged." In the Commission's view, long-term fixed-rate credits based on avoided costs cannot be adequately reconciled with this fundamental requirement.

In summary, the Commission concludes that these bill credit options are consistent with the requirement in N.C.G.S. § 62-159.2(e) that nonparticipating customers be held neutral, because each methodology relies on updated or nearly real-time cost data and offer either a rate that is fixed for two or five years, or a rate formula that is fixed for up to twenty years, and that these bill credit options are structured to ensure that the bill credit will not "exceed the utility's avoided cost," as is required under the GSA Statute.

<u>Availability</u>

The availability section of Duke's proposed riders reflect that the GSA Program is available to major military installations, the University of North Carolina, and nonresidential customers with either a contract demand (i) equal to or greater than one MW, or (ii) multiple service locations that, in the aggregate, is equal to or greater than 5 MW, as required by N.C.G.S. § 62-159.2(a). The availability section also reflects the requirements of N.C.G.S. § 62-159.2(d), namely, that the program shall be offered for a period of five years, or until December 31, 2022, whichever is later,

[1] It is altogether possible that in the future natural gas prices will rise. Should that occur, avoided costs rates would likely increase as well. Authorizing periodic adjustments to the GSA credit should be beneficial to participating GSA customers.

shall be limited to 600 MW of total capacity, and shall provide reserved capacity of 100 MW for major military installations, and 250 MW for The University of North Carolina. Further, as is also consistent with N.C.G.S. § 62-159.2(d), the availability section provides that any unsubscribed amount of that reserved capacity shall, at the end of the first three years of the program, be added to the 250 MW of remaining available capacity and made available to the other eligible customers. The Commission determines that the provisions of N.C.G.S. § 62-159.2 related to customer eligibility and the availability of the GSA Program are unambiguous, and that Duke's proposed rider provisions related to the same are consistent with the plain language of the statute. Therefore, subject to the following discussion, the Commission determines that these provisions should be approved.

The other parties to these proceedings have objected to the following provision in the availability section of Duke's proposed riders: Duke's proposal to allocate the 250 MW of capacity that is "unreserved" under the GSA Program between DEC and DEP based upon the load-ratio share between DEC and DEP's commercial and industrial customer classes. Duke's proposed riders identify 160 MW to be made available to DEC customers and 90 MW to be available to DEP customers. Duke supports its proposal through its reply comments, stating that the proposed allocation is not prohibited by the GSA Statute, is reasonable based on the load ratio share of the two utilities, and is designed to provide an equitable allocation to allow fair participation opportunities for customers served by both utilities. NCCEBA, NCSEA, SACE, and Apple and Google have questioned whether there is a statutory basis for this proposed allocation and suggest that the unreserved capacity be available across both utilities on a first-come, first-served basis. In its initial comments, the Public Staff stated that it does not take exception to Duke's proposed allocation of the unreserved capacity across the two utilities.

The Commission agrees with Duke that the proposed allocation of unreserved capacity is not expressly authorized, nor prohibited, by the GSA Statute, leaving the resolution of this question to the discretion of the Commission. The Commission determines that Duke has articulated a reasonable basis for the proposed allocation method and that the Public Staff having found no reason to object to this proposed allocation lends support to deferring to Duke's business judgment on this issue. The other parties' objections, based on a lack of express authorization under the GSA Statute are not persuasive. The Commission, therefore, will approve the proposed allocation of unreserved capacity between DEC and DEP. However, the Commission further concludes that this issue, among others in these proceedings, deserves monitoring with regard to the impact on participation by both utilities' customers, and, therefore, the Commission may consider making adjustments to this allocation in future years of the GSA Program, particularly in those years when any un-awarded "reserved" capacity becomes available to other eligible customers.

Directed Procurement of GSA Facilities

The section of Duke's proposed riders titled, "Direct Procurement of GSA Facilities," outlines the basic structure of Duke's proposed GSA Program as allowing eligible customers to direct DEC or DEP to procure renewable energy and to obtain the RECs "generated by a GSA Facility or portfolio of GSA Facilities." Duke first proposes to require that a participating renewable energy facility be located in either North Carolina or South Carolina within the service territory of the respective utility that serves the participating customer's premises. Duke next proposes its "standard offer" (facilities selected through a competitive solicitation) and "self-supply" (facilities that are either Duke-developed, or subject of a negotiated agreement by the participating customer) options, and details the requirements of both options, including that the owner of the respective renewable energy facility enter into a PPA with the utility. This section of the proposed riders relies heavily on Duke's view that the GSA Program is "integrated" with the CPRE Program.

The other parties generally object to this portion of the proposed riders, contending that it is contrary to the requirements of N.C.G.S. § 62-159.2(b). They argue that this section is inconsistent with the requirements of N.C.G.S. § 62-159.2 in two ways: (1) that the proposed program does not "provide standard contract terms and conditions for participating customers and for renewable energy suppliers from which the electric public utility procures energy and capacity on behalf of the participating customer," and, (2) that the proposed program does not "allow eligible customers to select the new renewable energy facility from which the electric public utility shall procure energy and capacity." N.C.G.S. § 62-159.2(b). In addition, NCSEA specifically objects to the requirement that GSA renewable energy facilities be located in DEC or DEP's respective service territories in North Carolina or South Carolina, and in the same service territory as the participating customer's premises, or multiple premises if the customer is aggregating its load to meet the eligibility threshold.

The Commission agrees that N.C.G.S. § 62-159.2 expressly requires standard contract terms and conditions for both participating customers and the participating renewable energy facilities, meaning fill-in-the-blank forms used to express the terms of the agreement between Duke, its customer, and the renewable energy facility owner. Duke initially did not file the standard forms, and the other parties complained about the lack of opportunity for review and comment. Duke has since filed a proposed GSA PPA, GSA Service Agreement, GSA Term Sheet, and other related documents with the Commission, but the other parties have not had a meaningful opportunity to present arguments related to these documents. The Commission generally agrees with the positions of the other parties, and, thus, will also direct Duke to include revised versions of these documents in the compliance filing required by this Order. This directive recognizes that, because this Order requires Duke to make substantial changes to its proposed program, a detailed review of these documents at this time would be an unproductive effort.

The parties also disagree on whether Duke's proposed riders are consistent with the directive that the GSA Program "application shall allow eligible customers to select the new renewable energy facility from which the utility procures energy and capacity on behalf of the participating customer." See N.C.G.S. § 62-159.2(b). The Commission disagrees that Duke's proposed standard offer option is not authorized by the GSA Statute because eligible customers subscribing to that option cannot choose their renewable energy supplier. The Commission determines that this reading of the statute, advanced in support of the objections to the standard offer option, is too narrow and restrictive and may tend to limit participation by eligible customers without the sophistication and wherewithal to select their own renewable energy supplier. This result, or course, makes more of the 600 MW of the GSA Program set aside available for customers without these limitations. The requirements of the statute are broad enough to permit eligible customers to authorize Duke to select a renewable energy supplier for them. Any eligible customer wishing to self-select its supplier is free to do so and not elect the standard offer option. However, as no party to this docket representing those potentially interested in participating in the GSA Program, including the Public Staff and the AGO, expresses any support for this standard option, the Commission for the moment at least, will refrain from approving it.[1]

Under the remaining "self-supply option," as proposed by Duke, the customer can choose to have Duke procure energy and capacity from a facility that Duke develops, or from a facility that the customer has negotiated with regarding the price of the energy and capacity. This ameliorates the alleged short-coming of the standard offer, and complies with the requirements of N.C.G.S. § 62-159.2(b) in that the customer is empowered to "select the new renewable energy facility from which the utility procures energy and capacity on behalf of the participating customer." However, other parties have criticized this option as well, on the basis that the participating customer is provided an "unbundled REC" and nothing more (some of this criticism is targeted at the proposed rate design, which is addressed below). The Commission, in its discretion, agrees with this criticism because the fundamental economics of the transaction under Duke's proposed self-supply option is a negotiation for the sale of RECs, through a separate contractual arrangement between the participating customer and the GSA renewable energy facility. In this sense, the eligible customer is denied the opportunity to "negotiate with renewable energy suppliers regarding price terms" for the procurement of energy and capacity supplied by the renewable energy facility selected by the eligible customer. While the language in N.C.G.S. § 62-159.2(b) does not expressly provide for negotiation regarding the price for renewable energy and capacity, the Commission concludes that its determination is in accord with the GSA Statute. Therefore, while the basic concept of the self-supply option is one the Commission will require Duke to retain, the Commission will require Duke to revise the structure of the self-supply option, consistent with the conclusions reached in this Order. In rejecting this option the Commission will remain open to receiving from Duke a proposed REC-purchase program similar to that proposed as the standard offer, separate and apart from the GSA Program.[2] The revised structure of the self-supply option should empower the eligible customer to negotiate a price with the renewable energy facility the customer has selected, which sets the GSA Product Charge as part of the three-party agreement for participation in the GSA Program, consistent with the basic structure proposed in the Walmart Settlement.

Finally, the Commission recognizes that NCSEA has identified a proposed limitation on the participating customer's ability to select the new renewable facility in that Duke has proposed a requirement that the facility be located in North Carolina or South Carolina, within the same utility service territory as the customer's premises. The Commission determines that Duke has articulated a reasonable basis for these requirements related to the siting of new renewable energy facilities, namely, that the facility will serve all DEC or DEP customers in both North Carolina

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[1] While some commenters predict that insufficient interest in the GSA Program as proposed by Duke will materialize to make the program successful, these same commenters advocate positions limiting the potential participation by some customers without the wherewithal to utilize the self-select option.

[2] On November 20, 2018, in Docket Nos. E-2, Sub 1190; E-7, Sub 1185; and E-100, Sub 90; DEP and DEC filed a request for approval of proposed Renewable Advantage Riders and modifications to the existing NC GreenPower Program. In its filings, Duke describes the proposed Renewable Advantage Rider as a "new voluntary program allowing residential and non-residential (small business) customers to purchase RECs to offset all or a portion of their electrical consumption." That matter is pending before the Commission.

and South Carolina, as "system assets." As with other issues in these proceedings, the lack of express statutory authorization for Duke's proposed requirement is not persuasive, because the resolution of this issue lies in the discretion delegated to the Commission through the GSA Statute.

Application Process and GSA Service Agreement

The section of Duke's proposed riders titled "Application Process and GSA Service Agreement," outlines Duke's proposed procedures for eligible customers to apply to participate in the GSA Program, and for memorializing the terms of an eligible customer's participation in the GSA Program. First, Duke proposes that an eligible customer be required to submit an application during the GSA Program enrollment window and request an annual amount of renewable capacity to be developed or procured on the customer's behalf, subject to the limitation established in N.C.G.S. § 62-159.2(c) (providing that the contracted amount of capacity shall be limited to no more than 125% of the maximum annual peak demand of the eligible customer premises). Duke proposes that the application require the eligible customer to indicate whether the customer is requesting that Duke develop a facility for the customer's participation in the Program, or whether the eligible customer is electing to participate under the standard offer option or self-supply option, and to identify the customer's requested length of contract term for participation in the Program (as originally proposed, Duke would require designation of a two-, five-, or twenty-year contract term; however, in its reply comments, Duke agreed to include ten- and fifteen-year options).

Duke's proposed program would also require that the application be accompanied by the payment of a $2,000 application fee, which fee would be nonrefundable, except where the application is rejected because the GSA Program already reached its full available capacity. Duke's proposes that applications be accepted on a first-come-first-served basis based on the date and time of the receipt of the application and application fee. Duke's proposed application process would also require eligible customers electing to participate through the self-supply option to provide a "term sheet" executed by the eligible customer and the renewable energy supplier, which shall identify the renewable energy supplier and provide other information about the facility, and to make payment of a capacity reservation bond in the appropriate amount as determined according to the methodology under the CPRE Program. Finally,[1] this section of the proposed riders would require the eligible customer to execute a GSA Service Agreement and return it to Duke within 30 days of delivery to the eligible customer.

This section of the proposed riders, with the exception of the issue of calculating the GSA bill credit, is largely administrative and non-controversial. However, NCSEA and NCCEBA objected to Duke's proposed "enrollment window" concept as not supported by the GSA Statute and as unnecessarily restricting the ability of eligible customers to participate. In addition, NCSEA and other parties criticized the restricted offerings of contract terms. The Commission understands that Duke's basis for proposing an enrollment window is to coordinate the timing of the close of a CPRE RFP Solicitation, with the need to identify the applicable

[1] This section also provides for Duke, after review of the customer's application and completion of an RFP to inform the customer of the applicable GSA Bill Credit based upon the results of the CPRE RFP Solicitation. The Commission addresses Duke's proposed rate design below and, therefore, omits discussion of this issue here.

GSA Bill Credit that is based on the results of the CPRE RFP Solicitations.[1] As discussed above, the Commission has chosen not to approve Duke's proposed integration of the CPRE Program with the GSA Program. The Commission determines that the proposed enrollment window is unnecessary in light of that decision and the related determination of the appropriate bill credit options that Duke must offer. The Commission, therefore, will require Duke to revise this section of the proposed riders consistent with these conclusions.

In response to comments submitted by other parties, Duke, in its reply comments, agreed to offer two-, five-, ten-, fifteen-, and twenty-year term options for participation in the GSA Program under the bill credit option that is based on the Commission-approved avoided cost rate methodology. The Commission determines that Duke's proposed additional contract term lengths appropriately responds to the concerns expressed by the other parties. Therefore, the Commission will approve Duke's proposed contract term options of two-, five-, ten-, fifteen-, and twenty-years for use in that bill credit option. Under the bill credit option based on hourly, day-ahead production data, as proposed in the Walmart Settlement, the customer could elect to participate for a term of any number of years up to the 20-year limit provided in the GSA Statute. The Commission determines that this is also appropriate and should be made generally available as an alternative bill credit option. The two options with the varying term lengths provides sufficient flexibility for the eligible customers' participation in the GSA Program.

GSA PPA Rates and Terms

The section of Duke's proposed riders titled "GSA PPA Rates and Terms" details Duke's proposal that the GSA PPA (i.e., the contract for the sale of the output from the GSA renewable energy facility to Duke) delivered to the GSA renewable energy facility will be "in substantially the same form as the PPA approved for the CPRE Program procurement." Significantly, this affords Duke the authority to dispatch, operate, and control the GSA renewable energy facility in the same manner as the utility's own generating resources, consistent with the authority afforded to Duke under the CPRE Program. See N.C.G.S. § 62-110.8(b). The other parties object to the inclusion of these provisions, based upon a lack of statutory support.

The Commission is not persuaded that importing this feature of the CPRE Program is appropriate for the GSA Program, and, therefore, in its discretion, determines not to approve it. The CPRE Program is unique in providing this authority to the utility, and the Commission is unwilling to extend such authority to the GSA Program. Instead, for the reasons articulated by the Public Staff, the Commission determines that the rights of the utility to dispatch and control the output of a GSA renewable energy facility should be more similar to those rights provided for in dealings with QFs that are not eligible for the utility's standard contract. Therefore, the Commission will require Duke to revise the GSA riders and PPA terms and conditions to reflect this conclusion. These terms and conditions shall include the right to order a GSA renewable

[1] The Commission notes that Duke clarified in its reply comments that the opportunity for eligible customers to "enroll" in the program is available throughout the existence of the GSA Program, but the "applicable" bill credit amount would change based on the results of the most recently concluded CPRE RFP Solicitation. Thus, Duke responds to NCSEA by stating that the participation restrictions NCSEA perceives do not exist.

energy facility to dispatch-down or fully curtail its output when the utility is faced with a system emergency. See, e.g., Order Establishing Standard Rates and Contract Terms for Qualifying Facilities, pp. 7-8 and 78-83, Docket No. E-100, Sub 148 (2017). Consistent with the Public Staff's comments, the Commission will also require Duke to include instances of dispatch-down instructions or curtailment as applied to GSA renewable energy facilities in the similar reports required for other renewable energy facilities.

This section of Duke's proposed riders also addresses the "contract price" paid by Duke to the GSA renewable energy facility. Consistent with the Commission's decision to not approve the CPRE Program linkage proposed by Duke, the Commission similarly determines not to approve Duke's proposed contract price that would be based on the capacity-weighted average of all proposals selected through a CPRE RFP Solicitation or, for shorter-term agreements, on the lesser of the utility's avoided cost rate or the price negotiated between the eligible customer and the renewable energy facility owner. The Commission determines that the eligible customer shall be allowed to negotiate with the renewable energy suppliers regarding the price terms. Again, the Commission has chosen not to link the implementation of the GSA and CPRE Programs. When reading subsection (b) of the GSA Statute together with subsection (e) (providing that the total cost of the renewable energy and capacity procured on behalf of the eligible customer shall be paid by that customer, in addition to the customer's "normal retail bill," and that the electric public shall pay the owner of the renewable energy facility), the Commission determines that the contract price is to be established based on the negotiations between the eligible customer and the renewable energy facility owner, and that the eligible customer will be required to pay Duke that contract price, which shall then be passed on to the owner of the GSA renewable energy facility. Therefore, the Commission, in its discretion, determines that the GSA PPA contract price shall be the rate negotiated between the eligible customer and the owner of the GSA renewable energy facility (in $/MWh) multiplied by the energy actually produced by the facility (in MWh), to derive an amount expressed in dollars. This pricing mechanism shall apply for all contract term lengths, and shall establish the GSA Product Charge, consistent with that construct proposed under the Walmart Settlement. The Commission will, therefore, require Duke to revise this portion of its rider to reflect the foregoing conclusions.

Renewable Energy Credits

The section of Duke's proposed tariffs titled "Renewable Energy Credits" sets out Duke's proposed treatment of RECs under the GSA Program. For self-supply customers, Duke proposes that the value of the RECs shall be negotiated and agreed to through a REC purchase agreement between the eligible customer and the renewable supplier. Under this arrangement, Duke would not be responsible for procuring, delivering, or transferring RECs to the eligible customer. Above, the Commission required Duke to make changes to its self-supply option that are unrelated to the treatment of RECs. The Commission now determines, consistent with the Walmart Settlement, that the GSA renewable energy supplier shall transfer all RECs earned by the facility to the GSA Customer. Thus, the GSA Program shall provide for a "bundled PPA" in which the cost of the REC will be included in the energy and capacity price negotiated by the GSA customer with the renewable energy supplier, and provide for the transfer of RECs to Duke and then to the GSA customer. To implement this aspect of the GSA Program, renewable energy facilities participating in the GSA Program must be registered as new renewable energy facilities pursuant to Commission Rule R8-66, and must participate in NC-RETS or another REC tracking system to facilitate the issuance of RECs. The Commission will, therefore, require Duke to incorporate registration of renewable energy facilities as a requirement for renewable energy facilities participating in the GSA Program, and otherwise revise this section of its proposed riders to reflect the foregoing conclusions.

Monthly Rate

The section of Duke's proposed tariffs titled "Monthly Rate" sets out the key economic terms of the proposed GSA Program: the charges that a participating customer must pay and the bill credit that the participating customer is entitled to receive. Under Duke's proposed monthly rate, the GSA Customer's monthly rate or charges would be the "amount computed under the GSA Customer's primary rate schedule and any other applicable riders," plus the sum of the GSA Product Charge, GSA Bill Credit, and the GSA Administrative Charge. Duke supports its proposed monthly rate with a detailed explanation of the calculation of these charges and credits, and with legal and policy arguments. The other parties generally object to the use of the results of a CPRE RFP Solicitation to establish the GSA Bill Credit, and have offered alternative rate designs. The Commission determines that the basic structure of Duke's proposed monthly rate is appropriate because it reflects the requirement of N.C.G.S. § 62-159.2(e) that "in addition to the participating customer's normal retail bill, the total cost of any renewable energy and capacity procured by or provided by the electric public utility for the benefit of the program customer shall be paid by that customer." The Commission will now address each of the individual proposed charges and credits.

First, the Commission concludes that Duke has proposed an appropriate definition of the GSA Product Charge under the Walmart Settlement.[1] The GSA Product Charge shall be an amount expressed in dollars that is equal to the energy produced by the GSA Facility in the prior billing month (expressed in kWh or MWh) multiplied by the fixed rate for the power purchased from the renewable energy supplier (expressed in \$/kWh or \$/MWh), as specified in the GSA Service Agreement. The "fixed rate for the power purchased from the renewable energy supplier" shall be the rate that the participating customer negotiated and agreed to with the renewable energy supplier that the participating customer selected. Reflecting the plain language of N.C.G.S. § 62-159.2(b), the participating customer shall be permitted to negotiate the price term with the renewable energy supplier it has selected. As also addressed above, the GSA Product Charge shall be collected from the participating customer by Duke, and then remitted to the renewable energy supplier, in a manner consistent with the assignment proposed in the Walmart Settlement. This implements the requirement of N.C.G.S. § 62-159.2(e) that the electric public utility "pay the owner of the renewable energy facility which provided the energy." In summary, the GSA Product Charge shall be a monthly charge to the participating customer that is equal to the price the customer would have paid directly to the renewable energy supplier under a negotiated contract for the sale of the

[1] As addressed above in the discussion of the PPA Rates and Terms, the Commission will require Duke to alter the inputs that determine the GSA Product Charge to ensure that the participating customer is able to negotiate the price term with the renewable energy supplier that it has selected, as required by N.C.G.S. § 62-159.2(b).

electric output of the facility, with the only difference being that Duke shall collect the GSA Product Charge and remit the same amount to the renewable energy supplier.

Second, the Commission notes its determination of the appropriate bill credit options above. The Commission recognizes the arguments made by a number of parties in favor of a long-term, fixed bill credit amount based on the Commission-established avoided cost rates, particularly as it relates to providing a measure of certainty for participating customers and renewable energy facility owners. However, the Commission determines that such a bill credit would be inconsistent with the intent supporting the enactment of House Bill 589, including the reduced emphasis on long-term fixed rates. Moreover, to the extent that these arguments rest on PURPA's mandate to provide QFs with a reasonable opportunity to obtain financing, these arguments are misplaced because there is no similar mandate under the GSA Statute. Thus, the Commission determines not to agree with arguments presented in favor of a ten-year fixed bill credit, as exemplified in the stipulation between NCCEBA, UNC-Chapel Hill, and SACE, and in favor of a 20-year fixed bill credit, as advocated by NCSEA. The Commission also recognizes that the establishment of the bill credit is critical to attracting participation among the eligible customers, and, therefore, is at the heart of establishing a successful GSA Program. However, the Commission is not persuaded that a bill credit fixed for longer than five years is necessary to attract participation in the program, or that the bill credit methodology proposed under the Walmart Settlement (under which the methodology is fixed, but the credit itself will vary as marginal costs change) will go wholly unsubscribed or even significantly under-subscribed. Moreover, unlike under the implementation of PURPA, where long-term, fixed rates support the ability of QF projects to obtain financing,[1] there is no similar mandate in the GSA Statute. In addition, the General Assembly has directed the Commission to limit the term of PURPA negotiated contracts to five years. See N.C.G.S. § 62 156(c). As discussed above, the Commission determines that it would be anomalous to approve a negotiated GSA option for greater than five years when the GSA Program is part of the same legislation limiting PURPA negotiated PPAs to five years. Based upon these considerations, the Commission will not require Duke to offer a GSA Program bill credit that is fixed for longer than five years at this time. The Commission will, however, monitor participation in this program and remain open to revisiting this issue in the future.

Third, the Commission determines that Duke's proposed GSA Administrative Charge is appropriate and should be approved. Under Duke's proposed program, the GSA Administrative Charge is defined as the applicable monthly administrative charge of $375 per customer account, plus an additional $50 charge per additional account billed. No party raised an objection to the proposed GSA Administrative Charge, and Duke represents in its comments that the proposed charge was based on Duke's costs for administering the program. The Commission concludes that these proposed charges are reasonable and should be approved.

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[1] See Order Establishing Standard Rates and Contract Terms for Qualifying Facilities, pp. 34-39, Docket No. E-100, Sub 148 (2017).

General Provisions

The section of Duke's proposed riders titled "General Provisions" includes miscellaneous provisions regarding the terms of participation in the program. This section provides that the participating customer provide security as required in the GSA Service Agreement and that the Duke utilities will not be liable to the participating customer in the event that the renewable energy facility does not produce energy as required or expected. This section also addresses procedures for termination or default on the GSA Service Agreement.

The Commission has reviewed Duke's proposed GSA Service Agreement, and will withhold approval of that agreement, with regard to the financial security provisions of Article 11 of the GSA Service Agreement. Pursuant to N.C.G.S. § 62-159.2(c), Duke is directed to "establish reasonable credit requirements for financial assurance that are consistent with the Uniform Commercial Code of North Carolina." Duke has not demonstrated how Article 11 of the GSA Service Agreement is consistent with the Uniform Commercial Code of North Carolina, nor does the GSA Service Agreement or Duke's comments reference Chapter 25 of the North Carolina General Statutes. While none of the other parties objected to the security provisions, the Commission is not prepared to approve these provisions where the record fails to demonstrate that these provisions meet the express requirement of the GSA Statute. Therefore, the Commission will direct Duke to either revise its proposed credit requirements or otherwise demonstrate to the Commission that those requirements "are consistent with the Uniform Commercial Code of North Carolina."

Remaining Issues

1. Cost Recovery

The complexity of the issues involved in establishing the GSA Program rate design, including the bill credit, and the vigorous opposition to Duke's initial proposed GSA Program, encompass disagreements about what costs Duke is entitled to recover pursuant to amended N.C.G.S. § 62-133.2(a1)(11). Duke proposes that it be allowed to recover the cost of energy and capacity generated or delivered by all GSA Program facilities, which shall be equal to the GSA bill credit multiplied by MWhs generated by GSA facilities. Duke supports this proposal by arguing that because the bill credit for energy delivered under the GSA Program is equal to or below the utility's avoided cost, non-participating customers will be held neutral. NCCEBA, and other parties, objected to this proposal based on their view that the proposed program is cost-contained, meaning all costs are recovered from the participating customers, and, thus, there are no non-administrative costs to be recovered through N.C.G.S. § 62-133.2(a1)(11).

In resolving this issue, the Commission finds helpful the arguments of counsel for Duke and counsel for the Public Staff at the oral argument. These arguments clarified Duke's proposal that GSA renewable energy facilities will be "system assets," meaning that the energy delivered to Duke will be dispersed throughout the electric system and will serve all retail customers. In other words, the electrons generated by the GSA renewable energy facilities and procured under the GSA Program may not, and need not, be delivered to the participating customer for consumption at that customer's premises. For purposes of implementing a GSA Program that complies with the requirements of the GSA Statute, it is sufficient that the amount of energy generated by the GSA renewable energy facility is metered, and that the bill credit is appropriately established to ensure that all non-participating customers are held neutral and that the bill credit does not exceed the utility's avoided costs. Viewed in this light, and as stated by counsel for the Public Staff, the bill credit as determined by the Commission is "basically the price that [Duke] would be paying for that additional power being added as a system resource." Tr. Vol. 1, p. 159. In this manner, the nonparticipating customers will bear the costs of the electric power delivered to the Duke utilities, but the cost that they will bear is approximately the same as they would have paid in the absence of the electric power procured under the GSA Program. This, the Commission determines, ensures that all nonparticipating customers "are held neutral, neither advantaged nor disadvantaged, from the impact of the renewable energy procured on behalf of the program customer." N.C.G.S. § 62-159.2(e).

The Commission, therefore, anticipates that Duke will seek recovery of the non-administrative costs related to the GSA Program not recovered from program participants, as authorized by N.C.G.S. § 62-133.2(a1)(11). While the Commission agrees with counsel for Duke that there is a "real cost" to be recovered, the Commission finds that the parties have not addressed with sufficient precision how to account for these costs in the fuel cost recovery proceeding. The Commission expects that Duke's application for cost recovery will demonstrate the following:

1. That customers participating in the GSA Program continue to pay their "normal retail bill," requiring that the participating customer continue under an appropriate rate schedule generally available to nonresidential customers;

2. That Duke has collected a GSA Administrative Charge equal to $375 per customer account per month, plus an additional $50 per month per additional account, from each customer participating in the GSA Program. The revenue from collecting this administrative charge recovers the program administrative costs, including expenses for manual billing;

3. That Duke has collected a GSA Product Charge from each customer participating in the GSA Program, and that the GSA Product Charge is equal to the price negotiated between the participating customer and the owner of the GSA renewable energy facility (expressed in $/MWh, fixed for the term of the PPA) multiplied by the amount of energy delivered to Duke by the GSA renewable energy facility (expressed in MWh). The revenue collected by Duke as the GSA Product Charge shall ultimately be paid to the relevant GSA renewable energy facility.

4. That Duke has paid a GSA Bill Credit each month, to each participating customer. For customers that elect to participate through a GSA Service Agreement with a two- or five-year term, the bill credit shall be based on the most recently approved avoided cost rate methodology applicable in the PURPA negotiated contract setting, fixed for the full two- or five-year term of the agreement, and multiplied by the amount of energy delivered to Duke by the relevant renewable energy facility. For customers that elect to

> participate through a GSA Service Agreement that has a term longer than five years, the bill credit will be based on the most recently approved avoided cost rate methodology applicable in the PURPA negotiated contract setting, refreshed after five years to reflect the then- most recently approved avoided cost rate methodology applicable in the PURPA negotiated contract setting. Alternatively, the bill credit will be based on the marginal hourly production cost data, consistent with the methodology proposed in the Walmart Settlement for any length of term. In either case, the applicable rate will be multiplied by the amount of energy delivered to Duke by the relevant renewable energy facility to arrive at a bill credit expressed in dollars. Duke shall present the total of all bill credit payments in the relevant test period as the amount sought to be recovered through N.C.G.S. § 62-133.2(a1)(11).

In addition, and in recognition that these proceedings are focused on establishing a GSA Program that complies with the GSA Statute, the Commission will be open to further recommendations from the Public Staff regarding its needs for auditing the GSA Program costs that Duke seeks to recover through N.C.G.S. § 62-133.2(a1)(11), and for presenting appropriate recommendations to the Commission in the relevant proceeding for recovery of fuel and fuel-related costs.

2. Interconnection Application Status and Payment of Costs

Duke initially proposed to use the CPRE Program to identify and select projects for the Standard Offer under the GSA Program and to require renewable energy facilities participating in the GSA Program to have completed the system impact study under the North Carolina Interconnection Procedures (NCIP). After receipt of the other parties' comments, and in particular those of the Public Staff, Duke revised its proposal in two ways. First, Duke proposes to require that renewable energy facilities participating in the GSA Program "separately bid the full cost of delivering their potential project (including potential grid upgrades)" as a measure of mitigating the concern of bias toward a standard offer option that does not capture "grid upgrade costs." Second, Duke proposed to revise the GSA Program by eliminating the requirement that the participating renewable energy facilities must have completed the system impact study before submission of an application by an eligible customer.

For the following reasons, the Commission is not prepared to address these issues at this stage in these proceedings. First, the Commission's determination that the integration of the CPRE Program and the GSA Program is inappropriate will require Duke to substantially alter its proposed approach to evaluating and collecting grid upgrade costs within the GSA Program. Second, after the parties filed their comments in these proceedings, the Commission approved interim modifications to the NCIP to accommodate the CPRE Program Tranche I RFP Solicitation, and expressed an intent to consider changes to the treatment of grid upgrade costs under the CPRE Program. Third, the Commission is in the process of considering broader modifications to the NCIP, and has scheduled a hearing for January 28, 2018, for that purpose. See Docket No. E-100, Sub 101.

However, the Commission will provide the following guidance to Duke and the other parties for approaching these issues in these proceedings and in Docket No. E-100, Sub 101. For the purposes of interconnecting GSA Program renewable energy facilities, the Commission shares the Public Staff's preference for the "traditional approach" of assigning all interconnection costs to the GSA Program customer and/or the GSA renewable energy facility. Unlike the CPRE Program, where there is guidance to market participants about where to locate their proposed renewable energy facilities to minimize grid upgrade costs, the GSA Program does not provide the same feature. Further, where the "total cost of any renewable energy and capacity procured" on behalf of the GSA Program customer, including the relevant interconnection costs or grid upgrade costs, "shall be paid by that customer" considerations of who pays these costs are resolved by the plain language of the GSA Statute. Finally, under the GSA Program there is no statutory limit on the price that the eligible customer can agree to in its negotiations with the owner of a renewable energy facility participating in the GSA Program. Thus, the Commission is not tasked with monitoring or enforcing considerations of cost-effectiveness under the GSA Program in the same way as under the CPRE Program, because the limit placed on the bill credit, not to exceed the utility's avoided cost, provides a cost-effectiveness measure under the GSA Program. Further, the Commission recognizes that Duke must provide the eligible customer with information regarding the interconnection costs and/or grid upgrade costs fairly attributed to accommodating the renewable energy facility selected by the GSA customer relatively early in the GSA Program application process. Although Duke states that it has revised the GSA Program design to address the Public Staff's comments by eliminating the requirement to complete the system impact study, it is not clear to the Commission when the GSA Program customer and its selected renewable energy facility will be informed about these costs. Therefore, the Commission will require Duke to address these issues with more specificity through its compliance filing required by this Order.

3. Continued Market Based Revenues

Duke proposes that it be authorized to recover costs for any Duke-owned renewable energy facility developed for and participating in the GSA Program on a "market-based recovery," after the initial term of the GSA Service Agreement expires. This proposal is similar to the recovery method expressly authorized under the CPRE Program by N.C.G.S. § 62-110.8(g). In support of its proposal, Duke argues that both third-party owned facilities and utility-owned facilities "should be given an equal opportunity to recover market based revenues after" the initial agreement concludes, at a rate that does not exceed the Companies' then-prevailing avoided cost rate established pursuant to N.C.G.S. § 62-156. The other parties have not specifically addressed this issue.

The Commission understands that Duke's proposed market-based recovery follows naturally from Duke's misplaced view that the CPRE Program and the GSA Program are integrally linked. For reasons discussed above, the Commission does not agree with the view that the two programs should be linked in the way Duke proposed. The Commission also disagrees that Duke's proposal for market-based recovery beyond the term of the GSA agreement should be approved. The recovery allowed under N.C.G.S. § 62-110.8(g) is extraordinary in the context of the economic regulation of public service companies, which are generally entitled to recover the costs of service, plus a reasonable return on capital invested to serve the utility's customers. The Commission finds no compelling justification for departing from the general rule in this case.

4. Concerns of the University of North Carolina and Major Military Installations

The University of North Carolina and the State's Major Military Installations are granted special status under the GSA Statute by provisions that require reservation of 100 MW for Major Military Installations and 250 MW for the University of North Carolina. UNC-Chapel Hill and DoD/FEA have argued that they are in a unique position as taxpayer-funded entities with purposes that are different than the for-profit nonresidential customers that are also eligible to participate in the GSA Program. UNC-Chapel Hill and DoD/FEA present these arguments to support their view that the appropriate bill credit would be based on the rates established by the Commission in biennial avoided cost proceedings, with the bill credit being fixed for up to ten years, with a reset based on the Commission's more recently approved avoided cost rates under longer term GSA service agreements.

While the General Assembly expressly addressed these entities' eligibility, by reserving a discrete portion of the GSA 600 MW set aside, the GSA Statute does not distinguish the economic terms on which these entities would be allowed to participate in the GSA Program. Thus, participation of the University of North Carolina or the Major Military Installations in the GSA Program is subject to the General Assembly's instruction that all nonparticipating customers be "held neutral from the impact of the renewable electricity procured on behalf of the program customer." As discussed throughout this Order, the bill credit methodologies proposed by UNC-Chapel Hill and DoD/FEA would not reflect the utility's avoided costs as precisely as the methodologies approved in this Order, raising the potential for cost-shifting between customers or overpayment by Duke when purchasing power on behalf of all customers. Therefore, the Commission will not approve a separate set of economic terms for these eligible customers at this time, but will direct Duke to continue discussions with these eligible customers and report to the Commission on whether an alternative rate design can be agreed upon. Such an alternative should be generally consistent with the conclusions reached in this Order and should attract a commitment to participate in the GSA Program by these eligible customers.

IT IS, THEREFORE, ORDERED as follows:

1. That the Walmart Settlement filed in these proceedings on August 16, 2018, shall be, and is hereby, approved;

2. That the Agreement and Stipulation of Partial Settlement filed in these proceedings on October 24, 2018, shall be, and is hereby, rejected;

3. That within 45 days of the date of this Order, DEC and DEP shall make a compliance filing in these dockets, requesting Commission approval of a revised GSA Program that complies with the conclusions reached in this Order. That filing shall consist of revised rider leaflets, GSA Service Agreements, GSA Program PPAs, and any other documents that Duke proposes to use in the administration of the GSA Program. That filing may also include a narrative explanation of the revisions to aid the Commission and the parties in determining whether the revised program complies with the requirements of this Order and may identify any additional issues that arise in the required restructuring of the Program;

4. That within 60 days of the date of this Order, all parties may, and the Public Staff shall, provide comments for the sole purpose of aiding the Commission in determining whether the revised GSA Program complies with the requirements of this Order, responding to any additional issues identified by Duke, and addressing whether the GSA Service Agreements, GSA Program PPAs, and any other documents on which the parties have not had opportunity to comment, comply with this Order; and

5. That within 70 days of the date of this Order, Duke may file reply comments in response to those comments; and

6. The Commission will proceed appropriately upon receipt of the compliance filing and the parties' comments.

ISSUED BY ORDER OF THE COMMISSION.
This the 1st day of February, 2019.

NORTH CAROLINA UTILITIES COMMISSION
M. Lynn Jarvis, Chief Clerk

Commissioner Daniel G. Clodfelter concurs.
Commissioner Charlotte A. Mitchell concurs in part.
Commissioner ToNola D. Brown-Bland concurs in part, and dissents in part.

DOCKET NO. E-2, SUB 1170
DOCKET NO. E-7, SUB 1169

Commissioner Daniel G. Clodfelter, concurring:

Although I concur in the Commission majority's opinion, I also believe that the proposal advanced by Commissioners Mitchell and Brown-Bland to permit an additional bill credit option based on the Commission's determination of the utility's energy-only avoided cost, fixed for a term of ten years, is not an unreasonable one. Like the majority, however, I am of the view that the legislative mandate in G.S. 62-159.2(e) requiring the Commission to administer the program in a manner that neither advantages nor disadvantages non-participating customers counsels the selection of a shorter, rather than a longer period, in establishing the fixed bill credit allowed to program participants. It may prove that Commissioners Mitchell and Brown-Bland turn out to be correct that the use of the five-year full avoided cost to establish the amount of the bill credit will be insufficient to attract the participation of some who are interested in the program, but the Commission always retains the ability to monitor the responses of interested parties and take appropriate action, if needed, in the future.

/s/ Daniel G. Clodfelter
Commissioner Daniel G. Clodfelter

DOCKET NO. E-2, SUB 1170
DOCKET NO. E-7, SUB 1169

Commissioner Charlotte A. Mitchell, concurring in part:

I write separately to indicate that, in addition to the bill credit options approved by the majority, I would approve a bill credit option based on the utility's avoided energy costs, calculated using the Commission's most-recently approved avoided cost methodology, fixed for a term of ten years.

While I agree with the majority's sentiment that establishing the bill credit was the contested issue and is the most complex issue in this proceeding, the comments and statements received from eligible customers indicate that the bill credit is critical, perhaps the most critical, to their participation in the program. However, the statutory directive that non-participating customers be neither advantaged nor disadvantaged from the impact of the electricity procured on behalf of participating customers is clear and unambiguous and must be read to limit the credit offered to participating customers. Striking the appropriate balance between providing eligible customers with an option that will afford participation in the program and holding non-participating customers harmless will dictate the success of the program contemplated by the plain language of the statute.

At the outset, it is worth noting that the large energy customers eligible to participate in the program constitute a diverse group with varied energy preferences, load profiles, corporate or institutional goals and risk tolerances. I am persuaded that an arrangement that may enable participation in the program for one eligible customer may not work for another eligible customer. Thus, in approving this program, the Commission must endeavor to accommodate this diversity to the extent possible within the clear directives set forth in the statute.

Presumably, the bill credit as set forth in the Walmart Settlement and approved by the Commission, will afford participation in the program by the customers that participated in the settlement effort. In addition, the majority approves a bill credit option calculated using the utility's full avoided cost for a maximum term of five years, with a refresh of the credit every five years thereafter through the end of the term of the contract with the renewable energy supplier. Whether a five year credit will afford participation by eligible customers remains to be seen. The Commission did not hear from any eligible customer that a five year bill credit calculated using the Commission-approved avoided cost methodology would be sufficient to enable participation in the program. The Commission did hear from certain eligible customers, including the public institutions specifically identified in the statute, that these parties need certainty over a reasonable period of time regarding the costs they will incur as a result of participating in the program and that a five year time horizon does not provide that certainty. <u>See, e.g.</u>, Tr. P. 73, ll 4-8 (arguing that a bill credit term of 10 years would attract participation by the University of North Carolina).

Additionally, a statement filed by New Belgium Brewing, SAS Institute Inc., Sierra Nevada Brewing Co., Unilever and VF Corporation emphasizes the need for "long-term price stability". Perspective of Potential Green Source Advantage Business Participants, February 23, 2018, p. 2. A statement provided by Davidson College, Duke University and Wake Forest University includes this same emphasis. NCSEA's Initial Comments, Attachment B, February 23, 2018.

Perhaps most significantly, the Public Staff recognized that, while a bill credit term up to the maximum PPA term allowed by the statute would involve inappropriate risk to non-participating customers, a bill credit term of 10 years would be appropriate. The Public Staff noted that:

> While G.S. 62-159.2(b) provides that the standard terms and conditions available to renewable energy suppliers under the GSA Program "shall provide a range of terms between two years and 20 years from which the participating customer may elect," it does not require the Commission to fix the bill credit for the same term as the contract between the renewable energy supplier and the utility. To the extent that renewable energy suppliers and GSA participants agree to maximum length PPAs with terms longer than 10 years, the Public Staff believes that utilizing a fixed bill credit of an equivalent length would result in non-participating customers facing overpayment and underpayment risk for the same reasons considered in the 2016 Avoided Cost Order, thereby violating the neutrality concept required by G.S. 62-159.2(e).

Reply Comments of the Public Staff, pp 7-8. Thus, the Public Staff recommended that the bill credit should be equal in length to the term of the contract between the renewable energy supplier and the utility but, in no case, longer than 10 years. Reply Comments of the Public Staff, p. 9. The Public Staff noted that while this recommendation reflects a longer term than would otherwise be available for a negotiated contract for a qualifying facility (QF) greater than 1 MW, it is equivalent in length to the maximum term for QFs eligible for the standard offer.

Therefore, I conclude that a bill credit term of 10 years is more likely to enable participation in the program by certain customers—including those public institutions identified in the statute and for which 350 MW of the total 600 MW is specifically set aside in the statute—than a shorter term.

As to the issue of how the bill credit should be calculated, I agree with the Public Staff's recognition that calculating the credit using the Commission-approved avoided cost methodology is consistent with the neutrality requirement of the statute. Specifically, the Public Staff noted that the properly established avoided cost rates would make the purchasing utility "indifferent" to the source of electric output, which is comparable to the "neutrality" requirement in the statute with regard to the impact of the program on non- participating customers. Reply Comments of the Public Staff, pp 6-7. On this issue, the Public Staff observed that a bill credit calculated using the Commission-approved avoided cost methodology would be appropriate if the term of the bill credit is limited to 10 years. Reply Comments of the Public Staff, p. 9.

As an alternative to calculating the bill credit using the utility's full avoided cost, the Public Staff offered the following bill credit option to better ensure that nonparticipating customers are neither advantaged nor disadvantaged by the GSA Program:

> • Bill Credit Based on Energy Only: G.S. 62-159.2(e) provides that the "[t]he program customer shall receive a bill credit for the energy as determined by the Commission; provided, however, that the bill credit shall not exceed [the] utility's avoided cost." (emphasis added). Tracking this statutory language, utilizing the energy-only component of avoided costs would remove the capacity portion of avoided costs from the bill credit, allowing that reduction to serve as a proxy for the potential costs associated with long-term forecast risk and the integration costs associated with distributed generation.

Reply Comments of the Public Staff, pp 10-11.

As recognized by one of the parties to the proceeding, "[t]he longer the horizon used, the greater the risk that the projection of the costs that the utility would otherwise incur will be inaccurate." NCCEBA's Amended Post-Hearing Comments, September 21, 2018, p. 9. Because I conclude that a 10-year term is likely necessary to enable participation in the program by certain eligible customers, I would have approved the alternative recommendation of the Public Staff to calculate the bill credit based on the utility's avoided energy cost to mitigate the risks inherent to forecasting costs.

Consistent with the recommendation of the Public Staff, following the initial term of the bill credit, I would allow a second 10-year term, recalculated using then current avoided cost data.

For these reasons, I would go farther than the majority and would have approved the option of an avoided energy-only bill credit, fixed for a term of up to 10 years, which I find strikes the appropriate balance called for under the statute, particularly as it relates to providing a necessary measure of certainty for certain eligible customers that are identified in the statute and that have expressed to the Commission a desire to participate in the program.

/s/ Charlotte A. Mitchell
Commissioner Charlotte A. Mitchell

DOCKET NO. E-2, SUB 1170
DOCKET NO. E-7, SUB 1169

Commissioner ToNola D. Brown-Bland, concurring in part and dissenting in part:

The Commission approved DEC's Rider GS (Green Source Rider) pilot program in December, 2013. The program was proposed to enable certain nonresidential customers to elect to displace all or a portion of the energy supplied for the customer's new load with procurement of power (energy and capacity) from renewable energy sources. The pilot program provided for bill credits to participating customers based on the DEC's avoided cost model. However, the program limited such credits to an amount equal to the cost of the renewable energy and RECs procured or produced by DEC. Based on DEC's final (March 2017) report on implementation of the pilot program, customer participation in the pilot only amounted to approximately twenty percent of the annual (MWh) aggregate cap available in the program. The Company noted in the report that "[p]ricing is the most significant reason why existing customers did not contract for more capacity, and the program did not attract more than four customers." It is against this backdrop of failure to attract participants that the General Assembly enacted the Green Source Advantage Program as an improvement over the Green Source Rider Pilot Program. I believe the failure of the pilot program is therefore instructive to this Commission's efforts to implement a successful GSA Program.

I concur with the majority in concluding "that the appropriate structure of the GSA Program should attract participation from the eligible customers, because, as many of the parties have argued, the General Assembly did not intend to establish a program that would be unsuccessful in attracting participation from eligible customers." Moreover, in legislating an opportunity for eligible non-residential customers to have their public utility provider procure renewable energy on their behalves, the General Assembly made express reference only to two customer categories: major military installations and The University of North Carolina, defined to include its constituent institutions. Thus, it is reasonable to conclude from the express language of N.C.G.S § 62-159.2 that the legislature had a specific and precisely focused interest in these two customer categories participating in the GSA Program. Therefore, in my opinion, compliant implementation of the Program requires this Commission to approve a program with a bill credit that is likely to encourage and enable participation by both UNC and DoD/FEA. While I agree with the majority and join in its opinion and in its decision regarding the bill credit options it approves, I write to dissent from the majority's decision not to approve a ten-year bill credit option that would provide a better incentive for UNC and DoD/FEA to participate in the GSA Program as desired by the General Assembly.

The clear interests of UNC and DoD/FEA (and others) have been properly stated in the majority Order.

On October 24, 2018, NCCEBA, UNC-Chapel Hill, and SACE filed an agreement and stipulation of partial settlement reached among these parties. These parties agreed among themselves to an alternative bill credit that would be fixed for a period up to ten years, and then refreshed based upon updated data for any GSA agreement that lasts longer than ten years. These parties agree that this alternative bill credit strikes an appropriate balance between providing reasonable certainty to the participating customer regarding their electricity costs and ensuring that the projection of costs is accurate. These parties also identified the following other parties who did not join the agreement and stipulation, but who also do not object to the use of the alternative bill credit proposed therein: the Public Staff, NCSEA, and DoD/FEA.

I cannot ignore the interests expressed by these customers who are provided special status in the GSA enabling statute. The majority appropriately notes that "[t]he Commission also recognizes that the establishment of the bill credit is critical to attracting participation among the eligible customers, and, therefore, is at the heart of establishing a successful GSA Program." I believe, based on the input of the customers noted above, for the GSA Program to be successful, a ten-year fixed bill credit option is needed to help ensure the General Assembly's goal in attracting these customers to the Program.

I disagree with the majority's position that "it would be anomalous to approve a negotiated GSA option for greater than five years when the GSA Program is part of the same legislation limiting PURPA negotiated PPAs to five years." The CPRE is also part of this same legislation and it includes fixed 20-year levelized cost payments. The enabling statute for the GSA Program provides that "[i]f any portion of total capacity set aside to major military installations or The University of North Carolina is not used, it shall be reallocated for use by any eligible program participant. If any portion of the 600 megawatts (MW) of renewable energy capacity provided for in this section is not awarded prior to the expiration of the program, it shall be reallocated to and included in a competitive procurement in accordance with G.S. 62-110.8(a)," where (if reallocated) it would then be subject to a 20-year levelized fixed cost rate. It is also worth noting that the language the majority references as having changed or amended the PURPA landscape, found in N.C.G.S. § 62-156(c), expressly limits negotiated purchase power agreements to five years, but the GSA Program legislation, §62-159.2, contains no such limitation. In my opinion, this absence of a five-year reference represents a conscious choice of the General Assembly to provide the Commission with the flexibility, based on its judgment and the information made available to it, to approve a Program that could successfully attract participants including UNC and DoD/FEA. UNC and DOD/FEA have appeared before this Commission and informed us that, for reasons I found credible, they do not find or agree that a five year bill credit option will reasonably lead to their participation in the GSA Program.

Based on the General Assembly's goal to include UNC and DoD/FEA in the GSA Program, and the balance of risk-sharing provided by the Public Staff's ten-year bill credit alternative, I would vote to approve the ten-year bill credit. Inasmuch as the approved program fails to address the concerns of those intended to benefit, the program is not compliant with the statute and I dissent from the majority's decision not to allow a longer bill credit option. Aside from not allowing a longer bill credit option as discussed hereinabove, I concur in the majority opinion. Further, I join in the Concurring Opinion of Commissioner Mitchell and would find that concerns regarding inaccuracies of cost projections over a period longer than five years would be sufficiently addressed and mitigated by calculation of the bill credit based solely on the utility's avoided energy costs.

/s/ ToNola D. Brown-Bland
Commissioner ToNola D. Brown-Bland

DOCKET NO. E-2, SUB 1190
DOCKET NO. E-7, SUB 1185
DOCKET NO. E-100, SUB 90

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1190 In the Matter of Application by Duke Energy Progress, LLC, for Approval of Renewable Advantage Rider DOCKET NO. E-7, SUB 1185 In the Matter of Application by Duke Energy Carolinas, LLC, for Approval of Renewable Advantage Rider DOCKET NO. E-100, SUB 90 In the Matter of Investigation of Voluntary Green and Public Benefit Check-Off Programs – NC GreenPower	)	ORDER APPROVING RENEWABLE ADVANTAGE RIDER AND NC GREENPOWER PROGRAM CHANGES

BY THE COMMISSION: On November 20, 2018, Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC (collectively, Duke), individually filed applications in the above-referenced dockets for approval of a new tariff called the Renewable Advantage Program Rider (Renewable Advantage tariff), as well as proposed changes to the NC GreenPower program tariffs. In summary, Duke states that the Renewable Advantage tariff is a voluntary program that will allow residential and small business customers to purchase renewable energy credits (RECs) to offset all or a portion of their electrical consumption. Duke requests that the Renewable Advantage tariffs be offered as a pilot program through 2024. Duke also requests changes to its NC GreenPower tariffs to concur with the program changes requested by NC GreenPower, including a change to the program to no longer offer RECs on a mass market basis and to use all funds to install solar generation at schools throughout North Carolina.

On November 26, 2018, NC GreenPower (NCGP) filed a revised program plan that coincided with Duke's proposed changes to the NCGP program. NCGP states that it has discussed the proposed changes with Duke for over a year and that the revised program plan has been approved by the Boards of Directors for NC GreenPower Corporation and NC Advanced Energy

Corporation. On November 30, 2018, the North Carolina Utilities Commission - Public Staff (Public Staff) filed a Motion to Suspend Tariffs and Request Comments. On December 12, 2018, the Commission issued an order suspending the tariffs and requesting comments.

Following the filing of the Duke Renewable Advantage tariffs and NCGP's filings proposing revisions to its program plan, the Commission issued an order on February 1, 2019, modifying and approving Duke's Green Source Advantage Program (GSA), in Docket Nos. E-7, Sub 1169 and E-2, Sub 1170. As a result, on February 7, 2019, Duke filed a motion to withdraw its Renewable Advantage tariff applications stating that it was reviewing the Commission's order and reserved the right to refile the tariffs at a future time based on the Commission's stated willingness to "remain open to receiving from Duke a proposed REC-purchase program similar to" but "separate and apart from the GSA Program."

On April 18, 2019, Duke re-filed its applications for approval of the Renewable Advantage tariffs, as well as proposed changes to the NCGP program tariffs. In the filing, Duke states that the Company has made a few changes to the original tariff filing. Duke indicates that the Company is no longer proposing to offer the program as a time-limited pilot and has removed the termination date proposed for this offering. Duke explains that the tariff allows a customer to acquire multiple blocks in 250 kWh increments of RECs that could be sufficient to offset a portion or all of a customer's consumption. Duke further notes that for every REC purchased, the Company will donate $2.00 to NC GreenPower. The tariff defines a REC as equal to 1,000 kWh produced from a renewable resource. Duke states that NCGP has indicated that it will seek revisions to its mass market program to no longer acquire RECs and will use all funds to install solar generation at schools throughout North Carolina.

On April 30, 2019, NCGP filed a revised program plan which contains most of the same requested changes as the November 26, 2018, filing with a few exceptions. NCGP's updated filing contains the following revisions:

1- The $4.00 mass market (MM) product will not be terminated as previously filed; rather it will continue to be offered to non-Duke customers with some revisions such as: a- each donation will continue to support both North Carolina RECs and solar installation packages at K-12 schools, but not at the 50/50 split; b- a portion of each donation will support in-state RECs and the block size will increase from 50 kWh to 125 kWh; and c- the balance of each donation will continue to support solar projects at schools.

2- For Duke customers who currently donate to the $4.00 MM product, the contributions will be changed to solely support Solar^{+} Schools and not REC projects; these customers may "opt out" if they do not wish to support the schools initiative.

3- The block size for the $2.50 LV REC for Clean Energy Supporters will increase from 100 kWh to 250 kWh.

4- NCGP's Board of Directors may adjust grant amounts to schools depending on the type of solar system installed (top of pole versus roof-mounted) and the economic need of the school.

On June 5, 2019, the Commission issued an Order Seeking Comments regarding NCGP's proposed changes with a June 26, 2019 deadline. On June 5, 2019, the Public Staff filed a letter in lieu of comments in response to the Commission's Order addressing both the NCGP filing and Duke's Requests for approval of its Renewable Advantage tariffs. In its filing, the Public Staff states it has reviewed NCGP's filing, as well as the proposed Renewable Advantage tariffs and the revisions to Duke's NC GreenPower Program tariffs. The Public Staff supports the NCGP program changes, including the changes to the Solar$^+$ Schools program as presented by NCGP. The Public Staff also states that it does not object to the Commission's approval of the Renewable Advantage tariffs and the revisions to the NC GreenPower Program tariffs. On June 21, 2019, Duke filed a letter in support of NCGP's Solar$^+$ Schools Program stating it will complement the Companies' respective proposed Renewable Advantage Riders and offer electric customers multiple options with respect to their voluntary support of the development of renewable generation resources.

Based on the foregoing and the record, the Commission determines that Duke's Renewable Advantage tariffs provide a REC purchase program that is separate and apart from the Green Source Advantage program. The Commission further finds that the Renewable Advantage tariffs will provide an option to customers that wish to offset a portion or all of their consumption. The Commission agrees with the Company that this offering may foster and promote the use of renewable attributes from renewable energy resources. The Commission notes that both NCGP and Duke agree to the changes requested by the other, and Duke has agreed to continue to offer the NC GreenPower program and the NC Renewable Energy program to those participants preferring the tax advantages and other attributes of these programs.

Accordingly, the Commission concludes that there is good cause to approve Duke's Renewable Advantage tariffs, Duke's proposed revisions to the NC GreenPower Program Rider GP tariffs, and NC GreenPower's Revised Program Plan.

IT IS, THEREFORE, ORDERED as follows:

1. That the proposed Renewable Advantage Rider RA-1 tariffs filed by Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC, are approved.

2. That the proposed revisions to the NC GreenPower Program Rider GP tariffs, filed by Duke Energy Carolinas, LLC and Duke Energy Progress, LLC, are approved.

3. That the Solar$^+$ Schools Revised Program Plan filed by NC GreenPower is approved.

4. That NC GreenPower's Solar$^+$ Schools program shall begin concurrently with the start of Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC's RECs program on or before January 1, 2020.

5. That Duke shall work with the Public Staff to prepare a notice to inform NC GreenPower tariff participants of Duke of these revisions and the options available and shall file that notice with the Commission within thirty (30) days.

ISSUED BY ORDER OF THE COMMISSION.
This the 15th day of October, 2019.

NORTH CAROLINA UTILITIES COMMISSION
Kimberley A. Campbell, Chief Clerk

DOCKET NO. E-2, SUB 1204

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of Duke Energy Progress, LLC Pursuant to N.C.G.S. § 62-133.2 and Commission Rule R8-55 Relating to Fuel and Fuel-Related Charge Adjustments for Electric Utilities	)))))	ORDER APPROVING INTERIM FUEL CHARGE ADJUSTMENT, REQUIRING FURTHER TESTIMONY, AND SCHEDULING HEARING

HEARD: Monday, September 9, 2019, at 2:00 p.m., and Tuesday, September 10, 2019, at 9:00 a.m., in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Commissioner Charlotte A. Mitchell, Chair; Commissioner ToNola D. Brown-Bland,[1] Commissioner Lyons Gray, and Commissioner Daniel G. Clodfelter

APPEARANCES:

For Duke Energy Progress, LLC:

Jack E. Jirak, Esq., Duke Energy Corporation, P.O. Box 1551 / NCRH 20, Raleigh, NC 27602

Dwight Allen, Esq., Allen Law Offices, PLLC, 1514 Glenwood Ave., Suite 200, Raleigh, North Carolina 27608

[1] Commissioner Brown-Bland was unable to attend the portion of the hearing held on Tuesday morning, September 10, 2019. The parties stated that they did not object to Commissioner Brown-Bland participating in the decision in this docket.

For Carolina Utility Customer Association, Inc.:

Robert F. Page, Esq., Crisp & Page, PLLC, 4010 Barrett Drive, Suite 205, Raleigh, North Carolina 27609-6622

For North Carolina Sustainable Energy Association:

Benjamin W. Smith, Esq., 4800 Six Forks Road, Suite 300, Raleigh, North, Carolina 27609

For Carolinas Industrial Group for Fair Utility Rates II:

Ralph McDonald, Esq., Bailey & Dixon, L.L.P., Post Office Box 1351, Raleigh, North Carolina 27602

For Fayetteville Public Works Commission:

James P. West, Esq., Fayetteville Public Works Commission, Post Office Box 1089, Fayetteville, North Carolina 28302-1089

For Sierra Club:

Gudrun Thompson, Esq., Tirrill Moore, Esq., Southern Environmental Law Center, 601 West Rosemary Street, Suite 220, Chapel Hill, NC 27516

For the Using and Consuming Public:

Dianna Downey, Esq., Public Staff, North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4300

BY THE COMMISSION: On June 11, 2019, Duke Energy Progress, LLC (Duke Energy Progress, DEP, or the Company), filed an application pursuant to N.C. Gen.Stat. § 62-133.2 and Commission Rule R8-55 regarding fuel and fuel-related cost adjustments for electric utilities, along with the testimony and exhibits of Dana M. Harrington, Brett Phipps, Regis Repko, Kenneth D. Church, and Kelvin Henderson.

Petitions to intervene were filed by the North Carolina Electric Membership Corporation (NCEMC) on June 24, 2019, Fayetteville Public Works Commission (FPWC) on July 1, 2019, Carolina Utility Customers Association, Inc. (CUCA) on July 22, 2019, Sierra Club on August 1, 2019, North Carolina Sustainable Energy Association (NCSEA) on August 9, 2019, and Carolina Industrial Group for Fair Utility Rates II (CIGFUR) on August 19, 2019. The Commission granted NCEMC's and FPWC's petitions to intervene on July 2, 2019, CUCA's petition to intervene on July 24, 2019, NCSEA's petition to intervene on August 13, 2019, Sierra Club's petition to intervene on August 15, 2019, and CIGFUR's petition to intervene on August 20, 2019. The intervention of the Public Staff is recognized pursuant to N.C. Gen. Stat. § 62-15(d) and Commission Rule R1-19(e).

On June 20, 2019, the Commission entered an Order Scheduling Hearing, Requiring Filing of Testimony, Establishing Discovery Guidelines, and Requiring Public Notice. Among other things, the Order provided that direct testimony of intervenors should be filed on or before August 19, 2019, that rebuttal testimony should be filed on or before August 28, 2019, and that a hearing on this matter would be held on September 9, 2019.

On August 15, 2019, DEP filed the supplemental testimony and exhibits of witness Harrington and based on an update of its fuel and fuel-related costs through June 30, 2019, DEP requested an increase in the fuel rates initially included in its application.

On August 23, 2019, DEP filed a request to publish a Second Public Notice. By Order dated August 26, 2019, the Commission required DEP to publish a Second Customer Notice. On September 6, 2019, and September 13, 2019, DEP filed affidavits of publication indicating that public notices had been provided in accordance with the Commission's procedural orders.

On August 19, 2019, the Public Staff filed the testimony of Jay B. Lucas, Jenny X. Li, and Dustin R. Metz, in accordance with N.C. Gen. Stat. § 62-68.

On August 28, 2019, the Company filed the rebuttal testimony of Kelvin Henderson and the joint rebuttal testimony of Barbara Coppola and John Halm.

On September 5, 2019, the Public Staff filed a motion requesting that Public Staff witnesses Li and Metz be excused from appearance at the expert witness hearing, and DEP filed a motion requesting that DEP witnesses Regis Repko, Kenneth D. Church, and Kelvin Henderson, be excused from appearance at the expert witness hearing, representing that all parties to the proceeding had agreed to waive cross-examination of the witnesses. On September 6, 2019, the Commission granted the motion, excusing DEP witnesses Repko, Church, and Henderson, and Public Staff witnesses Li and Metz from appearing at the expert witness hearing.

The case came on for hearing as scheduled on September 9 and 10, 2019. The application, prefiled direct, supplemental and rebuttal testimony and exhibits of DEP's witnesses and the prefiled direct testimony of the Public Staff's witnesses were received into evidence.

On November 4, 2019, DEP filed a proposed order and brief. The Public Staff and Sierra Club each filed a brief.

On November 20, 2019, DEP filed a motion stating that it had inadvertently not moved into evidence the prefiled rebuttal testimony of DEP witness Henderson during the hearing, and requesting that the Commission issue an order receiving witness Henderson's rebuttal testimony into the record and amending the transcript to include said testimony.

On November 21, 2019, the Commission issued an Order receiving into evidence the prefiled rebuttal testimony of witness Henderson, and directing the court reporter to amend Volume 1 of the transcript to include said testimony.

Based upon the Company's verified application, the testimony and exhibits received into evidence at the hearing, and the record as a whole, the Commission makes the following:

FINDINGS OF FACT

1. Duke Energy Progress is a duly organized corporation existing under the laws of the State of North Carolina, is engaged in the business of developing, generating, transmitting, distributing, and selling electric power to the public in North Carolina, and is subject to the jurisdiction of the Commission as a public utility. Duke Energy Progress is lawfully before this Commission based upon its application filed pursuant to N.C. Gen. Stat. § 62-133.2.

2. The test period for purposes of this proceeding is the 12 months ended March 31, 2019 (test period).

3. Commission Rule R8-55(d)(3) allows the Company to update the fuel and fuel-related cost recovery balance up to thirty (30) days prior to the hearing. The Company elected this option and supplemented the direct testimony and exhibits to include the fuel and fuel-related cost recovery balance as of the 15 months ended June 30, 2019.

4. In its application, direct testimony, and exhibits in this proceeding, DEP requested a total decrease of $89 million to its North Carolina retail revenue requirement associated with fuel and fuel-related costs, excluding the regulatory fee. The fuel and fuel-related cost factors requested by DEP included an Experience Modification Factor (EMF) to take into account fuel and fuel-related cost under-recoveries experienced during the test period, with an overall under-recovery of $110 million experienced during the test period.

5. In its direct supplemental testimony and exhibits in this proceeding, DEP updated its requested decrease in the North Carolina retail revenue requirement associated with fuel and fuel-related costs, excluding the regulatory fee, to $47 million, which included an updated under-recovery of $151 million through the period ending June 30, 2019.

6. The Company's appropriate North Carolina retail jurisdictional fuel and fuel-related expense under-collection for purposes of the EMF is $143,775,161, consisting of under-recoveries of $59,835,706, $3,842,749, $24,006,222, $54,214,580, and $1,875,903, for the Residential, Small General Service, Medium General Service, Large General Service, and Lighting classes, respectively.

7. Gypsum is a by-product produced in the electric generation process and the input leading to gypsum is coal.

8. The Company entered a long-term agreement to sell gypsum to BPB NC, Inc. (BPB) in 2004. CertainTeed Gypsum NC, Inc. (CTG) is the successor-in-interest to BPB.

9. Under the agreement, CTG was obligated to construct a wallboard manufacturing facility adjacent to DEP's Roxboro coal-fired generation plant and committed to purchase substantial amounts of gypsum from the Roxboro and Mayo plants (Roxboro units).

10. The initial agreement included a liquidated damages provision. The initial agreement was amended on a number of occasions—ultimately resulting in the Second Amended and Restated Supply Agreement—but the liquidated damages provision was an essential part of the agreement and remained substantially unchanged from the initial agreement through to the Second Amended and Restated Supply Agreement (Gypsum Supply Agreement).

11. In light of CTG's substantial capital investment in its wallboard manufacturing facility adjacent to the Roxboro plant, one purpose of the liquidated damages provision was to provide CTG with certainty regarding the damages it would be entitled to recover in the event that DEP was unable to supply the full amount of gypsum required under the Gypsum Supply Agreement.

12. The evidence tends to show that the amount of gypsum produced by the Roxboro units substantially declined due to lower natural gas prices that decreased DEP's use of coal-fired generation, and several other factors.

13. As a result of the decrease in generation by the Roxboro units, the Company was unable to meet the monthly minimum delivery obligations under the Gypsum Supply Agreement.

14. In litigation filed by CTG against DEP in the North Carolina Business Court (Court) for breach of the Gypsum Supply Agreement, the Court entered a Judgment finding DEP liable for breach of the contract. The Court ordered DEP to pay actual damages to CTG for gypsum not delivered, and to meet its future contract obligations.

15. In light of the options available to the Company under the Gypsum Supply Agreement and the Court's Judgment, the Company discontinued supply under the Gypsum Supply Agreement, after providing some gypsum for a limited period of time and in limited amounts under a replacement agreement, and paid CTG liquidated damages rather than delivering replacement gypsum.

16. The actual damages and liquidated damages paid and to be paid by DEP under the Gypsum Supply Agreement are part and parcel of the sale of gypsum that was agreed upon by DEP and CTG in the Gypsum Supply Agreement.

17. If DEP's decisions and actions in connection with the Gypsum Supply Agreement with CTG were reasonable and prudent, then DEP's payments of liquidated damages to CTG can be recovered as fuel-related costs pursuant to N.C.G.S. § 62-133.2(a1)(9).

18. The evidence of record is insufficient to enable the Commission to determine whether DEP's decisions and actions in connection with the Gypsum Supply Agreement with CTG were prudent and reasonable. As a result, it is appropriate for the Commission to receive additional evidence and hold a further hearing on the issue of whether DEP's decisions and actions in connection with the Gypsum Supply Agreement with CTG were prudent and reasonable.

19. The evidence of record is sufficient to enable the Commission to set rates for DEP's interim fuel cost recovery based on DEP's fuel and fuel-related costs other than the actual damages and liquidated damages paid and to be paid by DEP under the Gypsum Supply Agreement.

20. For the purpose of setting DEP's interim fuel cost recovery, DEP's proposed test year N.C. retail fuel and fuel-related costs should be adjusted by removing liquidated damages in the amount of $6,640,945 and removing the judgment payment in the amount of $619,200 for purposes of determining the under-recovery and EMFs. Further, DEP's proposed and projected N.C. retail fuel and fuel-related costs must be adjusted by removing $5,181,120 for such costs for the purposes of determining the prospective fuel and fuel-related factors for the billing period.

21. The Company's baseload plants were generally managed prudently and efficiently during the test period so as to minimize fuel and fuel-related costs.

22. The decisions and actions of DEP in connection with the outage at the H.B. Robinson Nuclear Station Plant (Robinson plant) in the fall of 2018 for refueling (Robinson Refueling Outage) were prudent and reasonable. The outage extension resulted from causes beyond the control of the Company, including a shortage of qualified labor resources, which was exacerbated by extensive hurricane activity that occurred during the period of the outage.

23. It is appropriate for DEP to recover the replacement power costs resulting from the Robinson Refueling Outage, including the extended period of the outage.

24. The Company's fuel and reagent procurement and power purchasing practices during the test period were reasonable and prudent. However, given DEP's increased reliance on natural gas and the resulting increased risk of under-recoveries if natural gas prices are not forecasted as accurately as possible, the Company should evaluate historic price fluctuations and whether its current method of forecasting and hedging programs should be adjusted to mitigate the risk of significant under-recovery of fuel costs. The Company shall report the results of this evaluation in the next fuel proceeding.

25. The test period per book system sales are 62,568,164 megawatt-hours (MWh). The test period per book system generation and purchased power is 70,945,428 MWh (net of auxiliary use) and is categorized as follows:

Net Generation Type	System MWh Generated
Coal	8,081,365
Natural Gas, Oil, and Biomass	23,239,469
Nuclear	27,748,149
Hydro – Conventional	848,406
Solar	227,472
Purchased Power – subject to economic dispatch or curtailment	5,601,750
Other Purchased Power	5,198,817
Total Net Generation (may not add to sum due to rounding)	70,945,428

26. The North Carolina retail test period sales, adjusted for customer growth and weather, for use in calculating the EMF are 37,693,746 MWh. The adjusted North Carolina retail customer class MWh sales are as follows:

N.C. Retail Customer Class	Adjusted NC Retail MWh Sales
Residential	16,022,203
Small General Service	1,941,728
Medium General Service	11,007,307
Large General Service	8,368,542
Lighting	353,965
Total (may not add to sum due to rounding)	37,693,746

27. The appropriate nuclear capacity factor for use in this proceeding is 94.62%.

28. The projected billing period system generation and purchased power for use in this proceeding in accordance with projected billing period system sales is 71,517,770 MWh and is categorized as follows:

Generation Type	Projected System MWh Generated
Coal	11,131,286
Gas Combined Cycle (CC) and Combustion Turbine (CT)	22,185,181
Nuclear	29,713,146
Hydro	648,112
Solar	279,675
Purchased Power	7,560,370
Total (may not add to sum due to rounding)	71,517,770

29. The projected billing period (December 2019 - November 2020) sales for use in this proceeding are 62,155,919 MWh on a system basis and 38,091,457 MWh on a North Carolina retail basis. The projected billing period North Carolina retail customer class MWh sales are as follows:

N.C. Retail Customer Class	Projected NC Retail MWh Sales
Residential	16,265,079
Small General Service	1,806,876
Medium General Service	10,414,506
Large General Service	9,223,825
Lighting	381,171
Total (may not add to sum due to rounding)	38,091,457

30. The appropriate fuel and fuel-related prices and expenses for use in this proceeding to determine projected system fuel expense are as follows:

A. The coal fuel price is $31.35/MWh.
B. The gas CC and CT fuel price is $26.68/MWh.
C. The appropriate expense for ammonia, lime, limestone, urea, dibasic acid, sorbents, and catalysts consumed in reducing or treating emissions (collectively, Reagents) is $26,265,057.
D. The total nuclear fuel price is $6.17/MWh.
E. The total system purchased power cost (including the impact of Joint Dispatch Agreement (JDA) Savings Shared and the impact of House Bill 589, N.C. Sess. L. 2017-192, is $442,407,406.
F. System fuel expense recovered through intersystem sales is $161,032,005.

31. The projected fuel and fuel-related costs for the North Carolina retail jurisdiction for use in this proceeding are $878,210,565.

32. The decrease in customer class fuel and fuel-related cost factors from the amounts approved in Docket No. E-2, Sub 1173 should be allocated among the rate classes on a uniform percentage basis, using the uniform bill adjustment methodology that was approved by the Commission in that docket.

33. The appropriate prospective fuel and fuel-related cost factors for this proceeding for each of DEP's rate classes, excluding the regulatory fee, are as follows: 2.326¢/kilowatt-hour (kWh) for the Residential class; 2.499¢/kWh for the Small General Service class; 2.456¢/kWh for the Medium General Service class; 2.054¢/kWh for the Large General Service class; and 2.217¢/kWh for the Lighting class.

34. The appropriate EMF riders established in this proceeding, excluding the regulatory fee, are as follows: 0.373¢/kWh for the Residential class; 0.198¢/kWh for the Small General Service class; 0.218¢/kWh for the Medium General Service class; 0.648¢/kWh for the Large General Service class; and 0.530¢/kWh for the Lighting class.

35. The coal inventory rider established in Ordering Paragraph 12 of the Commission's February 23, 2018 Order Accepting Stipulation, Deciding Contested Issue and Granting Partial Rate Increase in Docket No. E-2, Sub 1142 expired in October 2018 and was removed from billed rates on December 1, 2018. Additional amounts collected through January 2019 further reduced the under-collected balance and interest on the under-collected balance was calculated through November 30, 2019. The under-collected balance of $257,250 is included in the EMF.

36. The total net fuel and fuel-related cost factors for this proceeding for each of DEP's rate classes, excluding the regulatory fee, are as follows: 2.699¢/kWh for the Residential class, 2.697¢/kWh for the Small General Service class, 2.674¢/kWh for the Medium General Service class, 2.702¢/kWh for the Large General Service class, and 2.747¢/kWh for the Lighting class.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 1

This finding of fact is essentially informational, procedural, and jurisdictional in nature and is uncontroverted.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 2

North Carolina General Statute § 62-133.2(c) sets out the verified, annualized information that each electric utility is required to furnish to the Commission in an annual fuel and fuel-related cost adjustment proceeding for a historical 12-month test period. Commission Rule R8-55(b) prescribes the 12 months ending March 31 as the test period for DEP. The Company's initial filing and direct testimony in this proceeding was based on the 12 months ended March 31, 2019.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 3

Commission Rule R8-55(d)(3) allows the Company to update the fuel and fuel-related cost recovery balance up to thirty (30) days prior to the hearing. The Company elected this option and supplemented the direct testimony and exhibits to include the fuel and fuel-related cost recovery balance as of the 15 months ended June 30, 2019.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 4 - 20

The evidence for these findings of fact is contained in the application, the direct testimony and supplemental direct testimony of Company witness Harrington, the direct testimony and exhibits of Public Staff witnesses Jay B. Lucas and Jenny X. Li, and the rebuttal testimony of Company witnesses Coppola and Halm.

In its application and testimony in this proceeding, DEP requested a total decrease of $89 million to its North Carolina retail revenue requirement associated with fuel and fuel-related costs, excluding the regulatory fee. The fuel and fuel-related cost factors requested by DEP included an Experience Modification Factor (EMF) to take into account fuel and fuel-related cost under-recoveries experienced during the test period. On Harrington Exhibit 3, Pages 1-6, Company witness Harrington proposed fuel and fuel-related cost under-recoveries of $110 million experienced during the test period through the reporting date of March 31, 2019.

Test Period through March 31, 2019

N.C. Retail Customer Class	Under - Recovery
Residential	$40,376,037
Small General Service	2,324,536
Medium General Service	18,739,830
Large General Service	46,571,176
Lighting	1,539,374
Total (may not add to sum due to rounding)	$109,550,954

In the direct supplemental testimony and exhibits of Company witness Harrington, DEP updated its North Carolina retail revenue requirement associated with fuel and fuel-related costs, excluding the regulatory fee, to a total decrease of $47 million through June 30, 2019. Revised Harrington Exhibit 3, Pages 1 - 6, reflect updated EMFs to recover an under-recovery of $151 million as of June 30, 2019. The updated total adjusted system fuel and fuel-related expense, based in part on the use of these amounts, is utilized to calculate the prospective fuel and fuel-related cost factors recommended by the Company.

Test Period updated through June 30, 2019

N.C. Retail Customer Class	Under - Recovery
Residential	$63,138,790
Small General Service	4,209,287
Medium General Service	26,020,608
Large General Service	55,725,485
Lighting	1,941,135
Total (may not add to sum due to rounding)	$151,035,306

In her testimony, Public Staff witness Li stated that, based on the testimony and recommendation of Public Staff witness Lucas, she recommended removing North Carolina's retail share of the cash payments made to CTG for liquidated damages in the amount of $6,640,945 million and North Carolina's retail share of the CTG judgment payment in the amount of $619,200 from the test period costs. Following these adjustments, Public Staff witness Li recommended the following under-recovery amounts by North Carolina retail customer class as follows:

Test Period updated through June 30, 2019

N.C. Retail Customer Class	Under - Recovery
Residential	$59,835,706
Small General Service	3,842,749
Medium General Service	24,006,222
Large General Service	54,214,580
Lighting	1,875,903
Total (may not add to sum due to rounding)	$143,775,160

The issue presented by the testimony of Public Staff witness Lucas and addressed in the adjustments made by Public Staff witness Li revolves around an agreement entered into in 2004 between DEP's predecessor, Progress Energy Carolinas, Inc., and BPB NC, Inc. (BPB) for the sale of synthetic gypsum from the Roxboro and Mayo plants to BPB for the manufacture of wallboard. Tr. Vol. 2, p. 61. Witness Lucas testified that gypsum is a mineral that is the primary component of gypsum wallboard and can be mined in its natural state, and that synthetic gypsum is a suitable substitute and is a by-product of the flue gas desulfurization (FGD) equipment installed at some coal-fired plants, including DEP's Roxboro and Mayo coal-fired power plants (Roxboro units). Id. at 60-61. He stated that the Roxboro plant consists of four generating units with a total capacity of 2,462 MW (winter rating), and the Mayo plant has one generating unit with a capacity of 746 MW (winter rating), and that both of these plants are located in Person County, approximately 16 road miles apart. Id.

Witness Lucas testified that in order to mitigate the cost of disposing of the gypsum produced in the FGD process, in 2004 DEP executed a contract with BPB for the future sale of artificial gypsum from the Roxboro units to BPB for the manufacture of gypsum board. He stated that in 2005, BPB acquired approximately 121 acres of land from DEP adjacent to the Roxboro plant with the intent of constructing a gypsum board manufacturing facility. Also in 2005, CertainTeed's parent company, Saint-Gobain North America, bought BPB and merged it with the existing CertainTeed operations. According to witness Lucas, CertainTeed (CTG) delayed construction of the wallboard manufacturing facility due to the housing market decline and economic downturn (Great Recession). In late 2007, CTG contacted DEP in an effort to amend the 2004 agreement and to maintain the supply of artificial gypsum in the future. Id. at 61-62.

Witness Lucas testified that in 2008 DEP and CTG executed an Amended and Restated Supply Agreement that made refinements to the 2004 contract, and that CTG began accepting artificial gypsum from DEP on May 1, 2009, but transported it to other locations because the CTG facility adjacent to the Roxboro plant had not yet been completed. The CTG facility at the Roxboro plant began operation on March 28, 2012. Id. at 62.

Witness Lucas further testified that in August 2012, DEP and CTG executed a Second Amended and Restated Supply Agreement (Gypsum Supply Agreement). FPWC Harrington Confidential Cross-Exam Exhibit No. 1. He stated that two key provisions of the Gypsum Supply Agreement were that DEP would provide 50,000 tons of gypsum per month to CTG and would maintain a gypsum stockpile of 250,000 tons. Id.

Witness Lucas testified that several factors led to the reduced dispatch of the Roxboro units, and as a result, the amount of gypsum produced by the plants was below the minimum amounts required by the Gypsum Supply Agreement. He stated that the first factor was a result of the merger between Duke Energy Corporation and Progress Energy, Inc. Following that merger the two companies entered into a Joint Dispatch Agreement (JDA) which facilitated the energy purchases between Duke Energy Carolinas, LLC (DEC), and DEP and thereby enabled the two companies to optimize the efficient dispatch of their combined generating fleets. Witness Lucas explained that the JDA allowed DEC to sell cheaper energy to DEP when not needed for DEC's own use. As a result DEP's Roxboro units operated less often than before the merger. Id. at 63. The second factor enumerated by witness Lucas was the significant and continuous decline in natural gas prices after 2009. He stated that natural gas prices have not approached the 2009 prices since that time. According to witness Lucas, this decline in natural gas prices resulted in utilities dispatching natural gas-fired combined cycle plants (CCs) ahead of coal-fired units such as those at Roxboro. A third factor discussed by witness Lucas was the conversion of DEC and DEP from coal-fired generation to natural gas-fired generation. As an example, he cited the dates of commercial operation of DEC's Buck CC in 2011 and Dan River CC in 2012, and DEP's H.F. Lee CC in 2012, and Sutton CC in 2013. Witness Lucas stated that the reduced dispatch of coal generating plants resulting from these factors caused DEP to burn less coal at the Roxboro units resulting in the inability of DEP to provide the quantities of gypsum that CTG contracted for and anticipated when it built the wallboard manufacturing facility next to the Roxboro plant. Id. at 63-64.

Public Staff witness Lucas testified that on June 30, 2017, CTG filed a breach of contract action against DEP in the North Carolina Business Court. See Opinion and Final Judgment, CertainTeed Gypsum NC, Inc. v. Duke Energy Progress, LLC, 17 CVS 395 (Person County), 2018 NCBC 90 (CTG v. DEP); FPWC Harrington Cross-Exam Exhibit No. 3. In the lawsuit CTG contended that the Gypsum Supply Agreement required DEP to deliver 50,000 tons every month, with a 10% variance up or down, and with the variance being made up over each 12-month period of the calendar year. DEP defended by contending that the Gypsum Supply Agreement allowed DEP to deliver a flexible amount of gypsum to CTG, based on the actual production of the Roxboro units. On August 28, 2018, the Court ruled in CTG's favor and ordered DEP to pay $1,084,216 to cover CTG's cost of replacement gypsum from May 2017 through January 2018, and to provide a replenishment plan for meeting the contract requirements within 90 days. Id. Witness Lucas testified that after the Court ruled against DEP that DEP and CTG reached a settlement. The settlement included DEP's payment of the actual damages amount ordered by the Court, and DEP's payment of liquidated damages as stipulated in the Gypsum Supply Agreement. Tr. Vol. 2, p. 65-66. The terms of the settlement agreement were filed by DEP with the Commission under seal as a confidential trade secret. The settlement agreement was introduced into evidence as FPWC Confidential Harrington Cross-Exam Exhibit No. 4.

Witness Lucas testified that the Public Staff recommends that the Commission deny DEP's request for the recovery of the liquidated damages and judgment payment costs in this proceeding because they are not appropriate for recovery in a fuel proceeding. The Public Staff's position is that the failure to deliver the required amount of gypsum and the resulting expenses arising from the legal action taken against DEP by CTG do not constitute a "sale" of by-products under the provisions of N.C. Gen. Stat. § 62-133.2(a1)(9). Witness Lucas stated that, in his opinion, the more appropriate proceeding in which to consider these costs is a general rate case. In addition witness Lucas testified that the Public Staff has concerns about the prudence and reasonableness of the actual damages and liquidated damages as a recoverable cost, but that it had not t undertaken a prudence and reasonableness analysis of the costs. Tr. Vol. 2, p. 68-69 and 75-76.

In her pre-filed direct testimony DEP witness Harrington testified that liquidated damages incurred in connection with the Gypsum Supply Agreement are properly recovered in fuel rates based on the Company's understanding of N.C. Gen. Stat. § 62-133.2(a1)(9). Tr. Vol. 1, p. 97. The statute specifies that "cost of fuel and fuel-related costs shall be adjusted for any net gains or losses resulting from any sales by the electric public utility of by-products produced in the generation process to the extent the costs of the inputs leading to that by-product are costs of fuel or fuel-related costs." According to witness Harrington the Company's position is that the liquidated damages in this case are properly included in the calculation of the aggregate net gain/loss on the sale of by-products because the liquidated damages provision was an essential commercial term of a larger sales transaction that was reasonably and prudently entered into by the Company for the benefit of customers. Witness Harrington testified that due to changes in coal consumption over time driven by lower natural gas prices, the Company was not able to meet the minimum gypsum supply obligations as originally contemplated by the parties to the Gypsum Supply Agreement. Nevertheless, witness Harrington stated that the Company's decision to enter into the arrangement was reasonable and prudent and the transaction as a whole still provided a benefit to customers. Id. She testified that the Company proposes to recover the liquidated damages on a cash basis rather than an accrual basis, and that the NC retail share of these costs is reflected in the test period under-collection balance of $146.8 million, but the Company believes that it is more equitable to customers to recover these costs as the amounts are paid, rather than when the liability first accrued. Id. at 96.

In their rebuttal testimony DEP witnesses Coppola and Halm stated that in assessing whether a loss occurred for purposes of determining the recoverability under N.C. Gen. Stat. § 62-133.2(a1)(9), it is necessary to look at the entire flow of revenue and costs under the Gypsum Supply Agreement. Tr. Vol. 2, p. 149. According to witnesses Coppola and Halm from that perspective DEP experienced a "net loss" because the amount of costs incurred by the Company due to its obligations under the Gypsum Supply Agreement exceeded the amount of revenue received by DEP under that agreement. Id. That is, DEP sold a substantial amount of gypsum to CTG for which DEP received revenue of approximately $24.3 million and was also obligated to pay liquidated damages and other costs totaling approximately $90 million. Therefore, with respect to the Gypsum Supply Agreement and the sale of gypsum thereunder, they contended that DEP has experienced a net loss. Id. at 149-150.

DEP witnesses Coppola and Halm, like Public Staff Witness Lucas, discussed the numerous changes in circumstances over the approximately 15-year time period that resulted in the reduced dispatch of the Roxboro units. Witnesses Coppola and Halm testified that the Company considered all reasonable avenues, including further litigation, but ultimately determined that discontinuing supply under the Gypsum Supply Agreement and paying the liquidated damages was the most prudent and reasonable course for customers. In their view each and every decision that the Company made was reasonable and prudent given what was known or reasonably should have been known at the time the decision was made. Id. at 153-156

In responding to the testimony of Public Staff Witness Lucas, DEP witnesses Coppola and Halm noted that witness Lucas made no attempt to identify any decision or action by the Company that may have been imprudent. Id. at 148. They further noted that the Company provided four sets of data responses with thousands of pages of documents to the Public Staff on this question, which they contended should have been sufficient for the Public Staff to assess the reasonableness and prudence of the Company's actions. Id. at 149.

DEP witnesses Coppola and Halm also testified that liquidated damages are a common commercial term by which parties allocate risks of non-performance under various types of contracts. The Company contends that the Public Staff's interpretation of N.C. Gen. Stat. § 62-133.2(a1)(9) would incent the Company to avoid liquidated damages provisions and instead allocate risk through more indirect means that may not be as optimal for the Company or its customers. Id. at 151.

Witnesses Coppola and Halm also reviewed several previous dockets in which the Commission had permitted the recovery of liquidated damages through fuel rates. Id. at 152. They also noted that CTG was investing approximately $200 million to construct a wallboard production facility near the Roxboro plant and that it was therefore necessary for the contract to contain a minimum delivery obligation. This delivery obligation was backed and reinforced by the liquidated damages provision. Id. at 155. According to Witnesses Coppola and Halm, however, the liquidated damages provision also benefitted the Company and customers by limiting and defining liability in the event that the supply of gypsum was discontinued altogether. Further, they testified that although the Company could have chosen to continue the Gypsum Supply Agreement by obtaining gypsum from another source, such a decision would have resulted in higher costs to the Company and its customers. Id. at 154.

While acknowledging that prudence decisions are evaluated based on what was known or should have been known at the time the decision was made, witnesses Coppola and Halm noted that the Company had performed two hindsight analyses in order to put the results of the transaction in proper context. Id. at 157. According to witnesses Coppola and Halm, the first analysis showed that customers saved approximately $134 million in fuel costs between 2016 and 2018 alone by displacing Roxboro and Mayo coal-fired generation with natural gas-fired generation, and the second showed an overall benefit to customers of $55 million of estimated avoided disposal costs without even attempting to take into account the savings resulting from lower-cost natural gas generation. Id. at 159-160. Witnesses Coppola and Halm also noted that the Public Staff, without acknowledging that the analysis was based on hindsight, had taken issue with the reasonableness of the gypsum disposal cost and stockpile management cost assumptions included in the second hindsight analysis. They agreed that the result of any analysis is dependent on what assumptions are made, but stated that there is evidence to suggest that the results of the analysis could have shown higher costs to customers because of the need for additional off-site landfills if all of the Roxboro and Mayo gypsum had required disposal. Id. at 160-161.

Discussion and Conclusions

The above evidence and the contrasting positions of DEP and the Public Staff present the Commission with two questions. The threshold question is whether the liquidated damages paid in connection with the Gypsum Supply Agreement constitute recoverable costs under the fuel adjustment clause. If so, then the second question is whether the decisions and actions of the Company in connection with the Gypsum Supply Agreement were reasonable and prudent.

Application of N.C. Gen. Stat § 62-133.2(al)(9)

North Carolina General Statute § 62-133.2(a1) states:

As used in this section, "cost of fuel and fuel-related costs" means all of the following:

> (9) Cost of fuel and fuel-related costs shall be adjusted for any net gains or losses resulting from any sales by the electric public utility of by-products produced in the generation process to the extent the costs of the inputs leading to that by-product are costs of fuel or fuel-related costs.

As DEP and the Public Staff acknowledge, it is well established that statutory interpretation begins with an examination of the plain words of the statute. Further, if the language of the statute is clear and unambiguous, the Commission must conclude that the legislature intended the statute to be implemented according to the plain meaning of its terms. Three Guys Real Estate v. Harnett County, 345 N.C. 468, 472, 480 S.E.2d 681, 683 (1997). In addition, when the language of a statute is clear and unambiguous, it must be given its plain and definite meaning, without imposing provisions and limitations not contained therein. Union Carbide Corp. v. Offerman, 351 N.C. 310, 526 S.E. 2d 167 (2000).

North Carolina General Statute § 62-133.2(a1)(9) contemplates the recovery of "net gains or losses resulting from any sales..." of generation by-products. It is undisputed that the Gypsum Supply Agreement was a contract for the sale of synthetic gypsum, which was a by-product of generating electricity from coal at the Roxboro units. Thus, the Commission determines that for purposes of the present issue the key words in N.C.G.S. § 62-133.2(a1) (9) are "resulting from any sales."

The American Heritage Dictionary defines "resulting" as "To occur or exist as a consequence of a particular cause." American Heritage Dictionary, at 1109 (Houghton Mifflin Co., 1978). DEP maintains that its obligation to pay liquidated damages "occurred or exists" as a consequence of the fact that DEP sold millions of tons of gypsum to CTG under the Gypsum Supply Agreement, and, therefore, the liquidated damages were the result of actual sales of gypsum. Further, DEP emphasizes the fact that the liquidated damages were negotiated as part of the original agreement for the sale of synthetic gypsum to CTG in 2004, and were included in all subsequent versions of the Agreement. Tr. Vol. 2, p. 150.

In addition, DEP witnesses Coppola and Halm cited three prior instances in which the Commission allowed the recovery of liquidated damages through the fuel clause. The first was in 2013, when DEP incurred and recovered through fuel rates $10.6 million due to a tonnage shortfall under a railroad transportation contract in connection with the retirement of the Robinson and Sutton coal-fired generating units. The liquidated damages - referred to as "dead weight" charges - were incurred because DEP was not able to meet certain minimum contractual obligations under a CSX transportation contract. The Public Staff did not oppose DEP's recovery of liquidated damages through the fuel clause in that proceeding. In the Commission's Order the Company's recovery of liquidated damages was specifically identified, albeit not discussed by the Commission. Order Approving Fuel Charge Adjustment, Docket No. E-2, Sub 1031, at 28 (November 25, 2013).

In 2014 DEP incurred and recovered through fuel rates $10.5 million in liquidated damages due to a tonnage shortfall under another railroad contract in connection with the retirement of the Sutton coal-fired generating facility. The Public Staff entered into a Stipulation with DEP and did not oppose DEP's recovery of liquidated damages through the fuel clause. The Commission approved the Stipulation without discussion of the inclusion of the liquidated damages. Order Approving Fuel Charge Adjustment, Docket No. E-2, Sub 1045, at 28 (November 19, 2014).

In 2019 Duke Energy Carolinas, LLC (DEC) incurred $786,615 in liquidated damages due to a limestone tonnage shortfall. The Public Staff also did not oppose DEC's recovery of the liquidated damages through the fuel clause. The Commission approved a fuel charge adjustment for DEC that included recovery of the liquidated damages without discussion of this cost. Order Approving Fuel Charge Adjustment, Docket No. E-7, Sub 1190 (August 7, 2019).

In all three of the above instances the liquidated damages were owed due to the failure of the utility to meet a minimum contractual obligation for the transportation of fuel or reagents. In all three cases payment was made because fuel or reagents were not being transported as contemplated by the transportation contract. (i.e., the utility was paying liquidated damages under a transportation agreement and not receiving transportation in return). Moreover, in the two DEP dockets the obligation to pay liquidated damages was caused by at least two of the same factors at play in this case - namely, the reduction in coal consumption caused by lower natural gas prices and the conversion from coal-fired generation to natural gas-fired generation. The Commission finds the above three examples of the recovery of liquidated damages through the fuel clause to be consistent with the Company's view that the liquidated damages in the present case are recoverable as fuel costs.

Nevertheless, the Commission does not rely on the above orders as binding precedent in the present case, mainly because the facts in those dockets involved liquidated damages paid under contracts for transportation costs, recoverable under N.C.G.S. § 62-133.2(a1)(2), rather than sales of by-products of electric generation under subsection (a1)(9). However, the Commission notes that subsection (a1)(9) provides even more latitude to include liquidated damages than does subsection (a1)(2), based on the inclusion of the phrase "net gains and losses." That is, if liquidated damages are properly recoverable as a "cost of fuel transportation" under subsection (a1)(2), then it is likewise reasonable to find that liquidated damages should be considered as part of the "net gains or losses" resulting from a sale of by-products under subsection (a1)(9). Further, the fact that the General Assembly specifically contemplated that a utility should be able to recover "net losses" as a fuel-related cost supports the intent of the statute to encourage sales of generation by-products, even though such sales might result in a net loss. Finally, there is no material difference in DEP's payment of liquidated damages resulting from its inability to meet its obligations under a contract for transportation services and DEP's payment of liquidated damages resulting from its inability to meet its obligations under a contract for the sale of synthetic gypsum.

In its post-hearing brief the Public Staff stated that the damages payment and the liquidated damages did not result from the sale of a by-roduct because no gypsum was exchanged for the payments, as one would otherwise expect in a "sale." Rather, the Company made the actual damages and liquidated damages payments because the Company failed to sell gypsum to CTG. According to the Public Staff, the payments are the antithesis of a sale and are not covered under the plain language of subdivision (a1)(9).

The Public Staff added that the only case in which the Commission has interpreted subdivision (a1)(9) is the Company's most recently concluded general rate case in Docket No. E-2, Sub 1142. In its Order dated February 23, 2018 in that case, the Commission found that the beneficial reuse of coal combustion residuals (CCRs), in and of itself and absent an actual sale, did not constitute the sale of a by-product under subdivision (a1)(9), and that the transaction between DEP and a third party (Charah) did not represent the sale of a by-product. Order Accepting Stipulation, Deciding Contested Issues and Granting Partial Rate Increase, Docket No. E-2, Sub 1142 at pp. 215-16. (Sub 1142 Order) The Commission stated that "the record in this case does not support a finding that the costs associated with the Master Contract resulted from a 'sale' of CCRs." Id. at 215. The Public Staff opined that the Commission's analysis focused on the value and sale of an asset (CCRs). According to the Public Staff, the Commission determined that there was no sale of CCRs that availed the Company of cost recovery under subdivision (a1)(9), and, therefore, the Commission correctly declined to take an expansive view of subdivision (a1)(9) absent the transfer of an asset with value.

With respect to DEP's argument that the liquidated damages should be recoverable through the fuel clause because the liquidated damages provision is an "essential term" of the contract, the Public Staff contended that this argument misses the point and ignores the plain language of the statute. According to the Public Staff, whether or not a counterparty would require different terms of a contract in the absence of a liquidated damages clause is speculative and presents no basis for disregarding the plain language of the statute. Likewise, whether a contract appropriately balances risk and obligations relates to the reasonableness of the contract terms, not the appropriate statutory basis (if any) for recovering costs incurred under that contract and is not a basis for disregarding the plain language of the statute.

Further, the Public Staff maintained that the Company's functional argument that the Commission should "look at the flow of revenues and costs" fails for two reasons. First, as set forth above, this argument ignores the plain words of the statute. Second, the Company contradicted this position when its own witnesses acknowledged during cross-examination that not all of the costs under the Gypsum Supply Agreement are recoverable under subdivision (a1)(9). Thus, says the Public Staff, the Company is selective in the costs it seeks to recover through the fuel clause related to the Gypsum Supply Agreement; and adopting its position in this case would result in an arbitrary application of the statute.

The Commission concludes that the Public Staff's reading of N.C.G.S. § 62-133.2(al)(9) is too narrow because it would artificially isolate the liquidated damages payment from the underlying Gypsum Supply Agreement. Based on its plain words, the intent and spirit of the statute is to encourage public utilities to find ways to sell the by-products of electric generation, even though the sales may end up being at a net loss. As DEP's witnesses testified, liquidated damages provisions are fairly standard clauses in commercial sales contracts. In the instant case, the Commission finds and concludes that the liquidated damages provisions were part and parcel of the Gypsum Supply Agreement. In that context, it would be unduly restrictive to conclude that DEP's payments for actual and liquidated damages are not part and parcel of the sales made and contemplated to be made under the Gypsum Supply Agreement.

In addition the Public Staff's reliance on the Charah contract interpretation in the Sub 1142 Order is not persuasive. The Commission concluded that the Charah contract costs were not recoverable under subsection (a1)(9) because the contract had no provision for the sale of CCRs from DEP to Charah. Rather, the contract was for the transportation and disposal of CCRs as a waste product. There was no beneficial use or reuse of the ash wastes contemplated by the parties. In the Commission's view, N.C.G.S. § 62-133.2(a1)(9) was intended to extend to contracts involving the sale for beneficial use or reuse of by-products but not to include contracts for the disposal of waste products.

Based on the foregoing and the record, the Commission concludes that the actual damages and liquidated damages paid and to be paid by DEP under the Gypsum Supply Agreement constitute fuel-related costs under N.C. Gen. Stat. § 62-133.2(al)(9), provided DEP's obligation to make such payments was reasonably and prudently incurred.

Prudence and Reasonableness

Having concluded that the liquidated damages in this case may qualify as fuel-related costs under N.C.G.S. 62-133.2(a1)(9), the Commission must next consider whether the Company's decisions and actions in connection with the CTG transaction were prudent and reasonable.

Pursuant to N.C.G.S. 62-133.2(d), in pertinent part:

> [I]n reaching its decision the Commission shall consider all evidence required under subsection (c) of this section as well as any and all other competent evidence that may assist the Commission in reaching its decision...
>
> [T]he burden of proof as to the correctness and reasonableness of the charge and as to whether the cost of fuel and fuel-related costs were reasonably and prudently incurred shall be on the utility.

Prudent is defined, in pertinent part, as "1. Wise in handling practical matters; exercising good judgment or common sense. 2. Careful in regard to one's own interests; provident." American Heritage Dictionary, at 1054 (Houghton Mifflin Co., 1978).

The prudence and reasonableness standard applied by the Commission is generally stated as:

> [w]hether management decisions were made in a reasonable manner and at an appropriate time on the basis of what was reasonably known or reasonably should have been known at that time (citation omitted)...The Commission notes that this standard is one of reasonableness that must be based on a contemporaneous view of the action or decision under question. Perfection is not required. Hindsight analysis – the judging of events based on subsequent developments – is not permitted.

78 North Carolina Utilities Commission Orders and Decisions 238, at 251-52 (August 5, 1988); reversed in part, and remanded (on other grounds), Utilities Commission v. Thornburg, 325 N.C. 484, 385 S.E.2d 463 (1989).

As a general rule, if the utility presents evidence that costs were reasonably incurred and no additional evidence of prudence and reasonableness is presented, a prima facie case is made that the costs were reasonably incurred. State ex rel. Utilities Comm'n. v. Intervenor Residents, 305 N.C. 62, 76-77, 286 S.E.2d 770, 779, (1982). In the present case, although the Public Staff expressed no opinion on the prudence and reasonableness of the Gypsum Supply Agreement with CTG, witness Lucas testified that the Public Staff had concerns about the prudence and reasonableness of the actual damages and liquidated damages as a recoverable cost. Tr. Vol. 2, p. 68-69. More importantly, witness Lucas testified about three factors that led to the reduced dispatch of the Roxboro units: (1) the JDA, (2) the sustained decline in natural gas prices, and (3) DEP's and DEC's conversion from coal-fired generation to natural gas-fired generation. Id. at 62-64. According to witness Lucas:

> The effect of low natural gas prices and the large increase in natural gas-fired CC capacity resulted in the Roxboro and Mayo power plants being dispatched less. The reduced dispatch resulted in less coal burned, resulting in the inability of DEP to provide the quantities of artificial gypsum that CertainTeed contracted for and anticipated when it built the gypsum board manufacturing facility next to the Roxboro plant.

Id. at 64.

The Commission takes note of the dates of the events described by witness Lucas as related to the date that DEP entered into the Gypsum Supply Agreement. First, the application for approval of the merger of Duke Energy Corporation and Progress Energy, Inc., was filed on April 4, 2011, in Docket Nos. E-2, Sub 998 and E-7, Sub 986. The proposed JDA was attached to the merger application as Exhibit No. 3. On June 29, 2012, the Commission issued its Order Approving Merger Subject to Regulatory Conditions and Code of Conduct (Merger Order). Second, as witness

Lucas stated, the decline in natural gas prices began after 2009, and has persisted since that time. Third, witness Lucas testified that DEC's Buck CC began commercial operation in 2011, its Dan River CC began commercial operation in 2012, and DEP's H.F. Lee CC began commercial operation in 2012. All of these facts, plus the commercial operation of DEP's Sutton CC being on the horizon for 2013, were known to DEP when it entered into the Gypsum Supply Agreement with CTG on August 1, 2012. Nevertheless, DEP negotiated and signed a Gypsum Supply Agreement that committed DEP to deliver 50,000 tons of gypsum per month from the Roxboro plant through April 2029, and to maintain a gypsum stockpile of 250,000 tons for that same period of time.

In addition there are other facts in evidence that bear upon the issue of DEP's prudence and reasonableness in connection with the Gypsum Supply Agreement. For example, in the Business Court litigation, DEP took the position that its supply obligation was limited to the actual amount of gypsum produced at the Roxboro units. Opinion and Final Judgment (Judgment), CTG v. DEP, ¶ 13.a., at 5.

Another example of facts in evidence that bear upon the issue of DEP's prudence and reasonableness in connection with the Gypsum Supply Agreement is the Business Court's finding of fact that during negotiations for the Gypsum Supply Agreement CTG proposed shifting from a fixed supply contract to a variable supply agreement based on CTG's need for gypsum and DEP's production of gypsum, but DEP rejected this proposal. Judgment, Finding of Fact No. 71, at 24.

In their rebuttal testimony DEP witnesses Coppola and Halm testified to the conditions and factors that existed in 2002 as the basis for the original agreement with CTG, and opined that DEP's decision to enter into the original agreement was reasonable and prudent. However, witnesses Coppola and Halm did not address the three factors discussed by Public Staff witness Lucas – the JDA, the consistent decline in natural gas prices, and the conversion to natural gas-fired generation - that existed in 2012 when DEP entered into the revised Gypsum Supply Agreement with CTG. The Commission acknowledges that DEP's failure to respond to witness Lucas's testimony about those three factors may have been based on the fact that the Public Staff was not expressing an opinion on the prudence and reasonableness of DEP's decisions and actions in connection with the Gypsum Supply Agreement. On the other hand, the Public Staff's decision not to engage in a prudence analysis and express an opinion on prudence was based on its position that the liquidated damages were not a fuel cost recoverable in this proceeding, and that the issues surrounding their recovery should be addressed in DEP's pending general rate case.

The Commission concludes that because of the Public Staff's decision not to perform a prudence analysis and express an opinion on DEP's prudence surrounding the Gypsum Supply Agreement, and DEP's failure to address the factors raised by the testimony of witness Lucas, the issue of DEP's prudence in connection with the Gypsum Supply Agreement has not been fully joined. As a result, the evidence of record in this proceeding is not sufficient to enable the Commission to make a final decision on the issue of DEP's prudence and reasonableness in connection with the Gypsum Supply Agreement.

Based on the above-described circumstances, the Commission finds good cause to allow DEP the opportunity to present additional rebuttal testimony in response to a more precise analysis and expression of opinion by the Public Staff. As a result, the Commission will require that the Public Staff conduct an analysis of the prudence and reasonableness of DEP's decisions and actions in connection with the Gypsum Supply Agreement, including an analysis of the effects, if any, of the JDA, the consistent decline in natural gas prices, and the conversion to natural gas-fired generation. Further, the Commission will require the Public Staff to file testimony explaining its analysis and stating its opinion as to the prudence and reasonableness of DEP's decisions and actions in connection with the Gypsum Supply Agreement. In addition, the Commission will allow DEP to file rebuttal testimony in response to the Public Staff's testimony, and, if DEP so desires, providing other information that DEP deems relevant to the prudence issue. Finally, the Commission will schedule an additional hearing to consider further the matters arising from the Gypsum Supply Agreement and whether as a result of such matters an adjustment should be made to the interim rates and schedules established pursuant to this Order.

Based upon the lack of sufficient evidence in the record on the prudence and reasonableness of DEP's decisions and actions in connection with the Gypsum Supply Agreement, and the testimony of Public Staff witness Li , DEP's proposed test year N.C. retail fuel and fuel-related costs shall be adjusted on an interim basis pending further orders by the Commission, by removing liquidated damages in the amount of $6,640,945 and removing the judgment payment in the amount of $619,200 for purposes of determining the under-recovery and EMFs. Further, DEP's proposed and projected N.C. retail fuel and fuel-related costs must be adjusted on an interim basis, pending further orders by the Commission, by removing $5,181,120 for such costs for the purpose of determining the prospective fuel and fuel-related cost factors for the billing period.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 21 – 23

Commission Rule R8-55(d)(1) provides that capacity factors for nuclear production facilities will be normalized based generally on the national average for nuclear production facilities as reflected in the most recent North American Electric Reliability Corporation (NERC) Generating Availability Report (GAR), adjusted to reflect the unique, inherent characteristics of the utility facilities and any unusual events. Company witness Henderson testified that DEP's nuclear fleet consists of three generating stations and a total of four units. He testified that the Company's four nuclear units operated at an actual system average capacity factor of 89.21% during the test period, which reflects the significant impact of Hurricane Florence on three of the four DEP nuclear units. This annual average capacity factor came in below the five-year industry average of 91.80% for the period 2013-2017 for average comparable units on a capacity-rated basis, as reported by NERC in its latest Generating Unit Statistical Brochure, but the Company's 2-year average capacity factor of 92.44% and the Company's 5-year average capacity factor of 93.29%, exceeded the five-year industry average capacity factor.

Company witness Repko testified concerning the performance of DEP's fossil/hydro assets. He stated that the Company's generating units operated efficiently and reliably during the test period. He explained that several key measures are used to evaluate operational performance, depending on the generator type: (1) equivalent availability factor (EAF), which refers to the percentage of a given time period a facility was available to operate at full power, if needed (EAF is not affected by the manner in which the unit is dispatched or by the system demands; it is impacted, however, by planned and unplanned (i.e., forced) outage time); (2) net capacity factor (NCF), which measures the generation that a facility actually produces against the amount of generation that theoretically could be produced in a given time period, based upon its maximum dependable capacity (NCF *is* affected by the dispatch of the unit to serve customer needs); (3) equivalent forced outage rate (EFOR), which represents the percentage of unit failure (unplanned outage hours and equivalent unplanned derated hours); a low EFOR represents fewer unplanned outage and derated hours, which equates to a higher reliability measure; and (4) starting reliability, which represents the percentage of successful starts.

Witness Repko presented the following chart, which shows operational results, categorized by generator type, as well as results from the most recently published NERC Generating Unit Statistical Brochure for the period 2013 through 2017:

Generator Type	Measure	Review Period DEP Operational Results	2013-2017 NERC Average	Nbr of Units
Coal-Fired Test Period	EAF	71.4%	81.6%	418
	NCF	25.9%	57.8%	
	EFOR	6.1%	8.1%	
Coal-Fired Summer Peak	EAF	93.1%	n/a	n/a
Total CC Average	EAF	80.3%	85.0%	338
	NCF	72.5%	52.7%	
	EFOR	4.77%	5.3%	
Total CT Average	EAF	80.2%	87.8%	716
	SR	98.7%	98.1%	
Hydro	EAF	79.7%	80.4%	1,113

Company witness Repko also testified that the Company, like other utilities across the United States, has experienced a change in the dispatch order for each type of generating facility due to continued favorable economics resulting from the lower pricing of natural gas. Gas-fired facilities provided 59% of the DEP fossil/hydro generation during the test period.

In his direct testimony, witness Henderson testified that the Robinson Refueling Outage was originally scheduled to begin on September 15, 2018, just one day after Hurricane Florence made landfall along North Carolina's southeast coast. Tr. Vol. 1, p. 46. The outage start was delayed by one week, and on September 22, 2018, Robinson entered the fall refueling outage, which began one week after the hurricane's landfall and was impacted by resource constraints directly attributable to the hurricane and its aftermath. Id. In addition to refueling activities, significant safety, regulatory, and reliability enhancements were completed. Regulatory and safety enhancements included the transmission upgrade project (Robinson TUP) and modifications required to transition to the National Fire Protection Association standard (NFPA 805). Id. Significant activities associated with the Robinson TUP included replacement of the 115KV startup transformer, addition of a second transformer, and upgrades to the 4KV bus and transmission lines. The Robinson TUP provides the Robinson plant with a second off-site power path, aligning the station with the current industry standard for U.S. nuclear plants. Reliability enhancements included the replacement of both low-pressure turbines, which addressed blade design issues that have impacted generation since 2012. Id. After refueling, maintenance, projects and inspection activities were completed, the Robinson plant returned to service on November 26, 2018. The 65-day outage extended beyond the originally scheduled allocation of 37 days, with the overrun primarily attributable to direct impacts on resource availability related to Hurricane Florence and Michael and challenges with the complex Robinson TUP.

Public Staff witness Metz described the Public Staff's investigation and review of the Company's test period and projected fuel and fuel related costs. Witness Metz utilized an updated NERC GAR capacity factor that was released after the Company's filing but prior to the filing of Public Staff testimony. Based on this updated value, witness Metz initially observed that the Company did not meet either of the two benchmarks under Commission Rule R8-55(k). However, witness Metz also acknowledged, consistent with the testimony of DEP witness Henderson, that the test year weather-related events that caused Brunswick Units 1 and 2 to be offline were beyond the Company's control. When the effect of the hurricane was removed, the Company's performance satisfied the Commission Rule R8-55(k) standard and therefore, witness Metz concluded that the rebuttal presumption of imprudence was avoided. Witness Metz also noted that he did not completely agree with the Company's inputs to its calculation of its capacity factors but noted that such disagreement was immaterial to the end result in this proceeding.

With respect to the Robinson Refueling Outage, in addition to reviewing extensive discovery documents provided by the Company, the Public Staff engaged in multiple discussions and meetings with Company personnel regarding the subject matters of this docket and conducted a site visit to the Robinson plant. In his testimony, witness Metz acknowledged that the 67-day outage, which included a scheduled 39-day refueling and transmission project outage, was impacted, at least in part, to weather events beyond the control of the Company. Tr. Vol. 2, p. 116. The Public Staff recognizes that the Robinson TUP was expansive and required a significant level of engineering and oversight. Based on his review, witness Metz was unable to conclude that the additional 28 outage days of replacement power costs incurred during the outage were imprudently incurred. Although witness Metz expressed significant doubt as to whether the Company's management of the project should have resulted in the outage being shifted from the Spring 2017 refueling outage to the Fall 2018 refueling outage, he did not recommend a disallowance for any portion of the replacement costs for which the Company seeks recovery in this docket. Id. at 118.

Witness Metz testified that he was unable to reach a conclusion because the Company's lack of document access or retention restricted the Public Staff's ability to review and evaluate the prudency of project management regarding the Robinson TUP. Id. at 119. Witness Metz stated the Robinson TUP started before the merger of Duke Energy Corporation and Progress Energy, Inc. in 2012. During the project life cycle, the merger led to the introduction of new policies and procedures regarding project management. The Company was able to produce applicable guidelines and procedures that should have been followed, but, in the opinion of witness Metz, the documentation to ensure that these items were, in fact, appropriately implemented and completed could not be produced consistently. Id. at 120. Witness Metz testified the Company worked in good faith to respond to Public Staff discovery requests, made technical experts and senior management available for discussion, and had open dialogue as the Public Staff and DEP worked through the discovery process. Id. at 120-121. Nonetheless, he has concerns about the Company's apparent lack of records retention in this case and that this concern has broader implications that could impact future investigations and proceedings regarding the capital costs of the Robinson TUP in the context of a future general rate case.

On rebuttal, witness Henderson testified that the Company made a prudent and reasonable decision in implementing the Robinson TUP, including managing an engineering firm that was ultimately unable to deliver on its contractual obligations. Henderson Prefiled Rebuttal Testimony, p. 2. Witness Henderson stated that, having effectively mitigated such issue and taken substantial steps to ensure design completion and other detailed preparatory actions, the Company was fully prepared to implement the Robinson TUP at the start of the Robinson Refueling Outage. Id. The Company was aware of the labor issues and undertook substantial efforts to address the shortage. The Company conferred weekly with a major supplemental labor provider to the nuclear industry and independently contacted fifteen additional sub-tier vendors in an effort to secure additional electrical workers. Unfortunately, the shortage of qualified, electrical workers was exacerbated by the impact of two hurricanes. Id. The refueling outage was originally scheduled to begin on September 15, 2018, just one day after Hurricane Florence made landfall. Ultimately, the Company was able to obtain only approximately 50% of the needed electricians for this project. Id. at 6.

In further efforts to solve the resource gap, the Company reviewed non-critical electric projects underway or scheduled to determine if those projects could be delayed, thereby freeing additional resources to assist on the Robinson TUP. Id. at 7. Witness Henderson also noted that the unit had reached the period where refueling was required, and any additional delays would have required the unit to operate at increasingly reduced power, and would have impacted other scheduled unit outages and the ability of the Company to efficiently meet load demands. Id. Putting aside the fact that there was no practical way to further delay the outage, the Company could not have anticipated the wide-spread regional flooding that would result from the hurricanes. Due to the flooding, some of the already limited available resources had to leave work to respond to emergency situations and tend to homes damaged by the flooding. Other qualified contractors were prevented from traveling to the Robinson plant because of the flooding. Id. at 8.

Witness Henderson also addressed the concerns expressed by witness Metz regarding the shift of the Robinson TUP project from Spring 2017 to Fall 2018. In witness Henderson's view, witness Metz seems to suggest that the shift might be a potential cause of the extended outage, but witness Metz provides no explanation to establish a causal connection between the shift and the extended outage. Witness Henderson stated that the delay of the Robinson TUP project to Fall 2018 had no direct impact on the extension of the Robinson Refueling Outage and, moreover, the delay was a prudent decision, which avoided potential challenges that might have arisen due to the project not being in a ready state for implementation. Id. at 9.

While witness Metz provided general, non-specific concerns about the availability of information, witness Henderson noted that in addition to multiple meetings and an on-site visit to Robinson, the Company responded to 31 detailed data requests and provided thousands of pages of responsive documents. Id. at 10. The documents included detailed project timelines, business analysis documents and details about the RFP process used to select the contractor. The responses also included the underlying contract and all amendments, annual estimated and actual project spend, project oversight guidelines, and records of monthly hours charged by employees. In the view of witness Henderson, the information provided to the Public Staff provides a very clear and detailed picture of the Company's oversight of the Robinson TUP.

In regard to witness Metz's concerns that the Company did not comply fully with Commission Rule R8-28, witness Henderson noted that witness Metz did not identify any ways in which the Company's document retention policies do not comply with the specific document retention policy of the NARUC policies referenced in Commission Rule R8-28. Id. at 12. Rather, witness Metz appears to reference general guidelines of the NARUC policies, which provide that a utility shall retain appropriate records to support the costs and adjustments that it plans to propose in a current or future rate case. Witness Henderson testified that the vast majority of the issues explored in discovery by the Public Staff related to the Robinson TUP more directly address the prudence of capital costs, which are not related to this proceeding. Id. at 13-14. Witness Henderson stated that the Company had provided sufficient information to demonstrate the reasonableness and prudence of the fuel related costs at issue in this proceeding and understands that additional information may be required in the context of the next base rate case in which capital issues are considered. Id. at 14.

Noting that the Public Staff did not identify any alleged imprudence that caused the outage extension, in response to witness Metz's concerns about the Company's management of the Robinson TUP and the fact that this issue has base rate case implications, witness Henderson testified that questions regarding the Company's management of the Robinson TUP are not relevant in light of the clear evidence that labor shortages were the cause of the extended outage. Id. at 3. Further, he noted that the Company has, in response to extensive data requests from the Public Staff, produced a significant amount of information in this case, but to the extent the Company can produce additional information that will address base rate impacts of the Robinson TUP, the Company will continue to do so. In the final analysis, witness Henderson noted that witness Metz stated that he could not conclude that it is appropriate to disallow recovery of replacement power costs for an outage that was impacted by severe weather events.

Finally, witness Henderson also responded to the testimony of witness Metz regarding the Company's input to its calculation of its capacity factors. Witness Metz described that Company's timing of official maximum dependable capacity adjustments at the beginning of a calendar year complies with industry norms and is driven to some extent by regulatory reporting requirements. Based both on regulatory reporting requirements, and the business need for the Company to establish and maintain valid MDC ratings, the Company follows procedural guidelines in establishing and reporting MDC values.

Pursuant to N.C. Gen. Stat. § 62-133.2(d) and Commission Rule R8-55, the burden of proof, as to the correctness and reasonableness of any charge and as to whether the test year fuel costs were reasonable and prudently incurred, is on the utility. For purposes of determining the EMF rider, a utility must achieve either (a) an actual system-wide nuclear capacity factor in the test year that is at least equal to the national average capacity factor for nuclear production facilities based on the most recent five year period available as reflected in the most recent

NERC Generating Availability Report, appropriately weighted for size and type of plant, the NERC average, or (b) an average system-wide nuclear capacity factor, based upon a two-year simple average of the system-wide capacity factors actually experienced in the test year and the preceding year, that is at least equal to the NERC average in order to avoid a presumption that the utility imprudently incurred the increased fuel costs and that disallowance of those costs is appropriate.

In accordance with Commission Rule R8-55, the Company utilized the NERC GAR capacity that was "most recent" at the time of the filing of the Company's application. Public Staff witness Metz recommend using an updated NERC GAR capacity factor that was not available at the time of the Company's filing but was released earlier than normal and just prior to the filing of Public Staff's testimony. The Commission has concerns with the procedural issues that could arise in the unique circumstances where such an update in the NERC GAR capacity factors late in a proceeding could cause a shift in presumption at a late-stage in the proceeding. However, in this proceeding, the issue is immaterial, as witness Metz acknowledged, after adjusting for weather impacts, that the rebuttal presumption of imprudence was avoided.

Therefore, the Commission concludes that the Company's nuclear fleet achieved a capacity factor above the NERC average, rendering the rebuttable presumption of imprudence under Commission Rule R8-55(k) inapplicable. Thus, based upon the provisions of the fuel adjustment statute, the question before the Commission is whether the Company has met its burden of proving that the replacement power costs resulting from the Robinson Refueling Outage were reasonable and were prudently incurred under efficient management and economic operations.

Based on the preponderance of evidence, the Commission concludes that there is no basis for a disallowance of the replacement fuel costs for the outage at the Robinson plant. More specifically, the preponderance of evidence indicates that the Company's actions in connection with the Robinson Refueling Outage were reasonable and prudent. Further, no party introduced evidence indicating imprudent conduct or decisions. The Commission places great weight on the fact that after numerous meetings with Company representatives, a site visit to the Robinson plant and review of extensive responses to discovery requests, the Public Staff stated that it could not conclude that replacement power costs should be disallowed because of the impact of factors outside of the Company's control.

The Commission also agrees with the Company that whether different management decisions could have resulted in an opportunity to implement the Robinson TUP in an earlier refueling outage would not be a helpful analysis. Rather, the questions for this proceeding is whether the Company's decision to implement the Robinson TUP during the 2018 fall outage was reasonable and prudent, and whether the Company's actions during the outage were reasonable and prudent. No party to this proceeding has challenged the Company's position that it was reasonable to implement the Robinson TUP during the fall 2018 outage and that it was, in fact, fully prepared to do so. The evidence demonstrates that it was circumstances outside of the Company's control and not any imprudent action or decision that caused the extended outage. Specifically, the cause of the 28-day outage extension was a shortage of qualified technical contractors, a situation regarding which the Company was aware of prior to the outage but which was exacerbated by the impact of Hurricanes Florence and Michael. Furthermore, delaying the refueling of the plant was not a viable option. The Commission therefore concludes that the replacement power costs associated with Robinson Refueling Outage were reasonably and prudently incurred under efficient management and economic operations.

The Commission appreciates the Public Staff's concerns about DEP's records retention policies. However, the Commission declines the Public Staff's request in this proceeding to review DEP's record retention policies. Such a matter is beyond the scope of this proceeding, and the record herein is not adequate or specific enough to justify such a review. However, the Commission reminds the Company of the need to maintain and follow reasonable document retention policies, including the NARUC guidelines identified in Commission Rule R8-28. Under the facts of this case, the Commission cannot conclude that the Company is not in compliance with the Commission Rule. To the extent that document retention policies become an issue in future proceedings, the Commission will address those issues as they arise.

In response to the Public Staff's request for guidance on how to proceed if necessary utility documents are unavailable during the Public Staff's investigation of costs, the Commission recommends three steps. First, keep a detailed log of the documents requested but not produced by the utility. Second, in a pre-trial motion or during cross-examination of the witnesses, present evidence of the lack of documentation by the utility. Third, if the utility's lack of documentation materially impairs the Public Staff's ability to fully investigate the prudence or reasonableness of a utility's costs, then the Public Staff could consider opposing the recovery of the costs.

In summary, the Commission concludes that DEP managed its baseload plants prudently and efficiently to minimize fuel and fuel-related costs.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 24

Commission Rule R8-52(b) requires each electric utility to file a Fuel Procurement Practices Report at least once every 10 years and each time the utility's fuel procurement practices change. The Company's revised fuel procurement practices were filed with the Commission in Docket No. E-100, Sub 47A in 2015, and were in effect throughout the 12 months ending March 31, 2019. In addition, the Company files monthly reports of its fuel and fuel-related costs pursuant to Commission Rule R8-52(a). Further evidence for this finding of fact is contained in the testimony of Company witnesses Harrington, Phipps, Henderson, and Church.

Company witness Harrington testified that DEP's fuel procurement strategies that mitigate volatility in supply costs are a key factor in DEP's ability to maintain lower fuel and fuel-related rates. Other key factors include DEP's and D DEC's respective expertise in transporting, managing and blending fuels, procuring reagents, and utilizing purchasing synergies of the combined Company, as well as the joint dispatch of DEP's and DEC's generation resources.

Company witness Phipps described DEP's fossil fuel procurement practices, set forth in Phipps Exhibit 1. Those practices include computing near and long-term consumption forecasts, developing inventory targets, inviting proposals from all qualified suppliers, awarding contracts based on the lowest evaluated offer, monitoring delivered coal volume and quality against contract commitments, and conducting short-term and spot purchases to supplement term supply.

According to witness Phipps, the Company's average delivered coal cost per ton increased approximately 5%, from $80.82 per ton in the prior test period to $84.81 per ton in the test period. The Company's transportation costs increased approximately 11%, from $29.42 per ton in the prior test period to $32.72 per ton in the test period.

Witness Phipps stated that DEP's current coal burn projection for the billing period is 4.4 million tons compared to 3.6 million tons consumed during the test period. DEP's billing period projections for coal generation may be impacted due to changes from, but not limited to, the following factors: delivered natural gas prices versus the average delivered cost of coal, volatile power prices, and electric demand. Combining coal and transportation costs, DEP projects average delivered coal costs of approximately $65.43 per ton for the billing period compared to $84.81 per ton in the test period due, in part to newly negotiated rail transportation contracts that went into effect March 1, 2019.

According to witness Phipps, DEP continues to maintain a comprehensive coal and natural gas procurement strategy that has proven successful over the years in limiting average annual fuel price changes while actively managing the dynamic demands of its fossil fuel generation fleet in a reliable and cost-effective manner.

Witness Phipps further testified that DEP's current natural gas burn projection for the billing period is approximately 158.5 million MMBtu, which is a decrease from the 182.4 million MMBtu consumed during the test period. The current average forward Henry Hub price for the billing period is $2.76 per MMBtu, compared to $3.12 per MMBtu in the test period. Witness Phipps also testified that the Company's average price of gas purchased for the test period was $4.05 per MMBtu, compared to $4.68 per MMBtu in the prior test period, representing a decrease of approximately 13%.

North Carolina General Statute § 62-133.2(a1)(3) permits DEP to recover the cost of "ammonia, lime, limestone, urea, dibasic acid, sorbents, and catalysts consumed in reducing or treating emissions." Company witness Repko testified that the Company's fossil/hydro/solar generation portfolio consists of 9,204 MWs of generating capacity, 3,544 MWs of which is coal-fired generation across three generating stations and a total of seven units. These units are equipped with emission control equipment, including selective catalytic reduction (SCR) equipment for removing nitrogen oxides (NOx), flue gas desulfurization (FGD or scrubber) equipment for removing sulfur dioxide (SO_2), and low NOx burners. This inventory of coal-fired assets with emission control equipment enhances DEP's ability to maintain current environmental compliance and concurrently utilize coal with increased sulfur content, thereby providing flexibility for DEP to procure the most cost-effective options for fuel supply.

Company witness Repko further testified that overall, the type and quantity of chemicals used to reduce emissions at the plants vary depending on the generation output of the unit, the chemical constituents in the fuel burned, and/or the level of emissions reduction required.

Company witness Church testified that DEP's nuclear fuel procurement practices involve computing near and long-term consumption forecasts, establishing nuclear system inventory levels, projecting required annual fuel purchases, requesting proposals from qualified suppliers, negotiating a portfolio of long-term contracts from diverse sources of supply, and monitoring deliveries against contract commitments. Witness Church explained that for uranium concentrates, conversion and enrichment services, long-term contracts are used extensively in the industry to cover forward requirements and ensure security of supply. He also stated that, throughout the industry, the initial delivery under new long-term contracts commonly occurs several years after contract execution. For this reason, DEP relies extensively on long-term contracts to cover the largest portion of its forward requirements. By staggering long-term contracts over time for these components of the nuclear fuel cycle, DEP's purchases within a given year consist of a blend of contract prices negotiated at many different periods in the markets, which has the effect of smoothing out the Company's exposure to price volatility. He further stated that diversifying fuel suppliers reduces DEP's exposure to possible disruptions from any single source of supply. Due to the technical complexities of changing fabrication services suppliers, DEP generally sources these services to a single domestic supplier on a plant-by-plant basis using multi-year contracts.

North Carolina General Statute. §§ 62-133.2(a1)(4), (5), (6), and (7) permit the recovery of the cost of non-capacity power purchases subject to economic dispatch or economic curtailment; capacity costs of power purchases associated with qualifying facilities subject to economic dispatch; certain costs associated with power purchases from renewable energy facilities; and the fuel costs of other power purchases. Company witness Phipps testified that DEP and DEC utilize the same process to ensure that the assets of the Companies are reliably and economically available to serve their respective customers. To that end, both companies consider numerous factors such as the latest forecasted fuel prices, transportation rates, planned maintenance and refueling outages at the generating units, generating unit performance parameters, and expected market conditions associated with power purchases and off-system sales opportunities in order to determine the most economic and reliable means of serving their customers.

In his testimony, Public Staff witness Metz expressed concerns about the Company's natural gas pricing methodology, similar to the concerns expressed by Public Staff witness Lucas in DEC's most recent fuel charge adjustment proceeding, Docket No. E-7, Sub 1190. He noted that as the Company has shifted to a fuel commodity with greater price variances, compared to nuclear and coal, customers are exposed to greater risk of under- and over-recoveries. The Company's natural gas consumption, combined with recent winter weather events, has caused exposure to higher than anticipated natural gas fuel commodity prices. To address this concern, witness Metz noted that the Commission required DEC to evaluate historic price fluctuations and whether its current method of forecasting and hedging programs should be adjusted to mitigate the risk of significant under-recovery of fuel costs and report on the results of that evaluation in the DEC's next fuel proceeding. Witness Metz recommended that DEP should be required to undertake the same evaluation and report the results to the Commission in its next fuel proceeding. (The Commission notes that DEP effectively agreed to witness Metz's recommendation in its Finding of Fact No. 21 in its proposed order filed in this proceeding.)

In its post-hearing brief, Sierra Club contended that DEP's current data collection and reporting practices make it impossible to evaluate whether DEP's natural gas costs have been reasonably and prudently incurred. According to Sierra Club, without access to hourly or daily information concerning DEP's generation fleet gas burn, pipeline capacity, or potential to release unused capacity, an evaluation and determination cannot be made as to whether DEP's fixed gas capacity costs have been reasonably and prudently incurred, and whether DEP is over-reliant on fixed capacity. Sierra Club recommended that: 1) DEP should be required to track and report its gas pipeline utilization on an hourly and daily basis, 2) DEP should be required to present evidence in its next fuel case regarding whether or not opportunities exist to monetize unused gas capacity, and 3) the Commission should examine to what extent DEP's reliance on firm capacity constitutes reasonable and prudent costs where that capacity is consistently and dramatically underutilized.

With respect to Sierra Club recommendations, the Commission concludes that Sierra Club has not presented sufficient evidence to justify an investigation into DEP's pipeline capacity utilization practices. DEP witness Phipps responded to Sierra Club's questions on cross-examination with testimony about DEP's Asset Management Agreement with DEC, and DEP's need for reliable pipeline capacity in order to ensure an adequate supply of natural gas to its generating plants. Tr. Vil. 1, pp. 77-81. Sierra Club did not present any material evidence that DEP is incurring unreasonable pipeline capacity costs or is over-reliant on fixed pipeline capacity. With regard to Sierra Club's request that DEP be required to track and report its gas pipeline utilization on an hourly and daily basis, N.C. Gen. Stat. § 62-133.2(c) and Rule R8-55 are very specific as to the information required of DEP for purposes of the Commission's review of its fuel costs. The Commission is not persuaded that it should add to those requirements the hourly and daily tracking of gas pipeline utilization without some evidence of the cost of compiling such information, or that such information would be useful, which evidence Sierra Club did not present.

Based upon the record, the Commission finds and concludes that the Company's fuel and reagent procurement and power purchasing practices were reasonable and prudent during the test period. However, given the Company's increased reliance on natural gas and the resulting increased risk of under-recoveries if natural gas prices are not forecasted accurately as possible, the Company should evaluate historic price fluctuations and whether its current method of forecasting and hedging programs should be adjusted to mitigate the risk of significant under-recovery of fuel costs. The Company shall report the results of this evaluation in its next fuel proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 25

The evidence supporting this finding of fact is contained in the testimony and exhibits of Company witness Harrington.

According to the exhibits filed by Company witness Harrington, the test period per book system sales were 62,568,164 MWh, and test period per book system generation and purchased power amounted to 70,945,428 MWh (net of auxiliary use). The test period per book system generation and purchased power are categorized as follows (Harrington Exhibit 6):

Net Generation Type	System MWh Generated
Coal	8,081,365
Natural Gas, Oil, and Biomass	23,239,469
Nuclear	27,748,149
Hydro – Conventional	848,406
Solar	227,472
Purchased Power – subject to economic dispatch or curtailment	5,601,750
Other Purchased Power	5,198,817
Total Net Generation (may not add to sum due to round	70,945,428

The evidence presented regarding the operation and performance of the Company's generation facilities is discussed in the Evidence and Conclusions for Finding of Fact No. 5.

No party contested witness Harrington's exhibits setting forth per books system sales, generation by fuel type, and purchased power. Therefore, based on the evidence presented and noting the absence of evidence presented to the contrary, the Commission concludes that the per books levels of test period system sales of 62,568,164 MWh and system generation and purchased power of 70,945,428 MWh are reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 26

The evidence supporting this finding of fact is contained in the testimony and exhibits of Company witness Harrington and supported in the testimony of Public Staff witness Li.

On her Exhibit 4, Company witness Harrington set forth the test year per books North Carolina retail sales, adjusted for weather and customer growth, of 37,693,746 MWh, comprised of Residential class sales of 16,022,203 MWh, Small General Service sales of 1,941,728 MWh, Medium General Service sales of 11,007,307 MWh, Large General Service sales 8,368,542 MWh, and Lighting class sales of 353,965 MWh.

Based on the evidence presented by the Company, the Public Staff's acceptance of the amounts presented by the Company, and the absence of evidence presented to the contrary, the Commission concludes that the projected North Carolina retail levels of sales set forth in the Company's exhibits, normalized for customer growth and weather, are reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 27

The evidence supporting this finding of fact is contained in the testimony and exhibits of Company witness Henderson and the testimony of Public Staff witness Metz.

Commission Rule R8-55(d)(1) provides that capacity factors for nuclear production facilities will be normalized based generally on the national average for nuclear production facilities as reflected in the most recent NERC Generating Availability Report, adjusted to reflect the unique, inherent characteristics of the utility's facilities and any unusual events. The Company proposed using a 94.62% capacity factor in this proceeding based on the operational history of the Company's nuclear units, and the number of planned outage days scheduled during the 2019-2020 billing period. This proposed capacity factor exceeds the five-year industry weighted average capacity factor of 91.80% for the period 2013-2017 for average comparable units on a capacity-rated basis, as reported by NERC in its latest Generating Availability Report. Public Staff witness Metz did not dispute the Company's proposed use of a 94.62% capacity factor.

Based upon the requirements of Commission Rule R8-55(d)(1), the historical and reasonably expected performance of the DEP system, and the fact that the Public Staff did not dispute the Company's proposed capacity factor, the Commission concludes that the 94.62% nuclear capacity factor, and its associated generation of 29,713,146 MWh, are reasonable and appropriate for determining the appropriate fuel and fuel-related costs in this proceeding.

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

The evidence supporting these findings of fact is contained in the testimony and exhibits of Company witness Harrington.

Company witness Harrington used projected billing period system sales, generation, and purchased power to calculate the proposed prospective component of the fuel and fuel-related cost rate. The projected system sales level used, as set forth on Harrington Exhibit 2, Schedule 1, is 62,155,919 MWh. The projected level of generation and purchased power used was 71,517,770 MWh (calculated using the 94.62% capacity factor found reasonable and appropriate above), and was broken down by witness Harrington as follows, as set forth on that same schedule:

Generation Type	Projected System MWh Generated
Coal	11,131,286
Gas Combustion Turbine and Combined Cycle	22,185,181
Nuclear	29,713,146
Hydro	648,112
Solar	279,675
Purchased Power	7,560,370
Total add to um due to rounding)	71,517,770

As part of her Workpaper 8, Company witness Harrington also presented an estimate of the projected billing period North Carolina retail Residential, Small General Service, Medium General Service, Large General Service, and Lighting MWh sales. The Company estimates billing period North Carolina retail MWh sales to be as follows:

N.C. Retail Customer Class	Projected NC Retail MWh Sales
Residential	16,265,079
Small General Service	1,806,876
Medium General Service	10,414,506
Large General Service	9,223,825
Lighting	381,171
Total (may not add to sum due to rounding)	38,091,457

These class totals were used in Harrington Exhibit 2, Schedule 1, Page 2 of 3 and Revised Harrington Exhibit 2, Schedule 1, Page 3 of 3, in calculating the total fuel and fuel-related cost factors by customer class.

Based on the evidence presented by the Company and the absence of evidence presented to the contrary, the Commission concludes that the projected levels of generation and purchased power set forth in the Company's exhibits, are reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 30 – 31

The evidence supporting these findings of fact is contained in the testimony and exhibits of Company witness Harrington and the testimony of Public Staff witnesses Lucas, Metz and Li.

Company witness Harrington recommended fuel and fuel-related prices and expenses, for purposes of determining projected system fuel expense, as follows:

A. The coal fuel price is $31.35/MWh.
B. The gas CC and CT fuel price is $26.68/MWh.
C. The appropriate expense for ammonia, lime, limestone, urea, dibasic acid, sorbents, and catalysts consumed in reducing or treating emissions (collectively, Reagents) is $26,265,057.
D. The total nuclear fuel price is $6.17/MWh.
E. The total system purchased power cost (including the impact of Joint Dispatch Agreement (JDA) Savings Shared and the impact of House Bill 589, N.C. Sess. L. 2017-192, is $442,407,406.
F. System fuel expense recovered through intersystem sales is $161,032,005.

These amounts are set forth on or derived from Revised Harrington Exhibit 2, Schedule 1. The total adjusted system fuel and fuel-related expense, based in part on the use of these amounts, is utilized to calculate the prospective fuel and fuel-related cost factors recommended by the Company. According to Revised Harrington Exhibit 2, Schedule 1, the projected fuel and fuel-related costs for the North Carolina retail jurisdiction for use in this proceeding are $883,391,685.

Public Staff witness Metz concluded that the projected fuel and reagent costs are reasonable and were calculated appropriately with the exception of CTG-related costs. Similarly, Public Staff witness Li stated that, based on the testimony and recommendation of Public Staff witness Lucas, she recommended removing North Carolina's retail share of the projected cash payments to be made on the liquidated damages from the projected billing period costs. After removal, Li Exhibit 1, Schedule 2, shows a projected N.C. retail jurisdiction fuel cost of $878,210,565.

Aside from the Company and the Public Staff, no other party presented testimony contesting the Company's projected fuel and fuel-related costs for the North Carolina retail jurisdiction. Based upon the evidence in the record and the Commission's conclusions with respect to the CTG liquidated damages, the Commission concludes that the Company's projected total fuel and fuel-related cost for the North Carolina retail jurisdiction of $878,210,565 is reasonable.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 32

The evidence supporting these findings of fact is contained in the testimony and exhibits of Company witness Harrington.

Company witness Harrington calculated the Company's proposed fuel and fuel-related cost factors for which there is no specific guidance in N.C. Gen. Stat. § 62-133.2(a2) using a uniform bill adjustment method. She stated that DEP proposes to use the same uniform percentage average bill adjustment methodology to adjust its fuel rates to reflect a proposed decrease in fuel and fuel-related costs as it did in the prior year fuel and fuel-related cost recovery proceeding in Docket No. E-2, Sub 1173. No party opposed the use of this allocation method.

Based on the evidence presented by the Company and the absence of evidence presented to the contrary, the Commission concludes it appropriate to allocate fuel and fuel-related costs, with the exception of capacity-related purchased power costs, among customer classes using the uniform percentage average bill adjustment methodology as adopted in DEP's 2018 fuel and fuel-related cost recovery proceeding under Docket No. E-2, Sub 1173.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 33

The evidence supporting this finding of fact is contained in the supplemental direct testimony and exhibits of Company witness Harrington and the testimony of Public Staff witness Metz.

Based on the NC retail share of projected billing period costs as presented by the Company and discussed in the Evidence and Conclusions for Finding of Fact No. 28, and the NC projected retail sales for the billing period as presented by the Company and discussed in the Evidence and Conclusions for Finding of Fact No. 26, the Company proposed the following increment/(decrement) prospective fuel and fuel-related cost factors by customer class, excluding regulatory fees:

N.C. Retail Customer Class	DEP Proposed in ¢/kWh
Residential	2.344
Small General Service	2.527
Medium General Service	2.468
Large General Service	2.056
Lighting	2.281

In his testimony, Public Staff witness Metz stated that, based on his investigation, the projected fuel and reagent costs are reasonable and were calculated appropriately with the exception of CTG lawsuit-related costs. Therefore, witness Metz proposed the following increment/(decrement) prospective fuel and fuel-related cost factors by customer class, excluding regulatory fees:

N.C. Retail Customer Class	Public Staff Proposed in ¢/kWh
Residential	2.326
Small General Service	2.499
Medium General Service	2.456
Large General Service	2.054
Lighting	2.217

The Commission concludes that the proposed increment/(decrement) prospective fuel and fuel-related cost factors set forth by Public Staff witness Metz are reasonable and appropriate for purposes of setting DEP's interim fuel cost rates in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 34

The evidence supporting this finding of fact is contained in the supplemental direct testimony and exhibits of Company witness Harrington and Public Staff witness Lucas and the testimony of Public Staff witness Li and Metz.

Based on the Company's updated under-recovery through the period ending June 30, 2019 as presented by the Company and discussed in the Evidence and Conclusions for Finding of Fact No. 6, and the North Carolina retail test period sales, normalized for customer growth and weather, as discussed in the Evidence and Conclusions for Finding of Fact No.26, the Company proposed the following EMF increment/(decrement) riders by customer class, excluding regulatory fees:

N.C. Retail Customer Class	DEP Proposed in ¢/kWh
Residential	0.394
Small General Service	0.217
Medium General Service	0.236
Large General Service	0.666
Lighting	0.548

In her testimony, Public Staff witness Jenny X. Li stated that, based on the testimony and recommendation of Public Staff witness Lucas, she recommended removing North Carolina's retail share of the cash payments made on the liquidated damages from test period costs. Therefore, witnesses Li and Metz proposed the following EMF increment/(decrement) riders by customer class, excluding regulatory fees:

N.C. Retail Customer Class	Public Staff Proposed in ¢/kWh
Residential	0.373
Small General Service	0.198
Medium General Service	0.218
Large General Service	0.648
Lighting	0.530

The Commission concludes that the proposed EMF increment/(decrement) riders set forth by Public Staff witness Li are reasonable and appropriate for purposes of setting DEP's interim fuel cost rates in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 35

The evidence supporting this Finding of Fact is contained in the direct testimony and exhibits of Company witness Harrington.

Company witness Harrington testified that the coal inventory rider established in Ordering Paragraph 12 of the Commission's February 23, 2018 Order Accepting Stipulation, Deciding Contested Issue and Granting Partial Rate Increase in Docket No. E-2, Sub 1142 expired in October 2018 and was removed from billed rates on December 1, 2018, and that amounts collected through January 2019 further reduced the under-collected balance. Witness Harrington further testified that interest has been calculated on the under-collected balance through November 30, 2019 yielding the total under-collection as of $257,250, which will be recovered over a 12-month period expiring on and after November 30, 2020. This amount is included in EMF balances previously addressed and quantified.

Based on the evidence presented by DEP, and noting the absence of evidence presented to the contrary by any other party, the Commission finds and concludes that including the coal inventory rider under-collected balance in the Company's fuel EMF rider rates is reasonable.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 36

Accordingly, the overall fuel and fuel-related cost calculation, incorporating the conclusions reached herein, results in net fuel and fuel-related interim cost factors of 2.699¢/kWh for the Residential class, 2.697¢/kWh for the Small General Service class, 2.674¢/kWh for the Medium General Service class, 2.702¢/kWh for the Large General Service class, and 2.747¢/kWh for the Lighting class, consisting of the prospective fuel and fuel-related cost increments/(decrements) of 2.326¢/kWh, 2.499¢/kWh, 2.456¢/kWh, 2.054¢/kWh, and 2.217¢/kWh, for the classes respectively, and EMF riders of 0.373¢/kWh, 0.198¢/kWh.

0.218¢/kWh, 0.648¢/kWh and 0.530¢/KWh, for the classes respectively, all excluding the regulatory fee.

IT IS, THEREFORE, ORDERED as follows:

1. That, effective for service rendered on and after December 1, 2019, and pending further orders by the Commission, DEP shall adjust the base fuel and fuel-related cost factors in its North Carolina retail rates, as approved in Docket No. E-2, Sub 1142, amounting to 1.993¢/kWh for the Residential class, 2.088¢/kWh for the Small General Service class, 2.431¢/kWh for the Medium General Service class, 2.253¢/kWh for the Large General Service class, and 0.596¢/kWh for the Lighting class (all excluding the regulatory fee), by amounts equal to 0.333¢/kWh, 0.411¢/kWh, 0.025¢/kWh, (0.199)¢/kWh, and 1.621¢/kWh, respectively, and further, that DEP shall adjust the resulting approved prospective fuel and fuel-related cost factors by EMF increments/(decrements) of 0.373¢/kWh for the Residential class, 0.198¢/kWh for the Small General Service class, 0.218¢/kWh for the Medium General Service class, 0.648¢/kWh for the Large General Service class, and 0.530¢/kWh for the Lighting class (all excluding the regulatory fee). The EMF increments/(decrements) are to remain in effect for service rendered through November 30, 2020, or until the Commission issues a further order in this matter. DEP shall adjust the billing factors to include and collect the regulatory fee;

2. That DEP shall file appropriate rate schedules and riders with the Commission in order to implement these approved rate adjustments no later than 10 days from the date of this Order;

3. That DEP shall work with the Public Staff to jointly prepare a proposed notice to customers of the rate adjustments ordered by the Commission in Docket Nos. E-2, Subs 1204, 1205, and 1207 and the Company shall file the proposed notice to customers for Commission approval as soon as practicable;

4. That DEP shall evaluate historic price fluctuations and whether its current method of forecasting and hedging programs should be adjusted to mitigate the risk of significant under-recovery of fuel costs and report the results of that evaluation in the Company's next fuel proceeding;

5. That on or before January 17, 2020, the Public Staff shall conduct an analysis of the prudence and reasonableness of DEP's decisions and actions in connection with the Gypsum Supply Agreement and shall file testimony explaining its analysis and stating its opinion as to the prudence and reasonableness of DEP's decisions and actions in connection with the Gypsum Supply Agreement;

6. That on or before February 17, 2020, DEP may file rebuttal testimony in response to the Public Staff's testimony; and

7. That on Tuesday, March 10, 2020, at 10:00 a.m., the Commission will hold an expert witness hearing in this docket in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina to consider further the matters arising from the Gypsum Supply Agreement and whether as a result of such matters an adjustment should be made to the interim rates and schedules established pursuant to this Order.

ISSUED BY ORDER OF THE COMMISSION.
This the 25th day of November, 2019.

NORTH CAROLINA UTILITIES COMMISSION
Kimberly A. Campbell, Chief Clerk

DOCKET NO. E-2, SUB 1205

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of: Application of Duke Energy Progress, LLC for Approval of Renewable Energy and Energy Efficiency Portfolio Standard (REPS) Compliance Report and Cost Recovery Rider Pursuant to N.C.G.S. 62-133.8 and Commission Rule R8-67	))))))	ORDER APPROVING REPS AND REPS EMF RIDERS AND 2018 REPS COMPLIANCE REPORT

HEARD: Monday, September 9, 2019 at 2:00 p.m. in the Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Commissioner Daniel E. Clodfelter, Presiding; Chair Charlotte A. Mitchell, Commissioner ToNola D. Brown-Bland, Commissioner Lyons Gray

APPEARANCES:

For Duke Energy Progress, LLC:

Kendrick C. Fentress, Associate General Counsel, Duke Energy Corporation, 410 South Wilmington Street, NCRH 20/P.O. Box 1551, Raleigh, North Carolina 27602

Robert W. Kaylor, Law Office of Robert W. Kaylor, P.A., 353 E. Six Forks Road, Suite 260, Raleigh, North Carolina 27609

For Carolina Utility Customers Association, Inc.:

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

For North Carolina Sustainable Energy Association:

Peter Ledford, General Counsel, North Carolina Sustainable Energy Association, 4800 Six Forks Road, Suite 300, Raleigh, North Carolina 27609

Benjamin Smith, Regulatory Counsel, North Carolina Sustainable Energy Association, 4800 Six Forks Road, Suite 300, Raleigh, North Carolina 27609

For the Using and Consuming Public:

Tim R. Dodge, Staff Attorney, Public Staff, North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4300

Heather Fennell, Staff Attorney, Public Staff, North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4300

BY THE COMMISSION: On June 11, 2019, Duke Energy Progress, LLC (DEP or the Company) filed its 2018 Renewable Energy and Energy Efficiency Portfolio Standard (REPS) Compliance Report and an application seeking an adjustment to its North Carolina retail rates and charges pursuant to N.C.G.S. § 62-133.8(h) and Commission Rule R8-67, which require the Commission to conduct an annual proceeding for the purpose of determining whether a rider should be established to permit the recovery of the incremental costs incurred to comply with the requirements of the REPS, N.C.G.S. §§ 62-133.8(b), (d), (e) and (f), and to true up any under-recovery or over-recovery of compliance costs. DEP's application was accompanied by the testimony and exhibits of Travis E. Payne, Business Development Manager, and Veronica I. Williams, Rates and Regulatory Strategy Manager. In its application and pre-filed testimony, DEP sought approval of its proposed REPS rider, which incorporated the Company's proposed adjustments to its North Carolina retail rates.

On June 21, 2019, the Commission issued an Order setting this matter for hearing; establishing deadlines for the submission of intervention petitions, intervenor testimony, and DEP rebuttal testimony; requiring the provision of appropriate public notice; and mandating compliance with certain discovery guidelines.

The North Carolina Sustainable Energy Association (NCSEA) and the Carolina Utility Customers Association, Inc., filed separate petitions to intervene in this docket, and the interventions were allowed by the Commission. The intervention and participation by the Public Staff are recognized pursuant to N.C.G.S. § 62-15(d) and Commission Rule R1-19(e).

On July 16, 2019, DEP filed supplemental testimony and revised exhibits of witnesses Payne and Williams, along with a proposed public notice reflecting the revised rates.

On August 19, 2019, the Public Staff filed the affidavits and exhibits of Evan B. Lawrence, Utilities Engineer in the Electric Division, and Michelle M. Boswell, Staff Accountant in the Accounting Division.

On August 27, 2019, DEP filed additional supplemental testimony and a 2nd Revised Exhibit No. 4 of witness Williams and the Rebuttal Testimony of witness Payne.

On August 30, 2019, DEP filed a motion for witnesses to be excused from the evidentiary hearing, which was allowed by the Commission.

On September 6 and 10, 2019, DEP filed affidavits of publication demonstrating that the notice of the public hearing was published as required by the Commission's Orders issued in this proceeding.

This matter came on for hearing on September 9, 2019. DEP presented the testimony and exhibits of witnesses Payne and Williams, and the Public Staff presented the affidavits of witnesses Boswell and Lawrence. All pre-filed testimony, exhibits, and affidavits from DEP and Public Staff witnesses were received into evidence.

Based upon the foregoing, including the testimony, exhibits, and affidavits of the parties' witnesses, the records in the North Carolina Renewable Energy Tracking System (NC-RETS), and the entire record in this proceeding, the Commission now makes the following:

FINDINGS OF FACT

1. DEP is a duly organized limited liability company existing under the laws of the State of North Carolina, is engaged in the business of developing, generating, transmitting, distributing, and selling electric power to the public in North Carolina, and is subject to the jurisdiction of the North Carolina Utilities Commission as a public utility. DEP is lawfully before this Commission based upon its application filed pursuant to N.C.G.S. § 62-133.8 and Commission Rule R8-67.

2. For calendar year 2018, the Company was required to meet at least 10% of its previous year's North Carolina retail electric sales by a combination of renewable energy and energy reductions due to the implementation of energy efficiency measures. Also in 2018, energy in the amount of at least 0.20% of the previous year's total electric power sold by DEP to its North Carolina retail customers must be supplied by solar energy resources.

3. Beginning in 2012, N.C.G.S. § 62-133.8(e) and (f) require DEP and the other electric suppliers of North Carolina, in the aggregate, to procure a certain portion of their renewable energy requirements from electricity generated from swine and poultry waste, with the poultry waste requirement being based on each electric power supplier's respective pro-rata share derived from the ratio of its North Carolina retail sales as compared to total state-wide North

Carolina retail sales. In its Order Modifying the Swine and Poultry Waste Set-Aside Requirements and Providing Other Relief, issued on October 8, 2018, in Docket No. E-100, Sub 113 (2018 Delay Order), the Commission modified the 2018 Swine Waste Set-Aside requirement for public utilities to require that the public utilities supply 0.02% of their prior year North Carolina retail sales from swine-waste resources, and delayed for one year the scheduled increases in the swine-waste requirements. In addition, the 2018 Delay Order modified the 2018 state-wide poultry waste set-aside requirement to 300,000 MWh, and delayed the subsequent scheduled increases by one year.

4. DEP complied with the 2018 solar set-aside requirements by submitting for retirement 73,660 renewable energy certificates (RECs) procured or generated from solar electric facilities and metered solar thermal energy facilities. DEP also complied with the 2018 poultry waste set-aside requirements by submitting for retirement 66,987 poultry waste RECs and 8,789 Senate Bill 886 RECs, which are credited as 17,578 poultry waste RECs pursuant to S.L. 2010-195 (Senate Bill 886), for a total of 84,565 poultry waste RECs. The Company also complied with the modified 2018 Swine Waste Set-Aside requirement by submitting for retirement 7,366 swine waste RECs. Finally, DEP submitted for retirement 3,517,399 general requirement RECs, representing the Company's total 2018 compliance requirement, net of the set-aside requirements detailed above.

5. DEP met its total 2018 REPS obligations, except for those from which it has been relieved under the Commission's Orders issued in Docket No. E-100, Sub 113.

6. At the time of the original filing, DEP noted that current projections indicated it would not be able to acquire enough RECs to comply with its swine waste requirement for compliance year 2019, and compliance with its poultry waste requirement beyond 2019 is dependent on supplier performance on current contracts as well as new facilities expected to come on line beginning in 2019. On September 23, 2019 (after the September 9 hearing date in this REPS docket), DEP and other North Carolina electric power suppliers filed a joint motion to modify and delay the 2019 requirements of N.C.G.S. § 62-133.8(e) and (f) in response to a lack of sufficient swine and poultry waste resources.

7. DEP's REC inventory available for future use appropriately includes RECs generated from net metering customers receiving electric service under schedules other than time-of-use schedules with demand rates (NMNTD customers).

8. DEP's other incremental REPS compliance costs and its Solar Rebate Program costs are recoverable under N.C.G.S. § 62-133.8(h)(1)(a) and N.C.G.S. § 62-133.8(h)(1)(d), respectively, and should be approved for this proceeding.

9. The research activities funded by DEP during the test period are within the $1 million annual limit established pursuant to N.C.G.S. § 62-133.8(h)(1)(b).

10. For purposes of DEP's annual rider pursuant to N.C.G.S. § 62-133.8(h), the test period for this proceeding is the twelve-month period beginning April 1, 2018 and ending March 31, 2019 (Test Period). The billing period for this proceeding is the 12-month period beginning December 1, 2019 and ending November 30, 2020 (Billing Period).

11. For purposes of establishing the REPS experience modification factor (EMF) rider in this proceeding, DEP's incremental costs for REPS compliance during the Test Period were \$37,201,361. The Company's projected incremental costs for REPS compliance for the Billing Period total \$43,246,220.

12. Pursuant to N.C.G.S. § 62-133.8(h) electric power suppliers are authorized to recover the "incremental costs" of compliance with the REPS requirement through an annual REPS rider. The "incremental costs," as defined in N.C.G.S. § 62-133.8(h)(1), include the reasonable and prudent costs of compliance with REPS "that are in excess of the electric supplier's avoided costs other than those costs recovered pursuant to N.C.G.S. § 62-133.9." The term "avoided costs" includes both avoided energy costs and avoided capacity costs.

13. Under Commission Rule R8-67(e)(2), the total costs reasonably and prudently incurred during the test period to purchase unbundled renewable energy certificates (RECs) constitute incremental costs. The projected costs to purchase such RECs during the billing period constitute forecasted incremental costs.

14. DEP appropriately calculated its avoided costs and incremental REPS compliance costs for the Test Period and Billing Period.

15. DEP's Test Period REPS expense under-collection was \$1,288,029 for the residential class. DEP's Test Period REPS expense over-collections, including interest, were \$(1,087,606) for the general service class and \$(55,585) for the industrial class. In addition, the Company credited to customers amounts received from REC suppliers during the Test Period related to contract amendments, penalties, and other conditions of the supply agreements. Contract-related receipts credited to each customer class are \$(388,096) for residential, \$(348,680) for general service, and \$(21,224) for industrial. Total net Test Period cost, including an offsetting credit amount for contract-related receipts, is \$899,933 for the residential class. Total net Test Period credits, including credits for contract-related receipts, for the general service and industrial classes are \$(1,436,286) and \$(76,809), respectively. The foregoing amounts exclude the North Carolina regulatory fee (regulatory fee).

16. DEP's North Carolina prospective Billing Period expenses for use in this proceeding are \$20,578,687, \$21,309,868, and \$1,357,665, for the residential, general service, and industrial classes, respectively, excluding the regulatory fee.

17. The appropriate monthly REPS EMF riders, excluding the regulatory fee, to be charged to / (credited to) customer accounts during the upcoming billing period are \$0.06 per month for residential accounts, \$(0.60) per month for general service accounts, and \$(3.57) per month for industrial accounts.

18. The appropriate prospective REPS riders per customer account, excluding the regulatory fee, to be collected each month during the billing period are $1.39 for residential accounts, $8.84 for general service accounts, and $63.07 for industrial accounts.

19. The combined REPS and REPS EMF rider charges per customer account, excluding the regulatory fee, to be collected each month during the Billing Period are $1.45 for residential accounts, $8.24 for general service accounts, and $59.50 for industrial accounts. Including the regulatory fee, the combined monthly REPS and REPS EMF rider charges per customer account to be collected during the Billing Period are $1.45 for residential accounts, $8.25 for general service accounts, and $59.58 for industrial accounts.

20. DEP's REPS incremental cost rider, including the regulatory fee, to be charged to each customer account for the twelve-month Billing Period is within the annual cost cap established for each customer class in N.C.G.S. § 62-133.8(h)(4).

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-3

These findings of fact are essentially informational, jurisdictional, and procedural in nature and are not contested.

Section 62-133.8(b)(1) establishes a REPS requirement for all electric power suppliers in the State. The statute requires each electric public utility to provide a certain percentage of its North Carolina retail sales from various renewable energy or energy efficiency resources, including the following: (a) generating electric power at a new renewable energy facility; (b) using a renewable energy resource to generate electric power at a generating facility other than the generation of electric power from waste heat derived from the combustion of fossil fuel; (c) reducing energy consumption through the implementation of energy efficiency measures; (d) purchasing electric power from a new renewable energy facility; (e) purchasing RECs; (f) using electric power that is supplied by a new renewable energy facility or saved due to the implementation of an energy efficiency measure that exceeds the requirements of the REPS in any calendar year as a credit toward the requirements of the REPS in the following calendar year; or (g) electricity demand reduction. Each of these measures is subject to additional limitations and conditions. For 2018, DEP must meet a total REPS requirement of 10% of its previous year's North Carolina retail electric sales by a combination of these measures.

Section 62-133.8(d) requires a certain percentage of the total electric power sold to retail electric customers in the State, or an equivalent amount of energy, to be supplied by a combination of new solar electric facilities and new metered solar thermal energy facilities. The percentage requirement for solar resources in 2018 is 0.20%.

Sections 62-133.8(e) and (f) require DEP and the other electric suppliers of North Carolina, in the aggregate, to procure a certain portion of their renewable energy requirements from electricity generated from swine and poultry waste, . The swine waste energy requirement is based on a percentage of retail sales, similar to the solar energy requirement. The poultry waste energy requirement is based on each electric power supplier's respective pro-rata share derived from the ratio of its North Carolina retail sales as compared to the total North Carolina retail sales. Pursuant to the Commission's Order on Pro-Rata Allocation of Aggregate Swine and Poultry Waste Set-Aside Requirements and Motion for Clarification, issued on March 31, 2010, in Docket No. E-100, Sub 113, DEP's share of the aggregate State set-aside requirements for energy from swine and poultry waste is based on the ratio of its North Carolina retail kilowatt-hour sales for the previous year divided by the previous year's total North Carolina retail kilowatt-hour sales. In its 2018 Delay Order, the Commission modified the 2018 Swine Waste Set-Aside requirement to be applicable to electric public utilities only, set the requirement at 0.02% of North Carolina retail sales, and delayed for one year the scheduled increases in the requirement. In addition, the 2018 Delay Order also modified the 2018 state-wide Poultry Waste Set-Aside requirement to 300,000 MWh, and delayed by one year the scheduled increases in the requirement.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 4-6

The evidence supporting these findings of fact is found in the direct testimony and exhibits of DEP witness Payne, including DEP's 2018 REPS compliance report, which was admitted into evidence as Payne Exhibit No.1, as subsequently revised, and the affidavit of Public Staff witness Lawrence. In addition, the Commission takes judicial notice of the information contained in NC-RETS.

Witness Payne testified that DEP complied with the 2018 solar set-aside requirements by submitting for retirement 73,660 RECs procured or generated from solar electric facilities and metered solar thermal energy facilities. DEP also complied with the 2018 Poultry Waste Set-Aside requirement by submitting for retirement 66,987 poultry waste RECs and 8,789 SB 886 RECs (which count as 17,578 poultry waste RECs), for a total of 84,565 poultry waste RECs. Witness Payne further testified that the Company complied with the modified 2018 Swine Waste Set-Aside requirement, applicable only to electric public utilities, by submitting for retirement 7,366 swine waste RECs. Finally, witness Payne's testimony indicated DEP submitted for retirement 3,517,399 general requirement RECs, representing the Company's 2018 total compliance requirement, net of the set-aside requirements detailed above. Accordingly, DEP met its total 2018 REPS obligation of 3,682,990 RECs, as adjusted by previous Commission orders in Docket No. E-100, Sub 113, by submitting for retirement 3,665,412 RECs including 8,789 SB 886 RECs which also counted for an additional 17,578 poultry waste RECs. (T. at pp. 17-18)

The Billing Period for this Application covers two separate compliance reporting periods with different requirements for each period. Witness Payne testified the Company estimates that it will be required to submit for retirement 3,868,727 RECs to meet its total 2019 compliance year requirements of N.C.G.S. § 62-133.8(b). Within this estimated total, the Company expects to be required to retire the following: 77,375 solar RECs, 27,082 swine waste RECs, and 197,319 poultry waste RECs to meet the requirements set out in N.C.G.S. §§ 62-133.8(d), (e), and (f) respectively. In 2020, the Company estimates that it will be required to submit for retirement 3,796,477 RECs to meet its total requirement. Within this total, the Company projects that it will be required to retire approximately 75,930 solar RECs, 26,576 swine waste RECs, and 253,695 poultry waste RECs to meet the requirements set out in N.C.G.S. §§ 62-133.8(d), (e), and (f) respectively. (T. at p. 18)

Witness Payne testified that DEP met its Solar Set-Aside requirement for the 2018 compliance year by procuring and earning 73,660 solar RECs and that, pursuant to the NC-RETS Operating Procedures, the Company submitted these RECs for retirement by transferring them from the NC-RETS Progress Energy Electric Power Supplier Account to the Progress Energy Compliance Sub-Account. (T. at pp. 23-24)

Witness Payne testified that DEP met its 2018 Poultry Waste Set-Aside requirement of 84,565 RECs. Pursuant to NC-RETS Operating Procedures, the Company submitted for retirement 66,987 poultry RECs and 8,789 SB 886 RECs (which count as 17,578 poultry waste RECs). Accordingly, the equivalent of 84,565 RECs was submitted for retirement by transferring the RECs from the NC-RETS Progress Energy Electric Power Supplier Account to the Progress Energy Compliance Sub-Account. (T. at p. 25)

Witness Payne testified that DEP met the modified 2018 Swine Waste Set-Aside requirement of 0.02%, or 7,366 swine waste RECs. Pursuant to NC-RETS Operating Procedures, the Company submitted these RECs for retirement by transferring them from the NC-RETS Progress Energy Electric Power Supplier Account to the Progress Energy Compliance Sub-Account. (T. at p. 27)

Witness Payne further testified that the Company had complied with its General Requirement for 2018. Pursuant to NC-RETS Operating Procedures, the Company submitted for retirement 3,517,399 RECs to meet the General Requirement (DEP's total requirement, net of the Solar, Swine Waste, and Poultry Waste Set-Aside requirements). Specifically, the RECs to be used for 2018 compliance were transferred from the NC-RETS Progress Energy Electric Power Supplier account to the Progress Energy Compliance Sub-Account. (T. at pp. 18-19)

In his direct testimony, witness Payne testified that DEP expects to comply with its 2019 Poultry Waste Set-Aside requirement, but future compliance is dependent on the performance of poultry waste-to-energy developers on current contracts and new waste-to-energy projects scheduled to come on line, including one scheduled to become operational during 2019. Witness Payne cited delayed projects or lower than expected facility REC production volume, and other facilities that have undergone extended outages to perform repairs, as challenges to meeting increased compliance levels. (T at p. 25) Witness Payne also enumerated in his testimony the numerous actions undertaken by the Company to develop or procure poultry waste REC supplies, including: continuing direct negotiations and executing contracts for new in-state or out-of-state supplies; helping developers identify and overcome operational risks and modifying expected contractual output if applicable; seeking increased REC output from existing facilities by adding poultry waste feedstock or thermal REC production capability; among other efforts. (T. at p. 26)

Regarding expected compliance with near-term future Swine Waste Set-Aside requirements, witness Payne reported that existing contracts have not been able to reach contractual production levels, and new swine waste-to-energy supplier facilities are not achieving operational status in the time frames originally expected. Witness Payne noted facility siting difficulty, swine waste feedstock scarcity, and project financing and operational challenges, as factors inhibiting continuing and new swine REC procurement at levels necessary to meet future Swine Waste Set-Aside requirements. (T at pp. 27-28) The Company has continued to engage in a variety of actions to procure or develop swine waste-to-energy resources to meet its future requirements, including: negotiating and executing contracts for in-state and out-of-state supplies; working extensively with potential suppliers to overcome production risks and/or amend contracts to accommodate changing circumstances; and pursuing new biomass and biogas swine resource options; among other efforts. (T. at pp. 28-29)

Public Staff witness Lawrence recommended that the Commission approve DEP's 2018 REPS Compliance Report. (T. at p. 82) Specifically, he testified that for 2018 compliance, DEP needed to obtain a sufficient number of RECs and energy efficiency certificates (EECs) derived from eligible sources so that the total equaled 10% of the Company's 2017 North Carolina retail electricity sales. Additionally, DEP needed to pursue retirement of sufficient solar RECs to match 0.20% of 2017 retail sales, and sufficient poultry waste RECs to match its pro-rata share of the 300,000 poultry waste RECs required by N.C.G.S. § 62-133.8(f). The number of poultry waste RECs was determined by the Commission in its 2018 Delay Order. The 2018 Delay Order also modified the swine waste requirement under N.C.G.S. § 62-133.8(e) to lower the 2018 compliance requirement to 0.02% of 2017 retail sales for the investor-owned utilities only. (T. at p. 82)

No party disputed that DEP had fully complied with the applicable 2018 REPS requirements, or argued that DEP's REPS compliance report for 2018 should not be approved.

Based upon the foregoing and the entire record herein, the Commission concludes that DEP complied with the REPS requirements for 2018, as modified by the Commission in its 2018 Delay Order, and that DEP's 2018 REPS Compliance Report should be approved. The Commission further concludes that the RECs and EECs in the related NC-RETS compliance sub-account should be permanently retired.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 7

The evidence supporting this finding of fact is found in the testimony of DEP witness Payne.

Witness Payne explained that under the current Net Metering for Renewable Energy Facilities Rider offered by DEP (Rider NM-4B), a customer receiving electric service under a schedule other than a time-of-use schedule with demand rates shall provide any RECs to DEP at no cost. He further stated the Company had complied with the measurement, verification, and reporting requirements set out by the Commission in its June 5, 2018 Order Approving Rider and Granting Waiver Request in Docket Nos. E-2, Sub 1106 and E-7, Sub 1113, and the RECs associated with these net metering facilities are currently in DEP's REC inventory and available for use in meeting future compliance requirements. (T. at pp. 20-21) No party to this proceeding contested this testimony.

Based upon the foregoing and the entire record herein, the Commission finds that the RECs generated by the net metering facilities as described above are appropriately included in DEP's inventory of RECs available for future REPS compliance use.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 8-9

The evidence supporting these findings of fact is found in the testimony and exhibits of DEP witnesses Payne and Williams, as well as in the affidavits of Public Staff witnesses Boswell and Lawrence.

Witness Payne sponsored Confidential Payne Exhibit No. 3 as an exhibit to his testimony, wherein he identified the "Research," "Solar Rebate Program," and "Other Incremental" costs that the Company has incurred or projects to incur in association with REPS compliance. With respect to research costs, Confidential Payne Exhibit No. 3 shows that the research costs are under the $1 million per year cap established in N.C.G.S. § 62-133.8(h)(1)(b). Consistent with the Commission's orders in prior REPS proceedings, witness Payne also provided testimony and exhibits on the results and status of various studies, the costs of which DEP is including for recovery in its incremental REPS cost for the Test Period. (T. at pp. 37-45)

Witness Payne described in his testimony "Other Incremental" costs of REPS compliance as including labor costs associated with REPS compliance activities and non-labor costs associated with administration of REPS compliance. Among the non-labor costs associated with REPS compliance are the Company's subscription to NC-RETS, and accounting and tracking tools related to RECs, reduced prescribed liquidated damages paid by sellers for failure to meet contractual milestones, and amounts received for administrative contractual amendments requested by sellers. (T. at pp. 30-31)

Witness Payne also stated that, pursuant to N.C.G.S. § 62-155(f), each public utility required to offer a solar rebate program:

> [S]hall be authorized to recover all reasonable and prudent costs of incentives provided to customers and program administrative costs by amortizing the total program incentives distributed during a calendar year and administrative costs over a 20-year period, including a return component adjusted for income taxes at the utility's overall weighted average cost of capital established in its most recent general rate case, which shall be included in the costs recoverable by the public utility pursuant to G.S. 62-133.8(h).

N.C.G.S. § 62-133.8(h) provides for an electric power supplier's cost recovery and customer charges under the REPS statute; North Carolina HB 589 amended subsection (h) by adding a provision to allow for the recovery of incremental costs incurred to "provide incentives to customers, including program costs, incurred pursuant to N.C.G.S. § 62-155(f)." Therefore, DEP has included for recovery in this filing costs incurred during the Test Period, and projected to be incurred in the Billing Period, related to the implementation of the Solar Rebate Program. As detailed on Confidential Payne Exhibit No. 3, these costs include the annual amortization of incentives paid to customers and program administration costs, which includes labor, information technology, and marketing costs. (T. a pp. 32)

Research, Other Incremental, and Solar Rebate Program costs included for recovery in the REPS EMF and REPS riders in this proceeding were not contested by any party.

Based upon the foregoing and the entire record herein, the Commission finds that the research activities funded by DEP during the Test Period are renewable research and development costs recoverable under N.C.G.S. § 62-133.8(h)(1)(b) and that such research costs included in the Test Period are within the $1 million annual limit provided in that statute. The Commission also concludes that the Company has complied with the prior Commission orders requiring filing results of such research studies and that DEP should continue to file this information with future REPS compliance reports and to provide procedures for third parties to access the results of studies that are subject to confidentiality agreements. For research projects sponsored by Electric Power Research Institute, DEP should provide the overall program number and specific project number for each project, as well as an internet address or mailing address that will enable third parties to inquire about the terms and conditions for access to any portions of the study results that are proprietary. Finally, the Commission concludes the costs identified as Other Incremental and Solar Rebate Program are recoverable in the REPS EMF and REPS riders calculated in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 10

The evidence supporting this finding is procedural in nature, is found in the testimony of DEP witness Williams and the affidavits of Public Staff witnesses Boswell and Lawrence, and is not contested.

Commission Rule R8-67(e)(3) provides that the test period for REPS rider proceedings shall be the same as that used by the utility in its fuel charge adjustment proceedings, which is specified in Commission Rule R8-55(c) for DEP to be the twelve months ending March 31 of each year. Company witness Williams testified that the Test Period or EMF period used for this proceeding was the twelve months beginning on April 1, 2018 and ending March 31, 2019. (T. at p. 59) Commission Rule R8-67(e)(5) provides that "the REPS EMF rider will reflect the difference between reasonable and prudently incurred incremental costs and the revenues that were actually realized during the test period under the REPS rider then in effect." Witness Williams stated that the rider includes the REPS EMF component to recover the difference between the compliance costs incurred and revenues realized during the Test Period. (T. at p. 61) The costs incurred during the totality of the Test Period are presented in this filing to demonstrate their reasonableness and prudency as provided in Rule R8-67(e). (T. at p. 60) Witness Williams also testified that the Billing Period for the REPS rider requested in the Company's application is the twelve months beginning on December 1, 2019 and ending on November 30, 2020. (T. at p. 59) Witness Williams stated that, in addition to an EMF component, the current proposed rider includes a component to recover the costs expected to be incurred for the Billing Period. (T. at p. 61) The test period and the billing period proposed by DEP were not challenged by any party.

Based on the foregoing, the Commission concludes that, consistent with Commission Rule R8-67(e)(3), the test period for this proceeding is the twelve months from April 1, 2018 through March 31, 2019, and the billing period for this proceeding is the twelve month period beginning December 1, 2019 and ending November 30, 2020.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 11-14

The evidence for these findings of fact is found in DEP's Application and in the testimony and exhibits of DEP witnesses Payne and Williams, as well as in the affidavits of Public Staff witnesses Boswell and Lawrence.

N.C.G.S. § 62-133.8(h)(4) requires the Commission to allow an electric power supplier to recover all of its incremental costs incurred to comply with N.C.G.S. § 62-133.8 though an annual rider. N.C.G.S. § 62-133.8(h)(1) provides that "incremental costs" means all reasonable and prudent costs incurred by an electric power supplier to comply with the REPS requirements that are in excess of the electric power supplier's avoided costs other than those costs recovered pursuant to N.C.G.S. § 62-133.9. The term "avoided costs" includes both avoided energy and avoided capacity costs. Commission Rule R8-67(e)(2) provides that the "cost of an unbundled renewable energy certificate to the extent that it is reasonable and prudently incurred is an incremental cost and has no avoided cost component."

DEP witness Williams testified regarding the calculation of DEP's various incremental costs of compliance with REPS requirements, based on detailed incurred and projected costs provided by witness Payne. (T. at pp. 60-62) Confidential Revised Williams Exhibit No. 1, page 1, identified total incremental REPS compliance costs incurred during the Test Period as $37,201,361, and Confidential Williams Exhibit No. 1, page 2 showed estimated incremental costs for the Billing Period as $43,246,220.

In their affidavits, witnesses Boswell and Lawrence described the Public Staff's investigation and review of the Company's filing, including its evaluation of costs submitted by DEP for recovery in the REPS rider. (T. at pp. 81, 83-84, and 90-91) Pursuant to their review, witnesses Boswell and Lawrence took no issue with incremental REPS costs presented for recovery in this proceeding, and recommended approval of the REPS and REPS EMF components of the riders (excluding the regulatory fee) incorporating these costs, as requested by the Company. (T. at pp. 84, 91)

Witness Lawrence further commented that Confidential Payne Exhibit No. 2 serves to provide detail for actual and forecasted REPS compliance costs, by resource type and individual supplier. The exhibit typically lists a supplier multiple times if, for instance, the supplier provided both thermal and electric RECs of a particular resource type. He noted an example of purchases from one supplier of both thermal and non-thermal poultry RECs being combined on one line on the exhibit, which does not affect the costs included for recovery, but also does not allow for as efficient a review process as practicable. Witness Lawrence stated that the Public Staff recommended a requirement to separately list each REC type on the applicable compliance cost exhibit, in addition to the current breakdown of purchases by resource type and supplier within resource type.

Based upon the foregoing and the entire record herein, the Commission finds that DEP's total incremental costs incurred during the Test Period is $37,201,361, and that DEP's estimated incremental costs for the Billing Period are $43,246,220. The Commission also determines that the Public Staff's recommendation to provide the requested detail on its compliance cost exhibit in future DEP REPS cost recovery proceedings should be accepted.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 15-20

The evidence for these findings of fact is found in DEP's Application and in the direct testimony and exhibits of DEP witnesses Payne and Williams, as well as in the affidavits of Public Staff witnesses Boswell and Lawrence.

Revised Williams Exhibit No. 2, Page 2 shows a Test Period under-collection of $1,288,029 for the residential class, and Test Period over-collections including interest of $(1,087,606) for the general service class and $(55,585) for the industrial class. Second Revised Williams Exhibit No. 4 shows additional credits for contract receipts by customer class of $(388,096) for residential, $(348,680) for general service, and $(21,224) for industrial. The total EMF period under-collection net of contract-related credits for the residential class is $899,933. The EMF period over-collections including interest and contract-related credits are $(1,436,286) for the general service class, and $(76,809) for the industrial class. As reflected on 2nd Revised Williams Exhibit No. 4, witness Williams calculated a monthly per-account REPS EMF charge (excluding regulatory fee) of $0.06 for residential accounts, and monthly per-account REPS EMF credits (excluding regulatory fee) of $(0.60) for general service accounts and $(3.57) for industrial accounts. Also on 2nd Revised Williams Exhibit No. 4, she calculated the projected REPS costs for the Billing Period of $20,578,687 for the residential class, $21,309,868 for the general service class, and $1,357,665 for the industrial class. 2nd Revised Williams Exhibit No. 4 shows that the proposed monthly prospective REPS riders per customer account, excluding the regulatory fee, to be collected during the Billing Period are $1.39 for residential accounts, $8.84 for general service accounts, and $63.07 for industrial accounts. The combined monthly REPS and REPS EMF rider charges per customer account, excluding regulatory fee, to be collected during the Billing Period are $1.45 for residential accounts, $8.24 for general service accounts, and $59.50 for industrial accounts.

In his affidavit, witness Lawrence noted the Commission reduced the utility regulatory fee established in N.C.G.S. § 62-302 by its June 18, 2019 Order Decreasing Regulatory Fee Effective July 1, 2019 in Docket No. M-100, Sub 142, and recommended DEP make a supplemental filing to update Revised Williams Exhibit No. 4 to reflect the current fee. The Company filed additional supplemental testimony of witness Williams and incorporated the updated 0.13% regulatory fee in 2nd Revised Williams Exhibit No. 4. Including the regulatory fee, the combined monthly REPS and REPS EMF rider charges per customer account to be collected during the billing period are $1.45 for residential accounts, $8.25 for general service accounts, and $59.58 for industrial accounts. As further illustrated on 2nd Revised Williams Exhibit No. 4, the Company's REPS incremental cost rider to be charged to each customer account for the twelve-month Billing Period is within the annual cost cap established for each customer class in N.C.G.S. § 62-133.8(h)(4).

Public Staff witness Boswell stated in her affidavit that as a result of its investigation, the Public Staff is recommending annual REPS EMF increment/(decrement) riders of $0.73, $(7.15), and $(42.81), per customer account for DEP's residential, general service, and industrial customers, respectively, excluding the North Carolina regulatory fee. The corresponding monthly rider amounts are $0.06, $(0.60), and $(3.57), per customer account (T. at p. 91)

Public Staff witness Lawrence recommended the Company's proposed prospective monthly REPS rider amounts per customer account, excluding regulatory fee, of $1.39 for residential accounts, $8.84 for general service accounts, and $63.07 for industrial accounts be approved. Combined with the monthly EMF rider amounts recommended by witness Boswell, witness Lawrence recommended approval of the following total monthly REPS charge per customer account, excluding regulatory fee: $1.45 for residential accounts, $8.24 for general service accounts, and $59.50 for industrial accounts. (T. at pp. 83-84)

Public Staff witness Lawrence stated that the Public Staff had reviewed the costs that produced the proposed, revised rates and that it took no issue with them. He recommended approval of the Company's proposed monthly charges per account for the combined REPS and EMF billing components of the REPS riders for the Billing Period, reflecting the updated regulatory fee, as shown on 2nd Revised Williams Exhibit No. 4, as follows: $1.45 for residential accounts, $8.25 for general service accounts, and $59.58 for industrial accounts, all including the regulatory fee. (T. at pp. 83-84)

Based upon the foregoing and the entire record herein, the Commission finds that DEP's calculations of its REPS and REPS EMF riders are appropriate for this proceeding. The Commission further finds that these amounts are below the respective annual per-account cost caps as established in N.C.G.S. § 62-133.8(h)(4). Accordingly, the Commission concludes that the Company's Test Period REPS costs and associated monthly REPS EMF riders, as well as the projected Billing Period REPS costs and the corresponding monthly REPS riders, as set out on 2nd Revised Williams Exhibit No. 4, should be approved.

IT IS, THEREFORE, ORDERED as follows:

1. That DEP shall establish a REPS rider as described herein, in the amounts approved herein, and that this rider shall remain in effect for a twelve-month period beginning on December 1, 2019, and expiring on November 30, 2020;

2. That DEP shall establish an EMF rider as described herein, in the amounts approved herein, and that this rider shall remain in effect for a twelve-month period beginning on December 1, 2019, and expiring on November 30, 2020;

3. That DEP shall file the appropriate rate schedules and riders with the Commission to implement the provisions of this Order as soon as practicable, but not later than ten (10) days after the date that the Commission issues orders in this docket and in Docket Nos. E-2, Sub 1204 and E-2, Sub 1207;

4. That DEP shall work with the Public Staff to prepare a joint notice to customers of the rate changes ordered by the Commission in this docket, as well as in Docket Nos. E-2, Sub 1204 and E-2, Sub 1207, and the Company shall file such notice for Commission approval as soon as practicable, but not later than ten (10) days after the Commission issues orders in all three dockets;

5. That DEP's 2018 REPS compliance report shall be, and is hereby, approved and the RECs in DEP's 2018 compliance sub-accounts in NC-RETS;

6. That DEP shall file in all future REPS rider applications the results of studies the costs of which were or are proposed to be recovered via its REPS EMF and rider and, for those studies that are subject to confidentiality agreements, information regarding whether and how parties can access the results of those studies; and

7. That DEP shall continue to file a worksheet explaining the discrete costs it includes as "other incremental costs" in all future REPS Rider proceedings. DEP shall also include detail on its primary compliance cost exhibit of its renewable energy and REC purchases by REC type (e.g., thermal. electric), in addition to the established resource type and supplier breakdown.

ISSUED BY ORDER OF THE COMMISSION.
This the 19th day of November, 2019.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

DOCKET NO. E-2, SUB 1207

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of:		
Application by Duke Energy Progress, LLC	)	
for Approval of Joint Agency Asset Rider for	)	
Recovery of Costs Related to Facilities	)	ORDER APPROVING JOINT
Purchased from Joint Power Agency	)	AGENCY ASSET RIDER
Pursuant to N.C. Gen. Stat. § 62-133.14	)	ADJUSTMENT
and Rule R8-70	)	

HEARD: Tuesday, September 9, 2019 at 2:00 p.m. in the Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Chair Charlotte A. Mitchell, Presiding; Commissioner ToNola D. Brown-Bland, Commissioner Lyons Gray and Commissioner Daniel G. Clodfelter

APPEARANCES:

For Duke Energy Progress, LLC:

Lawrence B. Somers, Deputy General Counsel, Duke Energy Corporation, NCRH 20/Post Office Box 1551, Raleigh, North Carolina 27602-1551

For the Using and Consuming Public:

Heather D. Fennell, Staff Attorney, Public Staff - North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4300

For the Carolina Utility Customers Association, Inc.:

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

For the Carolina Industrial Group for Fair Utility Rates II:

Ralph McDonald, Bailey & Dixon, LLP, Post Office Box 1351, Raleigh, North Carolina 27602

BY THE COMMISSION: On June 11, 2019, Duke Energy Progress, LLC (DEP or the Company) filed its Application for Approval of Joint Agency Asset Rider (JAAR) to recover costs related to facilities purchased from the North Carolina Eastern Municipal Power Agency (NCEMPA) pursuant to N.C. Gen. Stat. § 62-133.14 and Commission Rule R8-70. DEP's application was accompanied by the testimony and exhibits of LaWanda M. Jiggetts – Rates and Regulatory Strategy Manager. In its application and pre-filed testimony, DEP sought approval of the proposed rider, which incorporated the Company's proposed adjustments in its North Carolina retail rates.

On June 24, 2019, the Commission issued an Order Scheduling Hearing, Requiring Filing of Testimony, Establishing Discovery Guidelines, and Requiring Public Notice, in which the Commission set this matter for public witness and expert witness hearings, established discovery guidelines, and provided for public notice of the hearings.

On July 22, 2019, Carolina Utility Customers Association, Inc. (CUCA) filed its petition to intervene. CUCA's petition was granted on July 24, 2019. On August 19, 2019, Carolina Industrial Group for Fair Utility Rates II (CIGFUR II) filed its petition to intervene. The Commission granted the petition on August 20, 2019. The intervention and participation by the Public Staff is recognized pursuant to N.C. Gen. Stat. § 62-15(d) and Commission Rule R1-19(e).

On August 19, 2019, the Public Staff filed the affidavit of Darlene P. Peedin – Manager of the Electric Section of the Accounting Division of the Public Staff.

No other party pre-filed testimony in this docket.

ELECTRIC – RATE SCHEDULES/RIDERS/SERVICE RULES AND REGULATIONS

On August 22, 2019, DEP and the Public Staff filed a Joint Motion to Excuse All Witnesses from appearing at the September 9, 2019 hearing in this proceeding. The Commission granted this motion on August 28, 2019.

On September 6, 2019, DEP filed its affidavits of publication for the public notice.

This matter came on for hearing as scheduled on September 9, 2019. No public witnesses appeared. Because the parties had waived cross-examination of witnesses, the Commission accepted into evidence and into the record the Company's application and the direct testimony and exhibits of DEP witness Jiggetts and the affidavit of Public Staff witness Peedin. No other party presented witnesses.

On October 18, 2019, DEP and the Public Staff filed a Joint Proposed Order.

Based upon the foregoing, DEP's verified application, the testimony, and exhibits received into evidence at the hearing, and the entire record in this proceeding, the Commission makes the following:

FINDINGS OF FACT

1. DEP is a duly organized corporation existing under the laws of the State of North Carolina, engaged in the business of developing, generating, transmitting, distributing, and selling electric power to the public in North Carolina and South Carolina, and is subject to the jurisdiction of the North Carolina Utilities Commission as a public utility. DEP is lawfully before this Commission based upon its Application filed pursuant to N.C. Gen. Stat. § 62-133.14 and Commission Rule R8-70.

2. On July 31, 2015, DEP acquired NCEMPA's undivided ownership interests of 18.33% in the Brunswick Steam Electric Plant (Brunswick Units 1 and 2), 12.94% in Unit No. 4 of the Roxboro Steam Electric Plant (Roxboro Unit 4), 3.77% in the Roxboro Plant Common Facilities, 16.17% in the Mayo Electric Generating Plant (Mayo Unit 1), and 16.17% in the Shearon Harris Nuclear Power Plant (Harris Unit 1) (collectively, Joint Units). On May 12, 2015, the Commission issued an Order Approving Transfer of Certificate and Ownership Interests in Generating Facilities in Docket No. E-2, Sub 1067 and Docket No. E-48, Sub 8, which approved the transfer of NCEMPA's ownership interests in the Joint Units to DEP.

3. Pursuant to N.C. Gen. Stat. § 62-133.14, DEP is allowed to recover the North Carolina retail portion of all reasonable and prudent costs incurred to acquire, operate, and maintain the proportional interest in the generating facilities purchased from NCEMPA. Commission Rule R8-70(c) provides for an annual proceeding to establish the JAAR and requires the electric public utility to submit an application at the same time that it files the fuel proceeding information required by Commission Rule R8-55.

4. Commission Rule R8-70 schedules an annual adjustment hearing for DEP and requires that the Company use a test period of the calendar year that precedes the end of the test period used for purposes of Commission Rule R8-55. The test period covered by the proposed

rates in this proceeding is January 1, 2018 through December 31, 2018. Pursuant to Commission Rule R8-70, each annual filing will provide for the recovery of costs expected to be incurred in the rate period (prospective component), including the levelized annual cost of the plant initially acquired and appropriate annual portions of the cost of other assets acquired (excluding construction work in progress), as well as ongoing annual non-fuel operating costs, reduced by the annual effects of the acquisition on North Carolina retail allocation factors. Commission Rule R8-70(b) provides for an over- or underrecovery component as a Rolling Recovery Factor (Joint Agency Asset RRF) and requires the Company to use deferral accounting and maintain a cumulative balance of costs incurred but not recovered through the JAAR. This cumulative balance will accrue a monthly return as prescribed by the Rule.

5. DEP's proposed rates consist of a prospective component related to the future billing period December 2019 through November 2020 and a Joint Agency Asset RRF component that accomplishes the true-up of costs incurred through the test year ended December 31, 2018.

6. In its application and testimony in this proceeding, DEP requested a total of $152.923 million for the prospective component of its North Carolina retail revenue requirement, for the period December 1, 2019 through November 30, 2020, associated with the acquisition and operating costs of NCEMPA's undivided ownership interest in the Joint Units.

7. The annual levelized costs associated with the acquisition of the Joint Units at the time of purchase were $56.265 million. DEP also requested an additional $8.472 million in annual pre-tax costs associated with the acquisition costs not included in the levelized costs. The acquisition costs underlying these amounts are deemed reasonable and prudent under N.C. Gen. Stat. § 62-133.14(b)(1).

8. DEP requested an additional $15.945 million in annual financing and operating costs relating to estimated capital additions during the rate period. The Commission finds it reasonable for the Company to recover these estimated costs during the rate period, subject to true-up through the Joint Agency Asset RRF.

9. DEP estimates the annual non-fuel operating costs from December 1, 2019 to November 30, 2020 to be $72.026 million. The Commission finds it reasonable for the Company to recover these estimated costs during the rate period, subject to true-up through the Joint Agency Asset RRF.

10. DEP requested $0.214 million for incremental regulatory fees. The Commission finds it reasonable for the Company to recover these estimated costs during the rate period, subject to true-up through the Joint Agency Asset RRF.

11. The prospective annual revenue requirement of $152.923 million resulting from the summing of the amounts set forth in Findings of Fact Nos. 7 through 10 has not been reduced by the annual effects of the acquisition on North Carolina retail allocation factors. This credit is no longer applicable in the JAAR as new North Carolina retail base rates were established effective March 16, 2018, in DEP's general rate case in Docket No. E-2, Sub 1142. North Carolina retail base rates approved in Sub 1142 reflect greater costs being allocated to wholesale customers because the Company is now supplying the entire electric requirements for NCEMPA.

12. In addition to the prospective components, DEP requests to return to ratepayers $33.618 million through the Joint Agency Asset RRF component of its North Carolina retail revenue requirement charged during the period December 1, 2019 through November 30, 2020, related to the overrecovery of financing and non-fuel operating costs experienced through the test year ended December 31, 2018. The Commission finds the actual costs and credits underlying this true-up amount to be reasonable and prudent for purposes of this proceeding, and the return of this amount to be reasonable and appropriate.

13. Under N.C. Gen. Stat. § 62-133.14(b)(5), the prospective components and Joint Agency Asset RRF have been allocated under the customer allocation methodology approved by the Commission in Docket No. E-2, Sub 1142, DEP's general rate case, to produce the following rates by customer class, which rates the Commission finds to be just and reasonable.

Rate Class	Applicable Schedule(s)		Prospective Rate	Rolling Recovery Factor			Combined Rate*
	Non-Demand Rate Class (dollars per kilowatt-hour)						
Residential	RES, R-TOUD, R-TOUE, R-TOU		0.00474	(0.00084)			0.00390
Small General Service	SGS, SGS-TOUE		0.00522	(0.00179)			0.00343
Medium General Service	CH-TOUE, CSE, CSG		0.00415	(0.00162)			0.00253
Seasonal and Intermittent Service	SI		0.00251	(0.00423)			(0.00172)
Traffic Signal Service	TSS, TFS		0.00236	(0.00065)			0.00171
Outdoor Lighting Service	ALS, SLS, SLR, SFLS		-	-			-
	Demand Rate Classes (dollars per kilowatt)						
Medium General Service	MGS, GS-TES, AP-TES, SGS-TOU		1.37	(0.49)			0.88
Large General Service	LGS, LGS-TOU		1.45	(0.08)			1.37

*Incremental Rates, shown above, include North Carolina regulatory fee of 0.14%.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 1

This Finding of Fact is essentially informational, procedural, and jurisdictional in nature and is uncontroverted.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 2-4

The evidence for these Findings of Fact can be found in DEP's application, N.C. Gen. Stat. § 62-133.14, and Commission Rule R8-70.

Under N.C. Gen. Stat. § 62-133.14(a), upon the filing of a petition of an electric public utility and a public hearing, the Commission is required to approve an annual rider to the utility's rates for the North Carolina retail portion of reasonable and prudent costs incurred to acquire, operate and maintain the Joint Units. The acquisition costs shall be deemed reasonable and prudent and shall be levelized over the useful life of the Joint Units at the time of acquisition. Financing costs shall be included and shall be equal to the weighted average cost of capital as authorized in the utility's most recent general rate case.

The utility may recover an estimate of operating costs based on the experience of the test period and the costs projected for operation of the Joint Units for the next twelve months, subject to the filing of an annual adjustment including any under- or overrecovery, any changes necessary to recover costs for the next twelve-month period, or any changes to the cost of capital or customer allocation methodology occurring in a general rate case after the establishment of the initial rider. Commission Rule R8-70(c) requires the Company to propose annual updates to its JAAR in order for the hearing to be held as soon as practicable after the hearing held by the Commission under Rule R8-55.

The Commission concludes that DEP's application is in compliance with N.C. Gen. Stat. § 62-133.14 and Commission Rule R8-70.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 5-7

The evidence for these Findings of Fact can be found in the direct testimony of DEP witness LaWanda M. Jiggetts and in the affidavit of Public Staff witness Darlene P. Peedin.

Witness Jiggetts' exhibits reflect that DEP's annual levelized cost associated with the acquisition price of the Joint Units was $56.265 million. In her direct testimony, witness Jiggetts explained that the Company seeks to recover its acquisition costs, which are the amounts DEP paid to NCEMPA to acquire the proportional ownership interest in the joint agency assets, including the amount paid above the net book value of the facilities. Within this first category of acquisition costs there are also two subgroups: costs for which the recovery is levelized and costs for which the recovery is not levelized. In general terms, the levelized revenue requirement represents recovery of the acquisition cost for the NCEMPA assets, spread evenly over the remaining life of the assets at the time the Joint Units were purchased. Witness Jiggetts also included additional financing and operating costs of $8.472 million associated with assets purchased that were not included as part of the levelized costs. In her direct testimony, witness Jiggetts described these costs as including inventory amounts that are part of the asset acquisition costs, nuclear fuel inventory, dry cask storage, and materials and supplies inventory. Because these assets are not depreciated, the financing costs for these amounts are calculated on the basis of the average investment for the rate period.

Pursuant to N.C. Gen. Stat. § 62-133.14(b)(2), the JAAR shall include financing costs equal to the weighted average cost of capital as authorized by the Commission in the electric public utility's most recent general rate case. Witness Jiggetts' exhibits reflect that the Company computed the debt and equity rate of return and the Company's weighted average net-of-tax cost of capital as authorized by the Commission in DEP's most recent general rate case. The net-of-tax cost of capital incorporates the 2.5% North Carolina state income tax rate that became effective January 1, 2019.

In her affidavit filed with the Commission, Public Staff witness Peedin stated that the Public Staff's investigation included a review of DEP's application, testimony, and exhibits filed in this docket, as well as the JAAR monthly reports. Additionally, the Public Staff's investigation included the review of responses to written data requests. Witness Peedin further testified that the Public Staff performed a limited review of the underlying capital additions and operating costs added to the calculation of the rider in this proceeding and did not perform a full-scale review of the prudence and reasonableness of all such additions or expenses. She testified that Commission Rule R8-70(b)(4) provides that the Commission is to determine the reasonableness and prudence of the cost of capital additions or operating costs incurred related to the acquired plant in a general rate proceeding. She stated, however, that should the Public Staff discover imprudent or unreasonable costs in a JAAR proceeding, it will recommend an adjustment in that proceeding; in that case, it would also recommend that the impact of any disallowance also be reflected in the Company's cost of service in a general rate case. She testified the Public Staff did not find any adjustments that should be made to the calculations of either the prospective or Joint Agency Asset RRF revenue requirements.

Based on the evidence and the record, the Commission concludes that, pursuant to N.C. Gen. Stat. § 62-133.14(b)(1), DEP should be allowed to recover in the annual JAAR the financing and depreciation costs associated with the acquisition costs of the Joint Units on a levelized basis in the amount of $56.265 million annually, and the annual amount of $8.472 million of financing and operating costs associated with acquisition costs that are not levelized. To the extent the costs underlying these amounts are acquisition costs, such costs are deemed reasonable and prudent under N.C. Gen. Stat. § 62-133.14(b)(1). The Commission further finds it reasonable for the Company to recover the remainder of these estimated costs during the rate period, subject to true-up through the Joint Agency Asset RRF.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 8-9

The evidence for these Findings of Fact can be found in DEP's application, the testimony of DEP witness LaWanda M. Jiggetts and the affidavit of Public Staff witness Darlene P. Peedin.

The Company requested annual costs of $15.945 million to be included in the JAAR for financing and operating costs related to estimated capital additions to be incurred during the period December 1, 2019 through November 30, 2020, and an estimated $72.026 million for annual non-fuel operating costs over the period December 1, 2019 to November 30, 2020. Under N.C. Gen. Stat. § 62-133.14(b)(3), the Commission shall include in the rider an estimate of operating costs based on the prior year's experience and the costs projected for the next twelve months, and shall include the annual financing and operating costs for any proportional capital investments in the acquired electric generation facility. Public Staff witness Peedin did not oppose the recovery of these cost components in her affidavit filed in this proceeding, and stated that the Public Staff recommended approval of the Company's proposed JAAR rates. The Commission concludes that it is reasonable for the Company to recover these estimated costs during the rate period, subject to true-up through the Joint Ageney Asset RRF.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 10

The evidence for this Finding of Fact can be found in the testimony of DEP witness LaWanda M. Jiggetts.

Witness Jiggetts' exhibits reflected an increase in DEP's regulatory fee to $0.214 million based on the increase in the estimated JAAR costs for the period December 1, 2019 through November 30, 2020. The Commission concludes that the calculation of the regulatory fee is just and reasonable.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 11

The evidence for this Finding of Fact can be found in DEP's application and the testimony of DEP witness LaWanda M. Jiggetts, as well as the affidavit of Public Staff witness Darlene P. Peedin.

Under N.C. Gen. Stat. § 62-133.14(b)(4), the JAAR shall include adjustments to reflect the North Carolina retail portion of financing and operating costs related to the electric public utility's other used and useful generating facilities owned at the time of the acquisitions to properly account for updated jurisdictional allocation factors. This adjustment benefits DEP customers by reducing DEP's annual retail revenue requirement. Witness Jiggetts testified that the revenue reductions reflect changes in jurisdictional allocation factors resulting from the additional NCEMPA load that will be served by the Company's portfolio of generating facilities owned at the time of the acquisition. As a consequence, a greater portion of the cost of the Company's other generating facilities will be allocated to its wholesale jurisdiction, while a lesser portion will be allocated to its retail jurisdictions. In her direct testimony, witness Jiggetts testified that in the Company's filing, the annual revenue reduction to North Carolina retail revenue requirements for the test period January 2018 through December 2018 totaled $17 million. For the prospective period December 2019 through November 2020, the reduction is zero. Witness Jiggetts testified that the change in allocation approach was due to the Company's base rate request filed in Docket No. E-2, Sub 1142. The reallocation between retail and wholesale jurisdictions is reflected in the base rates approved by the Commission in Docket No. E-2, Sub 1142. Therefore, the Commission concludes that the reduction should not be included in JAAR revenue requirements from March 16, 2018 forward, the effective date for new base rates.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 12

The evidence for this Finding of Fact can be found in DEP's application, the direct testimony of DEP witness LaWanda M. Jiggetts, DEP's exhibits to the JAAR, and the affidavit of Public Staff witness Darlene P. Peedin.

The Company requested a Joint Agency Asset RRF decrement adjustment of $33.618 million related to the overrecovery of costs incurred through the test year ended December 31, 2018. The Commission notes that DEP should file a Joint Agency Asset RRF adjustment rider to include a true-up between estimated and actual costs incurred during the test period under N.C. Gen. Stat. § 62-133.14(c). The deferred costs related to any true-up are to be recorded as a regulatory asset or regulatory liability, including a return on the deferred balance each month. Public Staff witness Peedin did not oppose the return on this rate component in her affidavit filed in this proceeding. The Commission finds the actual costs and credits underlying this true-up amount to be reasonable and prudent, and that the return of this amount is reasonable and appropriate.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 13

The evidence for this Finding of Fact can be found in DEP's application, the direct testimony and exhibits of DEP witness LaWanda M. Jiggetts, and the affidavit of Public Staff witness Darlene P. Peedin.

Pursuant to N.C. Gen. Stat. § 62-133.14(b)(5), the costs of the rider shall be allocated utilizing the cost allocation methodology approved in DEP's last general rate case, Docket No. E-2, Sub 1142. In her direct testimony, witness Jiggetts testified that the Company's filing used the customer allocation methods approved in DEP's last general rate case. The North Carolina retail revenue requirement was allocated among customer classes using the production demand allocation factors. The allocated revenue requirement for each North Carolina retail customer class was then divided by estimated billing units, either kilowatt-hours (kWh) or kilowatts (kW), to produce the Company's proposed rates for each rate class, with which Public Staff witness Peedin agreed, as shown in the table below.

Rate Class	Applicable Schedule(s)	Prospective Rate	Rolling Recovery Factor	Combined Rate*
Non-Demand Rate Class (dollars per kilowatt-hour)				
Residential	RES, R-TOUD, R-TOUE, R-TOU	0.00474	(0.00084)	0.00390
Small General Service	SGS, SGS-TOUE	0.00522	(0.00179)	0.00343
Medium General Service	CH-TOUE, CSE, CSG	0.00415	(0.00162)	0.00253
Seasonal and Intermittent Service	SI	0.00251	(0.00423)	(0.00172)
Traffic Signal Service	TSS, TFS	0.00236	(0.00065)	0.00171
Outdoor Lighting Service	ALS, SLS, SLR, SFLS	-	-	-
Demand Rate Classes (dollars per kilowatt)				
Medium General Service	MGS, GS-TES, AP-TES, SGS-TOU	1.37	(0.49)	0.88
Large General Service	LGS, LGS-TOU	1.45	(0.08)	1.37

*Incremental Rates, shown above, include North Carolina regulatory fee of 0.14%.

Based on the evidence and the record, the Commission finds and concludes that the rates set forth above and in Finding of Fact No. 13 are just and reasonable.

IT IS, THEREFORE, ORDERED, as follows:

1. That DEP shall be allowed to charge in a rider $119.305 million ($152.923 million as the prospective component and $(33.618) million in the Joint Agency Asset RRF) on an annual basis to recover the costs in relation to the acquisition and operation of the Joint Units;

2. That the costs shall be allocated using the customer allocation methodology used in DEP's last general rate case as shown in DEP's application and the testimony of DEP witness Jiggetts;

3. That DEP shall file appropriate rate schedules and riders with the Commission in order to implement these approved rate adjustments to be effective for service rendered on and after December 1, 2019, as soon as practicable; and

4. That DEP shall work with the Public Staff to jointly prepare a proposed notice to customers of the rate adjustments ordered by the Commission in Docket Nos. E-2, Subs 1204, 1205, and 1207, and the Company shall file the proposed notice to customers for Commission approval as soon as practicable.

ISSUED BY THE ORDER OF THE COMMISSION.
This the 30th day of October, 2019.

NORTH CAROLINA UTILITIES COMMISSION
A. Shonta Dunston, Deputy Clerk

DOCKET NO. E-2, SUB 1208

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Petition of Duke Energy Progress, LLC,	)	ORDER CANCELLING PUBLIC
for an Accounting Order to Defer	)	HEARING, APPROVING PROPOSED
Costs Associated with Compliance	)	ACCOUNTING TREATMENT,
with N.C.G.S. § 62-110.8 and for	)	AUTHORIZING EXTENDED TEST
Approval of Extended CPRE EMF	)	PERIOD, AND APPROVING 2018
Rider Test Period	)	CPRE COMPLIANCE REPORT

BY THE COMMISSION: On July 27, 2017, the Governor signed into law House Bill 589 (S.L. 2017-192). Part II of S.L. 2017-192, codified at N.C.G.S. § 62-110.8, requires Duke Energy Progress, LLC (DEP) and Duke Energy Carolinas, LLC (DEP), to file for Commission approval a program for the competitive procurement of energy and capacity from renewable energy facilities with the purpose of adding renewable energy to the State's generation portfolio in a manner that allows the State's electric public utilities to continue to reliably and cost-effectively serve customers' future energy needs (CPRE Program). Subsection N.C.G.S. § 62-110.8(h) requires the Commission to adopt rules to implement the requirements of the CPRE Program, including, among other things, addressing the establishment of a methodology to allow an electric public utility to recover its costs pursuant to N.C.G.S. § 62-110.8(g).

On November 6, 2017, in Docket No. E-100, Sub 150, after receiving comments and proposed rules from Duke, the Public Staff, and other interested parties, the Commission issued an Order adopting Commission Rule R8-71. Commission Rule R8-71(j) addresses how the Commission will review each electric public utility's application for recovery of costs incurred or anticipated to be incurred by the electric public utility to comply with the requirements of N.C.G.S. § 62-110.8(g).

On February 21, 2018, in Docket Nos. E-2, Sub 1159 and E-7, Sub 1156, in response to Duke's petition for approval of a joint CPRE Program (on behalf of DEP and DEP), and after receiving comments from the parties and the Public Staff's report on Duke's proposed program, the Commission issued an Order Modifying and Approving Joint CPRE Program (CPRE Program Order).

On October 29, 2018, in Docket No. E-2, Sub 1179, the Commission issued an Order Cancelling Hearing, Approving Proposed Accounting Treatment, and Authorizing Extended Test Period (October 2018 Order). The October 2018 Order provided that the Commission's approval of the accounting treatment and extended test period were granted without prejudice to the right of the Public Staff, or any other party, to review and contest the amount or reasonableness of any costs DEP seeks to recover in the 2019 proceeding.

On June 11, 2019, in the above-captioned docket, DEP filed a verified petition requesting that the Commission approve an additional twelve-month extension of the initial test period for DEP's CPRE Program experience modification factor (EMF) to be filed in June 2020, such that the test period for the 2020 CPRE Rider filing will be August 1, 2017, through March 31, 2020. In addition, and consistent with the approach approved in the October 2018 Order, DEP requests authorization of deferral accounting authority for certain costs incurred in connection with DEP's compliance with N.C.G.S. 62-110.8. Further, DEP requests approval of its 2018 CPRE Program compliance report, which request is was supported by the filing of the direct testimony of DEP witness David B. Johnson included with DEP's compliance report.

In support of its requests, DEP states that it is still in the development phase of its CPRE Program implementation and that the requested test period extension will permit DEP to capture its reasonable and prudent CPRE compliance costs incurred and deferred during the extended test period for the purpose of its CPRE cost recovery request to be filed in 2020. In addition, DEP states that it anticipates that new renewable energy facilities to be procured through the CPRE Program Tranche 1 RFP Solicitation will likely not be placed into service during the test period or during the billing period relevant to this proceeding. Therefore, DEP states that while it has incurred and will continue to incur CPRE Program implementation expenses, DEP anticipates potentially incurring a "small amount of purchased power costs" during the December 1, 2019 through November 30, 2020, prospective billing period. Finally, Duke argues that its 2018 CPRE Program compliance report demonstrate DEP's reasonable efforts to comply with the requirements of N.C.G.S. § 62-110.8.

On August 16, 2019, in the above-captioned proceeding, the Public Staff filed a letter in response to DEP's petition. The Public Staff states that it has reviewed DEP's petition and agrees with DEP that it is appropriate to deviate from the normal, historical test period established in Commission Rule R8-55 for the initial test period in order to allow for continued implementation of the CPRE Program while allowing DEP an opportunity to recover its reasonable and prudently incurred costs. The Public Staff further states that it agrees with DEP that it is appropriate to grant the additional extension of the test period. Consistent with the Public Staff's filing in Docket No. E-2, Sub 1179, the Public Staff also states that it has not attempted to quantify or review the costs incurred by DEP to date, or the reasonableness of those costs; thus the Public Staff's recommendation of the accounting procedure to extend the historical test year should be viewed as contingent on the right of the Public Staff and any party to review the amount of or the reasonableness of these costs in the 2020 CPRE EMF Rider proceeding or any other future regulatory proceeding. Finally, the Public Staff states that it has reviewed DEP's 2018 CPRE Program compliance report and finds that DEP has complied with the requirements of both Commission Rule R8-71 and N.C.G.S. § 62-110.8, and, therefore, the Public Staff recommends that the Commission approve DEP's 2018 CPRE Program compliance report.

Pursuant to Commission Rule R8-71(j)(1), beginning in 2018, for each electric public utility, the Commission shall schedule an annual public hearing pursuant to N.C.G.S. 62-110.8(g) to review the costs incurred or anticipated to be incurred by the electric public utility to comply with N.C.G.S. § 62-110.8. That annual public hearing is to be scheduled as soon as practicable after the hearing held by the Commission for the electric public utility under Rule R8-55 (Annual Hearings to Review Changes in the Cost of Fuel and Fuel-Related Costs).[1] Further, pursuant to Commission Rule R8-71(j)(3), unless otherwise ordered by the Commission, the test period for each electric public utility shall be the same as its test period for the purposes of Commission Rule R8-55. In addition, pursuant to Commission Rule R8-71(j)(8), each electric public utility shall follow deferred accounting with respect to the difference between actual reasonably and prudently-incurred costs or authorized revenue and related revenues realized under rates in effect. Commission Rule R8-71 also sets forth the filings required prior to each electric public utility's annual hearing, the procedure for the Public Staff and other interested persons to participate in the proceeding, and the requirement for the electric public utility to give notice to the public of its pending application for recovery of costs and authorized revenue under the CPRE Program. Pursuant to Commission Rule R8-71(h), DEP is required to report annually to the Commission certain information related to DEP's efforts to comply with the requirements of N.C.G.S. § 62-110.8.

No person has sought to intervene in this proceeding or otherwise responded to DEP's petition.

Pursuant to Commission Rule R1-30, in special cases, the Commission may permit deviation from its rules insofar as the Commission finds compliance therewith to be impossible or impracticable.

Based upon the foregoing and the entire record in this proceeding, including DEP's verified petition and 2018 CPRE compliance report and the Public Staff's letter, the Commission determines that approval of DEP's requested extension in the test period, for purposes of establishing the 2020 CPRE EMF Rider, is appropriate. The Commission also agrees with DEP and the Public Staff that this determination is consistent with the approach taken in previous CPRE rider proceedings, and is supported by practical considerations related to the amount of expenses DEP has incurred to date in implementing the CPRE Program. In addition, the Commission determines that the issues involved in this proceeding are identical to those involved

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[1] On June 20, 2019, in Docket No. E-2, Sub 1204, the Commission issued an Order pursuant to Commission Rule R8-55 scheduling a public hearing on September 9, 2019, for the purpose of considering the annual fuel charge adjustment proceeding for DEP.

in the October 2018 Order. Therefore, consistent with that Order, the Commission concludes that DEP should be authorized to defer and seek recovery of the costs DEP incurs to comply with the requirements of N.C.G.S. § 62-110.8 in the 2020 proceeding established to review its application for recovery of those costs, which approval should be without prejudice as to the right of the Public Staff, or any other party, to contest the amount or reasonableness of those costs. Finally, the Commission agrees with DEP and the Public Staff that DEP's 2018 CPRE Program compliance report contains the information required by Commission Rule R8-71(h) and demonstrates DEP's reasonable efforts to comply with the requirements of N.C.G.S. § 62-110.8. Therefore, the Commission also concludes that DEP's 2018 CPRE Program compliance report should be approved.

IT IS, THEREFORE, ORDERED:

1. That DEP's request to cancel the annual public hearing that would have been scheduled pursuant to Commission Rule R8-71(j) for September 9, 2019, shall be, and is hereby, granted;

2. That, for the purposes of DEP's initial application to recover costs pursuant to N.C.G.S. § 62-110.8(g), which shall be filed with the Commission in June 2020, DEP's proposal to defer and seek recovery of costs reasonably and prudently incurred to comply with the requirements of N.C.G.S. § 62-110.8, shall be, and is hereby, approved as a reasonable means of complying with the requirements of Commission Rule R8-71(j);

3. That the test period to be used in DEP's initial application to recover costs pursuant to N.C.G.S. § 62-110.8(g), which shall be filed with the Commission in June 2019, shall be the period beginning on August 1, 2017, and ending March 31, 2020; and

4. That the accounting treatment and the extended test period approved in this Order shall be without prejudice to the right of the Public Staff or any other party to review and contest the amount or reasonableness of any costs included in DEP's application for recovery of costs incurred to comply with the requirements of N.C.G.S. § 62-110.8, which shall be filed with the Commission in June 2020.

ISSUED BY ORDER OF THE COMMISSION.
This the 30th day of August, 2019.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

DOCKET NO. E-2, SUB 1213
DOCKET NO. E-7, SUB 1209

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Petition by Duke Energy Carolinas, LLC and	)	ORDER APPROVING
Duke Energy Progress, LLC, for Approval of	)	PILOT PROGRAMS
Smart Meter Usage App Pilot Programs	)	

BY THE COMMISSION: On June 18, 2019, Duke Energy Carolinas, LLC (DEC) and Duke Energy Progress, LLC (DEP) (collectively, the Companies), filed a request for approval of Smart Meter Usage App Pilot Programs (Pilots).

In their application, the Companies state that the Pilots will provide residential customers with the ability to monitor their "real-time" energy usage data, with the intention of providing customers control over how they use energy and the potential to save money on their energy bill. The Pilots intend to test the gateway device that will connect the smart meter to the internet, thus enabling customers to control their consumption from a smart phone.

The Companies further state that the Pilots will be offered to 5,000 residential customers for each Company (10,000 total) at a total cost of approximately $2.5 million (50% incurred by each Company). The Companies also state that the Pilots will initially be offered to customers in Mecklenburg County, but will expand availability to their remaining service territories after a three-month period. The Companies intend to offer the Pilots for approximately 18 to 24 months, a time period they deem sufficient to "understand customer adoption and to gain learnings of the technology's capabilities."

The Public Staff presented this matter to the Commission at its Regular Staff Conference on September 3, 2019.

The Public Staff stated that it had reviewed the request and believed that the Pilots are a reasonable test of the technology linking smart meters and smart phones to provide participants with real-time energy usage data. The Public Staff also stated that it was interested in understanding if and how the availability of near real-time energy usage data made available by the Pilots encourage customers to take more proactive steps to manage their energy usage. The Public Staff further stated that the Pilots may provide useful information to DEC in enhancing design of its current dynamic time of use pilot.

Based on the foregoing, the Commission is of the opinion that the Companies' request for approval of their Smart Meter Usage App Pilot Programs should be approved as filed.

IT IS, THEREFORE, ORDERED as follows:

1. That the Smart Meter Usage App Pilot Programs are hereby approved as filed, effective this date; and

2. That the Companies shall file a report on the status of participation, the costs incurred to date, and any notable observations or trends on how participants are using the technology associated with the Pilots to reduce their energy usage. The report shall be filed every six months, with the first report being filed six months after the initiation of the Pilots.

ISSUED BY ORDER OF THE COMMISSION.

This the 5th day of September, 2019.

NORTH CAROLINA UTILITIES COMMISSION
A. Shonta Dunston, Deputy Clerk

DOCKET NO. E-34, SUB 49

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Petition of Appalachian State University, d/b/a New River Light and Power Company for Approval of a Prepaid Rate Schedule and Request for Waivers of Billing and Metering Requirements	)	ORDER REQUESTING COMMENTS

BY THE CHAIRMAN: On May 9, 2019 Appalachian State University, d/b/a, New River Light and Power Company (NRLP) filed a petition requesting approval of a Pilot Prepaid Service Rider. In addition, NRLP filed a request that the Commission grant waivers of certain provisions of the Commission's Rules and Regulations related to billing and metering. In support of its petition NRLP states that it has received multiple requests from its customers for such pre-paid service program, that it discussed such a program during its most recent rate case in the context of the deployment of automated metering infrastructure (AMI), that the deployment of AMI and related software is now complete, and that the proposed Pilot Prepaid Service Rider would provide a voluntary payment option for residential customers and allow NRLP to evaluate its effectiveness. NRLP's petition makes reference to the separately filed request for waivers of certain provisions of the Commission's Rules and Regulations related to billing and metering. Included in NRLP's request for waivers is a detailed discussion of the specific provisions of the following rules, which are the subject of NRLP's requested waivers:

1. Commission Rule R8-8 Meter Readings and Bill Forms;
2. Commission Rule R8-20 Discontinuance of Service for Violation of Rules or Nonpayment of Bills;
3. Commission Rule R8-44 Method of Adjustment for Rates Varying from Schedule or for Other Billing Errors;
4. Commission Rule R12-8 Discontinuance of Service for Nonpayment;
5. Commission Rule R12-9 Uniform Billing Procedure; and
6. Commission Rule R12-11 Disconnection of Residential Customer's Electric Service.

Based on NRLP's petition and the entire record herein, the Chairman finds good cause to request comments from interested parties regarding the issues raised by NRLP's petition and the related requested waivers of the provisions of the Commission's Rules and Regulations.

IT IS, THEREFORE, ORDERED as follows:

1. That on or before Wednesday, June 5th, 2019, persons having an interest in this matter may file petitions to intervene in this docket;

2. That on or before Wednesday, June 5, 2019, the Public Staff and other parties allowed to intervene may file comments regarding NRLP's petition and requested waivers of billing and metering requirements;

3. That on or before June 19, 2019, all parties may file reply comments; and

4. That, upon receipt of the parties' comments and reply comments, the Commission will proceed as appropriate in addressing NRLP's petition and requested waivers.

ISSUED BY ORDER OF THE COMMISSION.
This the 22nd day of May, 2019.

NORTH CAROLINA UTILITIES COMMISSION
A. Shonta Dunston, Deputy Clerk

DOCKET NO. E-7, SUB 1181
DOCKET NO. SP-12478, SUB 0
DOCKET NO. SP-12479, SUB 0

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Transfer of Certificates of Public Convenience and Necessity and Ownership Interests in Generating Facilities from Duke Energy Carolinas, LLC, to Northbrook Carolina Hydro II, LLC, and Northbrook Tuxedo, LLC	))))))))	ORDER ALLOWING DEFERRAL ACCOUNTING, DENYING PUBLIC STAFF'S MOTION FOR RECONSIDERATION, GRANTING TRANSFER OF CPCNs, AND QUALIFYING THE TRANSFERRED FACILITIES AS NEW RENEWABLE ENERGY FACILITIES

HEARD: February 5, 2019, at 10:00 a.m., in Hearing Room 2115, Dobbs Building, Raleigh, North Carolina

BEFORE: Chairman, Edward S. Finley, Jr., Presiding;[1] Commissioners ToNola D. Brown Bland, Jerry C. Dockham, James G. Patterson, Lyons Gray, Daniel G. Clodfelter, and Charlotte A. Mitchell

APPEARANCES:

For Duke Energy Carolinas, LLC:

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Duke Energy Corporation
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For Northbrook Carolina Hydro II, LLC and Northbrook Tuxedo, LLC:

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[1] Chairman Edward S. Finley, Jr., resigned from the Commission effective June 1, 2019.

For the Using and Consuming Public:

David T. Drooz, Chief Counsel and Tim R. Dodge, Staff Attorney
Public Staff – North Carolina Utilities Commission
4326 Mail Service Center Raleigh, North Carolina 27699-4300

BY THE COMMISSION: On July 5, 2018, Duke Energy Carolinas, LLC (DEC or the Company), Northbrook Carolina Hydro II, LLC, and Northbrook Tuxedo, LLC (Northbrook, collectively Applicants) filed a Joint Notice of Transfer, Request for Approval of Certificates of Public Convenience and Necessity (CPCNs), Request for Accounting Order, and Request for Declaratory Ruling (Petition) in the above-captioned dockets.

In summary, Applicants stated that on May 15, 2018, DEC and Northbrook entered into an agreement whereby DEC will sell five hydroelectric generating facilities having a combined capacity of 18.7 megawatts (MW) to Northbrook. Four of the facilities are located in North Carolina, and the fifth is located in South Carolina, as follows:

(1) Bryson Hydroelectric Station, which has a nameplate capacity of 980 kilowatts (kW), is located on the Oconaluftee River in Swain County, and first commenced commercial operation in 1925.

(2) Franklin Hydroelectric Station, which has a nameplate capacity of 1,040 kW, is located on the Little Tennessee River in Macon County, and first commenced commercial operation in 1925.

(3) Gaston Shoals Hydroelectric Station, which has a nameplate capacity of 8.5 MW, is located on the Broad River in Cherokee County, South Carolina, and Cleveland County, North Carolina, and first commenced commercial operation in 1908.

(4) Mission Hydroelectric Station, which has a nameplate capacity of 1,800 kW, is located on the Hiwassee River in Clay County, and first commenced commercial operation in 1924.

(5) Tuxedo Hydroelectric Station, which has a nameplate capacity of 6.4 MW, is located on the Green River in Henderson County, and first commenced commercial operation in 1920.

Applicants stated that DEC's cost of maintaining these older facilities makes it more economical for DEC to sell the facilities than to continue using them to serve DEC's ratepayers, and that divestiture of the facilities will not affect DEC's ability to provide reliable service to its customers at just and reasonable rates. Applicants further stated that DEC will transfer ownership of the facilities to Northbrook for $4,750,000, and that the facilities have a current net book value of $42 million. DEC indicated in its application that approximately $1.6 million of transmission-related work will be required by the sale, as well as $1.0 million in legal and transaction-related costs, and $220,000 in plant material and operating supplies. Further, as part of the transaction, DEC noted that it has agreed to purchase all of the energy and renewable energy certificates (RECs) generated by the subject facilities for five years following the transaction through renewable purchase power agreements (RPPAs) with Northbrook. As such, DEC asserted that through the transaction, the facilities will continue to serve the customers with clean renewable energy, but at a lower cost.

DEC requested that the Commission enter an order allowing DEC to establish a regulatory asset to defer the North Carolina retail allocable portion of the loss on sale, approximately $27 million, to be amortized over a period of years, and with a return, to be set in DEC's next general rate case. In addition, Applicants requested a declaratory ruling that the facilities will be considered new renewable energy facilities, and that DEC can use RECs from the facilities to comply with its obligations under the Renewable Energy and Energy Efficiency Portfolio Standard (REPS). DEC is also seeking to have the CPCNs which were issued or deemed to be issued for the facilities to be transferred from DEC, contingent upon the closing of the transaction to Northbrook.

Moreover, Applicants stated that consummation of the transaction is contingent upon the necessary regulatory approvals by the Commission, the Public Service Commission of South Carolina, and the Federal Energy Regulatory Commission (FERC), and that pending such approvals the transaction is expected to close in the first quarter of 2019. Further, Applicants stated that approval of the requested accounting treatment is a condition to closing the transaction, and, thus, DEC would have no obligation to consummate the sale if the accounting order is not approved. DEC observed that at the time the regulatory asset is approved by the Commission, the facilities will be measured at the lower of carrying amount or fair value less cost to sale and classified as assets held for sale, depreciation of the asset will cease, and the estimated loss will be recorded in the regulatory asset approved by the Commission. In addition, DEC acknowledged that an accounting order granting the relief that DEC seeks will not preclude the Commission or other parties from addressing the reasonableness of the deferred costs arising from the transaction in DEC's next general rate proceeding.

Procedural Background

On July 25, 2018, the Commission issued an order requesting comments from interested parties and reply comments from Applicants.

On September 4, 2018, the Public Staff filed its comments. In summary, the Public Staff stated that it sent multiple data requests to DEC and Northbrook, and held meetings and conference calls with DEC to evaluate the proposed transaction, and that in its communications with the Public Staff DEC indicated that the divestiture of the assets benefited customers through reducing customer risk of increased operations and maintenance (O&M) costs and future capital investments, and minimized future regulatory obligations. The Public Staff stated that it reviewed the preliminary present value of revenue requirements (PVRR) analysis conducted by DEC to compare the option of retaining the facilities with the option of divesting the facilities to a third party and purchasing the energy back from the facilities at avoided cost rates. According to the Public Staff, DEC's analysis showed that the divestiture option was more favorable to customers. The PVRR benefit was disclosed by DEC under seal as confidential information.

The Public Staff stated that in response to data requests DEC indicated that it made capital expenditures on the facilities of approximately $10.25 million in 2015, $6.7 million in 2016, $883,000 in 2017, and spent or has budgeted approximately $865,000 in 2018. The Public Staff questioned whether at the time these costs were being incurred DEC had sufficiently evaluated the magnitude of expenditures required to keep the facilities operational, as opposed to retiring them, or selling them in their prior condition. The Public Staff acknowledged that the Commission completed its investigation of DEC's most recent general rate application and issued its order setting new rates in Docket No. E-7, Sub 1146, on June 22, 2018 (Sub 1146 Rate Order), but stated that it views DEC's proposal to sell the facilities as new information that creates special circumstances meriting further consideration of DEC's proposal to impose the full $27 million loss on sale on ratepayers. As a result, the Public Staff requested that this issue be preserved as an open issue until DEC's next general rate case, when the reasonableness of recovery of the deferred costs will be addressed. In addition, the Public Staff requested that the Commission direct DEC and the Public Staff to further evaluate the reasonableness of the expenditures made by DEC at the facilities during the 36 months leading up to the agreement between the Applicants for the sale of the facilities, to allow these costs for consideration in DEC's next general rate case.

The Public Staff further stated that it reviewed DEC's analysis underlying its decision to sell the facilities, noting that in October 2017 DEC performed a "non-binding market value test," and obtained non-binding bids as a result of that process. The Public Staff stated that DEC reviewed the non-binding offers using several selection criteria, which were disclosed by DEC under seal as confidential trade secret information. Following the initial analysis and screening, a second round of bidding was conducted, which resulted in Northbrook's bid being selected.

The Public Staff also stated that it evaluated the RPPAs between DEC and Northbrook, and found that the avoided cost rates and REC purchase prices were reasonable for the term of the five-year agreement. Further, the Public Staff stated that it evaluated DEC's ability to utilize the RECs generated by the facilities, which will be approximately 59,800, and found that while DEC's September 1, 2017, REPS Compliance Plan filed in Docket No. E-100, Sub 147, indicates that DEC has contracted for, or has plans to procure, sufficient resources to meet its general requirement for the planning period (2017 to 2019), the REPS general obligations in N.C. Gen. Stat. § 62-133.8(b) increase in upcoming years from 6% to 10%, starting in calendar year 2018, and to 12.5% in calendar year 2021. The Public Staff opined that the avoided cost rates, contract term, and REC purchase price agreed to as part of the transaction and used in the PVRR analysis are reasonable.

The Public Staff stated that it agrees with DEC's proposal to establish a regulatory asset to defer the $27 million North Carolina retail portion of the loss on sale, to be amortized over a period of years, and with a return to be set in DEC's next general rate case, subject to review during that case. However, the Public Staff stated that it does not agree with DEC's proposal to delay beginning amortization of the $27 million until the next rate case. Instead, the Public Staff stated that, as with certain other deferrals and amortizations previously approved by the Commission, the amortization should begin in the month in which the asset transfer is completed, subject to reevaluation and adjustment in DEC's next rate case.

The Public Staff opined that in most cases, even when it is not reasonable to assume that the entire cost underlying a requested regulatory asset is recovered in the rates existing at the time the cost is incurred, and thus deferral and amortization of the cost is appropriate, it is nonetheless not reasonable for the beginning of the amortization of the cost to be delayed until the utility's next general rate case. Further, the Public Staff stated that this approach is most in keeping with the Commission's underlying ratemaking policy that the utility's regulatory books and records should reflect the actual costs of providing utility service to the ratepayers, leaving it up to the utility to decide whether its annual cost of service affects its overall return in a manner that justifies the filing of a general rate case. According to the Public Staff, this approach is also most appropriate when the nature of the underlying cost to be deferred is such that it is best considered in general as a normal part of the cost of conducting utility business, and has been typically used in cases involving the expenses of storm damage repair. The Public Staff cites as the most recent example the Commission's deferral of Hurricane Matthew and other storm damage expenses incurred in 2016 by Duke Energy Progress, LLC (DEP), in DEP's last general rate case, Docket No. E-2, Sub 1142, with the amortization beginning in the month that Hurricane Matthew occurred. The Public Staff also cited the Commission's decision in Docket No. E-7, Sub 828 that amortization of the GridSouth Regional Transmission Organization (RTO) costs should be considered to have begun in June 2002, the date that the GridSouth participants notified FERC that they had ceased incurring GridSouth costs, rather than at the time of DEC's 2007 rate case in Docket No. E-7, Sub 828, as was proposed by DEC. Therefore, the Public Staff recommended that the Commission require DEC to begin amortizing the regulatory asset resulting from the loss on the sale of the hydro facilities as of the date the sale is closed. In addition, the Public Staff stated that based on its review of the average remaining life of the facilities, it recommends that the amortization period for the regulatory asset be set at 20 years, which is comparable to the period of time over which the facilities would have been depreciated if they had remained in service.

With respect to Applicants' request for a declaratory judgment that the facilities will qualify as new renewable energy facilities, and that DEC may use RECs purchased from the facilities for REPS compliance, the Public Staff opined that the transfer of the facilities to Northbrook will result in the electric power from the facilities being delivered to DEC, thereby meeting the criteria under N.C. Gen. Stat. § 62-133.8(a)(5)(c) to be designated as new renewable energy facilities. In addition, the Public Staff recommended that the Commission accept the registration statements filed by Applicants for the facilities.

In conclusion, the Public Staff recommended that the Commission approve Applicants' transaction as requested, with the conditions that DEC's capital expenditures on the facilities are subject to review in DEC's next general rate case, and that the amortization of the loss on sale will begin in the month that the sale of the facilities to Northbrook is completed.

On September 18, 2018, DEC filed reply comments. In summary, DEC stated that the Public Staff's proposal to leave the issue of DEC's prior capital expenditures on the facilities open for review in DEC's next general rate case is unreasonable and should be rejected by the Commission. DEC stated that it first met with the Public Staff to discuss the proposed sale of the facilities on August 23, 2017, two days before DEC filed its rate case application in Docket No. E-7, Sub 1146, and that subsequent meetings were held with the Public Staff to discuss the proposal on February 6, 2018, and May 9, 2018, while the general rate case was pending. Further, DEC stated that it responded to numerous formal and informal data requests from the Public Staff regarding the proposed transaction, and that the Public Staff had more than adequate opportunity to investigate the capital investments made by DEC and to raise them in the Sub 1146 rate case proceeding. According to DEC, allowing the Public Staff to have the ability to review the incurrence of these costs in the next general rate case through hindsight analysis would be contrary to the purpose of the ratemaking process, and would inject unprecedented and impermissible uncertainty into the determination and recovery of just and reasonable costs. DEC cited State ex rel. Utilities Com. v. Conservation Council of North Carolina, 312 N.C. 59, 64, 320 S.E.2d 679, 683 (1984) (citing Utilities Commission v. Intervenor Residents, 305 N.C. 62, 76-77, 286 S.E.2d 770, 779 (1982)), for the principle that a utility's costs are presumed to be reasonable unless challenged, and opined that although the Public Staff knew about the pending transaction it made no challenge to the reasonableness of the facilities' costs in the Sub 1146 rate case proceeding, and should be estopped from doing so in DEC's next rate case. In addition, DEC noted that its requested accounting order would not preclude the Commission or parties from addressing the reasonableness of the deferred legal and transaction costs arising from the sale in DEC's next general rate case.[1]

With regard to the Public Staff's recommendations about the beginning date and length of the regulatory asset amortization period, DEC agreed that it would be appropriate to recognize the amortization expense at the level of depreciation currently approved in DEC's rates until the time of its next general rate case, at which time DEC would address the appropriate amortization period for the remaining regulatory asset balance. DEC stated that this approach would result in a slightly higher amortization rate than the Public Staff's proposal, and is reasonable and appropriate.

On November 29, 2018, the Commission issued an Order Requiring Filing of Testimony and Scheduling a Hearing. The hearing was scheduled for Tuesday, February 5, 2019.

On December 21, 2018, DEC pre-filed the testimony and exhibits of Greg D. Lewis, who is on an interim assignment in the Carolinas Regulated Renewables Department; Manu Tewari, Corporate Development Director; and Veronica I. Williams, Rates and Regulatory Strategy Manager. Also on December 21, 2018, Northbrook pre-filed the testimony of John C. Ahlriches, President of Northbrook Energy, LLC.

The transaction was approved by the Federal Energy Regulatory Commission on December 27, 2018. Order Approving Transfer of Licenses, 165 FERC ¶ 62,199.

On January 18, 2019, the Public Staff pre-filed the joint testimony of Dustin R. Metz, Electric Engineer in the Electric Division of the Public Staff, and Michael C. Maness, Director - Accounting Division of the Public Staff. No other parties intervened in the docket.

Also on January 18, 2019, the Public Staff filed a motion for reconsideration of that portion of the Sub 1146 Rate Order that included the capital expenditures on the subject hydroelectric facilities from 2015-2017 in DEC's general rates and requested a finding that the reasonableness and prudency of the capital expenditures can be reviewed in DEC's next general rate case.

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[1] DEC noted that the estimated legal and transaction related costs have increased from the original estimate of $1.0 million and now total approximately $1.4 million.

On January 28, 2019, DEC filed a response opposing the Public Staff's motion for reconsideration.

On January 30, 2019, DEC, Northbrook, and the Public Staff filed a motion requesting that all evidence be stipulated into the record, that all witnesses be excused from testifying, and that the hearing be cancelled.

On Feb. 1, 2019, the Commission issued an order excusing Northbrook witness John Ahlrichs and DEC witness Manu Tewari from testifying, accepting the stipulation of their testimony into evidence, and accepting two Late-Filed Exhibits. The Commission declined to excuse DEC witnesses Lewis and Williams, and Public Staff witnesses Maness and Metz.

The hearing was held as scheduled on February 5, 2019.

On March 27, 2019, proposed orders were filed by DEC and the Public Staff.

On May 6, 2019, DEC filed a letter informing the Commission that Applicants have entered into a Third Amendment to their sales agreement. DEC stated that the Third Amendment extended the Transaction closing date to August 16, 2019.

Based upon consideration of the pleadings, testimony, and exhibits received into evidence, and the record as a whole, the Commission makes the following:

FINDINGS OF FACT

1. DEC is a public utility with a public service obligation to provide electric utility service to customers in its service area in North Carolina and is subject to the jurisdiction of the Commission.

2. Northbrook is owned by a partnership between the Alliance Fund II, LP and Northbrook Energy, LLC (Northbrook Energy). Northbrook Energy is a privately held independent power producer that has been in the hydroelectric power business for more than 30 years and operates hydroelectric facilities in 12 states, including in North Carolina and South Carolina.

3. Except for the transfer of the CPCN for one facility located in South Carolina, this Commission has jurisdiction over the parties and subject matter pursuant to the Public Utilities Act. A public utility or person must receive a CPCN prior to constructing electric generating facilities pursuant to N.C. Gen. Stat. § 62-110.1 and Commission Rule R8-61(b). A public utility may transfer such certificates and ownership interests pursuant to N.C. Gen. Stat. §§ 62-110(a) and 62-111(a).

4. The Facilities subject to the proposed sale have a combined 18.7-MW generation capacity and consist of the Bryson Hydroelectric Generation Facility in Swain County; the Franklin Hydroelectric Generation Facility in Macon County; the Mission Hydroelectric Generation

Facility in Clay County; the Tuxedo Hydroelectric Generation Facility in Henderson County; and the Gaston Shoals Hydroelectric Generation Facility in Cherokee County, South Carolina.

5. After an evaluation of increasing compliance, safety and maintenance costs demonstrated that divestiture of the Facilities would be more cost-effective for customers over time than continued ownership, in May 2017 DEC decided to begin the divestiture process.

6. After soliciting and evaluating offers from potential purchasers, on May 15, 2018, DEC entered into an asset purchase agreement (APA) whereby the Company will sell the Facilities to Northbrook for $4,750,000 (the Transaction). The APA includes certain closing conditions, including an order from the Commission approving transfer of the North Carolina Facilities' CPCNs and approving the establishment of a regulatory asset for the retail portion of any difference between the sales proceeds and the net book value of the plants.

7. The Facilities have a net book value of $42 million. Accordingly, DEC has proposed to sell the Facilities to Northbrook for an estimated loss on sale calculated as the difference between the sale proceeds of $4.75 million and net book value of the Facilities of $42 million, $0.2 million plant material and operating supplies, $1.4 million of legal and transaction-related costs, and $1.6 million of transmission-related work required by the sale. The total estimated loss on the Transaction is $40 million, of which the North Carolina retail allocable portion is $27 million.

8. The sale of the Facilities by DEC to Northbrook and the transfer of the North Carolina CPCNs issued or deemed to have been issued for the Bryson, Franklin, Mission and Tuxedo facilities is in the public convenience and necessity and should be approved, subject to the conditions ordered below.

9. DEC's request for Commission approval of an accounting order for regulatory and accounting purposes authorizing DEC to establish a regulatory asset for the estimated loss on the disposition of the Facilities is appropriate.

10. At the time the regulatory asset is approved by the Commission, the Facilities will be measured at the lower of carrying amount or fair value less cost to sale and classified as assets held for sale. Depreciation of the asset will cease, and the estimated loss will be recorded as a regulatory asset approved by the Commission.

11. It is appropriate for the amortization of the regulatory asset to begin upon the closing of the Transaction.

12. It is appropriate for the amortization expense to be the same as the currently approved depreciation expense for the Facilities, subject to review in DEC's next general rate case.

13. Between 2015 and November 2018, DEC incurred capital expenditures on the Facilities of approximately $17.4 million. More than 95% of the capital costs DEC incurred for the Facilities between 2015 and 2017 were included in net plant in rate base in DEC's general rate case, and were approved by the Commission in its June 22, 2018 order in Docket No. E-7,

Sub 1146 (Sub 1146 Rate Order), as having been reasonably and prudently incurred. As a result, the costs are currently being recovered from customers in DEC's rates.

14. DEC met with the Public Staff and discussed the potential sale of the Facilities on August 23, 2017, February 6, 2018, and May 9, 2018. Each of these meetings occurred before or during the pendency of DEC's general rate case in Docket No. E-7, Sub 1146. During these meetings, DEC informed the Public Staff that it expected to sell the Facilities at a loss, that the net book value of the Facilities began to significantly increase beginning in 2015 due to required regulatory spending, and that DEC intended to seek Commission approval to establish a regulatory asset for the retail portion of the loss on the sale of the Facilities.

15. During the general rate case proceeding in Docket No. E-7, Sub 1146, the Public Staff did not bring to the Commission's attention DEC's capital expenditures on the Facilities, DEC's potential sale of the Facilities, or DEC's plan to request deferral of the loss on the sale of the Facilities.

16. The Public Staff's motion under N.C. Gen. Stat. § 62-80 to reopen and preserve the ability of the Public Staff to investigate the 2015-2017 capital costs of the Facilities and hold open the issue of the reasonableness of recovery of these costs until DEC's next general rate case is not supported by a change of circumstances, or any misapprehension or disregard of pertinent facts by the Commission.

17. Once the Transaction is complete and the Facilities have been transferred to Northbrook, each Facility shall qualify as a New Renewable Energy Facility pursuant to the North Carolina Renewable Energy and Energy Efficiency Portfolio Standard(REPS) as outlined in N.C Gen. Stat. § 62-133.8.

18. It is appropriate that DEC use any RECs purchased from the Facilities for REPS compliance.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-3

These findings are informational, procedural, and jurisdictional in nature and are uncontroverted.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 4-8

The evidence in support of these findings is based upon the Petition and the testimony and exhibits of DEC witnesses Tewari, Lewis, and Williams (DEC witnesses), and the testimony of Public Staff witnesses Maness and Metz (Public Staff witnesses).

The DEC witnesses testified that the Facilities have a combined 18.7-MW generation capacity and consist of the Bryson Hydroelectric Generation Facility in Swain County, North Carolina; the Franklin Hydroelectric Generation Facility in Macon County, North Carolina; the Mission Hydroelectric Generation Facility in Clay County, North Carolina; the Tuxedo Hydroelectric Generation Facility in Henderson County, North Carolina; and the Gaston Shoals

Hydroelectric Generation Facility in Cherokee County, South Carolina. In the Petition, DEC stated that it will seek appropriate approval from the Public Service Commission of South Carolina (PSCSC) regarding the Gaston Shoals CPCN.

According to the DEC witnesses, the Facilities are some of the oldest in DEC's portfolio, having entered service more than ninety years ago, as follows: Gaston Shoals began commercial operation in 1908, Tuxedo began commercial operation in 1920, Mission began commercial operation in 1924, and Bryson and Franklin began commercial operation in 1925. The DEC witnesses testified that the combined capacity of the Facilities contributes less than one percent of DEC's hydroelectric generation, and that although these stations were once an important part of the 1900's electrical system, and they served their communities well, today they represent a very small portion of DEC's generating system, and their strategic importance in serving DEC's customers has significantly diminished. Tr., pp. 31-32.

According to the DEC witnesses, due to the significantly escalating compliance, safety, and maintenance costs associated with the small hydro facilities, DEC evaluated a potential sale and determined that divesting these small hydro facilities is more economical than continued ownership and will result in net savings for customers over time. In addition, they testified that the Transaction will allow DEC to optimize its capital investments by focusing on higher priority generation facilities, will eliminate the risk for continued significant investment in the Facilities, and will thereby enhance DEC's ability to provide continued affordable and reliable service to its customers. The DEC witnesses testified that in May 2017 DEC began the divesture process and proceeded to test the market potential. Tr., p. 15; pp. 32-35.

Company witness Lewis described the Present Value Revenue Requirement (PVRR) analysis that DEC performed to determine the benefits of divesting and purchasing back the power of the small hydro facilities versus continuing operation and ownership. He stated that the PVRR assessed future cost probabilities based on current and expected regulatory requirements for equipment maintenance, dam safety, licensing plans and risks, and operations and maintenance. According to witness Lewis, the analysis compared the difference in the present value of the anticipated future costs to the present value of purchasing back the power from a third party, and considered three scenarios that produced a range of amounts in customer benefits. The amounts of benefits and the range were filed by DEC as confidential proprietary trade secret information. Tr., pp. 111-12. Witness Lewis testified that by divesting the Facilities, DEC will only be required to pay for the power produced versus the long-term obligations of ownership and operations, and that the PVRR analysis shows that the sale of the small hydro units will provide significant benefits to customers. Tr., p. 34.

Public Staff witnesses Maness and Metz testified that the Public Staff conducted a detailed review of DEC's PVRR analysis and concluded that it was reasonably performed and indicates "a significant PVRR advantage to disposing of the facilities in the 2018 time frame." Tr., pp. 143-46.

The DEC witnesses testified that after DEC determined in August 2017 that it was more cost effective to sell the hydro units rather than to continue to own and operate them, DEC assembled a core team to develop a project plan and related marketing material for the potential sale using a two-phase process: Phase 1 to invite indicative non-binding offers and Phase 2 to invite binding offers to negotiate a definitive APA. The DEC witnesses stated that Phase 1 of the process concluded on November 15, 2017, with the receipt of non-binding offers from 11 interested parties, and that DEC then evaluated the Phase 1 offers and moved to Phase 2 of the process with four bidders. According to the DEC witnesses, DEC ultimately negotiated with Northbrook over four weeks, which concluded with the execution of the APA on May 15, 2018. Pursuant to the May 15, 2018 APA, DEC will sell and transfer the Facilities to Northbrook for $4,750,000. The DEC witnesses testified that the APA includes the following key closing conditions for the Transaction: (1) FERC License Transfer Approval to transfer each of the FERC Licenses to the Purchaser; (2) an order from the Commission approving (i) the establishment of a regulatory asset for the retail portion of any difference between the sales proceeds and the net book value of the plants and (ii) the transfer of the plant CPCNs from DEC to the Purchaser; and (3) an order from the PSCSC (i) granting permission to sell utility property and (ii) approving the establishment of a regulatory asset for the retail portion of any difference between the sales proceeds and the net book value of the plants. In summary, the DEC witnesses noted that approval of the requested accounting treatment is a condition to closing the Transaction, and DEC would have no obligation under the APA to consummate the sale if the accounting order is not approved. According to the DEC witnesses, the deadline for meeting all the closing conditions described above is on or before May 15, 2019, or either party can terminate the agreement. Tr., pp. 15-23.

The DEC witnesses testified that the loss on sale is calculated as the difference between the sale proceeds of $4.75 million and the net book value of the Facilities of $42 million, $0.2 million of plant material and operating supplies, $1.4 million of legal and transaction-related costs, and $1.6 million of transmission-related work required by the sale, and the North Carolina retail allocable portion of the total estimated loss of $40 million is approximately $27 million. Tr., pp. 53-54.

The Public Staff witnesses testified that the PVRR analysis adequately supports DEC's decision to dispose of the Facilities. Tr., pp. 142-143. No other party intervened or opposed the transfers.

CONCLUSIONS

The Commission finds and concludes that approval of the Transaction will serve the public interest by enabling DEC to divest the Facilities and avoid significant, ongoing maintenance costs. DEC has determined that divestiture of the Facilities is more economical than continued ownership and maintenance because it will make it easier for DEC to optimize and prioritize its ongoing investments in higher priority generation facilities, thereby resulting in net savings to customers over time. Further, as part of the Transaction DEC has agreed to purchase all of the energy and RECs generated by the Facilities for five years following the Transaction through renewable power purchase power agreements (RPPAs) with Northbrook. As such, the Facilities will continue to serve customers with clean renewable energy, but at a lower cost over time. In addition, the Commission gives significant weight to the fact that Northbrook Energy has been in the hydroelectric power business for over 30 years, and operates hydroelectric facilities in 12 states, including in North and South Carolina, and is qualified to operate the Facilities. Therefore, the proposed sale of the Facilities, and the transfer of the CPCNs issued or deemed to have been issued for the Bryson, Franklin, Mission, and Tuxedo hydroelectric Facilities will serve the public convenience and necessity, and the Commission concludes that the sale should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 9-12

The evidence in support of these findings is based upon the Petition and the testimony and exhibits of DEC witnesses Williams and Lewis, and the testimony of Public Staff witnesses Maness and Metz.

Company witness Williams described DEC's request for an accounting order authorizing DEC to establish a regulatory asset for the estimated loss on the disposition of the Facilities (calculated as the difference between the sale proceeds and net book value of the Facilities, plant material and operating supplies, transaction-related costs and transmission-related work required by the sale). She testified that DEC proposes to amortize the regulatory asset over a period of time and at the approved return, as determined in DEC's next general rate case. Further, she stated that at the time the regulatory asset is approved by the Commission, the cost of the Facilities will be removed from plant in service, the appropriate amounts reflecting the sale will be recorded as assets held for sale, depreciation of the assets will cease, and the estimated loss will be recorded in the regulatory asset approved by the Commission. According to witness Williams, absent the accounting treatment requested, DEC would be forced to write off the North Carolina retail allocation of approximately $27 million for the loss associated with the sale of the Facilities if DEC were to proceed with the Transaction. As previously noted, approval of the accounting treatment is a condition to closing the Transaction. Tr., pp. 53-54.

DEC witness Williams further testified to the deferral standard the Company recommends that the Commission utilize in considering its request. Witness Williams acknowledged the two-prong test which according to her the Commission "sometimes utilizes," consists of: (1) whether the costs in question are unusual or extraordinary in nature and (2) whether absent deferral the costs would have a material impact on the Company's financial condition. However, she suggested the Commission's test should not apply to the Company's request in this docket because this transaction is unique in that it is not like the typical situation for which deferral is sought. She discussed Docket No. E-7, Sub 828, in which the Commission approved deferral and amortization of costs related to another atypical set of facts concerning work performed to establish the GridSouth Regional Transmission Organization (RTO), which was subsequently discontinued as a result of a change in FERC regulatory policy. According to witness Williams, the Commission decided that the costs in question were "clearly unusual and not part of the ordinary cost of providing service," and further noted that the amounts at issue were "clearly material," citing comparable past deferrals ranging from approximately $15 million to $40 million. She added, however, that the Commission's analysis in that case went beyond the limited question of materiality. In the GridSouth matter, the Commission noted that for any item of cost the nature and scope of deferral and amortization are committed to the Commission's sound discretion. Witness Williams further testified that the net costs (i.e., loss) associated with the potential sale in this case qualify for deferral consistent with other tests previously applied by the Commission in similar situations, and such tests are still relevant today. It was her opinion that the sale of generating assets is not part of the conduct of a utility's ordinary course of business and would not normally be reflected in any given general rate case. Further, she opined that the loss associated with this sale is not immaterial in the context of other deferrals and costs itemized in general rate case proceedings. Finally, she stated that allowing the deferral and amortization of the prudently-incurred costs required to achieve the future benefits of lower costs of service provides an equitable balancing of the interests of customers and the Company's shareholders. Witness Williams stated that it is DEC's position that because customers received the benefits of the units under regulation, it is appropriate that the loss resulting from the sale should be included in the Company's cost of service and recovered over a reasonable period of time, particularly here where customers will receive an ongoing benefit due to decreased cost of service in the future. Tr., pp. 55-57.

Public Staff witnesses Maness and Metz testified that the Public Staff agrees in part with DEC witness Williams' statement that the Commission's two-prong deferral test should not apply to this request based on the unique or atypical nature of the transaction at issue. Consistent with the Public Staff's comments filed on September 4, 2018, witnesses Maness and Metz testified that the Public Staff agrees it is reasonable for the Commission to consider the apparent benefit of this transaction to the ratepayers, and in its discretion to authorize the creation of a regulatory asset and amortize it to expenses over a period of time, subject to review in DEC's next general rate case. However, they testified that the Public Staff does not agree that the transaction is *otherwise* [outside of apparent benefit and the Commission's discretion] unusual or large enough to merit deferral based on the Commission's two-prong test. They described the two-prong test as follows: (1) "whether the costs in question are unusual or extraordinary in nature, and (2) whether absent deferral, the costs would have a material impact on DEC's financial condition." Tr., pp. 150-51.

According to witnesses Maness and Metz, the types of costs to which this or a similar test is applicable typically fall into one of the following categories:

1. Major storm repair expenses that are relatively unusual and so large in magnitude (often expressed as an impact on earnings) that it is not reasonable to presume that the expenses are being recovered in then-current rates.

2. Other unexpected expenses or losses so obviously unusual in nature and large enough in magnitude (often expressed as an impact on earnings) that it is not reasonable to presume that the expenses/losses are being recovered in then-current rates.

3. Other expenses or losses that may not be so unusual in nature but are so excessively large in magnitude (often expressed as an impact on earnings) that it is not reasonable to presume that the expenses/losses are being recovered in then-current rates.

Witnesses Maness and Metz testified that the expense/loss under consideration in this proceeding does not fall into any of the categories listed above, in that it occurred as a result of a transaction taken in the normal course of business and is therefore not unusual, nor is it large enough in magnitude to automatically be considered a properly deferrable item in the absence of some other underlying rationale justifying deferral. Finally, they further noted that the expense/loss is not large enough in magnitude to be considered a major driver of a general rate case. Tr., pp. 151-52.

Witnesses Maness and Metz testified that despite the deferral, in their opinion, failing the two-prong test, deferral of the costs at issue is justified because of the nature of the actions that gave rise to the loss and the costs that make up the loss. The witnesses viewed the Company's actions as ceasing utility operation of the Facilities and engaging in a transaction that is expected to reduce the future cost of service (and thus, implicitly or explicitly, customers' rates) to a level below what would have been experienced in the absence of the action(s), regardless of costs incurred in the past. Witnesses Maness and Metz stated that the book loss recorded as part of the sales transaction is made up of those past costs incurred (net of closure and sales-related expenses) in a manner that was prudent and reasonable, but which have not yet been recovered in rates, and that past costs reasonably and prudently incurred generally remain reasonable and prudent, regardless of the Company's later decisions about future costs. Since the sale of the hydro units is expected to be the best forward-looking action for the Company to take, and since the loss consists of past prudently incurred costs, the Public Staff's opinion in this specific case is that it is reasonable for the unrecovered past costs (the loss) to be preserved for continued recovery in rates (subject to reasonable and appropriate amortization in the interim and subject to further investigation of the reasonableness and prudence of the 2015-2018 expenditures). Despite its opinion that the transaction and resulting loss fail the Commission's two-prong deferral test, the Public Staff stated that the appropriate regulatory accounting mechanism to achieve preservation of the costs is deferral of the loss by way of a regulatory asset. Tr., pp. 153-54.

As to the amortization period, DEC witness Williams testified that because depreciation of these assets is currently in rate base, it is appropriate to continue to recognize amortization expense at the level of depreciation expense currently in rates until DEC's next general rate case, at which time DEC would address the appropriate amortization period for the remaining regulatory asset balance. As such, the Company proposed approval of the regulatory asset, with amortization beginning at the time the regulatory asset is recorded on the books, at a rate equivalent to the remaining 20-year life of the assets. Once established, the Company would plan to address the proper amortization period for the then-remaining regulatory asset balance in its next general rate case. Further, witness Williams stated DEC's position is that it is appropriate for amortization to begin at the time that the regulatory asset is recorded on the books and not at the completion of the Transaction. Tr., p. 58.

The Public Staff witnesses recommended to the contrary that the Commission require DEC to begin amortization in the month in which the Transaction closes, subject to re-evaluation and adjustment in the next general rate case. Further, the Public Staff recommended that the amortization period for the regulatory asset be set at approximately 20 years, which it asserts is the average remaining book life of the Facilities, but should be subject to re-evaluation and adjustment in the Company's next general rate case. Tr., pp. 157-61. In their testimony, Public Staff witnesses Maness and Metz explained that although there might be slight differences between the annual amounts of amortization expense recorded under the Company's proposal and the Public Staff's proposal, the Public Staff considers the Company's proposal reasonable. Tr., p. 161.

DISCUSSION

The Commission has historically treated deferral accounting as a tool to be used only as an exception to the general rule, and its use has been allowed sparingly. Cost deferral is an exception to the principle of matching current costs with current revenues because it delays the recovery of a cost until a future reporting period and it may result in the delayed recognition of such costs until the utility begins receiving increased revenues as a result of its next general rate case. Deferrals of increased or decreased costs result in customers being charged or benefitted, respectively, in future periods for spending experiences associated with providing service in earlier periods, while deferrals of increased or decreased revenues result in customers benefitting or being charged, respectively, in future periods for receipt of income by the utility associated with providing service in earlier periods.

The Commission's justification for approving cost deferral, and thereby departing from the general rule of matching current costs with current revenues, is to grant the utility relief from an unexpected cost that, absent deferral, would materially reduce the utility's earnings. Thus, the Commission has often applied a two-prong test to consider whether a requested cost deferral is justified: (1) whether the costs in question are unusual or extraordinary in nature, and (2) whether, absent deferral, the costs would have a material impact on the utility's financial condition. Under the first prong of the test, the Commission has required that deferrals be justified on the basis of an unusual or extraordinary event or change of circumstance. Revenues or costs can be unusual or extraordinary either because of their occurrence or size, or both. Thus, the purpose of the first prong of the cost deferral test is to prevent the utility's financial viability from being harmed by an increased cost that the utility could not have anticipated or otherwise protected itself from incurring. The concept is that the utility should not be penalized in its effort to earn its authorized rate of return when it incurs unusual costs.

The purpose of the second prong of the cost deferral test is to determine whether in fact the utility needs the benefit of cost deferral in order to protect its financial viability from the detrimental impact of an unexpected cost.

In the current proceeding, DEC suggests that the loss on sale is unusual and unique in nature and that the Commission's two-prong test should not be applied, as DEC believes the unique nature of the sale transaction as a whole makes the test an imperfect if not inappropriate determinant of the decision to allow or deny deferral of costs. The Company points to the GridSouth RTO docket as being a similarly unique transaction, and surmises that the Commission applied a balancing test (not the two-prong test) to determine whether deferral and amortization was equitable to both ratepayers and shareholders.[1] In addition, DEC argues that the current loss on sale is not immaterial in the context of other deferrals approved by the Commission, that the loss on sale is a prudently incurred cost to achieve least-cost service, and that allowing the deferral will achieve an equitable balancing of the interests of ratepayers and shareholders. DEC's witness Williams further points out that if the sale had resulted in a gain, the Commission would expect DEC's customers to receive at least a portion of the gain.[2]

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[1] Order Approving Stipulation and Deciding Non-Settled Issues, Docket No. E-7, Sub 828 (Dec. 20, 2007) (GridSouth Order).

[2] For electric utilities, the Commission has generally concluded that a gain on the sale of property that has been used in providing service to the utility's customers should be passed through to the utility's ratepayers and, conversely, that a loss on the sale of utility property should be treated as a cost to be paid by the utility's ratepayers. See

The Public Staff posits that the transaction at issue is not otherwise unusual or large enough to merit automatic deferral under the two-prong test. Nonetheless, the Public Staff makes the argument that due to the apparent benefit of the sale transaction to ratepayers it is reasonable for the unrecovered costs (the loss) to be preserved for continued recovery in rates and, thus, the appropriate regulatory accounting mechanism to achieve this preservation is deferral of the loss by way of a regulatory asset.

The Commission agrees with DEC that the GridSouth cost deferral issue presented a unique set of facts. In October 2000, DEC, Progress Energy Carolinas, Inc. (now Duke Energy Progress, LLC), and South Carolina Electric & Gas (collectively, GridSouth participants), began the formation of GridSouth in compliance with FERC Order 2000 requiring transmission owning utilities to join or form a RTO. For various reasons, mostly beyond the control of the GridSouth participants, the participants suspended their formation efforts in June 2002. In the GridSouth Order, the Commission addressed DEC's request to defer $ 43.9 million in GridSouth costs to be recovered from North Carolina retail ratepayers. Even though the Commission acknowledged that the GridSouth situation was essentially "one of a kind," *i.e.* uniquely atypical, the Commission nonetheless, contrary to DEC's urging in the instant case, applied the two-prong cost deferral test. After concluding that both prongs of the test were satisfied, the Commission balanced the equities and allowed deferral of the GridSouth costs in part, the total North Carolina retail deferral being about $29 million. GridSouth Order, at 53-57. Thus, the Commission determined the test was met and then balanced the equities in determining the appropriate size or amount of the deferral.

In the present case, the sale transaction, and resulting loss, is no more atypical than the "one of a kind" formation of GridSouth. The atypical nature of the costs in the GridSouth matter did not make the two-prong test inapplicable to the question of deferral; thus, DEC is misguided in offering GridSouth for the proposition that the two-prong test should not be applied in deciding whether to allow DEC's request for an accounting order to establish a regulatory asset for the loss on sale of the Facilities.

When the two-prong test is applied to the present facts, the Commission is persuaded that the first prong of the test is met because the sale of these hydroelectric generating facilities is an unusual event. A utility's transfer of generating capacity is not a frequent occurrence, and not one that can typically be planned so as to coincide with a general rate case. In a comparable situation, where the timing of bringing on new generation could not be planned to coincide with a general rate case, the Commission has allowed deferrals of the cost of new generating plants that began commercial operation in between rate cases or during a rate case. See Order Approving Rate Increase and Cost Deferrals and Revising PJM Regulatory Conditions, Docket No. E-22, Sub 532, at 63-67 (Dec. 22, 2016); Sub 1146 Rate Order, at 77-78. However, regarding the second prong of the cost deferral test, the Commission cannot find that the loss, absent deferral, will have a material impact on DEC's financial condition. DEC made no effort to quantify the impact of the $27 million loss on sale on DEC's current financial condition. DEC has not provided substantial evidence to meet the second prong of the cost deferral test and, therefore, DEC has not established that deferral should be allowed on the basis of the Commission's two-prong deferral test.

Order Ruling on Proper Accounting Treatment to Record the Transfer of Certain Utility Assets, Docket No. SP-122, Sub 0 (May 20, 1999).

Still, even though the Commission does not agree that its two-prong deferral test is inapplicable to the loss on sale in this case, and despite its conclusion that DEC did not prove deferral was justified using the test, the inquiry on DEC's request does not end here. Both DEC and the Public Staff have correctly pointed out, albeit in different fashion, that the cost deferral test is not the exclusive factor in considering a deferral request. The Public Staff argued it is appropriate that the Commission consider the benefit of the transaction at issue to the ratepayers and exercise its discretion to create a regulatory asset, while DEC argued that equities at play in this transaction lend themselves to a balancing of lower costs of service in the future against delayed recognition of past costs for historical service that are collected in future periods. The Commission does not apply the two-prong test in a vacuum. Rather, the Commission considers all of the pertinent factors involved on a case-by-case basis, and weighs the equities to arrive at a decision that is fair to the utility and its ratepayers, and that serves the public interest. Thus, in the case at hand, the Commission is not unduly restricted to the results of applying the two-prong test. The Commission may analyze the merits of deferral using not only the well- established two-prong test but also considering the totality of the underlying facts, circumstances, and equities of this case, as discussed below.

Substantial evidence in this case establishes that the sale of the hydro plants to Northbrook, coupled with DEC's buy back of the power under the RPPA, is a least cost avenue for DEC to serve its ratepayers. As a result, ratepayers will experience a benefit from the sale and RPPA with Northbrook that will be reflected in DEC's future rates due to DEC's resulting lower cost service. The Commission gives significant weight to this evidence.

In addition, the Commission gives significant weight to the evidence presented by witness Lewis that these hydro plants will require capital expenditures by DEC in the near future. Witness Lewis testified that once DEC made the decision to sell the plants, it put on hold projects that could be delayed, and notified prospective buyers that they would need to complete these projects. Tr., pp. 39-40. As previously noted, witness Lewis testified that these plants' combined capacity of 18.7 MW contributes less than one percent of DEC's hydroelectric generation. Tr., pp. 31-32. As a result of the sale to Northbrook, ratepayers will avoid the cost and risk of making capital expenditures on these very old assets that get relatively little use in providing electricity on DEC's system. The Commission deems that result to be an important benefit to ratepayers.

Moreover, there is substantial evidence that the cost of retiring these hydro plants would be substantial. Witness Lewis testified to these costs in the context of DEC's decision to relicense the plants, as opposed to surrendering the licenses:

> [Y]ou would be exposed to significant costs associated with the environmental costs, environmental assessments potentially required to remove the dams – remove the dams, remove the sediment, dispose of the sediment...So all you have effectively done when you retire the units is you've retired the revenue-making portion of that. You haven't gotten rid of any of the risks of dam safety or the compliance risks.

Tr., p. 72.

Witness Lewis also testified to DEC's actual experience in removing a small dam.

> [D]uring the relicensing process you may recall a very small dam called Dillsboro that they [FERC] did recommend and order us to remove that dam. It was only a 10 or a 12-foot high dam, a very small dam, and we did remove that but only after lengthy litigation and studies were required. So we did surrender that license but it was quite painful.

Tr., p. 92.

As a result of the sale, ratepayers will avoid the cost and risk of retiring these five plants, a cost and risk that could be faced by DEC and ratepayers in the near future given the age of these assets. Again, based on the relatively small contribution that these plants make to DEC's provision of electric service, the future retirement of the plants is potentially an albatross, and should be avoided if reasonably possible. The Commission gives significant weight to the evidence that DEC's ratepayers will be spared the risk of this albatross by DEC's sale of the plants.

CONCLUSIONS

Accordingly, with respect to deferral of the loss on sale, in the final analysis the Commission's decision is guided by the overriding principle that the rates set by the Commission should be just and reasonable to ratepayers and to DEC. N.C.G.S. § 62-130. On one side of that balance, the Commission recognizes that the sale of the hydro plants, even at a loss, is expected to reduce DEC's future cost of service below what would be incurred in the absence of the sale. The substantial reduction of these costs is a significant benefit for ratepayers. On the other side of the balance, the deferral of the loss on sale would be a benefit for DEC, at some future cost to ratepayers, since absent deferral DEC would have to absorb the loss on sale within its current rates. Balancing the equities in favor of ratepayers and those in favor of DEC, the Commission concludes that the significant present and future benefits that will inure to ratepayers as a result of the sale outweigh the relatively small cost that ratepayers will incur in the future due to the deferral of the loss on sale. Therefore, the Commission determines that DEC's request to defer the loss on sale should be approved.

Based on the foregoing and the record, the Commission finds and concludes that DEC's loss on the sale of the hydro plants to Northbrook should be treated as a cost of service and assigned to DEC's ratepayers. Further, the Commission finds and concludes that the public interest will be served by allowing DEC to establish a regulatory asset for deferral of the loss on sale of the hydroelectric generating facilities to Northbrook.

With regard to the period of time over which to amortize the regulatory asset, the Commission has discretion; however, the purpose of deferral accounting is not to preserve costs for an indefinite period of time. Only in extraordinary circumstances, or in cases where a general rate case is pending, and when the Commission particularly wants to synchronize the recognition of a deferred cost and the approval of new rates, is the delay of beginning an amortization generally appropriate. Typically, when the nature of the underlying cost to be deferred is such that it is best considered in general as a normal part of the cost of conducting utility business, the Commission will require that the amortization begin when the related event/transaction occurs. For example, the deferral of storm costs in DEP's last general rate case in Docket No. E-2, Sub 1142, where the Commission required amortization to begin in the month the largest storm costs were incurred. The Commission deems this approach to be reasonable and appropriate as it best keeps with the basic ratemaking policy that a utility's regulatory books and records should reflect the actual costs of providing utility service to the ratepayers (including the reasonable amortization of periodically deferred costs), and that it should be up to the utility to decide whether that annual cost of service affects its overall return in a manner that justifies the filing of a general rate case. The Commission considers these sale transaction costs to be of a somewhat similar nature, and thus part of the normal cost of conducting utility business. For these reasons, the Commission finds and concludes that the amortization period in this situation should begin in the month in which the asset transfer is completed such that the amortization of the deferred costs into the cost of service begins upon their incurrence.

Further, the Public Staff recommended an amortization period of 20 years, which is the average remaining book life of the facilities, i.e., comparable to the period of time over which the facilities would have been depreciated if they had remained in service. In its reply comments DEC asserted that because depreciation on these assets is currently approved in rates, DEC agrees that it would be appropriate to recognize amortization expense at the level of depreciation currently approved in rates until the time of its next general rate case, at which time DEC would address the appropriate amortization period for the remaining regulatory asset balance. DEC also noted that its proposed treatment of amortization expense actually results in a slightly higher expense than the Public Staff's proposal. In testimony, the Public Staff stated that it considered the Company's proposal reasonable. Based upon the foregoing, the Commission finds and concludes that the amortization expense should be recognized at the annual level of depreciation expense currently approved in rates subject to re-evaluation and adjustment in DEC's next general rate case proceeding. Amortization of the regulatory asset should begin in the month the sale is closed.

In summary, the Commission concludes that the loss on the sale of the hydro plants to Northbrook should be treated as a cost of service and assigned to DEC's ratepayers, and that DEC's request to establish a regulatory asset for the loss on the sale should be approved, as the sale is in the interest of ratepayers. Further, amortization of the regulatory asset should begin at the time the Transaction is closed and be amortized at the level of depreciation currently approved in rates until the time of DEC's next general rate case. The amortization period for the remaining regulatory asset and the question of whether it should earn a return will be decided in DEC's next general rate case. Finally, the Commission notes that its decision on deferral of the loss on sale is based on the particular facts of this case, and should not be cited or relied on as precedent for future cost deferral decisions.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 13-16

The evidence in support of these findings is based upon the Petition and the testimony and exhibits of DEC witnesses Lewis and Williams, the joint late-filed exhibits, and the testimony of Public Staff witnesses Maness and Metz.

Between 2015 and November 2018, DEC incurred capital expenditures on the Facilities of approximately $17.4 million. DEC witness Lewis testified in detail as to the projects and pointed out that they were required to comply with license obligations, dam safety requirements, and personnel safety. Tr., pp. 35-39, 86-87, 123-24; Lewis Exhibit 2; Joint Partially Confidential Late-Filed Exhibit Nos. 1 and 2. Company witness Lewis made the analogy to the Model T Ford, which was produced in the same general timeframe of 1908 to 1925 when the Facilities were commissioned, and when many regulatory agencies such as the Federal Energy Regulatory Commission (FERC) and the Environmental Protection Agency did not exist. Witness Lewis explained that as FERC license and environmental regulations evolved over the decades, small hydro facilities, regardless of their small generating capability, their antiquated designs, and their lack of economies of scale, were required to comply with continuously evolving regulations, standards, and expectations. Tr., pp. 36-37.

DEC witness Lewis testified to the lengthy FERC relicensing process for the Gaston Shoals, Bryson, Franklin and Mission facilities. He stated that the Company made the decision to relicense the Gaston Shoals facility in the 1990 timeframe and received the new FERC license in 1996, and that the decision to relicense the Bryson, Franklin and Mission facilities was made in the 1999-2000 timeframe, but the new FERC licenses were not received until 2011. Tr., pp. 82-83; Joint Late-Filed Exhibit 2; DEC Response to Public Staff DR 7-3. According to witness Lewis, during the lengthy FERC relicensing process DEC asked FERC to allow it to delay making an investment in the units until it determined if new licenses would be issued and, if so, what the new conditions would be. Witness Lewis offered examples of the "onerous" new FERC license conditions the Company received, including maintaining lake levels within one and a quarter of an inch. Tr., pp. 84, 121-22; Joint Late-Filed Ex. 1, DEC Responses to Public Staff DR 6-3 and 6-4. He testified that after receiving the new FERC licenses in 2011, the Company went through a two-year period of engineering and design work, and thereafter, with FERC's approval, staggered the work necessary to complete the projects required to comply with the new FERC licenses. Tr., pp. 99-102, 122-23.

Company witness Lewis testified that none of the approximately $17.5 million in capital projects was incurred to make the units more attractive to a potential buyer. Tr., pp. 124, 128. Furthermore, he testified that none of the projects were initiated for the primary purpose of upgrading the units. Instead, any upgrade was a secondary benefit of replacing aging, deteriorated equipment with modern replacements as a means of reliably managing flows and staying in compliance. Tr., p. 40. Witness Lewis explained that the Facilities' capital costs were significantly lower in 2017 and 2018, after the Company put some projects on hold due to their pending and notified prospective buyers that such projects would need to be completed after acquisition. Tr., pp. 39-40; Joint Late-Filed Ex. 1.

According to witness Lewis, more than 95% of the capital costs DEC incurred for the Facilities between 2015 and 2017 were included in net plant in rate base in DEC's last general rate case and were approved by the Commission in its June 22, 2018 order in Docket No. E-7, Sub 1146. He stated that the remaining capital costs were mostly associated with a project that was suspended pending the sale. Tr., pp. 37-39, 59; Lewis Ex. 2.

Public Staff witnesses Maness and Metz acknowledged that the approximately $17.5 million of the costs at issue in this docket are 100% capital costs. Tr., p. 188. They testified to the extensive investigation the Public Staff conducted into DEC's 2015-2017 capital expenditures at the Facilities in this docket, including multiple data requests and "multiple detailed meetings and conference calls with DEC personnel regarding these investments." Tr., pp. 148-49. Nevertheless, they stated that the Public Staff concluded it was "unable to determine if the costs were for timely compliance with license and safety requirements, reflected capital projects that were deferred from previous years that were made to secure the sale of the assets, or other reasons." Id.

On January 18, 2019, the Public Staff filed a motion requesting that the Commission conclude that the reasonableness of the loss on sale, including the reasonableness of the capital expenditures from 2015-2017, can be reviewed in DEC's next general rate case. The Public Staff summarized the parties' discussions about the hydro facilities prior to and during the Sub 1146 general rate case. It contended that "The proposed hydroelectric sale was too remote, uncertain, and lacking in quantification at the time of the Public Staff's rate case investigation to put the Public Staff on notice that a detailed investigation of prior investment in those facilities was needed." Motion of the Public Staff, at 4-5. The Public Staff submitted that the Commission should reconsider the prudence of the hydro plant capital expenditures pursuant to N.C.G.S. § 62-80, based on changed circumstances.

DISCUSSION

Pursuant to N.C.G.S. § 62-80

> The Commission may at any time upon notice to the public utility and to the other parties of record affected, and after opportunity to be heard as provided in the case of complaints, rescind, alter or amend any order or decision made by it. Any order rescinding, altering or amending a prior order or decision shall, when served upon the public utility affected, have the same effect as is herein provided for original orders or decisions.

The Commission's decision to rescind, alter or amend an order upon reconsideration under G.S. 62-80 is within the Commission's discretion. State ex rel. Utilities Comm'n v. MCI Telecommunications Corp., 132 N.C. App. 625, 630, 514 S.E.2d 276, 280 (1999). However, the Commission cannot arbitrarily or capriciously rescind, alter or amend a prior order. Rather, there must be some change in circumstances or a misapprehension or disregard of a fact that provides a basis for the Commission to rescind, alter or amend a prior order. State ex rel. Utilities Comm'n v. North Carolina Gas Service, 128 N.C. App. 288, 293-294, 494 S.E.2d 621, 626, rev. denied, 348 N.C. 78, 505 S.E.2d 886 (1998).

The Public Staff conceded that DEC met with the Public Staff on August 23, 2017, to discuss the proposed sale of the facilities, but stated that DEC provided only a "bare outline of the sale proposal." Motion of the Public Staff, at 4. The Public Staff further stated that DEC provided it with a second update on the potential sale in February 2018, which was more than a month after the discovery period ended in DEC's Sub 1146 rate case, and was after the Public Staff had filed its testimony. In addition, the Public Staff cited the Supreme Court's definition of retroactive ratemaking in State ex rel. Utilities Comm'n v. Nantahala Power & Light Co., 326 N.C. 190, 205, 388 S.E.2d 118, 129 (1990), and contended that it is not requesting retroactive recovery of revenues from DEC, but, rather, it is requesting that the Commission make an adjustment to the amount of the recoverable loss on sale if it finds that the capital improvements were not prudent or reasonable.

On January 28, 2019, DEC filed a response to the Public Staff's motion for reconsideration. In summary, DEC stated that it not only met with the Public Staff several times to discuss the potential sale of the hydro plants, but that it also responded to approximately 75 data requests and participated in numerous conference calls with the Public Staff regarding the proposed transaction. DEC further stated that the Public Staff's motion is weakened because even after extensive fact gathering the Public Staff has not alleged any facts or pointed to any evidence that it contends demonstrates that any of the capital expenditures were imprudent or unreasonable. In addition, DEC cited State ex rel. Utilities Comm'n. v. Edmisten, 291 N.C. 575, 581-82, 232 S.E.2d 177, 181, (1977), and State ex rel. Utilities Comm'n. v. Carolina Water Service, 335 N.C. 493, 498, 439 S.E.2d 127, 129-20 (1994), for the proposition that a motion for reconsideration under N.C.G.S. § 62-80 must be filed within 30 days after the Commission's order is issued. Moreover, DEC submitted that the question of whether the capital improvements were prudent has no relationship to the issue of whether the sale of the hydro plants should be approved.

The Commission does not accept DEC's position that a motion for reconsideration under N.C.G.S. § 62-80 must be filed within 30 days after the Commission's order is issued, for three reasons. First, the plain wording of the statute is that "The Commission may at any time ... rescind, alter or amend any order or decision made by it." (Emphasis added). Second, the notion that the changed circumstances on which the Commission could act under N.C.G.S. § 62-80 must occur within 30 days after the date of the Commission's order would eviscerate the usefulness of the statute, i.e. a changed circumstance occurring 31 days or later after the Commission's order could not be used as a grounds for reconsideration. Third, in the cases cited by DEC the Supreme Court did not hold that there is a 30-day limit on motions for reconsideration under N.C.G.S. § 62-80.

According to the Public Staff, there are three steps in the reconsideration process under N.C.G.S. § 62-80,[1] with the first step being

> [a] hearing on evidence or change of conditions that might justify altering a prior order... The Public Staff's motion in the instant case does not require the filing of evidence. The evidence, if any, would be presented at step two; there is no requirement in N.C. Gen. Stat. § 62-80 for the Public Staff to make the case at this time.

Public Staff's Proposed Order, at 10.

The above statement is not correct. The first inquiry under N.C.G.S. § 62-80 is whether there is a change in circumstances or a misapprehension or disregard of a fact that provides a basis for the Commission to rescind, alter or amend the Sub 1146 Rate Order. In Sub 1146, the bulk of the capital expenditures on the hydro plants from 2015-2017 was included in DEC's cost of

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[1] The Public Staff did not file a post-hearing brief. This discussion of the Public Staff's position on reconsideration is based on points made in the Public Staff's proposed order.

service. Neither the Public Staff, nor any other party, challenged the reasonableness or prudence of the capital expenditures. As a result, a prima facie case was made that these costs were reasonably incurred. State ex rel. Utilities Comm'n. v. Intervenor Residents, 305 N.C. 62, 76-77, 286 S.E.2d 770, 779, (1982). As a result, in the Sub 1146 Rate Order the Commission approved DEC's recovery of the capital expenditures on the hydro plants, and those capital expenditures are today being recovered by DEC in its current rates as a depreciation expense on the plants.

The Commission agrees with the Public Staff that on the question of reconsideration under N.C.G.S. § 62-80 the Public Staff is not required to provide evidence that the capital expenditures were unreasonable or imprudent. However, in order for the Commission to reopen the inquiry into whether DEC should be allowed to continue to recover those expenditures - either in DEC's current rates, as they are presently being recovered, or as a part of the loss on sale of the plants - the Public Staff must provide some evidence that there has been a change of circumstances, or a misapprehension or disregard of the facts regarding the Commission's approval of DEC's recovery of the capital expenditures in the Sub 1146 Rate Order.

In addition, the Commission agrees with the Public Staff that DEC's characterizations of the post-rate case discovery and information exchange as including "an incredible number of data requests," and requiring copious amounts of witness Lewis' time are inapposite. Again, the question of whether the capital expenditures on the Facilities were reasonable and prudent is not before the Commission at this point.

Similarly inapposite is the Public Staff's position that DEC's inclusion of the statement, "An accounting Order granting the relief that DEC seeks will not preclude the Commission or parties from addressing the reasonableness of the costs deferred arising from the Transaction in the next general rate case" in DEC's Petition was a stipulation by DEC that the Commission could inquire into the reasonableness of the capital expenditures in DEC's next rate case. The statement is not ambiguous in its reference to the "costs deferred arising from the Transaction," in that DEC obviously did not include the capital expenditures, costs already in its rates and being recovered from ratepayers, as "costs arising from the Transaction." Moreover, it does not appear that the Public Staff suffered from such a misunderstanding, or was misled in any way, since the Public Staff included in its initial comments in this docket its arguments for reopening the inquiry into the reasonableness of the capital expenditures.

In addition, the Commission finds unpersuasive the Public Staff's contention that reopening the inquiry into the capital expenditures would reflect "the normal practice of the Commission when ruling on deferral requests." Public Staff's Proposed Order, at 11. The Commission is unaware of a prior instance in which it has ordered deferral of utility costs that are currently being recovered in the utility's rates, and the Public Staff cited no such instance. Indeed, such an order would be an anomaly, as the purpose of cost deferral is to preserve unusual costs for recovery by the utility in its next rate case. In the present case, DEC's capital expenditures were not unusual costs, the reasonableness of the costs has already been determined by the Commission in the Sub 1146 Rate Order, and the costs are presently being recovered in DEC's rates.

The question before the Commission is whether the Public Staff had a reasonable opportunity during the rate case to understand and in some manner address the significance of the capital expenditures on the hydro plants in relation to DEC's plan to sell the plants. The Public Staff and DEC presented evidence about the meetings on the potential sale of the hydro plants, and the information that was provided by DEC to the Public Staff immediately prior to the filing of the Sub 1146 rate case, during the rate case, and during this proceeding. The Public Staff's and DEC's evidence does not differ in any material respects, and the Commission will not recount it in detail here. The Commission finds the crucial portion of the evidence to be the meetings on August 23, 2017, and February 6, 2018. During the August 23 meeting, DEC informed the Public Staff that its PVRR analysis showed divestiture was positive for customers, the expected forced regulatory spend was significantly contributing to net book value growth and that the sale price for the plants was expected to be less than the current net book value. Lewis, Tr. pp. 115-17; Joint Late-Filed Ex. 1, DEC Response to Public Staff DR 6-11; Maness and Metz, Tr. pp. 189-90. On February 6, 2018, DEC again met with the Public Staff to provide an update on the sale, including the status of bids it had received to date. In that meeting, slides provided to the Public Staff stated, "Non-binding offers imply expected proceeds from divestiture to be considerably lower than net book value of the assets; if DEC agrees to sell the assets, it plans to make a regulatory asset request for the retail portion of the stranded costs." Lewis, Tr. p. 118. During the meeting, DEC also informed the Public Staff that the net book value of the hydro plants was approximately $42 million. Id. Witness Lewis testified that there was a give-and-take discussion between DEC and the Public Staff. Id. at 116.

CONCLUSIONS

The Commission, the regulated utilities, and the Public Staff have one common purpose – to serve the public interest. The Commission and parties may differ on how to meet that purpose, but in the end the public interest is best served when all participants in the ratemaking process are provided timely and adequate information about the manner in which ratepayers will be served and the cost of providing that service. In the present case, DEC witness Tewari testified that in December 2017 DEC moved into the second and final phase of the sale process by inviting four of the 11 bidders who submitted non-binding offers for the Facilities in Phase 1 to submit binding offers.

> [T]he decision to move these four bidders into Phase 2 created the right balance between the ability to support the detailed due diligence effort (host management presentations, provide responses to bidder questions, conduct site visits for each bidder) and to ensure receipt of at least one binding offer from a bidder that met the criteria described in the response to the prior question upon conclusion of the Phase 2 due diligence the [sic] process.

Tewari, Tr. p. 19.

On March 5, 2018, DEC sent binding bid instructions to the four Phase 2 bidders. Tewari, Tr. p. 20. The hearing in the Sub 1146 rate case began on March 5, 2018. Thus, on the date that the hearing began DEC was reasonably certain that it would sell the Facilities for a loss and request a deferral of the loss on sale. The Commission notes that, although not required of DEC, it would have been helpful to the Commission had DEC worked with the Public Staff to bring this situation to the attention of the Commission, and to request the Commission's guidance on whether and how potential issues about the capital expenditures and deferral of the loss on sale should be addressed, or preserved for later consideration.

The Commission agrees with the Public Staff that the Public Staff was put in a difficult position when it received the hydro sale information late in the rate case process, and too late for the Public Staff to effectively conduct discovery on the details of DEC's plan to sell the hydro plants, or to pre-file testimony on the issue. Nevertheless, the Commission is not persuaded that there is a change of circumstances, or a misapprehension or disregard of a fact that supports reconsideration of that portion of the Sub 1146 Rate Order that approved DEC's capital expenditures on the hydro plants. The Commission appreciates the dilemma in which the Public Staff found itself after being informed on the eve of the rate case that DEC was contemplating selling the hydro plants. As the Public Staff noted, electric rate cases are huge proceedings that involve thousands of pages of documents, and present multiple and immediate complex issues. For this reason, the Commission does not fault the Public Staff for being unable to piece together timely discovery or testimony on this potential issue during the pendency of the rate case. On the other hand, the issue was not hidden from the Public Staff. Indeed, DEC flagged the issue, albeit late in the process, for the Public Staff's attention. As previously noted, the hearing in the rate case began on March 5, 2018, and it lasted several days. The Commission concludes that the Public Staff had a reasonable opportunity to ask DEC questions about the hydro capital expenditures and DEC's potential sale of the plants during the rate case hearing. At a minimum, the Public Staff could have brought the issue to the Commission's attention and requested the Commission's guidance on how to preserve the issue for later investigation by the Public Staff and consideration by the Commission. In addition, the Public Staff could have requested that the approval of DEC's recovery of the capital expenditures be conditional, that the amount received in rates for these costs be placed in a deferred account, and that the deferred account be subject to being used as an off-set to the loss on sale. The Public Staff did not follow any of these possible courses for preserving the issue of the reasonableness and prudency of DEC's capital expenditures. Based on the foregoing and the record, the Commission finds and concludes that there has been no showing of a change of circumstances, or any misapprehension or disregard of pertinent facts that provides the basis for a reconsideration of the Commission's approval of DEC's capital expenditures on the hydro plants in the Sub 1146 Rate Order. As a result, the Public Staff's motion for reconsideration should be denied.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 17-18

The evidence in support of these findings is based upon the Petition and the records as whole.

DEC has agreed to purchase all of the energy and RECs generated by the Facilities for five years following the Transaction through the RPPAs with Northbrook. As such, after the Transaction the Facilities will continue to serve customers with clean renewable energy, but at a lower cost over time. In accordance with the Commission's June 23, 1995 Order Establishing Standard Rates and Contract Terms for Qualifying Facilities in Docket No. E-100, Sub 74, DEC and Northbrook filed form RPPAs for the Facilities agreed to by DEC and Northbrook, which will be entered into by the parties at the closing of the Transaction. In its comments, the Public Staff recommended that the Commission grant the Applicants' requested declaratory ruling that the Facilities are new renewable energy facilities, and that DEC can use the RECs to meet its REPS obligations.

Pursuant to N.C. Gen. Stat. § 62-133.8(b)(2), an electric public utility such as DEC may meet its REPS compliance requirement through several methods, including by "generat[ing] electric power at a new renewable energy facility" or "purchasing renewable energy certificates from a new renewable energy facility." In addition, the definition of a new renewable energy facility in N.C. Gen. Stat. §62-133.8(a)(5)(c) includes "a hydroelectric power facility with a generation capacity of 10 megawatts or less that delivers electric power to an electric power supplier."

The Commission accepted the registration of many of the DEC-owned hydroelectric facilities of less than 10 megawatts as renewable energy facilities, but not as new renewable energy facilities, in its Order Accepting Registration of Renewable Energy Facilities in Docket Nos. E-7, Subs 886, 887, 888, 900, 903, and 904 (July 31, 2009); and its Order Accepting Registration of Renewable Energy Facilities, in Docket Nos. E-7, Subs 942, 943, 945, and 946 (December 9, 2010) (Registration Orders). In the Registration Orders, the Commission specifically cited its June 17, 2009 Order on Public Staff's Motion for Clarification in Docket No. E-100, Sub 113, where it concluded that these utility-owned hydroelectric facilities do not, however, meet the delivery requirement of N.C. Gen. Stat. §62-133.8(a)(5)(c), which requires the delivery of electric power to an electric power supplier, such as DEC, by an entity other than the electric power supplier in order to qualify as a new renewable energy facility. In this case, the transfer of the Facilities to Northbrook will result in the electric power from these hydroelectric facilities, all of which are less than 10 megawatts in capacity, being delivered to DEC, thereby meeting the statutory criteria to be designated as new renewable energy facilities.

As part of the Petition, Northbrook filed registration statements for each of the hydroelectric facilities as new renewable energy facilities. The Public Staff reviewed the registration statements and determined that they contain the certified attestations required by Commission Rule R8-66(b). Therefore, the Public Staff recommended that the Commission accept the registration statements for each of the Facilities.

CONCLUSIONS

Based on the foregoing, the Commission concludes that the transfer of certificates for the Facilities from DEC to Northbrook is justified by the public convenience and necessity and should be approved, and that the certificates shall be issued to Northbrook upon the closing of the Transaction. Further, the Commission authorizes DEC to establish a regulatory asset for the loss on sale of the Facilities, with the period of amortization and the issue of a return on the deferred balance to be decided in DEC's next general rate case. In addition, the Commission finds and concludes that once the Facilities have been transferred to Northbrook, each Facility shall qualify as a new renewable energy facility pursuant to the REPS statute, and that DEC may use any RECs purchased from the Facilities for REPS compliance.

IT IS, THEREFORE, ORDERED as follows:

1. That the transfer of the Bryson, Franklin, Mission, Tuxedo, and Gaston Shoals hydroelectric generating facilities by DEC is hereby approved. The transfer of CPCNs which were issued or deemed to have been issued to DEC for the Bryson, Franklin, and Mission facilities to Northbrook Carolina Hydro II, LLC, and the transfer of the CPCN which was issued or deemed to have been issued for the Tuxedo facility from DEC to Northbrook Tuxedo, LLC, are approved, contingent upon the closing of the Transaction.

2. That DEC's certificates for the four North Carolina hydroelectric generating facilities are hereby cancelled and reissued to Northbrook upon the closing of the Transaction.

3. That DEC shall notify the Commission and the Public Staff within 10 days of the date of closing the Transaction.

4. That DEC shall provide the Commission and the Public Staff with the accounting entries related to the Transaction within 60 days of the date of closing the Transaction.

5. That DEC is hereby authorized to establish a regulatory asset for the loss on the disposition of the hydro units of approximately $27 million on a North Carolina retail allocable basis. Amortization of the regulatory asset shall begin at the time the Transaction is closed and amortization expense shall be at the level of depreciation currently approved in rates until the time of its next general rate case, at which time DEC shall address the appropriate amortization period for the remaining regulatory asset balance. The amortization period for the remaining regulatory asset and the question of whether it should earn a return will be decided in DEC's next general rate case.

6. That the Public Staff's motion under N.C.G.S. § 62-80 to reopen and preserve the ability of the Public Staff to investigate the 2015-2017 capital costs of the Facilities and hold open the issue of the reasonableness of recovery of the costs until DEC's next general rate case shall be, and is hereby, denied.

7. That, for ratemaking purposes, the issuance of this Order is without prejudice to the right of the Public Staff or any party to take issue with the reasonableness of the deferred costs arising from the Transaction itself and their treatment for ratemaking purposes in DEC's next general rate case.

8. That DEC may use RECs purchased from the Facilities for REPS compliance.

9. That Northbrook's registration statements for the Facilities are accepted upon completion of the transfer.

10. That the Commission's decision on deferral of the loss on sale is based on the unique facts of this case, and shall not be cited or relied on as precedent in future proceedings.

ISSUED BY ORDER OF THE COMMISSION.
This the 5th day of June, 2019.

NORTH CAROLINA UTILITIES COMMISSION
A. Shonta Dunston, Deputy Clerk

DOCKET NO. E-2, SUB 1217

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of Duke Energy Progress, LLC for Authorization under North Carolina General Statutes § 62-161 to Issue and Sell Securities	))))	ORDER GRANTING AUTHORITY TO ISSUE AND SELL ADDITIONAL SECURITIES

BY THE COMMISSION: Duke Energy Progress, LLC (the Company) filed an Application on September 3, 2019 requesting authorization under N.C. Gen. Stat. § 62-161 to issue and sell a maximum of $3,500,000,000 aggregate principal amount of securities of all or any combination of Proposed Debt Securities, Long-Term Bank Borrowings, Tax Exempt Bond Obligations, Financing Lease Obligations, and Interest Rate Management Agreements (collectively, the Proposed Securities). Based upon the verified Application and the Commission's entire files and records in this matter, the Commission now makes the following:

FINDINGS OF FACT

1. The Company is a limited liability company duly organized and existing under the laws of the State of North Carolina. It is duly authorized by its governing documents and the law of this State to engage in the business of generating, transmitting, distributing and selling electric power and energy. It holds a certificate of authority to transact business in the State of South Carolina and is authorized to conduct and carry on business in South Carolina and is conducting and carrying on the businesses above mentioned in each of said States. It is a public utility under the laws of North Carolina and in its operations in this State is subject to the jurisdiction of this Commission. It is also a public utility under the laws of the State of South Carolina, and in its operations in that State is subject to the jurisdiction of the Public Service Commission of South Carolina. It is a public utility under the Federal Power Act, and certain of its operations are subject to the jurisdiction of the Federal Energy Regulatory Commission. The Company is a wholly owned subsidiary of Duke Energy Corporation, which is a holding company headquartered in Charlotte, North Carolina. Duke Energy Corporation wholly owns six other regulated public utility subsidiaries, Duke Energy Carolinas, LLC, Duke Energy Florida, LLC, Duke Energy Indiana, LLC, Duke Energy Ohio, Inc., Duke Energy Kentucky, Inc., and Piedmont Natural Gas Company. In addition, Duke Energy Corporation owns various nonregulated energy businesses primarily in the U.S.

2. The Company's existing outstanding long-term debt principally consists of First Mortgage Bonds, Tax Exempt Bond Obligations, Capital Leases and Accounts Receivable Securitizations. A schedule of all such Bonds, Senior Debt, Tax Exempt Bond Obligations, Finance Leases, Accounts Receivable Securitizations, and other Long-Term Debt outstanding as of March 31, 2019 was provided to the Commission as Exhibit A. All of the outstanding First Mortgage Bonds were issued under the terms of a Mortgage and Deed of Trust, dated as of May 1, 1940, as amended from time to time, between the Company, The Bank of New York Mellon (formerly Irving Trust Company), and Christie Leppert (successor to Tina D. Gonzalez), as Trustees (hereafter sometimes referred to as the Mortgage), copies of all of which have been

filed with this Commission. The Accounts Receivable Securitization consists of debt of the Company's subsidiary, Duke Energy Progress Receivables, LLC, as further described in the Company's application in Docket No. E-2, Sub 1036.

3. The Company proposes to issue, sell, incur or undertake from time to time a maximum of $3,500,000,000 aggregate principal amount of all or any combination of Proposed Debt Securities, Long-Term Bank Borrowings, Tax Exempt Bond Obligations, and Finance Lease Obligations. The Company also proposes to enter into Interest Rate Management Agreements. All of such financial transactions are further defined or described below (and are collectively referred to as, the Proposed Securities):

(i) Long-Term Debt Securities (Proposed Debt Securities)

The Proposed Debt Securities may be unsecured debt instruments or First Mortgage Bonds.

To the extent the Proposed Debt Securities are unsecured senior notes, they will be created and issued under, and subject to the provisions of the Indenture (for Senior Notes), dated as of March 1, 1999 between the Company and The Bank of New York Mellon, as Trustee, as amended and supplemented, which is substantially in the form provided to the Commission as Exhibit B, as further supplemented by the Supplemental Senior Note Indentures, to be executed in connection with their issuance.

To the extent the Proposed Debt Securities are the Company's First Mortgage Bonds, they will be created and issued under the Mortgage, as heretofore supplemented and as to be further supplemented and amended by a Supplemental Indenture to be executed in connection with their issuance. They will be subject to all of the provisions of the Mortgage, as supplemented, and by virtue of said Mortgage will constitute (together with the Company's outstanding First Mortgage Bonds) a first lien on substantially all of the Company's fixed property and franchises.

When any of the Proposed Debt Securities are issued for refunding or refinancings, the Company proposes to execute the proposed transactions so that, over time, there will be no material effect on the Company's capitalization with respect to the source of funds.

The Proposed Debt Securities may also consist of debt securities subject to remarketing prior to maturity. Consistent with prior orders of the Commission, any remarketing of such securities or resetting of their interest rates prior to the scheduled maturity date would not be deemed to be a re-issuance of such securities by the Company, so as to reduce the amount of securities otherwise permitted to be issued by the Company pursuant to the terms of the Commission's order in this docket.

(ii) Long-Term Bank Borrowing

The Company further seeks permission to make long-term borrowings under its Master Credit Facility (Long-Term Bank Borrowings) or other similar bank borrowing arrangements. As of July 31, 2019, the Company currently has a $1.25 billion borrowing sublimit under Duke Energy's approximately $8.0 billion master credit facility with a group of banks. The Company may increase its borrowing sublimit under the master credit facility to a maximum of $1.4 billion, as may be necessary to improve its liquidity and financial flexibility. Borrowings under the facility are available for general corporate purposes. The current five-year facility will expire on March 16, 2024. Under the agreement, any borrowing of more than one year in duration by the Company (or any other borrower other than Duke Energy Corporation) must be specified as a long-term borrowing in the notice of borrowing to the lenders. The Company therefore requests the Commission's approval for borrowings in excess of one year in duration, under the Master Credit Facility or such other similar bank borrowing arrangements the Company may enter into from time to time.

(iii) Tax Exempt Bond Obligations

The Company proposes to enter into agreements to borrow proceeds from the sale of tax exempt debt securities issued by one or more governmental authorities (Tax Exempt Bonds), to fund construction of qualifying facilities associated with the Company's electric generation plants (and qualifying related expenditures), to reimburse costs previously expended for such purposes, or to refund previously outstanding Tax Exempt Bonds. The Company's obligation to repay the issuing authority may be direct, through a secured or unsecured loan agreement between it and the authority, or indirect through financing arrangements such as a letter of credit posted by a bank to secure the Company's obligations on the Tax Exempt Bonds. The Company's direct obligation under a loan agreement with the authority may be insured by a third party or secured by issuance of a First and Refunding Mortgage Bond or other secured instrument.

(iv) Finance Lease Obligations

The Company proposes to enter into finance lease obligations (Leases), under which it will utilize lease financing structures as another form of financing the capital requirements discussed in Section 9 of the Application. The Leases will have structures and terms similar to other forms of debt financing, but with the potential, in certain instances, to lower the overall cost of financing property acquisitions.

Leases may be used to finance the acquisition of new property, including in connection with construction of new electric plant, or refinancing of existing utility property, in order to optimize the cost of financing commensurate with such property's expected life. The property expected to be leased will consist of (a) electric generating facilities and equipment used in the Company's operations including, but not limited to, meters, landfill and coal yard heavy equipment, transportation equipment, turbines, transformers, water pumps, exhaust stacks, substations, computers and office equipment, and intangible property such as software and site licenses, and (b) real property, office buildings and other such property used in the Company's operations (collectively, the Property).

The amouot financed under each Lease, excluding transaction costs, is not expected to be more than the net capitalized cost of the Property or the appraised value of the Property (in the event more than the capitalized cost is financed).

In accordance with generally accepted accounting principles, the net capitalized cost of property usually includes installation, training, allowance for funds, administrative overhead and other costs capitalized in connection with acquiring and placing the property in service. Such costs are expected to be included in the Property cost financed under each Lease.

To effectuate Lease transactions, the Company will obtain third-party lease financing for the original purchase or refinancing of Property acquisitions, and an agreement will be executed with a financing counterparty (the Lessor) setting forth the terms of each Lease.

As part of the consummation of a Lease transaction, the Lessor will typically either (1) pay the vendor and the Company for their respective costs associated with the Property acquisition or (2) reimburse the Company for the capitalized cost of the Property, with the Company concurrently paying the vendor the invoice cost.

The Company may enter into one or more participation agreements with its affiliates and the Lessor in connection with the Leases, with such agreements defining the Company's role as principal and, as applicable, agent on behalf of its affiliates for billing and payment remittance purposes. Such arrangements will be undertaken solely for administrative efficiencies and the convenience of the parties involved and will be subject to applicable standards relating to transactions among affiliates.

At the end of each initial or renewal lease term, it is anticipated that the Company will have an option to either (a) renew each Lease pursuant to arm's-length negotiation with the Lessor or other potential lessors, (b) purchase the Property, or (c) terminate the Lease.

(v) <u>Interest Rate Management Agreements</u>

Although it is unclear whether or not such activities constitute the issuance of securities within the meaning of § 62-161 of the North Carolina General Statutes, the Company nevertheless respectfully requests that the Commission grant it authority to utilize interest rate management techniques and enter into Interest Rate Management Agreements to manage its interest costs.

Interest Rate Management Agreements will include products commonly used in today's capital markets. These products include, but are not limited to, interest rate swaps, caps, collars, floors, options, or other hedging products such as forwards or futures. The Company expects to enter into these agreements with counterparties that are highly rated financial institutions. The transactions will be for a fixed period and a stated notional amount and may be entered into in connection with underlying fixed or variable obligations of the Company.

The Company will establish pricing for Interest Rate Management Agreements through negotiated offerings, through a competitive bidding process, or otherwise in accordance with recognized market practices.

The notional amount of any given Interest Rate Management Agreement will correspond to all or a portion of a current or future debt security authorized by Commission order. Therefore, entry into a given Interest Rate Management Agreement itself will not reduce the amount of "shelf" authority under such Commission order.

4. To the extent the Proposed Securities are issued and sold in one or more public offerings subject to registration under the federal securities laws, the Company will sell the Proposed Securities during the effective period of a "shelf" registration statement which the Company has filed with the Securities and Exchange Commission in connection with the registration of such securities. The Company proposes to enter into negotiations with, or request competitive proposals from, investment banks or other financial institutions to act as agents, dealers, underwriters, or direct purchasers in connection with either the public or private offering of each issuance of Proposed Securities in accordance with the terms thereof. The Company will determine which sales method and financial institution(s) will provide the most favorable service to the Company for any issuance and sale of the Proposed Securities. Certain types of the Proposed Securities, such as bank borrowings, financial leases and interest rate management agreements, are not typically "sold" in a public or private offering. The method of issuance of such securities, or incurrence of obligations, will be as described in the corresponding part of Section 3.

5. The authority requested by the Company is to replenish the authority previously granted under the Commission's order in Docket No. E-2, Sub 1130, of which a substantial portion has been utilized as further described in the Company's Reports of Issue and Sale in such docket. The Company requests that the remaining authority granted in such docket be terminated upon the Commission's granting of the authority requested herein.

6. The Company will pay no fee for services (other than attorneys, accountants, trustees, rating agencies and fees for similar technical services) in connection with the negotiation and consummation of the issuance and sale of any of the Proposed Securities, nor for services in securing underwriters, agents, dealers or purchasers of such securities (other than fees negotiated with such persons).

7. Proceeds from issuance of the Proposed Securities may be used for (a) the purchase or redemption of the Company's outstanding higher cost securities as hereinafter provided, (b) refunding maturing securities, (c) financing the Company's ongoing construction, as further described in Section 9 hereof (including the acquisition of nuclear fuel) or (d) the Company's general purposes; however, no such proceeds will be used for the purpose of meeting the funding needs of any of the Company's affiliates except as allowed under the Money Pool Agreement approved by the Commission in Docket No. E-2, Sub 998A. In each case, such proceeds may be used for the repayment of short-term debt incurred for such purposes.

8. When the net proceeds from the issuance of any of the Proposed Securities will be applied and used by the Company to purchase or redeem certain of the Company's outstanding unmatured debt securities, such issuances will be made from time to time when market conditions permit, on terms which would result in a lower cost of money to the Company. Any premium paid on purchased or redeemed debt securities will be amortized over the life of the new securities, and the Company proposes to include the after-tax amount of such unamortized premium in

Company's rate base as a component of working capital. As previously noted, the net proceeds of any of the Proposed Securities may be applied and used by the Company to refund maturing securities, including the repayment of short-term debt incurred for that purpose.

9. The Company is continuing its construction program of additions to its electric generation, transmission and distribution facilities in order to, among other things, (i) meet the long-term expected increase in demand for electric service, (ii) construct and maintain an adequate margin of reserve generating capacity, and (iii) conduct necessary replacements of major generating plants and plant components, and is funding coal ash basin closure costs.

The Company connected approximately 23,515 new customers in 2018 and continues to incur significant capital expenditures related to expanding and replacing its transmission and distribution system.

The Company's electric energy sales were approximately 43.3 million, and 44.8 million megawatt hours for 2017 and 2018, respectively. Sufficient financing of its current construction program is essential if the Company is to continue to be able to meet its obligations to the public to provide adequate and reliable electric service. The Company's electric plant construction expenditures were $1.7 billion and $2.2 billion for 2017, and 2018, respectively. Further information is set forth in the Company's financial statements attached as exhibits to the Application.

The Company's plans include incurring significant capital expenditures for maintenance and expansion of its existing generation plants, modernization of the electric grid, and coal ash basin closure costs. During the period 2019 through 2023, the Company forecasts to invest approximately $9.6 billion in its electric plant, including grid modernization and coal ash basin closure costs. Adequate financing authority as applied for in the Application will allow the Company to access the capital markets to efficiently fund these necessary capital expenditures.

The Company submits that the purposes of the issuance, sale, and/or incurrence of the Proposed Securities are lawful objects within the limits of the Company's authority and purposes under the applicable laws and regulations, and as set forth in its Limited Liability Company Operating Agreement, as amended, which is on file with this Commission. For the reasons set forth above, the issuance and sale of the Proposed Securities will be compatible with the public interest, will be necessary and appropriate for, and consistent with, the proper performance by the Company of its service to the public as a utility, will not impair its ability to perform that service, and will be reasonably necessary and appropriate for such purpose.

10. The financial condition of the Company and its results of operations are shown by the Company's Annual Reports to the Commission and by other records of the Commission relating to the Company.

WHEREUPON, the Commission reaches the following:

CONCLUSIONS

Based upon the foregoing Findings of Fact and the entire record in this proceeding, the Commission is of the opinion and so finds and concludes that the transaction or transactions herein proposed:

- (i) Are for a lawful object within the limited liability company purposes of the Company;
- (ii) Are compatible with the public interest;
- (iii) Are necessary and appropriate for and consistent with the proper performance by the Company of its service to the public as a utility;
- (iv) Will not impair the Company's ability to perform its public service; and
- (v) Are reasonably necessary and appropriate to provide adequate funds for such purposes.

IT IS THEREFORE ORDERED that the Company is hereby authorized, empowered, and permitted to:

1. Issue and sell up to $3,500,000,000 aggregate principal amount of all or any combination of the "Proposed Securities" pursuant to the terms and conditions described herein at such times as the Company may deem necessary or advisable;

2. Execute, deliver, and carry out such instruments, documents, and agreements as shall be necessary or appropriate to effectuate such transaction or transactions; and

3. Use the net proceeds of such sales for its ongoing construction and maintenance program, to refund, repurchase, redeem, reduce, or retire outstanding indebtedness and for other general purposes, including meeting the funding needs of any of the Company's affiliates under the Money Pool Agreement approved by the Commission in Docket No. E-2, Sub 998A.

IT IS FURTHER ORDERED that:

4. If any of the securities are sold through a noncompetitive methodology such as a private placement at a negotiated price, the Company will, on the day of pricing or the next business day, notify the Commission in writing (initially by electronic mail is acceptable) of the terms and basis of the pricing including comparative current market data of other similar financing transactions;

5. The Company will report to the Commission in writing within thirty (30) days after the consummation of selling any of the securities herein authorized (the report to include as a minimum the stated interest rate, the offering price and yield to the public, the commission paid to the underwriter(s), the net proceeds to the Company, and the net costs to the Company);

6. In regard to executed Interest Rate Management Agreements, unless the income statement impact of Interest Rate Management Agreements is presented in the Company's Form 10-K and Form 10-Q reports, copies of related internal reports to the Company's Senior Management should be filed with the Commission within thirty (30) days or on a schedule that is consistent with such internal reporting;

7. The Commission's approval of the Application does not restrict the Commission's right to review and, if deemed appropriate, adjust the Company's cost of capital or expense levels for ratemaking purposes for the effect of the securities approved herein;

8. This proceeding be and the same is continued on the docket of the Commission, without delay, for the purpose of receiving the report as hereinabove provided; and

9. That the authority to issue any remaining securities previously granted by the Commission Order in Docket No. E-2, Sub 1130 is hereby terminated and that Docket No. E-2, Sub 1130 is hereby closed.

ISSUED BY ORDER OF THE COMMISSION
This the 30th day of September, 2019

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

DOCKET NO. E-2, SUB 1197
DOCKET NO. E-7, SUB 1195

In the Matter of Application by Duke Energy Carolinas, LLC and Duke Energy Progress, LLC, for Approval of Proposed Electric Transportation Pilot	))))	ORDER PROVIDING NOTICE OF HEARING TOPICS

BY THE CHAIR: On March 29, 2019, Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC (collectively, Duke) filed an application in the above-captioned dockets pursuant to N.C. Gen. Stat. § 62-140 and various Commission rules requesting approval of Duke's proposed electric transportation pilot program.

On April 4, 2019, the Commission issued an Order requesting comments and reply comments on Duke's proposal. The Commission has received numerous statements of position from interested persons, and comments and reply comments from numerous parties.

On October 25, 2019, the Commission issued an Order in which the Commission set this docket for a hearing on Thursday, November 21, 2019.

Based on the foregoing and the record, the Chair finds good cause to provide the parties with the following list of some of the topics that the Commission expects to ask questions about during the hearing.

1. The potential for Duke to place a value on electric vehicle (EV) batteries for second use purposes, translate that value into a bill credit or rebate pilot program to encourage EV purchases, and learn from the pilot what benefits Duke can derive from second use batteries.

2. The design, implementation, and estimated cost of an EV "make ready" program, as recommended by NCSEA in its initial comments.

3. The extent to which Duke's proposal is consistent with NCDOT's work on the Federal Highway Association's Alternative Fuel Corridor program. For example, whether Duke has considered the benefits of placing charging stations at strategically located NCDOT, municipal or other state agency assets (e.g., rest areas, truck weighing stations, highway patrol offices and stations, airport parking decks, municipal and courthouse parking facilities).

4. The extent to which Duke has investigated the resources already available to municipalities and school systems for fleet conversions, and the public interest aspects of requiring Duke's ratepayers to partially support what would typically be projects financed by local property taxes.

5. The extent to which Duke considered the benefits to be derived from including in the proposed pilot special tariffs to encourage EV charging at times that would be optimum for its system operations.

6. The interplay between Session Law 2019-132, which exempts a reseller of electricity at a vehicle charging station from being a "public utility," with Duke's participation in a competitive vehicle charging station market.

7. The extent to which Duke considered participation in a competitive market for EV charging services through a non-regulated subsidiary of the Company.

8. Duke's plan for recovering the costs of the proposed pilot program.

Therefore, the Chair directs that Duke have available at the hearing Duke personnel who are prepared to address the above topics, as well as other issues involved in Duke's application for approval of its proposed electric transportation pilot program.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 1st day of November, 2019.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

DOCKET NO. EGL-4, SUB 0

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of Secure Futures, LLC, d/b/a Secure Futures Solar, LLC, for a Certificate of Authority to Engage in Business as an Electric Generator Lessor Pursuant to N.C.G.S. § 62-126.7 and Commission Rule R8-73	))))))	ORDER GRANTING CERTIFICATE OF AUTHORITY TO ENGAGE IN BUSINESS AS AN ELECTRIC GENERATOR LESSOR

BY THE COMMISSION: On May 6, 2019, Secured Futures, LLC, d/b/a Secured Futures Solar, LLC (Secured Futures), filed an application for a certificate of authority to engage in business as an electric generator lessor in accordance with the provisions of N.C. Gen. Stat. § 62-126.7 and Commission Rule R8-73. Secured Futures filed a copy of its Articles of Organization as a supplemental application attachment on May 9, 2019.

On May 16, 2019, pursuant to Commission Rule R8-73(f)(2), the Commission issued an Order requiring Secured Futures to mail notice of its pending application to each electric service provider in whose service territory Secured Futures proposes to operate. On May 16, 2019, pursuant to the Commissions' Order of that same date, Secured Futures filed a certificate of service of its notice to both Duke Energy Carolinas, LLC (DEC), and Duke Energy Progress, LLC (DEP), advising of Secured Futures' pending application and intent to engage in business as an electric generator lessor in both DEC and DEP's respective service territories.

On June 5, 2019, the Public Staff filed the recommendation required by Commission Rule R8-73(f)(4), stating that Secured Futures' application was incomplete and deficient according to the requirements specified in Commission Rule R8-73 and N.C.G.S. § 62-126.6 and 126.7.

On July 22, 2019, Secured Futures filed its response to the Public Staff's deficiency notification along with supplemental attachments.

On August 9, 2019, the Public Staff filed its further recommendation stating that it has reviewed the application and supplemental filings of Secured Futures and determined them to be in compliance with the requirements of N.C.G.S. § 62-126 and Commission Rule R8-73. The Public Staff, therefore, recommends approval of Secured Futures' application for a certificate of authority to engage in business as an electric generator lessor.

Pursuant to Commission Rule R8-73(f)(5), more than 30 days have elapsed since Secured Futures filed its certificate of service, and no protests were filed with the Commission. Therefore, it is appropriate for the Commission to proceed in considering and deciding the application on the basis of information contained in Secured Futures' application and supplemental filings, the recommendations of the Public Staff, and the entire record in this proceeding.

ELECTRIC GENERATOR LESSOR -- CERTIFICATE

Having carefully reviewed Secured Futures' application and supplemental filings, the Public Staff's recommendation, and the entire record in this proceeding, the Commission determines that the application is complete and compliant with the requirements of Commission Rule R8-73 and N.C.G.S. § 62-126.7. The Commission further finds that the sample lease proposed by Secured Futures complies with the requirements of N.C.G.S. § 62-126.6.

Based upon the foregoing and the entire record in this proceeding, the Commission finds good cause to approve Secured Futures' application for a certificate of authority to engage in business as an electric generator lessor. The Commission further finds that Secured Futures has demonstrated that it is fit, willing, and able to conduct business in this State as an electric generator lessor. The Commission, therefore, issues to Secured Futures a certificate of authority to engage in business as an electric generator lessor.

IT IS, THEREFORE, ORDERED as follows:

1. That the application of Secured Futures, LLC, d/b/a, Secured Futures Solar, LLC, for a certificate of authority to engage in business as an electric generator lessor within the service territories of Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC, shall be, and is hereby, approved;

2. That Secured Futures shall register with the Commission each solar energy facility it leases in this State by filing a report of proposed construction, and, if the facility is intended to earn renewable energy certificates eligible for compliance with the North Carolina Renewable Energy and Energy Efficiency Portfolio Standard, register the facility as a new renewable energy facility pursuant to Commission Rule R8-66;

3. That Secured Futures shall notify the Commission of any material change to the information it provided to the Commission in this proceeding, including any change to the assigned service territories in which Secured Futures operates as an electric generator lessor;

4. That Secured Futures shall file with the Commission annually, on or before April 1 of each year, a certification of continued compliance with Article 6B of Chapter 62 and Commission Rule R8-73;

5. That Secured Futures shall, for the duration of the effectiveness of this Certificate of Authority, maintain general liability insurance coverage with at least $100,000 minimum limits, and shall provide the name and contact information of the insurance carrier and policy number as part of Secured Futures' annual report to the Commission; and

6. That this Order shall constitute the Certificate of Authority to Engage in Business as an Electric Generator Lessor, effective as of the date of issuance of this Order and to remain in effect unless terminated, suspended, or revoked by future Order of the Commission.

ISSUED BY ORDER OF THE COMMISSION.
This the 3rd day of September, 2019.

NORTH CAROLINA UTILITIES COMMISSION
A. Shonta Dunston, Deputy Clerk

DOCKET NO. EGL-4, SUB 0

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of Secure Futures, LLC, d/b/a Secure Futures Solar, LLC, for a Certificate of Authority to Engage in Business as an Electric Generator Lessor Pursuant to N.C.G.S. § 62-126.7 and Commission Rule R8-73	))))))	ERRATA ORDER

BY THE COMMISSION: On September 3, 2019, in the above captioned docket, the Commission issued an Order Granting Certificate of Authority to Engage in Business as an Electric Generator Lessor. It has come to the attention of the Commission that the Order incorrectly referred to the electric generator lessor as Secured Futures, LLC, d/b/a Secured Futures Solar, LLC. The correct entity name is Secure Futures, LLC, d/b/a Secure Futures Solar, LLC.

The Commission finds good cause to correct the entity name in the previously issued Order by issuing this order correctly stating the name of the electric generator lessor as Secure Futures, LLC, d/b/a Secure Futures Solar, LLC.

IT IS, THEREFORE, ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 16th day of September, 2019.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

DOCKET NO. EMP-105, SUB 0

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of Friesian Holdings, LLC, for a Certificate of Public Convenience and Necessity to Construct a 70-MW Solar Facility in Scotland County, North Carolina	)))))	INTERLOCUTORY ORDER ON LEGAL ISSUES, SCHEDULING HEARING, ALLOWING FILING OF TESTIMONY, AND ESTABLISHING DISCOVERY GUIDELINES

BY THE COMMISSION: On May 15, 2019, in the above-captioned proceeding, Friesian Holdings, LLC (Applicant), filed an application pursuant to N.C. Gen. Stat. § 62-110.1 and Commission Rule R8-63 for a certificate of public convenience and necessity (CPCN) to construct a 70-MW_{AC} solar photovoltaic (PV) electric generating facility to be located in Scotland County, North Carolina.

On June 13, 2019, the Commission issued an Order scheduling hearings in this matter, requiring the filing of testimony, establishing discovery guidelines, and requiring the Applicant to publish notice of the public hearing.

On August 5, 2019, in response to a motion by the Public Staff, the Commission issued an Order suspending the procedural schedule established pursuant to the Commission's June 13 Order and allowing the parties to file briefs addressing the following issues:

(1) The appropriate standard of review for the Commission to apply in determining the public convenience and necessity for a certificate to construct a merchant generating facility pursuant to N.C. Gen. Stat. § 62-110.1 and Commission Rule R8-63;

(2) Whether the Commission has authority under state and federal law to consider as part of its review of the CPCN application the costs associated with the approximately $227 million dollars in transmission network upgrades necessary to accommodate the FERC-jurisdictional interconnection of the merchant generating facility, and the resulting impact of those network costs on retail rates in North Carolina; and

(3) Whether the allocation of costs associated with interconnecting the Friesian project and any resulting additional capacity made available that is then utilized by State-jurisdictional interconnection projects is consistent with the Commission's guidance provided in the Commission's June 14, 2019, Order Approving Revised Interconnection Standard and Requiring Reports and Testimony, issued in Docket No. E-100, Sub 101, in which the Commission directed the utilities as follows: "to the greatest extent possible, to continue to seek to recover from Interconnection Customers all expenses ... associated with supporting the generator interconnection process under the NC Interconnection Standard."

On August 26, 2019, the Applicant, DEP, the Public Staff, and NCCEBA filed briefs; on September 9, 2019, the Applicant, DEP, the Public Staff, and NCCEBA and NCSEA (jointly) filed reply briefs.

On October 3, 2019, the Commission issued an Order scheduling oral arguments in this proceeding for the purpose of receiving arguments from the parties addressing the issues noted in the Commission's August 5 Order, and, additionally, the questions of whether and, if so, how the July 14, 2017 decision of the U.S. Court of Appeals for the D.C. Circuit in Orangeburg v. FERC, 862 F.3d 1071 (2017), applies to the issues noted in the Commission's August 5 Order.

On October 21, 2019, this matter came on for oral argument as scheduled.

Based upon the foregoing and the entire record herein, and in the interest of resuming this proceeding in a timely manner, the Commission finds good cause to issue this Order notifying the parties of the Commission's decisions on the legal issues noted in the Commission's August 5 Order and, additionally, the question of the application of Orangeburg to those issues. After careful consideration, the Commission agrees with the arguments of DEP and the Public Staff that the Commission may consider the costs for future network upgrades that are required to accommodate a proposed electric generating facility when considering an application for a CPCN pursuant to N.C.G.S. § 62-110.1 and Commission Rule R8-63. The Commission's final order on the merits of the CPCN application will include the Commission's full discussion and conclusions relevant to these issues, along with the Commission's findings of fact and ultimate decision to either issue or deny the CPCN requested by the Applicant. The Commission, therefore, further finds good cause to resume the procedural schedule in this matter by scheduling a hearing for the purpose of receiving expert witness testimony, establishing deadlines for the filing of testimony as an opportunity for the parties to address any factual issues that, because of the Commission's decisions on these legal issues, should be resolved in addressing the merits of the Applicant's application for a CPCN, and requiring the parties to comply with the discovery guidelines established pursuant to the Commission's June 13 Order.

IT IS, THEREFORE, ORDERED as follows:

1. That a hearing solely for the purpose of receiving expert witness testimony from the parties shall be held on Wednesday, December 18, 2019, at 10:00 a.m., in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, for the purpose of considering the Applicant's CPCN application;

2. That on or before Tuesday, November 26, 2019, the Applicant may file supplemental direct testimony and exhibits;

3. That on or before Friday, December 6, 2019, the Public Staff and intervenors may file direct testimony and exhibits;

4. That on or before Thursday, December 12, 2019, the Applicant may file rebuttal testimony and exhibits; and

5. That the parties shall comply with the discovery guidelines established pursuant to the Commission's Order issued in this proceeding on June 13, 2019.

ISSUED BY ORDER OF THE COMMISSION.
This the 25th day of October, 2019.

NORTH CAROLINA UTILITIES COMMISSION
A. Shonta Dunston, Deputy Clerk

ELECTRIC MERCHANT PLANTS – CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY AND REGISTRATION

DOCKET NO. EMP-101, SUB 0

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of Edgecombe Solar, LLC for a Certificate of Public Convenience and Necessity to Construct a 75-MW Solar Facility in Edgecombe County, North Carolina	))))	ORDER ALLOWING LIMITED CONSTRUCTION WITH CONDITIONS

BY THE CHAIR: On October 5, 2018, Edgecombe Solar, LLC (Applicant) filed an application pursuant to N.C. Gen. Stat. § 62-110.1 and Commission Rule R8-63 for a certificate of public convenience and necessity (CPCN) to construct a 75-MWAC solar photovoltaic (PV) electric generating facility in Edgecombe County, North Carolina. The Applicant also filed a registration statement pursuant to Commission Rule R8-66, seeking registration of the facility as a new renewable energy facility.

On October 16, 2018, the Public Staff filed a Notice of Completeness stating that the Public Staff has reviewed the application as required by Commission Rule R8-63(d) and that the Public Staff considers the application to be complete. In addition, the Public Staff requested that the Commission issue a procedural order setting the application for hearing, requiring public notice pursuant to N.C.G.S. § 62-82, and addressing other procedural matters.

On November 8, 2018, the Commission issued an Order Scheduling Hearing, Requiring Testimony, Establishing Procedural Guidelines and Requiring Public Notice (Scheduling Order). The Scheduling Order, among other things, scheduled a public witness hearing and an expert witness hearing for the purpose of receiving testimony regarding the application.

On December 18, 2018, the Applicant filed an affidavit of publication, evidencing that the Applicant caused to be published notice of the hearing in the Rocky Mount Telegram as required by the Scheduling Order.

On January 2, 2019, based upon no complaints having been filed in this docket, the Commission issued an Order cancelling the public hearing.

On January 3, 2019, based upon no petitions to intervene having been filed in this docket, and the Public Staff being the only parties to this proceeding, the Commission issued an Order cancelling the expert witness hearing. In that Order, the Commission noted that the Clearinghouse Coordinator of the Office of Policy and Planning of the Department of Administration filed comments from the State Historic Preservation Office (SHPO) of the North Carolina Department of Natural and Cultural Resources (NCDNCR). These comments reflect that the proposed site of the Applicant's facility is located in an area that has a "high probability for containing precolonial American Indian archeological sites" and that "archeological sites associated with the plantation of General William Ruffin Cox are likely present in the parcel." Therefore, NCDNCR recommends that prior to the initiation of any ground disturbing activities within the project area, a comprehensive archaeological survey of the project area be conducted by an experienced archeologist. On November 19, 2019, the Applicant filed a motion requesting that the Commission permit the Applicant to proceed with limited construction activities, including the construction of minimal pile installations and associated erosion control measures on portions of the site of the proposed facility. More specifically, the Applicant describes the archeological study activity that has occurred to date, which, in summary, identified 30 sites of potential archeological interest, 12 of which were determined to be ineligible for listing in the National Register of Historic Places. In addition, the Applicant and the SHPO of NCDNCR have agreed that there are no concerns with proceeding to limited construction activity on the 12 sites that have been studied to date. Included in the Applicant's filing are maps that more particularly identify the areas that have been studied, the areas that remain under study, and the areas where the proposed limited construction would be appropriate at this time. In support of its motion, the Applicant states that beginning construction in 2019 is critical to fulfill the Applicant's contractual obligations and for federal tax purposes. The Applicant further states that the limited construction activities would consist of minimal pile installations and associated erosion control measures related to the four inverter locations as shown in the map included as Exhibit B to the Applicant's filing, that each inverter location is within the project area, but outside of the areas still under archeologist study, and that the Applicant will mark off all areas still under study to ensure that the limited construction activity will not encroach on any of those areas. In addition, the Applicant commits that any construction undertaken would be without prejudice to any Commission action concerning the pending application and that the Applicant would assume all risks regarding the Commission's disposition of the application. The Applicant argues that the granting of the requested limited construction authority is in the public interest, will lead to the timely construction of a new renewable energy generation facility and increased investment in North Carolina, and that no risk to North Carolina utility ratepayers or the environment will result from granting the requested relief, as the Applicant commits to proceed with limited construction at its own risk subject to future Commission action. Finally, the Applicant states that the Public Staff has no objection to granting the limited construction authority requested by the Applicant. Based upon the foregoing and the entire record herein, the Chair finds good cause to grant the Applicant the authority to engage in construction of minimal pile installations and associated erosion control measures on portions of the site of the proposed facility that have been determined to be ineligible for inclusion on the National Register of Historic Places, as more particularly described in the Applicant's motion and depicted in Exhibit B of the Applicant's motion. The granting of this limited construction authority is subject to the conditions set forth in the ordering paragraphs below.

IT IS, THEREFORE, ORDERED as follows:

1. That the Applicant is hereby granted the authority to engage in construction of minimal pile installations and associated erosion control measures on portions of the site of the proposed facility, as requested in the Applicant's November 19, 2019 motion;

2. That the Applicant shall adhere to all applicable North Carolina Division of Environmental Quality erosion and sedimentation control guidelines;

3. That the Applicant shall implement the measures proposed in its November 19, 2019 motion for the fencing-off and non-disturbance of those portions of the site of the proposed facility that have not been subject of an archeological study or review by State Historic Preservation Office of the North Carolina Department of Natural and Cultural Resources;

4. That the Applicant shall bear all costs and other risks of the limited construction activities, and, specifically, the risk that the Commission may deny the Applicant's application for an amended certificate of public convenience and necessity to construct the proposed facility; and

5. That this Order is based on the unique facts and circumstances involved in this docket and shall not be cited by the Applicant or any other party as precedent in support of a request for future Commission action.

ISSUED BY ORDER OF THE COMMISSION.
This the 2nd day of December, 2019.

NORTH CAROLINA UTILITIES COMMISSION
Kimberley A, Campbell, Chief Clerk

DOCKET NO. ER-88, SUB 0

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Phenix Greenville, LP, for Authority to Resell Electric Service Pursuant to N.C. Gen. Stat. § 62-110(h) at Bellamy Greenville, 2200 Bellamy Circle, Greenville, NC 27858	)))))	ORDER GRANTING CERTIFICATE OF AUTHORITY

BY THE COMMISSION: On September 10, 2018, Phenix Greenville, LP (Phenix Greenville or Applicant), filed with the Commission an application in the above-captioned docket for a certificate of authority to resell electric service at Bellamy Greenville, 2200 Bellamy Circle, Greenville, NC 27858, in accordance with N.C. Gen .Stat. § 62-110(h) and Commission Rule R22. On November 6, 2018, the Public Staff filed its correspondence to the Applicant, outlining the deficiencies in Phenix Greenville's application. On November 9, 2018, the Commission filed an Order Finding Application Incomplete and Request for Additional Information.

On December 18, 2018, the Applicant filed a response to the Public Staff's correspondence of November 6, 2018. On February 15, 2019, the Public Staff filed an amended deficiency letter to the Applicant. On May 15, 2019, the Applicant filed a response to the Public Staff's correspondence of February 15, 2019. On July 11, 2019, the Public Staff filed with the Commission a letter to the Applicant outlining the remaining deficiencies that needed to be addressed.

On July 19, 2019, and August 8, 2019, the Applicant filed a response to the Public Staff's correspondence of July 11, 2019. On August 26, 2019, the Public Staff filed in this docket a letter opining that the application is complete as modified by Applicant's certified statements in the above-referenced filings, and that the completed application complies with the requirements of N.C.G.S. § 62-110(h) and Commission Rule R22. The Commission, therefore, approves Phenix Greenville's application and grants it a certificate of authority to resell electric service.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 2nd day of October, 2019.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

DOCKET NO. T-4744, SUB 0

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of

Virtues Moving Company, Inc., 811 9th Street, Suite 120-252, Durham, North Carolina 27705 – Application for Certificate of Exemption in North Carolina	ORDER RULING ON FITNESS

HEARD: Tuesday, May 7, 2019, at 10:00 a.m. in the Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina 27603

BEFORE: Commissioner Charlotte A. Mitchell, Presiding, and Commissioners ToNola D. Brown-Bland and Lyons Gray

APPEARANCES:

For Virtues Moving Company Inc.:

Peter A. Hanna, Hopler, Wilms, & Hanna, PLLC, 2216 South Miami Boulevard, Suite 101, Durham, North Carolina 27703

BY THE COMMISSION: On January 14, 2019, Virtues Moving Company, Inc. (Virtues or Applicant) filed an application (Application) in the above-captioned docket with the North Carolina Utilities Commission (Commission) for a certificate of exemption (certificate) to transport household goods by motor vehicle for compensation within North Carolina. The Application named Richard Lewis and Bertrand Lewis as the Applicant's principals. The Applicant filed the fingerprint cards for Richard Lewis and Bertrand Lewis so that the Commission could request the North Carolina State Bureau of Investigation (NCSBI) to provide a certified criminal history record check as required by North Carolina General Statute § 62-273.1 and Commission Rule R2-8.1(a)(3).

The Commission received the criminal history records from the NCSBI on February 4, 2019. After reviewing the records, the Commission had additional questions regarding the Application.

On April 18, 2019, the Commission issued an Order Scheduling Application for Hearing on Tuesday, May 7, 2019. The Order stated that the Public Staff of the North Carolina Utilities Commission (Public Staff) could appear and participate in the hearing on behalf of the using and consuming public. On April 23, 2019, the Commission issued an Errata Order correcting the filing date of the Application. On April 29, 2019, the Public Staff filed a letter in the docket, which was later amended on April 30, 2019, indicating that the Public Staff had not received any complaints from consumers involving the Applicant and would not be participating in the hearing.

TRANSPORTATION – COMMON CARRIER CERTIFICATE

The hearing was held in Raleigh, North Carolina on Tuesday, May 7, 2019 as scheduled. The Applicant was represented by counsel. Mr. Bertrand Lewis, one of the principals of the Applicant, appeared in support of the Application and responded to questions from the Commission. Applicant also offered testimony from Bernell Lewis in support of Bertrand Lewis.

FINDINGS OF FACT

1. On January 14, 2019, Mr. Bertrand Lewis and Mr. Richard Lewis, on behalf of Virtues Moving Company, Inc., filed an application with the Commission for a certificate of exemption to transport household goods by motor vehicle within North Carolina for compensation. Mr. Bertrand Lewis and his brother, Mr. Richard Lewis, are the sole shareholders of Virtue Moving Company, Inc. The principal place of business is located in Durham, North Carolina. Mr. Bertrand Lewis is properly before the Commission seeking a certificate pursuant to N.C. Gen. Stat. § 62-261(8) and Rule R2-8.1 to transport household goods by motor vehicle for compensation within North Carolina.

2. The Commission regulates public utilities in the state of North Carolina including household goods movers.

3. Mr. Bertrand Lewis appeared at the hearing scheduled on May 7, 2019, provided testimony and answered questions from the Commission. Mr. Richard Lewis was not in attendance for the hearing.

4. Mr. Bertrand Lewis resides at 3719 2nd Street South East, Apartment 103, Washington, D.C. 20032.

5. Mr. Bertrand Lewis and Mr. Richard Lewis incorporated Virtues Moving Company, Inc., on December 20, 2018. Virtues Moving Company, Inc.'s principal office is located at 811 9th Street, Suite 120-252, Durham, North Carolina 27705. Mr. Richard Lewis resides in North Carolina and serves as the president of company, and Mr. Bertrand Lewis is the acting vice president.

6. Mr. Bertrand Lewis maintains his trade certificate as an insulator and belongs to the trade union Insulators & Allied Workers Local 24. Mr. Lewis has worked in this trade from 2015 to present.

7. Mr. Bertrand Lewis is the president and a shareholder of King of Diamonds Logistic, Inc., and King of Diamonds Broker Division, Inc. These two companies work in conjunction for the purpose of interstate transportation of property and freight, but the companies have not engaged in the intrastate transporting of household goods for compensation. King of Diamonds Logisties, Inc., filed for and maintains a Common Carrier of Property Certificate which was issued by the U.S. Department of Transportation on March 6, 2017.

8. Mr. Bertrand Lewis and Mr. Richard Lewis both have experience in the moving business. Mr. Bertrand Lewis worked for Mayflower Transit, LLC, for a period of one year.

9. Mr. Bertrand Lewis has participated in rehabilitation programs and sought counseling in an effort to improve his life.

10. Ms. Bernell Lewis, Mr. Bertrand Lewis's mother, testified at the hearing as a character witness in support of her son's fitness for the certificate for Virtues Moving Company, Inc. Ms. Lewis testified to her son's high character and deep loyalty to his family.

11. Mr. Bertrand Lewis is committed to working with Mr. Richard Lewis to operate Virtues Moving Company, Inc., and ensure that it is fully compliant with the laws of the state of North Carolina and the rules and regulations adopted by the Commission.

DISCUSSION OF EVIDENCE AND CONCLUSIONS

On May, 7, 2019, Mr. Bertrand Lewis (Mr. Lewis), as a principal of Virtues Moving Company, Inc., appeared before the Commission to respond to questions of the Commission regarding whether Mr. Lewis, a principal of Applicant, is fit to provide for the transportation of household goods in intrastate commerce. After receiving evidence presented at the hearing, including Mr. Lewis and Ms. Bernell Lewis's testimony, and after reviewing the record as a whole, the Commission finds that Mr. Lewis has satisfactorily answered questions regarding his knowledge of and experience in the industry and overall fitness to provide for the transportation of household goods in intrastate commerce.

The record demonstrates that Mr. Lewis possesses experience in the fields of transportation of household goods, transportation as a common carrier, administration of transportation services, and trade. Mr. Lewis has worked in the area of household goods since 1994 whenhe began working for Mayflower Transit, LLC.[1] The record demonstrates that Mr. Lewis shall rely on Mr. Richard Lewis's 15 years of continued experience in the moving business as well.[2]

The record further indicates that Mr. Lewis, in conjunction with Mr. Richard Lewis, operates two successful and experienced freight and logistics firms.[3] King of Diamonds Logistic, Inc. and King of Diamonds Broker Division, Inc. (collectively, King of Diamonds) haul and manage freight and contract with Hart Transportation to deliver common goods and retail items such as clothes, dog food and other consumer items.[4] As the record indicates, King of Diamonds and its principals must be in compliance with Federal Regulations for the purpose of transporting property and must maintain an MC-8027-C certification.[5] At all times since March, 6, 2017 to the present, King of Diamonds has maintained this required certification. The record notes Mr. Lewis's responsibilities to King of Diamonds include managing administrative bookkeeping, scheduling,

[1] Transcript at 29, 32.

[2] *Id.* at 32.

[3] *Id.* at 33.

[4] *Id.* at 25, 51.

[5] *Id.* at 24.

and financial accounting.[1] Mr. Richard Lewis is responsible for operating company vehicles on behalf of King of Diamonds. As presented in the record, King of Diamonds Logistics Division maintains two vehicles currently.[2] Mr. Lewis and Mr. Richard Lewis shall provide similar services to the Applicant. Mr. Lewis will continue to reside in Washington, D.C. and Mr. Richard Lewis will continue to reside and be present in North Carolina.

Testimonial evidence in the record shows that Mr. Lewis is committed to and capable of operating Applicant in a manner fully compliant with all applicable laws and not in violation of law or Commission rules; that he is focused on succeeding in business and in life; and that he presently has a network of family and friends who support, encourage and motivate him to move forward, appropriately dealing with life's challenges. His mother, Ms. Bernell Lewis, testified that Mr. Lewis is a positive role model to his family, including his five children, and his community.[3] Ms. Bernell Lewis further testified she has seen Mr. Lewis mature and become a voice of reason for others which she attributes to his faith and trust in a higher power.[4] Mr. Lewis testified that he relies on his family, his faith and counsel from his faith leader for his continued growth.[5]

The Commission, having considered all evidence of record and having weighed and determined the credibility of the witnesses providing testimony at hearing, is persuaded that Mr. Lewis, along with his brother Mr. Richard Lewis, are committed to operating a business that is fully compliant with all applicable laws and does not violate any laws or Commission rules. Mr. Lewis and his brother also seek to use their company, the Applicant, to provide access to household moving services to an underserved population of the Durham community. Finally, Mr. Lewis's and Mr. Richard Lewis's work with King of Diamonds establishes that they have the practical experience and financial ability to provide good customer service and meet the regulatory requirements of the Commission.

Based on the foregoing, the Commission finds and concludes that Mr. Lewis has sufficiently addressed the Commission's questions regarding his fitness to obtain a certificate, has demonstrated reasonable and adequate knowledge of the household goods moving industry, has shown an ability to follow the applicable statutes and Commission rules, and has demonstrated a commitment to provide satisfactory service to the using and consuming public. Therefore, the Commission concludes that Mr. Lewis's fitness is not a basis for denying the Applicant a certificate

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[1] *Id.* at 31.

[2] *Id.* at 26.

[3] *Id.* at 59.

[4] *Id.* at 60.

[5] *Id.* at 41, 47, 61.

of exemption pursuant to N.C. Gen. Stat. § 62-261(8). Furthermore, upon completion of all requirements of applicable law and Commission rules, the Commission determines that it would be appropriate to issue a certificate of exemption to the Applicant to transport household goods within North Carolina.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 15th of July, 2019.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

DOCKET NO. T-4744, SUB 0

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Virtues Moving Company, Inc.,	)	
811 9th Street, Suite 120-252, Durham,	)	ORDER GRANTING
North Carolina, 27705 – Application	)	CERTIFICATE OF EXEMPTION
for Certificate of Exemption	)	

BY THE COMMISSION: On January 14, 2019, in the above-captioned docket, Virtues Moving Company, Inc. (Applicant), pursuant to N.C. Gen. Stat. § 62-273.1 and Commission Rule R2-8.1(a)(3), filed an application with the Commission for a certificate of exemption. No protests were filed to the application. The application included the required confidential SBI and FBI criminal history records check.

On April 18, 2019, the Commission issued an Order scheduling a hearing on Tuesday, May 7, 2019,[1] in Raleigh, North Carolina to address questions regarding the Applicant's application and fitness. The Order stated that the Public Staff – North Carolina Utilities Commission (Public Staff) could appear and participate in the hearing on behalf of the using and consuming public.

On April 29, 2019, the Public Staff filed a letter with the Commission[2] indicating that the Public Staff had not received any complaints from consumers involving the Applicant and would not be participating in the hearing.

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[1] On April 23, 2019, the Commission issued an Errata Order correcting errors included in the April 18, 2019 Order regarding the hearing date and the filing date of the Application.

[2] On April 30, 2019, The Public Staff amended its April 29, 2019 letter to reflect the correct name of the Applicant.

The hearing was held in Raleigh, North Carolina on Tuesday, May 7, 2019, as scheduled. The Applicant was represented by counsel. Mr. Bertrand Lewis, one of the principals of the Applicant, appeared in support of the Application and responded to questions from the Commission. The Applicant also offered testimony from Ms. Bernell Lewis in support of Mr. Bertrand Lewis.

On June 25, 2019, the Applicant, through counsel, filed a proposed order supporting the issuance of a certificate of exemption to the Applicant.

On July 15, 2019, the Commission issued an Order Ruling on Fitness concluding that Mr. Bertrand Lewis has shown to the satisfaction of the Commission that he possesses reasonable and adequate knowledge of the household goods moving industry, has the ability to follow the applicable general statutes and Commission rules, and has a desire to provide satisfactory service to the using and consuming public.

Upon consideration of the application for a certificate of exemption filed with the Commission on January 14, 2019, the Commission's July 15, 2019 Order, and the entire record in this docket, the Commission finds and concludes that the Applicant should be granted a certificate of exemption to transport household goods, and has complied with the terms and conditions attached to the certificate of exemption:

1. Applicant is fit, willing, and able to properly perform the service of household goods transportation within North Carolina, is familiar with the moving industry, and has a reasonable and adequate knowledge of the rules and regulations governing the moving industry, including safety requirements as enforced by the North Carolina Division of Motor Vehicles.

2. Applicant will abide by the tariff requirements as established by the Commission and adopted in Maximum Rate Tariff No. 1.

3. Applicant is financially solvent and able to furnish adequate service on a continuing basis by maintaining the required insurance protection, maintaining safe, dependable equipment, and being able to settle any damage claims which may arise.

4. Applicant will maintain and has on file with the North Carolina Division of Motor Vehicles liability and cargo insurance coverage as required by law and Commission rules and regulations.

5. Applicant will maintain and has on file with the Commission's Operations Division a certificate of general liability insurance coverage in the minimum amount of $50,000.

IT IS, THEREFORE, ORDERED as follows:

1. That the application for certificate of exemption filed by Virtues Moving Company, Inc., be, and the same is hereby, granted, and that the Applicant is hereby authorized to transport household goods between all points and places within North Carolina.

2. That the Applicant shall maintain its books and records in such a manner that all of the applicable items of information required in the prescribed Annual Report to the Commission can be used by the Applicant in the preparation of such Annual Report. A copy of the Annual Report form shall be furnished upon request made to the Public Staff – North Carolina Utilities Commission, Transportation Rates Division.

3. That the Applicant shall maintain its books and records in such a manner that all of the applicable items of information requested in its prescribed quarterly Public Utilities Regulatory Fee Report can be used by the Applicant in the preparation of such report and payment of quarterly regulatory fee. Any questions regarding the regulatory fee report and/or regulatory fee should be directed to the Commission's Fiscal Management Division at 919-733-5265.

4. That all vehicles, whether owned or leased, and used by the Applicant in its household goods operations must be identified with Applicant's name, city, state, and certificate of exemption number on both sides of each vehicle in letters not less than three (3) inches high. Such vehicles must also be identified with Applicant's certificate of exemption number on the left upper quadrant of the rear of each vehicle in letters not less than three (3) inches high.

5. That the Applicant shall attend a Maximum Rate Tariff (MRT) Seminar no later than three (3) months from the date of this Order.

6. That this Order shall constitute a certificate of exemption until formal Certificate of Exemption No. C-2933 has been issued and transmitted to the Applicant, along with a copy of Maximum Rate Tariff No. 1.

ISSUED BY ORDER OF THE COMMISSION.
This the 6th day of August, 2019.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

DOCKET NO. W-1160, SUB 42

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of KDHWWTP, LLC for Approval of a New Debt Arrangement and for Refinancing of Existing Debt Pursuant to G.S. 62-153, G.S. 62-161, and Rule R1-16	)))))	ORDER APPROVING NEW DEBT ARRANGEMENT AND REFINANCING OF EXISTING DEBT

BY THE COMMISSION: On January 25, 2019, KDHWWTP, LLC (KDH or the Company) filed an Application pursuant to G.S. 62-153, G.S. 62-161, and Rule R1-16, and amended the Application on February 7, 2019, requesting Commission approval to pledge utility assets to refinance an existing loan of $1,700,000.00 from TowneBank with a new loan of $1,000,000.00 from First National Bank of Pennsylvania (First Bank). KDH is also requesting approval to establish a $300,000.00 Line of Credit with First Bank.

The Public Staff did not object to approval of the Application.

Based upon the amended Application, and the Commission's entire files and records in this matter, the Commission now makes the following

FINDINGS OF FACT

1. KDH provides wastewater utility service to numerous residential and commercial customers located in and adjacent to Kill Devil Hills, North Carolina on the Outer Banks. KDH provides some bulk wastewater treatment service to the Town of Kill Devil Hills. KDH serves only those customers which the Commission has approved by prior Orders.

2. On or about March 21, 2013, KDH entered into a Promissory Note and a Deed of Trust in the principal amount of $1,700,000.00 with TowneBank. This loan was to be repaid over a five-year term. The purpose of the TowneBank loan was for acquisition of sewer system assets. KDH affixed copies of the TowneBank Promissory Note and Deed of Trust to the Application.

3. KDH has now entered into a refinance agreement with First Bank for a principal loan of $1,000,000.00 which will be used to retire the remaining debt owed to TowneBank. KDH attached to its Application a copy of the draft loan documents from First Bank, including a Borrowing Resolution, Business Loan Agreement, Promissory Note, Deed of Trust, and Agreement to Provide Insurance.

4. KDH also requests authority to enter into a $300,000.00 Line of Credit Agreement with First Bank. KDH asserted that it needed the Line of Credit because of the seasonal, tourist-oriented nature of its wastewater business on the Outer Banks of North Carolina. KDH also attached a copy of the draft Line of Credit loan documents to the Application.

5. KDH asserted a variety of benefits from the new First Bank financing arrangements (including the Line of Credit) when compared to the existing TowneBank financing arrangements. KDH asserted that these benefits included, but were not limited to the following: (a) the principal amount of the primary loan [secured by KDH assets] will be reduced from $1,700,000.00 to $1,000,000.00; (b) the payment of interest on the primary loan will be changed from a "straight line" payment methodology [meaning that the same amount of interest is collected with each and every principal payment] to a "declining balance" method of payment of interest [meaning that, as the principal amount of the loan is paid down, the amount of interest collected per payment will decline over time]; and (c) the new financing arrangements will improve KDH's cash flow and cash management.

6. KDH acknowledges that, if the Commission approves the proposed refinancing and pledging of assets, the Commission retains plenary rights to review and adjust, if appropriate, KDH's cost of capital and/or expense levels for ratemaking purposes in the next KDH general rate case.

7. Pursuant to G.S. 62-160 et seq., and Commission Rule R1-16, KDH asserts that its refinancing plan and pledging of assets: (i) are lawful objects within the corporate purposes of KDH as a public utility; (ii) are compatible with the public interest; (iii) are necessary, appropriate, and consistent with the proper performance by KDH of its utility service to the public; (iv) will not impair the Company's ability to perform its required utility service; and (v) are reasonably necessary and appropriate for the purposes for which issued.

WHEREUPON, the Commission now reaches the following

CONCLUSIONS

Based upon the foregoing Findings of Fact and the entire record in this proceeding, the Commission is of the opinion and, therefore, concludes that the transactions proposed herein:

1. Are for lawful objects within the corporate purposes of the Company as a public utility;
2. Are compatible with the public interest;
3. Are necessary, appropriate and consistent with the proper performance by the Company of its service to the public as a utility;
4. Will not impair the Company's ability to perform its public utility service; and
5. Are reasonably necessary and appropriate for the purposes for which issued.

IT IS, THEREFORE, ORDERED that KDHWWTP, LLC is hereby authorized, empowered, and permitted to implement and execute the proposed refinancing plan and pledging of assets in accordance with the terms thereof as set forth in the Application as amended and Appendices attached thereto.

IT IS FURTHER ORDERED that the Commission's approval in this docket does not restrict the Commission's regulatory authority to review and adjust, if the Commission deems it appropriate to do so, the Company's cost of capital and/or expense levels for ratemaking purposes in the Company's next general rate case.

ISSUED BY ORDER OF THE COMMISSION.
This, the 25th day of February, 2019.

NORTH CAROLINA UTILITIES COMMISSION
Shonta Dunston, Deputy Clerk

DOCKET NO. W-1274, SUB 7

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Lake Junaluska Assembly,	)	ORDER GRANTING INTERIM
Inc., for a Certificate of Public Convenience	)	AUTHORITY TO OPERATE
and Necessity, and for Approval of Rates	)	PURSUANT TO COMMISSION
	)	RULES R7-20 & R10-16

BY THE CHAIRMAN: On September 28, 2018, Lake Junaluska Assembly, Inc. (LJA), filed an Application for a Certificate and Public Convenience and Necessity (CPCN), and for Approval of Rates in the above-captioned proceeding.

On January 25, 2019, LJA filed a Request for Interim Authority to Operate Pursuant to Commission Rules R7-20 and R10-16 (Request). In the Request, LJA acknowledges that the Commission in its Ordering Paragraph 4 of its Order Ruling on LJA Status as a Public Utility, issued April 23, 2018, in Dockets W-1274, Subs 5 and 6, provides that LJA shall not discontinue water and/or wastewater service to any current customers while its CPCN application is pending without prior approval of the Commission. LJA informs the Commission that it provides water service to 862 customers and sewer service to 829 customers. At present, LJA's receivables for water/sewer service total approximately $7,000, of which $4,000 is owed by 12 customers and is more than 90 days past due. Prior to filing its Application, LJA would typically have 6-8 customers with bills greater than 90 days in age during a collections cycle, at which point LJA would have terminated their service after several warnings.

LJA further shows the Commission that prior to issuance of the Status Order and the prohibition set forth in Ordering paragraph 4, LJA would have given the 12 customers with billings that are currently 90 days past due several warnings that they are at risk of having their service discontinued. Moreover, if customers continue to fail to make payment, after their accounts became 90 days past due, their service would have been discontinued. Considering the language within Ordering Paragraph 4, LJA is unable to discontinue service to customers who fail to pay for their water and/or sewer service.

LJA contends that if the older unpaid receivables continue to grow, they will at some point impact LJA while it awaits a hearing and the ruling on its Application. Given this possibility, LJA requests that the Commission authorize it, on an interim basis until the Commission has ruled on the Application, to operate in accordance with Commission Rule R7-20 for discontinuing service to a water customer and Rule R10-16 for discontinuing service to a sewer customer. LJA recognizes that these rules set forth the Commission's requirements for a utility's discontinuance of service to such customers. If LJA can work in accordance to these rules on an interim basis, it will be able to notify customers that their service is in danger of disconnection if they continue to fail to pay their water and/or sewer bills. LJA represents to the Commission that it discussed the situation and the relief herein with the Public Staff and the Public Staff supports the request as set forth.

The Chairman has reviewed the record, including LJA's Request filed on January 25, 2019, and finds that good cause exist to grant the request in this matter.

IT IS, THEREFORE, ORDERED as follows:

1. That Lake Junaluska Assembly, Inc., is hereby granted the authority, on an interim basis, to operate in accordance with Commission Rule R7-20 for disconnecting service to a water customer and Rule R10-16 for disconnecting service to a sewer customer; and

2. That this Order shall be served on Lake Junaluska Assembly, Inc., by electronic mail, delivery confirmation requested.

ISSUED BY ORDER OF THE COMMISSION.
This the 13th day of February, 2019.

NORTH CAROLINA UTILITIES COMMISSION
A. Shonta Dunston, Deputy Clerk

DOCKET NO. W-1314, SUB 2
DOCKET NO. W-822, SUB 3
DOCKET NO. W-1314, SUB 0

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. W-1314, SUB 2 DOCKET NO. W-822, SUB 3 In the Matter of Application for Transfer of Public Utility Franchise of Pines Utilities, Inc. to Pluris Webb Creek, LLC DOCKET NO. W-1314, SUB 0 In the Matter of Application by Pluris Webb Creek, LLC for Temporary Operating Authority to Serve The Pines Development in Onslow County, North Carolina, and for the Eventual Approval of a Certificate of Public Convenience and Necessity	ORDER CANCELING TEMPORARY OPERATING AUTHORITY, APPROVING TRANSFER, GRANTING FRANCHISE, APPROVING INTERIM RATES, REQUIRING UNDERTAKING, AND REQUIRING CUSTOMER NOTICE

BY THE COMMISSION: On December 22, 2016, in Docket No. W-1314, Sub 0, Pluris Webb Creek, LLC (Pluris), filed an application for a certificate of public convenience and necessity (CPCN) to provide wastewater utility service for 34 existing single-family residences in areas of The Pines Development[1] in Onslow County known as Eastport I and Timber Ridge, and for 44 to be constructed single-family residences at Eastport Section III, Phase 1, and for approval of rates. In that filing Pluris also requested temporary operating authority to provide wastewater utility service for this service area pursuant to N.C. Gen. Stat. § 62-116, and for approval of interim rates. On January 25, 2017, Pluris posted a $10,000 bond with the Commission. On February 1, 2017, the Commission issued an Order Approving Temporary Operating Authority, Approving Interim Rates, Requiring Undertaking, and Requiring Customer Notice.

On February 3, 2017, in Docket No. W-1314, Sub 0, Pluris filed its certificate of service indicating that customer notice was provided as required by the February 1, 2017 Order. On February 14, 2017, Pluris filed its executed undertaking to refund.

On February 16, 2017, in Docket No. W-1314, Sub 0, the Commission issued an Order Scheduling Hearing and Requiring Customer Notice. Such hearing was scheduled subject to

[1] The Pines Development in Onslow County, North Carolina consists of The Pines Mobile Home Park (MHP) with 170 units, 34 existing single-family residences in areas known as Eastport I and Timber Ridge, and other lots to be developed as single-family residences. The next phase of The Pines Development will consist of 44 new homes in Eastport Section III, Phase 1.

cancellation if no significant protests were filed with the Commission. On February 23, 2017, Pluris filed its certificate of service indicating that the required customer notice was provided. On March 10, 2017, Pluris filed a motion to cancel the public hearing stating that no customer protests had been filed. Pluris stated that the Public Staff – North Carolina Utilities Commission (Public Staff) had no objection to Pluris's motion to cancel the public hearing. Pluris further stated that Pluris and the Public Staff are the only parties to this proceeding. On March 10, 2017, the Commission issued an Order Canceling Hearing and Requiring Customer Notice. On March 14, 2017, Pluris filed its certificate of service indicating that the required customer notice was provided.

On February 12, 2018, in Docket Nos. W-1314, Sub 2 and W-822, Sub 3, Pluris and Pines Utilities, Inc. (PUI) filed an Application for Transfer of Public Utility Franchise of Pines Utilities, Inc. to Pluris Webb Creek, LLC, and for Approval of Rates (Joint Application). PUI's service area is the portion of The Pines Development, which consists of The Pines MHP and other areas where there is now, or will be in the future, residential and commercial development.

PUI was granted a CPCN for the Pines MHP by Order issued on June 14, 1985, in Docket No. W-822, Sub 0.[1] Pluris seeks to acquire PUI's wastewater collection system and to obtain authority to serve pursuant to a CPCN for the entirety of The Pines Development, consisting of The Pines MHP with approximately 170 mobile homes, the areas of The Pines Development which are the subject of the temporary operating authority granted to Pluris on February 1, 2017, in Docket W-1314, Sub 0, and all areas where future residential and commercial development will occur in The Pines Development (collectively referred to hereinafter as The Pines).

PUI is authorized by the Commission to provide wastewater utility service to all customers in The Pines, except for the 34 existing and the 44 constructed or to be constructed new single-family residences which are served by Pluris pursuant to the temporary operating authority granted it in Docket No. W-1314, Sub 0. Pluris serves those single-family residences at an interim monthly flat rate of $37.69 per single-family equivalent (SFE).

By Order issued on August 8, 2016, in Docket No. W-864, Sub 11, the Commission appointed Pluris as the emergency operator of the wastewater treatment system of Webb Creek Water and Sewage, Inc. (Webb Creek) and, among other things, approved interim provisional rates for residential and commercial customers.[2] The Webb Creek service area is located in Onslow County in close proximity to PUI's service area and The Pines Development.

On June 7, 2017, in Docket No. W-864, Sub 14, the Public Staff filed a Complaint and Petition for Revocation of Franchise for the Webb Creek wastewater utility system and the service area assigned to Webb Creek.

[1] PUI was previously granted temporary operating authority for this service area pursuant to the Commission's Order issued on February 28, 1985, in Docket No. W-822, Sub 0.

[2] The Commission approved an interim provisional monthly flat sewer rate for a residential customer of $37.69.

WATER AND SEWER – CERTIFICATE

On June 13, 2017, in Docket No. W-1314, Sub 1, Pluris filed an application for a CPCN authorizing it to serve the Webb Creek service area, if the Commission revoked Webb Creek's franchise.

On March 26, 2019, in Docket Nos. W-864, Sub 14 and Sub 11 and W-1314, Sub 1, the Commission issued its Order revoking Webb Creek's franchise and granting a CPCN to Pluris authorizing it to provide wastewater utility service in the area formerly served by Webb Creek, continuing for Pluris as franchise owner the interim provisional rates previously approved for Pluris as the Commission-appointed emergency operator.

On May 8, 2019, in Docket Nos. W-1314, Sub 2 and W-822, Sub 3, Pluris and PUI jointly filed a Request for Issuance of Order Requiring Customer Notice (the Request), requesting that the Commission issue its proposed order requiring customer notice as described therein and providing for any further proceedings in these dockets as necessary for the Commission to proceed with its review and decision concerning the Joint Application.

In the Request, Pluris and PUI acknowledged that revocation of Webb Creek's franchise and issuance of a CPCN to Pluris authorizing it to serve the Webb Creek service area was a predicate to approval of the transfer of PUI's assets and franchise to Pluris. Pluris and PUI asserted that because Webb Creek's franchise has been revoked, and a CPCN authorizing Pluris to serve the Webb Creek service area has been issued by the Commission, that all predicates necessary for the Commission to proceed with its review of the Joint Application in Docket Nos. W-1314, Sub 2 and W-822, Sub 3, have been satisfied.

Pluris's Agreement for Sanitary Sewer Service dated October 26, 2016, with The Pines LLC, the developer of The Pines (Agreement), was filed with the Commission on December 22, 2016, in Docket No. W-1314, Sub 0. As reflected in the Agreement, monthly sanitary sewer utility usage charges for the 170 existing mobile homes are paid by the developer, based on the current interim monthly flat sewer rate (residential) for the Webb Creek service area of $37.69 per SFE. The developer of The Pines plans to develop the existing MHP as single-family residences, once the MHP is phased out. The Agreement provides that when a MHP lot is converted to a single-family residence, the new owner of the single-family home will pay the Commission-approved rate for sanitary sewer utility service. Until that conversion occurs, The Pines developer will continue to pay the monthly flat sewer rate (residential) for the lots occupied by mobile homes. The Onslow Water and Sewer Authority (ONWASA) provides the water utility service to both The Pines Development and Webb Creek.

Given the lack of any customer protest relating to either Pluris being granted temporary authority to serve the Eastport I, Timber Ridge, and Eastport Section III, Phase 1, areas of The Pines, or Pluris being granted a CPCN to serve the Webb Creek service area, Pluris and PUI requested that the Commission issue its Order Requiring Customer Notice advising all customers in The Pines that unless the Commission receives significant protests, the Commission may grant the Joint Application without scheduling a hearing. The Public Staff supported that request. On June 6, 2019, a Joint Proposed Order Requiring Customer Notice was filed by Pluris and the Public Staff.

On June 11, 2019, in Docket Nos. W-1314, Sub 2 and W-822, Sub 3, the Commission issued an Order Requiring Customer Notice (Notice Order). In the Notice Order the Commission concluded that the notice to customers required by that Order would communicate to customers that the Commission may decide this matter on the filings and approve the franchise transfer and continuation of the interim rate of $37.69, without scheduling a hearing, if no significant protests are filed with the Commission.

The Commission also concluded in the Notice Order that the interim rate of $37.69 per SFE previously approved for Pluris in connection with the grant of temporary operating authority to serve portions of The Pines shall continue for The Pines, with this interim monthly rate being subject to refund, with 10% interest per annum, if not ultimately found to be reasonable by the Commission.

The Notice Order required that a copy of the Notice to Customers attached to that Order be mailed or hand delivered to all PUI customers, and the Eastport I, Timber Ridge, and Eastport Section III, Phase 1 customers which Pluris presently serves, no later than seven days after the date of the Notice Order. The Notice Order also directed Pluris to submit to the Commission the certificate of service attached to that Order, properly signed and notarized, not later than 10 days after the date of the Notice Order.

On June 17, 2019, Pluris filed its certificate of service with the Commission, which documented that the required Notice to Customers was mailed or hand delivered to all customers as required by the Notice Order.

No protests have been filed with the Commission relating to the Joint Application.

On October 15, 2019, Pluris filed a Proposed Order Approving Transfer, Granting Franchise, Approving Rates, and Requiring Customer Notice.

On October 22, 2019, the Public Staff filed comments with the Commission stating that the Public Staff fully supports the issuance of Pluris's Proposed Order as filed. Further, the Public Staff recommended that the Commission require Pluris to file the $50,000 bond that was agreed to by Pluris and the Public Staff and noted in the Proposed Order.

On October 24, 2019, Pluris filed the required commitment letter for its $50,000 bond and surety that was hand delivered by Pluris to the Chief Clerk on October 17, 2019. On that same date, the Chief Clerk accepted all bond documents for filing.

On the basis of the Joint Application, and the entire record in the above-captioned dockets and the related proceedings, the Commission makes the following

FINDINGS OF FACT

1. The current CPCN for The Pines MHP and immediate environs was issued to PUI in Docket No. W-822, Sub 0, by Order dated June 14, 1985.

2. Pluris and PUI have entered into a Utility Asset Purchase Agreement (APA) dated January 3, 2018, whereby, subject to Commission approval, Pluris agreed to acquire the assets and franchise of PUI for the sum of $10.00. The Public Staff has reviewed the APA and recommended that it be approved as written.

3. .Pluris has temporary operating authority to provide sewer utility service to Eastport I, Timber Ridge, and Eastport Section III, Phase 1, areas of The Pines pursuant to the Commission's Order Approving Temporary Operating Authority, Approving Interim Rates, Requiring Undertaking, and Requiring Customer Notice issued on February 1, 2017, in Docket No. W-1314, Sub 0.

4. Pluris's Agreement for Sanitary Sewer Service dated October 26, 2016, with The Pines LLC, the developer of The Pines (Agreement), was filed with the Commission on December 22, 2016, in Docket No. W-1314, Sub 0. The Agreement provides that the monthly sanitary sewer utility usage charges for the 170 existing mobile homes are paid by the developer, based on the current interim monthly flat sewer rate (residential) for the Webb Creek service area of $37.69 per SFE. The Agreement further provides that when a MHP lot is converted to a single-family residence, the new owner of the single-family home will pay the Commission-approved rate for sanitary sewer utility service. Until that conversion occurs, The Pines developer will continue to pay the monthly flat sewer rate (residential) for the lots occupied by mobile homes. The Public Staff has reviewed the Agreement and recommended that it be approved as written.

5. Pluris is a public utility and a wholly owned subsidiary of Pluris Holdings, LLC. Other wholly owned subsidiaries of Pluris Holdings, LLC, include (1) Pluris, LLC, which is a public utility operating a wastewater utility system serving North Topsail and nearby mainland areas near Sneads Ferry in Onslow County, North Carolina and (2) Pluris Hampstead, LLC, which is a public utility operating a regional wastewater system near Hampstead in Pender County, North Carolina. Pluris's only business is providing wastewater utility service.

6. Pursuant to the Commission's Order issued on March 26, 2019, In Docket Nos. W-1314, Sub 1 and W-864, Sub 11 and Sub 14, Pluris acquired the Webb Creek wastewater utility system and was granted a franchise for the former Webb Creek service area. Prior to the issuance of its franchise, Pluris served as the emergency operator for the Webb Creek service area pursuant to the Commission's Order Appointing Emergency Operator, Approving Increased Rates, and Requiring Customer Notice issued on August 8, 2016, in Docket No. W-864, Sub 11. Pluris's record of service is satisfactory.

7. PUI's wastewater treatment plant was beyond the end of its useful life. The effluent disposal for the PUI wastewater system was through a drain field with underground low pressure pipe. Rather than build a new wastewater treatment facility to serve its franchised service area, PUI elected to connect to the former Webb Creek wastewater treatment plant operated by Pluris and to dismantle its aged wastewater treatment plant. Pluris is currently providing service to PUI and The Pines developer utilizing the Webb Creek wastewater utility system.

8. Pluris is currently building a new Membrane Bio-Reactor wastewater treatment plant sufficient to serve the Webb Creek service area, The Pines service area, and the general vicinity.

9.. Pluris currently serves approximately 204 wastewater customers in The Pines. The service area is shown on plans filed with the application.

10. Pluris proposes to charge The Pines the interim provisional rate of $37.69 per SFE approved for Pluris in connection with the grant of temporary operating authority to serve Eastport I, Timber Ridge, and Eastport III, Phase I, with this interim monthly rate being subject to refund, with 10% interest per annum, if not ultimately being found to be reasonable by the Commission.

11. Pluris has the technical, managerial, and financial capacity to own and operate the wastewater utility system serving The Pines.

12. No objections or protests have been filed with the Commission relating to the Joint Application or Docket Nos. W-1314, Sub 0 and Sub 2 or Docket No. W-822, Sub 3.

13. The Public Staff has recommended that Pluris be required to post a $50,000 bond for The Pines. On October 17, 2019, Pluris provided the Commission a commercial surety bond in the amount of $50,000. On October 24, 2019, Pluris filed its commitment letter. Pluris has met all filing requirements for a bond secured by a commercial surety. Including the bond posted in this proceeding, Pluris has a total of $250,000 of bond surety posted with the Commission.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-13

The evidence supporting these findings of fact is found in the Commission's records; the Joint Application; the entire record in the above-captioned dockets and the related proceedings noted herein; and the Public Staff's comments filed on October 22, 2019. These matters are undisputed, as no objections or protests have been filed with the Commission relating to the Joint Application or the above-captioned dockets. Pluris, PUI, and the Public Staff are the only parties in Docket Nos. W-1314, Sub 2 and W-822, Sub 3 and Pluris and the Public Staff are the only parties in Docket No. W-1314, Sub 0.

CONCLUSIONS

Based upon the foregoing, and given the lack of any customer protests relating to either Pluris being granted temporary authority to serve the Eastport I, Timber Ridge, and Eastport Section III, Phase I areas of The Pines, or Pluris being granted a CPCN to serve the Webb Creek service area, or the filing of any protest pursuant to the Notice Order, the Commission concludes that the transfer of the franchise and assets from PUI to Pluris is in the public interest and should be approved; that the APA between Pluris and PUI dated January 3, 2018, and the Agreement between Pluris and the developer of The Pines dated October 26, 2016 should be approved; that the temporary operating authority granted to Pluris for Eastport I, Timber Ridge, and Eastport

Section III, Phase 1 should be canceled; and that the CPCN attached hereto as Appendix B should be granted to Pluris authorizing it to provide wastewater utility service in The Pines.

Further, the Commission concludes that the interim rate of $37.69 per SFE approved for Pluris in connection with the grant of temporary operating authority to serve portions of The Pines shall continue, with this interim monthly rate being subject to refund, with 10% interest per annum, if not ultimately being found to be reasonable by the Commission. When permanent rates are set for the Webb Creek and The Pines service areas in Pluris's next general rate case or by further order of the Commission, the interim rates collected by Pluris either under temporary operating authority or thereafter pursuant to a CPCN, which are subject to an undertaking to refund by Pluris, will be audited by the Public Staff. The Public Staff will recommend to the Commission whether the Public Staff considers that there has been an overcollection and customer refunds should be ordered by the Commission.

IT IS, THEREFORE, ORDERED as follows:

1. That the commercial surety from Federal Insurance Company filed in this proceeding on October 17, 2019, as surety for the bond in the amount of $50,000 required by the Commission, is hereby accepted and approved.

2. That the APA between Pluris and PUI dated January 3, 2018, is hereby approved as written. That the Agreement between Pluris and the developer of The Pines dated October 26, 2016, is hereby approved as written.

3. That Pluris is hereby granted a certificate of public convenience and necessity to provide wastewater utility service in The Pines in Onslow County, North Carolina.

4. That Appendix A constitutes the Certifieate of Public Convenience and Necessity.

5. That the attached Appendix B — Schedule of Interim Provisional Rates, Appendix B, is approved and deemed filed with the Commission pursuant to N.C. Gen. Stat. § 62-138. Such interim rates reflect the previously Commission-approved rates for providing wastewater utility service in the Webb Creek and The Pines services areas. This Schedule of Interim Provisional Rates shall remain in effect until reviewed by the Commission in connection with Pluris's next general rate case or upon further order of the Commission.

6. That Pluris, as franchise owner for The Pines, shall execute and file the Undertaking for The Pines, attached hereto as Appendix D, no later than 10 days after the date of this Order.

7. That Pluris's temporary operating authority granted in Docket No. W-1314, Sub 0, is hereby canceled.

8. That the CPCN granted to PUI to provide wastewater utility service in Docket No. W-822, Sub 0, is hereby canceled.

9. That a copy of the Notice to Customers, attached hereto as Appendix C, shall be mailed with sufficient postage or hand delivered to all PUI customers, and the Eastport I and Timber Ridge customers which Pluris is presently serving pursuant to the temporary operating authority previously granted to it by the Commission, no later than seven days after the date of this Order and that Pluris shall submit to the Commission the attached Certificate of Service, properly signed and notarized, no later than 10 days after the date of this Order.

10. That when permanent rates are set for the Webb Creek and The Pines service areas in Pluris's next general rate case or by a further proceeding established by the Commission, the interim rates collected by Pluris either under temporary operating authority or thereafter pursuant to a CPCN, which are subject to an undertaking to refund by Pluris, shall be audited by the Public Staff. The Public Staff shall recommend to the Commission whether the Public Staff considers that there has been an overcollection and customer refunds should be ordered by the Commission.

ISSUED BY ORDER OF THE COMMISSION.
This the 14th day of November, 2019.

NORTH CAROLINA UTILITIES COMMISSION
Shonta Dunston, Deputy Clerk

Commissioner Kimberly W. Duffley did not participate in this decision.

APPENDIX A

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. W-1314, SUB 2

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

PLURIS WEBB CREEK, LLC

is granted this

CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

to provide wastewater utility service

in

THE PINES DEVELOPMENT,

WATER AND SEWER – CERTIFICATE

INCLUDING THE PINES MOBILE HOME PARK, EASTPORT I,
TIMBER RIDGE, AND
EASTPORT, SECTION III, PHASE 1

Onslow County, North Carolina

subject to any orders, rules, regulations,
and conditions now or hereafter lawfully made
by the North Carolina Utilities Commission.

ISSUED BY ORDER OF THE COMMISSION.
This the 14th day of November, 2019.

NORTH CAROLINA UTILITIES COMMISSION
A. Shonta Dunston, Deputy Clerk

APPENDIX B

SCHEDULE OF INTERIM PROVISIONAL RATES

for

PLURIS WEBB CREEK, LLC

for providing wastewater utility service in

THE PINES DEVELOPMENT,
INCLUDING THE PINES MOBILE HOME PARK, EASTPORT I,
TIMBER RIDGE, AND
EASTPORT, SECTION III, PHASE 1

Onslow County, North Carolina

WATER AND SEWER – CERTIFICATE

Monthly Flat Rate (Residential):	$37.69 per SFE [1/]
Connection Fee:	
Residential	$1,800 per SFE [1/]
Reconnection Fee:	
If sewer service is cut off by utility for good cause	$141.00
Bills Due:	On billing date
Bills Past Due:	15 days after billing date
Billing Frequency:	Shall be monthly for service in arrears
Returned Check Fee:	$20.00
Finance Charges for Late Payment:	1% per month will be applied to the unpaid balance of all bills still past due 25 days after billing date

[1/] SFE is single-family equivalent.

Issued in accordance with authority granted by the North Carolina Utilities Commission in Docket No. W-1314, Sub 2, on this the 14th day of November, 2019.

APPENDIX C
PAGE 1 OF 2

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. W-1314, SUB 2
DOCKET NO. W-822, SUB 3
DOCKET NO. W-1314, SUB 0

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. W-1314, SUB 2 DOCKET NO. W-822, SUB 3 In the Matter of Application for Transfer of Public Utility Franchise of Pines Utilities, Inc. to Pluris Webb Creek, LLC DOCKET NO. W-1314, SUB 0 In the Matter of Application by Pluris Webb Creek, LLC for Temporary Operating Authority to Serve The Pines Development in Onslow County, North Carolina, and for the Eventual Approval of a Certificate of Public Convenience and Necessity	NOTICE TO CUSTOMERS

NOTICE IS HEREBY GIVEN that the North Carolina Utilities Commission (Commission) has approved the transfer of the wastewater public utility franchise and system of Pines Utilities, Inc. (PUI) in Onslow County, North Carolina to Pluris Webb Creek, LLC (Pluris). The Commission has also issued a certificate of public convenience and necessity to Pluris authorizing it to provide wastewater utility service throughout The Pines Development, which consists of the existing mobile home park (MHP) known as The Pines MHP and Eastport I, Timber Ridge, and Eastport Section III, Phase 1, in Onslow County, North Carolina. By Order issued on February 1, 2017, in Docket No. W-1314, Sub 0, Pluris was granted temporary operating authority to provide wastewater utility service in Eastport I, Timber Ridge, and Eastport III, Phase 1.

On June 11, 2019, in Docket Nos. W-1314, Sub 2 and W-822, Sub 3, the Commission issued its Order Requiring Customer Notice (Notice Order). In that Order the

Commission concluded that the notice to be sent to PUI's customers would communicate to those customers that the Commission may decide this matter on the filings and approve the franchise transfer and continuation of the interim rate, without scheduling a hearing, if no significant protests were filed with the Commission.

The Commission also concluded in the Notice Order that the interim rate of $37.69 per single family equivalent (SFE) previously approved for Pluris in connection with the grant of temporary operating authority to serve portions of The Pines shall continue for The Pines, with this interim monthly rate being subject to refund, with 10% interest per annum, if not ultimately found to be reasonable by the Commission.

The Pines, LLC, the developer of The Pines, currently pays Pluris the monthly sanitary sewer utility usage charges for the 170 existing mobile homes in the MHP based on the $37.69 per SFE rate, which is the same as the interim monthly flat sewer rate (residential) that Pluris charges in the Webb Creek service area. When a MHP mobile home lot is converted to a single-family residence that is occupied and receiving service from Pluris, the new homeowner will pay the Commission-approved rate for sanitary sewer utility service. Until that conversion occurs, the developer will continue to pay for sanitary sewer service provided to The Pines residents in mobile homes at the interim rate of $37.69 per SFE.

No objections or protests have been filed with the Commission relating to the transfer application by Pluris and PUI filed in Docket Nos. W-1314, Sub 2 and W-822, Sub 3, since the Commission issued its June 11, 2019 Order in these dockets. Further, no objections or protests were filed in Docket No. W-1314, Sub 0 related to the temporary operating authority granted to Pluris in Eastport I, Timber Ridge, and Eastport Section III, Phase 1.

Pluris has the technical, managerial, and financial capacity to own and operate the wastewater utility system serving The Pines. It is in the public interest that the application for transfer by Pluris and PUI be approved and that a certificate of public convenience and necessity be granted to Pluris authorizing it to provide wastewater utility service throughout The Pines Development.

This the 14th day of November, 2019.

NORTH CAROLINA UTILITIES COMMISSION
A.Shonta Dunston, Deputy Clerk

APPENDIX D

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. W-1314, SUB 2

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. W-1314, SUB 2 DOCKET NO. W-822, SUB 3	)	
In the Matter of Application for Transfer of Public Utility Franchise of Pines Utilities, Inc. to Pluris Webb Creek, LLC	)	UNDERTAKING
DOCKET NO. W-1314, SUB 0	)	
In the Matter of Application by Pluris Webb Creek, LLC for Temporary Operating Authority to Serve The Pines Development in Onslow County, North Carolina, and for the Eventual Approval of a Certificate of Public Convenience and Necessity	)	

NOW COMES Pluris Webb Creek, LLC (Applicant), and files this Undertaking as follows:

UNDERTAKING

The Applicant, by and through its undersigned owner/executive officer, makes its written undertaking to the North Carolina Utilities Commission that it will refund to its customers any amount of the approved interim rate, plus 10% interest per annum, that may be finally determined by the Commission to be excessive and is required by final Order of the Commission.

This the _____ day of _____________, 2019.

By: ______________________________

____
(Owner/President)

WATER AND SEWER – CERTIFICATE

CERTIFICATE OF SERVICE

I, ____, mailed with sufficient postage or hand delivered to all affected customers a copy of the Notice to Customers required by the Order Canceling Temporary Operating Authority, Approving Transfer, Granting Franchise, Approving Interim Rates, and Requiring Customer Notice issued by the North Carolina Utilities Commission in Docket Nos. W-822, Sub 3, W-1314, Sub 2, and W-1314, Sub 0, and such Notice to Customers was mailed or hand delivered by the date specified in that Order.

This the ________ day of __________________, 2019.

By: ____
Signature

____
Name of Utility Company

The above named Applicant, ________________________, personally appeared before me this day and, being first duly sworn, says that the required copy of the Notice to Customers was mailed or hand delivered to all affected customers, as required by the Commission Order dated ____________________ in Docket Nos. W-822, Sub 3, W-1314, Sub 2, and W-1314, Sub 0.

Witness my hand and notarial seal, this the ________ day of ________________, 2019.

____
Notary Public

____
Printed Name

(SEAL) My Commission Expires: ______________________________________

WATER AND SEWER – EMERGENCY OPERATOR

DOCKET NO. W-390, SUB 13
DOCKET NO. W-390, SUB 14
DOCKET NO. W-354, SUB358

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Request by Public Staff – North Carolina Utilities Commission for Appointment of Carolina Water Service, Inc. of North Carolina as Emergency Operator of the Riverbend Estates Water System in Macon County, North Carolina	)	ORDER APPROVING TRANSFER, GRANTING FRANCHISE, APPROVING RATES, AND REQUIRING CUSTOMER NOTICE
In the Matter of Application for Transfer of Public Utility Franchise from Riverbend Estates Water Systems, Inc., to Carolina Water Service, Inc. of North Carolina and For Approval of Rates	)	

BY THE COMMISSION: On May 9, 2017, the Public Staff – North Carolina Utilities Commission (Public Staff) filed a Petition pursuant to G.S. 62-116(b) and G.S. 62-118(b) requesting that the Commission issue an Order: (1) declaring an emergency due to abandonment by Riverbend Estates Water Systems, Inc. (REWS) of the water system serving Riverbend Estates; (2) appointing Carolina Water Service, Inc. of North Carolina (CWSNC or Company) as emergency operator (EO); and (3) approving an emergency rate increase on a provisional basis for the water system serving Riverbend Estates in Macon County, North Carolina (Docket No. W-390, Sub 13, the EO Petition).

After the matter was presented to the Commission by the Public Staff at the May 15, 2017 Commission Staff Conference, the Commission issued an Order on May 16, 2017, declaring that an emergency existed, adopting the Public Staff's recommendations to appoint CWSNC as the EO for the Riverbend Estates water system effective May 16, 2017, approving the Public Staff's recommended provisional rates, and requiring that a copy of the Order be served on all customers of REWS by CWSNC no later than 15 days from the date of the Order.

On July 10, 2017, the Commission issued an Order Scheduling Show Cause Hearing, as the Commission found that good cause existed to require REWS and Ronald Hardegree, the REWS president, to appear before the Commission on a date certain to provide evidence to rebut the prima facie abandonment conclusion reached by the Commission and/or to show cause why sanctions and/or penalties should not be assessed by the Commission against REWS and/or Ronald L. Hardegree for abandoning REWS' obligation to provide water utility service in its franchised territory without first securing the Commission's consent as required by G.S. 62-118, and for failing to comply with the Public Utilities Act, the Commission's rules, regulations, and orders, and the explicit and implicit terms and conditions included in the certificate of public convenience and necessity (CPCN) which the Commission issued to REWS and/or Ronald L. Hardegree.

WATER AND SEWER – EMERGENCY OPERATOR

The Show Cause Hearing was held as scheduled on Tuesday, August 15, 2017, at the Macon County Courthouse in Franklin, North Carolina, and due to unexpected power outage at the courthouse, was recessed and rescheduled until October 25, 2019. REWS and Mr. Hardegree were represented throughout the hearing by attorney Stuart Sloan. The Public Staff was represented by Public Staff attorney William E. Grantmyre.

On October 24, 2017, CWSNC and REWS filed an application with the Commission (Docket No. W-390, Sub 14, the Transfer Application) requesting approval of the transfer of the Riverbend Estates CPCN and water system assets to CWSNC and approval of reduced rates. When the hearing reconvened the following day, October 25, 2017, attorneys Grantmyre and Sloan advised the Commission that REWS, the Public Staff, and CWSNC had reached a verbal settlement agreement, which — once completed — would resolve all the outstanding issues.

The Public Staff, at the October 25, 2017 hearing, advised the Commission and attending customers of the primary settlement agreement provisions and represented the following:

a. Pursuant to the terms of the October 24, 2017 Transfer Application, the franchise to operate the Riverbend Estates water system would be transferred to CWSNC, which would then be the utility. REWS at that point would no longer be a regulated public utility.

b. Pursuant to the Utility Asset Purchase Agreement (APA) by and between CWSNC, REWS, and Riverbend Water System, Inc. filed with the Transfer Application, CWSNC would acquire all water system assets, including the five real property parcels at Riverbend Estates that either were part of the water system or are still part of the water system properties.

c. The purchase price of $53,821.28 would be paid directly by CWSNC to the Town of Franklin to pay the amounts owed to the Town of Franklin as of May 16, 2017, when CWSNC took over as EO. The Public Staff recommended that the purchase price of $53,821.28, plus up to $3,000 of Stuart Sloan's legal fees for the transfer closing be included in CWSNC's rate base as part of CWSNC's uniform statewide system rate base.

d. The Public Staff recommended that the Riverbend Estates future rates be the same as CWSNC's uniform rates, expected at that time to be $24.44 per month for the base facility charge $6.86 per 1,000 gallons for the commodity charge, which was the same amount the Town of Franklin was charging for bulk water purchased and supplied to the REWS system.

e. Based on the average monthly per customer usage of 4,200 gallons, the average bill at that time under the new rates would be $53.25. Under the EO provisional rates, the average monthly bill for 4,200 gallons was then $85.19. The proposed new rates would result in a reduction of $31.94 in the average monthly bill per customer based on usage of 4,200 gallons.

f. The Public Staff recommended that the Commission expedite consideration of the Transfer Application.

g. The Commission-approved rates, which had become effective on May 16, 2017, for the EO, CWSNC, were provisional rates subject to refund and audit. The Public Staff committed to conduct an audit of the EO revenues, expenses, and capital costs and to recommend refunds if CWSNC had collected more than its authorized costs.

h. The Public Staff, not CWSNC, calculated the provisional rates.

i. After the Commission's approval of the transfer and after the closing of the water system and asset transfer, the Public Staff would withdraw its previous recommendation for the $84,000 fine or penalty that was recommended, based upon the Public Staff's assertion that REWS abandoned the system.

j. The supplemental testimony filed by the Public Staff on September 22, 2017, showed that REWS had been overbilling the customers since 2015. Part of the overbilling resulted from REWS' occasionally billing higher rates than approved by the Commission. Additionally, REWS failed to implement the Commission-ordered rate reductions pursuant to Orders issued in Docket No. W-390, Sub 12, based on the repeal of the gross receipts tax (Order issued October 13, 2015) and the reductions in the State corporate income tax rates (Orders issued May 26, 2016 and December 12, 2016). These overbillings were presented in detail in the Public Staff's filed supplemental testimony.

k. The Public Staff planned to calculate the refund due to each customer for the overbillings. The Public Staff would then present the refund numbers to REWS along with the Public Staff's calculations, and if REWS and the Public Staff could agree, then REWS would refund each of the customers the appropriate amount. Once REWS made the required refunds, the Public Staff would withdraw its recommendation for the $33,000 penalty which the Public Staff had recommended initially due to REWS' charging higher rates than authorized by the Commission.

(See Report of Public Staff, filed January 11, 2018, in Docket No. W-390, Sub 13 [January 11, 2018 Report]).

In the January 11, 2018 Report, the Public Staff stated that on December 15, 2017, it provided REWS a refund summary, including each active customer's name, mailing address, and refund amount including interest at 10%. Further, the Public Staff affirmed that the refunds, which totaled $2,615.96, were paid from the Kenney, Sloan, VanHook, PLLC, law firm's trust account, and were mailed on December 18, 2017.

On February 22, 2018, the Public Staff filed a Proposed Order Approving Transfer, Granting Franchise, Approving Rates, and Requiring Customer Notice. The Public Staff submitted in its Proposed Order that:

- CWSNC had advised the Public Staff that it revised its applied-for rates to be the same as CWSNC's uniform rates, which were approved by the Commission in the Docket No. W-354, Sub 356 Rate Case Order, dated November 8, 2017. This reflected a monthly base charge for no usage of $24.44, and the commodity charge of $6.86 per 1,000 gallons; which was the same commodity charge then being applied to CWSNC by the Town of Franklin;

- CWSNC and REWS had advised that documentation for the transfer was ready and that the transfer closing could take place once the Commission approved the transfer, approved the rate reduction, and issued a CPCN to CWSNC; and

- There was no need for an additional hearing in Franklin, North Carolina given the level of customer support for the proposal.

In the Proposed Order, the Public Staff reiterated its recommendation from the January 11, 2018 Report, as follows:

- That the Commission approve the transfer to CWSNC, issue a CPCN to CWSNC, approve the rates of $24.44 monthly base charge for no usage and the commodity charge of $6.86 per 1,000 gallons, and cancel the CPCN previously issued to REWS; all effective upon the filing of a written certification by CWSNC that the transfer closing took place and that the $53,821.28 purchase price was paid by CWSNC to the Town of Franklin.

- That the Commission approve the inclusion of the $53,821.28 purchase price plus up to $3,000 of Stuart Sloan's attorney fees for the transfer closing in CWSNC's rate base.

- That after the filing of CWSNC's closing certification, the Commission close the REWS Show Cause proceeding and not levy either of the Public Staff's previously recommended fines or penalties — which were for $84,000 and $33,000, respectively.

- That the Public Staff should audit the revenues collected with the provisional rates by the EO, as well as the expenses and capital expenditures incurred, and file a report with the Commission within 90 days of the filing of CWSNC's closing certification, with recommendations as to whether there should be customer refunds and the refund amounts, if any.

By letter of counsel dated March 2, 2018, CWSNC wrote to the Commission to: (a) provide information and make certain procedural requests on behalf of the Company; (b) facilitate an order from the Commission allowing immediate rate relief to the customers of Riverbend Estates water system in Macon County; (c) amend the Company's Application for Transfer and Approval of Rates, filed in Docket No. W-354, Sub 358, to request approval of the rates contained in the Proposed Order filed on February 22, 2018, by the Public Staff in these dockets; and (d) support and adopt by reference that Proposed Order, which addressed the transfer, franchise, rates, and customer notice. In support of this filing, CWSNC stated that, as EO for Riverbend, CWSNC agreed to imposition by the Commission of the rates attached to the Proposed Order filed on February 22, 2018, by the Public Staff in the dockets captioned herein. Specifically, CWSNC agreed to imposition of those rates for bills issued after the date of any Commission order which substitutes the proposed rates for the provisional rates. These proposed rates were lower than the provisional rates established in Docket No. W-390, Sub 13 (the EO Docket), and early adoption of them by the Commission would bring rate relief to the Riverbend customers. CWSNC filed this notice in the "transfer dockets" (Docket Nos. W-354, Sub 358 and W-390, Sub 14), to state on the record that:

a. It amends its Application for Transfer to request imposition of the rates contained in Appendix B, pp. 15-16 of the Proposed Order filed on February 22, 2018, by the Public Staff; and

b. It agrees to imposition of the lower rates, contained in Appendix B, pp. 15-16 of the Public Staff's Proposed Order of February 22, 2018, with no further filing or hearing and with provision of appropriate customer notice.

Finally, CWSNC submitted that: it participated in the preparation of the Proposed Order filed by the Public Staff in Docket Nos. W-354, Sub 358 and W-390, Sub 14; it supported and endorsed that Proposed Order as written, including the appendices which address rates and customer notice; and it adopted the Proposed Order by reference.

By filing of March 7, 2018, the Public Staff and REWS stipulated to agreement with CWSNC's proposal to reduce rates. On March 13, 2018, counsel for CWSNC formally requested approval of the new provisional rates, as agreed upon among CWSNC, REWS, and the Public Staff, for bills rendered on or after March 13, 2018. Additionally, the CWSNC requested the Commission to defer taking any action on the transfer application until it had performed additional due diligence to investigate easements and other related issues.

On March 13, 2018, in the EO Docket, the Commission concluded that the provisional rates then being charged by the EO to the Riverbend Estates Subdivision customers should be reduced to CWSNC's uniform statewide monthly base charge for zero consumption of $24.44 (for a meter size of less than one inch) and a usage charge of $6.86 per 1,000 gallons, which was the same usage charge per 1,000 gallons that the Town of Franklin then charged to CWSNC for the bulk purchased water. Furthermore, in the March 13, 2018 Order, the Commission concluded that by a further order of the Commission, the Public Staff would be required to audit the revenues CWSNC had received as EO from customers and all expenses and capital expenditures for the Riverbend Estates water system for the EO period beginning May 16, 2017 through March 13, 2018, and should file with the Commission a report including recommendations as to the amount of revenues from the provisional rates that exceeded the EO's expenditures, and that the over-collection amounts, if any, should be refunded by CWSNC to each customer.

By filing of August 13, 2018, CWSNC provided the Commission an update concerning the status of the required additional due diligence to investigate certain easements and other related issues. CWSNC stated that its inquiry into a range of property and title issues had been lengthy, complex, and very significant in terms of all resources: time, personnel attention, and expense

CWSNC further stated that the due diligence was ongoing and that proper management required resolution of these issues prior to a transfer of the utility and its assets from REWS to CWSNC. CWSNC informed the Commission that once such issues were resolved, the Company would renew its request for active consideration of the transfer application and would work with the Public Staff to provide the Commission with a new version of a Joint Proposed Order.

On April 24, 2019, a Joint Proposed Order was filed by CWSNC, REWS, and the Public Staff.

On the basis of the verified Transfer Application, the evidence presented at the hearings on August 15, 2017 and October 25, 2017, the Public Staff's Report, the various filings by CWSNC and the Public Staff, and the records of the Commission, the Commission makes the following

FINDINGS OF FACT

1. CWSNC has more than 40 years of experience managing and operating water systems in the North Carolina mountains. Currently, CWSNC manages and operates mountain water systems in the following North Carolina counties: Alleghany, Avery, Buncombe, Cherokee, Henderson, Jackson, Madison, Macon, Rutherford, Transylvania, Watauga, and Yancey.

2. The Order Granting Franchise, Granting Partial Rate Increase, and Requiring Customer Notice dated February 26, 2013, in Docket No. W-390, Sub 11, granted a CPCN to REWS and a rate increase to include the expenses relating to purchased bulk water from the Town of Franklin.

3. The Riverbend Estates water system currently has approximately 131 metered customers in single-family residential homes.

4. The Riverbend Estates water system is a purchased water system; all water is purchased from the Town of Franklin.

5. CWSNC was appointed EO for the Riverbend Estates water system by Commission Order dated May 16, 2017, in Docket No. W-390, Sub 13. On May 16, 2017, the date the EO was appointed, REWS owed the Town of Franklin a balance of $53,821.28 for bulk water purchases.

6. The APA filed with the Transfer Application provides the parties agreed on a purchase price of $53,821.28 for the Riverbend Estates water system, to be paid directly by CWSNC to the Town of Franklin.

7. The Public Staff has recommended that the $53,821.28 purchase price, plus up to $3,000 of REWS' attorney's fees for the transfer closing, be included in CWSNC's rate base as part of CWSNC's uniform statewide system rate base.

8. As part of its due diligence investigation in this matter, related in particular to the additional obligations associated with the irregular documentation of ownership of REWS' property — including the length of time and expense of additional support of counsel and consultants in the examination and in the regulatory process — CWSNC has, to date, incurred additional due diligence expenditures in the amount of $47,391.35. The Public Staff has audited the invoices in support of these additional expenditures.

9. In appointing the EO, the Commission found REWS to be an exceptionally-troubled water system. CWSNC, in assuming responsibility for REWS, should be fairly reimbursed for the costs and risks incurred and undertaken to "rescue" REWS.

10. In appointing CWSNC as the EO, the Commission approved the provisional emergency rate increase recommended by the Public Staff which resulted in Commission-approved provisional rates for the EO of $35.00 for the base monthly charge (zero usage) and $11.95 per 1,000 gallons for the usage charge. Pursuant to a subsequent request by CWSNC, the Commission approved lower rates for bills issued on or after March 13, 2018. The new rates were set to equal the then applicable CWSNC uniform water rates of $24.44 for the base monthly charge (zero usage) and $6.86 per 1,000 gallons for the usage charge.

11. In the Joint Proposed Order filed on April 24, 2019, in the transfer dockets, CWSNC requested Commission approval, effective on the water system transfer closing date, of CWSNC's current uniform statewide monthly base charge for zero consumption of $27.53 (set by the Commission in its Order of February 21, 2019, in Docket No. W-354, Sub 360, a general rate case proceeding) and a usage charge of $7.20 per 1,000 gallons, which is the current pass-through rate from the Town of Franklin. The Public Staff recommended approval of the CWSNC requested rates, noting they remain a significant reduction from the initial EO provisional rates.

12. The proposed new rates of $27.53 for the monthly base charge (zero usage) and $7.20 per 1,000 gallons for the usage charge are just and reasonable and should be approved effective for service rendered on and after the date of closing of the transfer of the Riverbend Estates water system to CWSNC.

13. As shown in detail on Junis Exhibit No. 6 of the supplemental testimony of Public Staff witness Junis filed on September 22, 2017, REWS had been overbilling its customers since 2015. On December 15, 2017, the Public Staff provided REWS a refund summary calculated by the Public Staff which included each active customer's name, mailing address, and refund amount including interest at 10%. On December 18, 2017, REWS refunded with interest the overbillings of customers in the amount of $2,615.96. Such refunds were paid from the Kenney, Sloan, VanHook, PLLC, law firm's trust account.

14. There is no need for another hearing in Franklin, North Carolina. The customers attending the October 25, 2017 hearing expressed approval for transfer to CWSNC and the anticipated resulting rate reduction.

15. It is reasonable and appropriate to include in CWSNC's statewide uniform rate base the $53,821.28 purchase price, plus up to $3,000 of REWS' attorney's fees for the transfer closing

16. It is reasonable and appropriate that the Company's due diligence costs in the amount of $47,391.35, as well as any other reasonable and prudently incurred unrecovered costs associated with the Company's performance of its duties as EO up through the time of its discharge by the Commission (including a return on the accumulated balance), be included in rate base and recovered in the Company's next general rate case as a component of the revenue requirement for the Company's Uniform Water Rate Division

17. The Public Staff's recommendation that a $10,000 bond be posted for the Riverbend Estates water system is reasonable and appropriate. CWSNC has $3,730,000 of bonds posted with the Commission. Of this amount, $3,690,000 of the bond amount is assigned to specific subdivisions, and $40,000 of the bond amount is unassigned.

18. CWSNC has the technical, managerial, operational, and financial capacity to provide water utility service in the REWS service area.

CONCLUSIONS

Based upon the foregoing, and the recommendations of the Public Staff, the Commission finds good cause to approve the transfer of the Riverbend Estates water system and franchise to CWSNC; to include the $53,821.28 purchase price plus up to $3,000 of the fees charged by REWS' attorney for the transfer closing in CWSNC's statewide uniform rate base as a plant acquisition adjustment; to approve the rates proposed by CWSNC; and to assign $10,000 of CWSNC's unassigned bond to this system.

In addition, the Commission finds good cause to approve the Company's request to recover and include in rate base its due diligence costs in the amount of $47,391.35, as well as any other reasonable and prudently incurred unrecovered costs associated with the Company's performance of its duties as EO up through the time of its discharge by the Commission (including a return on the accumulated balance), in the Company's next general rate case as a component of the revenue requirement for the Company's Uniform Water Rate Division.

IT IS, THEREFORE, ORDERED as follows:

1. That $10,000 of the CWSNC $40,000 unassigned bond shall be assigned to the Riverbend Estates Subdivision. The remaining unassigned bond surety shall be $30,000.

2. That CWSNC is granted a certificate of public convenience and necessity to provide water utility service in Riverbend Estates Subdivision in Macon County, North Carolina, effective upon the closing of the transfer of the water utility system assets to CWSNC.

3. That Appendix A, attached hereto, constitutes the Certificate of Public Convenience and Necessity.

4. That the Schedule of Rates, attached hereto as Appendix B, is approved for water utility service in Riverbend Estates Subdivision, effective for service rendered on and after the date of closing of the transfer of the water utility system assets to CWSNC.

5. That the Riverbend Estates water system shall not be charged the Water System Improvement Charge until being included in CWSNC's next general rate case.

6. That the $53,821.28 purchase price paid to the Town of Franklin, plus up to $3,000 of attorney's fees charged by REWS' attorney, Stuart Sloan, for the transfer closing, shall be included in CWSNC's rate base.

7. That the due diligence costs in the amount of $47,391.35, as well as any other reasonable and prudently incurred unrecovered costs associated with CWSNC's performance of its duties as EO up through the time of its discharge by the Commission (including a return on the accumulated balance) shall be included in rate base to be recovered in the Company's next general rate case as a component of the revenue requirement for the Uniform Water Rate Division.

8. That CWSNC shall provide written notification to the Commission within three days after the closing that the transfer has been completed and the date of such closing.

9. That upon the Commission's receipt of CWSNC's written notification that the closing is completed, the Public Staff's recommended fine or penalty of $84,000 for the Public Staff's assertion that REWS abandoned the system, and the Public Staff's recommended penalty of $33,000 for REWS' charging higher rates without Commission approval will be deemed withdrawn by the Public Staff; thus, the Commission will not assess or impose any fine or penalty in this matter.

10. That the Certificate of Public Convenience and Necessity to provide water utility service granted REWS is canceled effective on the date which CWSNC files with the Commission written notification that the closing of the transfer of the system has been completed.

11. That effective upon the transfer closing date and the granting of a CPCN to CWSNC for the Riverbend Estates Subdivision in Macon County, North Carolina, CWSNC shall be discharged as the EO.

12. That the Public Staff shall audit the revenues CWSNC received as EO from customers and all expenses and capital expenditures (including due diligence costs) for the Riverbend Estates water system for the EO period from May 16, 2017, through the transfer closing date, and shall file with the Commission within 90 days of the closing date, the Public Staff's report thereon, reconciling these revenues and expenses. Such analysis and report shall clearly reflect the Commission-approved reduction in rates effective on March 13, 2018 pursuant to the Commission's March 13, 2018 Order in the EO Docket.

13. That a copy of the Notice to Customers, attached hereto as Appendix C, shall be mailed with sufficient postage or hand delivered by CWSNC to all its affected customers in the Riverbend Estates Subdivision within 10 business days after the date of the closing of the transfer of the water system to CWSNC.

14. That CWSNC shall submit to the Commission the attached Certificate of Service, properly signed and notarized, not later than 15 business days after the closing of the transfer to CWSNC.

ISSUED BY ORDER OF THE COMMISSION.
This is the 16th day of May 2019.

NORTH CAROLINA UTILITIES COMMISSION
A. Shonta Dunston, Deputy Clerk

APPENDIX A

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. W-354, SUB 358

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

CAROLINA WATER SERVICE, INC. OF NORTH CAROLINA

is granted thi
s
CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

to provide water utility service in

RIVERBEND ESTATES SUBDIVISION
Macon County, North Carolina

subject to any orders, rules, regulations, and
conditions now or hereafter lawfully made
by the North Carolina Utilities Commission.

ISSUED BY ORDER OF THE COMMISSION.
This is the 16th day of May 2019.

NORTH CAROLINA UTILITIES COMMISSION
A. Shonta Dunston, Deputy Clerk

APPENDIX B
PAGE 1 OF 2

SCHEDULE OF RATES

for

CAROLINA WATER SERVICE, INC. OF NORTH CAROLINA

for providing water utility service

in
RIVERBEND ESTATES SUBDIVISION
WATER RATES AND CHARGES

Monthly Metered Water Service (Residential and Commercial):
Base Facility Charge (based on meter size with zero usage):

< 1" meter	$ 27.53
1" meter	$ 68.83
1½" meter	$ 137.65
2" meter	$ 220.24
3" meter	$ 412.95
4" meter	$ 688.25
6" meter	$1,376.50

Usage Charge:
Purchased Water for Resale, per 1,000 gallons:

Service Area	Bulk Provider	
Riverbend Estates	Town of Franklin	$ 7.20

Connection Charge: $ 1,000 plus actual cost to connect to the Town of Franklin

Meter Testing Fee: [1/]	$ 20.00
New Water Customer Charge:	$ 27.00

Reconnection Charge: [2/]

If water service is cut off by utility for good cause	$ 27.00
If water service is discontinued at customer's request	$ 27.00

APPENDIX B
PAGE 2 OF 2

Meter Fee:

For <1" meter	$ 50.00
For meters 1" or larger	Actual Cost

Irrigation Meter Installation: Actual Cost

MISCELLANEOUS UTILITY MATTERS

Charge for Processing NSF Checks:	$ 25.00
Bills Due:	On billing date
Bills Past Due:	21 days after billing date
Billing Frequency:	Shall be monthly for service in arrears
Finance Charge for Late Payment:	1% per month will be applied to the unpaid balance of all bills still past due 25 days after billing date.

Notes:

[1/] If a customer requests a test of a water meter more frequently than once in a 24-month period, the Company will collect a $20.00 service charge to defray the cost of the test. If the meter is found to register more than the prescribed accuracy limits, the meter testing charge will be waived. If the meter is found to register accurately or below prescribed accuracy limits, the charge shall be retained by the Company. Regardless of the test results, customers may request a meter test once in a 24-month period without charge.

[2/] Customers who request to be reconnected within nine months of disconnection at the same address shall be charged the base facility charge for the service period they were disconnected.

Issued in Accordance with Authority Granted by the North Carolina Utilities Commission in Docket No. W-354, Sub 358, on this the 16th day of May, 2019.

APPENDIX C
PAGE 1 OF 3

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

NOTICE TO CUSTOMERS
DOCKET NO. W-390, SUB 13
DOCKET NO. W-390, SUB 14
DOCKET NO. W-354, SUB 358

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

NOTICE IS HEREBY GIVEN that the North Carolina Utilities Commission (Commission) has approved the transfer of the Riverbend Estates water system in Macon County, North Carolina, from Riverbend Estates Water Systems, Inc., to Carolina Water Service, Inc. of North Carolina (CWSNC).

CWSNC has served as the Commission-appointed emergency operator for the Riverbend Estates water system since May 16, 2017, pursuant to the Commission's Order Appointing Emergency Operator, Approving Increased Rates, and Requiring Customer Notice issued in Docket No. W-390, Sub 13.

The Commission has approved the following new rates for CWSNC (as franchise owner) as set forth below. These rates are effective for service rendered on and after the date of the closing of the transfer.

<u>Monthly Metered Water Service (Residential and Commercial):</u>
Base Facility Charge (based on meter size with zero usage)

< 1" meter	$ 27.53
1" meter	$ 68.83
1½" meter	$ 137.65
2" meter	$ 220.24
3" meter	$ 412.95
4" meter	$ 688.25
6" meter	$1,376.50

Usage charge, per 1,000 gallons: (Purchased water from the Town of Franklin)	$ 7.20

<u>Connection Charge:</u> $ 1,000 plus actual cost to connect to the Town of Franklin

<u>Meter Testing Fee:</u> [1/] $ 20.00

WATER AND SEWER – EMERGENCY OPERATOR

APPENDIX C
PAGE 2 OF 3

New Water Customer Charge:	$ 27.00
Reconnection Charge: [2/]	
If water service is cut off by utility for good cause	$ 27.00
If water service is discontinued at customer's request	$ 27.00
Meter Fee:	
For <1" meter	$ 50.00
For meters 1" or larger	Actual Cost
Irrigation Meter Installation:	Actual Cost

MISCELLANEOUS UTILITY MATTERS

Charge for Processing NSF Checks:	$ 25.00
Bills Due:	On billing date
Bills Past Due:	21 days after billing date
Billing Frequency:	Shall be monthly for service in arrears
Finance Charge for Late Payment:	1% per month will be applied to the unpaid balance of all bills still past due 25 days after billing date.

Notes:

[1/] If a customer requests a test of a water meter more frequently than once in a 24-month period, the Company will collect a $20.00 service charge to defray the cost of the test. If the meter is found to register in excess of the prescribed accuracy limits, the meter testing charge will be waived. If the meter is found to register accurately or below prescribed accuracy limits, the charge shall be retained by the Company. Regardless of the test results, customers may request a meter test once in a 24-month period without charge.

[2/] Customers who request to be reconnected within nine months of disconnection at the same address shall be charged the base facility charge for the service period they were disconnected.

APPENDIX C
PAGE 3 OF 3

Provisional Rates and Public Staff Audit

The Public Staff – North Carolina Utilities Commission (Public Staff), in its emergency operator petition filed on May 9, 2017, in Docket No. W-390, Sub 13, recommended that the Commission appoint CWSNC as the emergency operator and approve an emergency rate increase with provisional rates for base monthly charge, zero usage, of $35.00 and usage charge per 1,000 gallons of $11.95, which the Commission did. Pursuant to a subsequent request by CWSNC, rates were lowered for bills issued on or after March 13, 2018, to the then applicable uniform water rate for a base monthly charge of $24.44, zero usage, and a usage charge of $6.86 per 1,000 gallons.

The Public Staff has been required by the Commission to audit the revenues CWSNC received as emergency operator from customers and all expenses and capital expenditures (including due diligence costs) for Riverbend for the emergency operator period of May 16, 2017, through the closing date of the system transfer to CWSNC. Within 90 days of the closing date, the Public Staff will file with the Commission an audit report reconciling these revenues and expenses.

ISSUED BY ORDER OF THE COMMISSION.

This is the 16th day of May, 2019.

NORTH CAROLINA UTILITIES COMMISSION
A. Shonta Dunston, Deputy Clerk

WATER AND SEWER – EMERGENCY OPERATOR

CERTIFICATE OF SERVICE

I,____, mailed with sufficient postage or hand delivered to all affected customers the attached Notice to Customers issued by the North Carolina Utilities Commission in Docket Nos. W-390, Subs 13 and 14, and W-354, Sub 358; and the Notice was mailed or hand delivered by the date specified in the Order.

This the______day of____________________, 2019.

By: ________________________________

Signature

____

Name of Utility Company

The above named Applicant, ____, personally appeared before me this day and, being first duly sworn, says that the required Notice to Customers was mailed or hand delivered to all affected customers, as required by the Commission Order dated __________________ in Docket Nos. W-390, Subs 13 and 14, and W-354, Sub 358.

Witness my hand and notarial seal, this the ________day of_______________, 2019.

____

Notary Public

____

Printed Name

(SEAL) My Commission Expires: ________________________________

Date

DOCKET NO. W-864, SUB 11
DOCKET NO. W-864, SUB 14
DOCKET NO. W-1314, SUB 1

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. W-864, SUB 11 In the Matter of Webb Creek Water and Sewage, Inc. – Petition for Appointment of Emergency Operator DOCKET NO. W-864, SUB 14 In the Matter of Complaint and Petition by Public Staff for Revocation of Franchise of Webb Creek Water and Sewage, Inc. DOCKET NO. W-1314, SUB 1 In the Matter of Application of Pluris Webb Creek, LLC for Certificate of Public Convenience and Necessity	ORDER REVOKING WEBB CREEK WATER AND SEWAGE, INC.'S FRANCHISE, GRANTING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY TO PLURIS WEBB CREEK, LLC, CONTINUING INTERIM RATES, DISCHARGING EMERGENCY OPERATOR, AND REQUIRING CUSTOMER NOTICE

HEARD: Wednesday, September 6, 2017, at 9:30 a.m. and Monday, January 8, 2018, at 9:30 a.m. in the Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina 27603

BEFORE: Commissioner Daniel G. Clodfelter, Presiding; Commissioners ToNola D. Brown-Bland and James G. Patterson

APPEARANCES:

For Webb Creek Water and Sewage, Inc.:

None

For Pluris Webb Creek, LLC:

Daniel C. Higgins, Burns, Day & Presnell, P.A., PO Box 10867, Raleigh, North Carolina 27605

WATER AND SEWER – EMERGENCY OPERATOR

For the Using and Consuming Public:

William Grantmyre, Public Staff-North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4300

BY THE COMMISSION: On June 7, 2017, the Public Staff – North Carolina Utilities Commission (Public Staff) filed a Complaint and Petition for Revocation of Franchise (Petition for Revocation) in Docket No. W-864, Sub 14, requesting that the Commission revoke the franchise and certificate of public convenience and necessity (CPCN) previously issued to Webb Creek Water and Sewage, Inc. (Webb Creek), in Onslow County, North Carolina. The Public Staff stated that the Webb Creek wastewater treatment plant (WWTP) is an aged (30 years + years old) 300,000 gallons per day (GPD) sequencing batch reactor WWTP. Webb Creek has the National Pollutant Discharge Elimination System (NPDES) permit. There are currently approximately 975 residential customers and seven commercial customers, including Sand Ridge Elementary School.

After the Public Staff filed its Petition for Revocation, Pluris Webb Creek, LLC (Pluris), subsequently filed an Application in Docket No. W-1314, Sub 1, requesting that Pluris be issued a certificate of public convenience and necessity authorizing it to serve the Webb Creek service area, if the Commission grants the Public Staff's request and revokes Webb Creek's CPCN and franchise.

On July 31, 2017, the Commission issued its Order Scheduling Hearing and Requiring Notice in Docket No. W-864, Sub 14, relating to the Public Staff's Petition for Revocation. That Order required that the Public Staff serve a copy of that Order, by certified mail and first class mail with sufficient postage, no later than the next business day after the issuance of that Order, on Webb Creek's Registered Agent addressed as follows:

Mr. J. Hal Kinlaw, Jr. (#62496-056)
Registered Agent for Webb Creek Water and Sewage, Inc.
FCI Ashland
Post Office Box 6001
Ashland, KY 41105

Pursuant to that Order, on August 31, 2017, the Public Staff filed the testimony and exhibits of Charles M. Junis, Utilities Engineer, Public Staff Water, Sewer, and Communications Division. The Public Staff also filed its Exhibit 1 on August 31, 2017, certifying service of that Order on Webb Creek's Registered Agent.

On September 6, 2017, the Petition for Revocation came on for hearing as scheduled. No one appeared on behalf of Webb Creek when the matter was called for hearing on that date. The Public Staff presented the testimony of Public Staff witness Junis. Because there is a logical relationship between the relief requested in the Public Staff's Petition for Revocation and Pluris's Application for issuance of a CPCN in Docket No. W-1314, Sub 1, after hearing the testimony of witness Junis, the Commission recessed the hearing and ordered that it be resumed at a later date when the Commission would also take up Pluris's Application for a CPCN.

On October 31, 2017, the Commission issued its Order Reconvening Hearing, Scheduling Hearing, and Requiring Notice. Pursuant to that Order, on November 22, 2017, the Public Staff filed the supplemental testimony of Charles M. Junis and the testimony of James Gregson, Interim Deputy Director, Division of Water Resources, North Carolina Department of Environmental Quality. Also pursuant to that Order, on November 22, 2017, Pluris filed the testimony of Maurice Gallarda, PE, Managing Member of Pluris.

On December 4, 2017, the Commission issued its Order Cancelling Hearings on December 7, 2017, and Rescheduling Those Hearings on January 8, 2018. On December 13, 2017, Pluris filed its Certificate of Service reflecting that it had served the Commission's December 4, 2017 Order.

On January 5, 2018, the Public Staff filed the supplemental testimony of Charles M. Junis and the testimony and exhibits of Windley E. Henry, Accounting Manager, Water/Communications Section, Public Staff Accounting Division. On January 5, 2018, the Public Staff also filed Exhibit 1 to the previously filed testimony of James Gregson.

The Public Staff's Petition for Revocation and Pluris's Application for a CPCN authorizing it to serve the Webb Creek service area came on for hearing as scheduled on January 8, 2018, at which time the Commission consolidated Docket No. W-864, Sub 14 with Docket No. W-1314, Sub 1. No representative appeared on behalf of Webb Creek when these matters were called for hearing on that date.

On June 28, 2018, the Commission issued its Order Requiring Specific Conditions to be Satisfied Concerning the Granting of a Certificate of Public Convenience and Necessity to Pluris Webb Creek, LLC (the Conditions Order). The Conditions Order set forth findings of fact as to various grounds for revocation of Webb Creek's CPCN and franchise, including the "willful failure to comply with" N.C. Gen. Stat. § 62-160 and Commission Rule R1-16, failure to pay the Branch Banking and Trust Company (BB&T) Judgment against Webb Creek, failure to pay taxes, failure to comply with N.C.G.S. § 143-215.1, its former NPDES permit, and failure to comply with other permits and applicable environmental standards and requirements.

In addition, Ordering Paragraph No. 1 of the Conditions Order set forth conditions for issuance of a CPCN to Pluris as follows:

> 1. A certificate of public convenience and necessity to provide wastewater utility service in the franchised service area presently being served by Webb Creek shall be granted to Pluris once Pluris:
>
> (1) Files a verified statement with Commission indicating that:
>
> (a) Pluris has acquired the new MBR tract, which Pluris has previously described to the Commission;
>
> (b) Pluris has purchased or acquired all lift station sites that are necessary to provide wastewater utility service to the residents and/or

customers located in Webb Creek's franchised service territory through the Onslow County tax foreclosure process, acquired them by other means, or has obtained lawful control of such assets;

(c) Pluris has acquired sufficient portions, of the Webb Creek system assets to provide adequate and reliable wastewater utility service to the residents and/or customers located in Webb Creek's franchised service territory; and

(d) Pluris has posted an additional bond in the amount of $190,000; for a total bond amount of $200,000 for the Webb Creek franchise including the previously posted bond of $10,000 in Docket No. W-1314, Sub 0.

The Conditions Order required that Pluris file a verified statement together with specific certifications: one from a North Carolina licensed attorney certifying that Pluris has acquired lawful control of all lift station sites necessary to provide wastewater utility service to the residents and/or customers located in Webb Creek's franchise service territory, and one from a North Carolina licensed professional engineer certifying that Pluris has acquired sufficient portions of the Webb Creek wastewater system assets to provide adequate and reliable wastewater utility service to the residents and/or customers located in Webb Creek's franchise service territory. The Conditions Order required that the aforementioned conditions be accomplished and the verified statement, certifications, and an increased bond all be filed by December 28, 2018.

On December 7, 2018, Pluris filed a Request for Modification of Conditions to be Satisfied Concerning the Granting of a Certificate of Public Convenience and Necessity to Pluris Webb Creek, LLC (Request for Modification). Specifically, Pluris advised the Commission that Pluris had achieved compliance with items (1)(b) and (1)(c) of Ordering Paragraph No. 1 of the Conditions Order. Pluris's Request for Modification focused on the Conditions Order's requirement that Pluris acquire a new tract suitable for construction of a new membrane bioreactor (MBR) wastewater treatment plant. As explained in Pluris's Request for Modification, the tract which Pluris had contracted to acquire for construction of the new MBR plant was determined to have unsuitable soils. Pluris noted that it had acquired the existing Webb Creek wastewater treatment plant site as well as three adjoining lots comprising a total of 8.96 acres and that geotechnical and engineering field investigation and analyses had confirmed that the existing plant site could serve as a site for the new MBR plant. Therefore, Pluris requested modification of the Conditions Order with regard to the requirement that Pluris acquire a "new tract" for construction of the MBR plant.

Further, Pluris also requested that upon issuance of a CPCN to Pluris that the Commission disburse to it the $100,000 proceeds the Commission received from forfeiture of Webb Creek's bond security.

By Order issued December 13, 2018, the Commission requested comments regarding Pluris's Request for Modification. The Public Staff filed comments on December 18, 2018, supporting Pluris's Request for Modification of the Conditions Order. By Order issued December 21, 2018, the Commission granted Pluris's Request for Modification.

On December 28, 2018, Pluris filed the verified statement and supporting certifications required by the original Conditions Order. At that time Pluris also posted an additional bond in the amount of $190,000, as required by the Conditions Order. Together with the $10,000 bond it posted in Docket No. W-1314, Sub 0, Pluris has posted a total bond of $200,000. On January 2, 2019, Pluris filed a revised certification from a professional engineer to correct a misstatement as to the various jurisdictions in which the attesting North Carolina-licensed engineer is certified.

On January 9, 2019, the Commission issued its Order Requesting Comments from the Public Staff Regarding Pluris Webb Creek, LLC's Verified Statement. On January 15, 2019, the Public Staff filed its comments wherein it recommended that the Commission find that Pluris has satisfied all required conditions set forth in the Conditions Order, and that the Commission issue its Order revoking the CPCN presently owned by Webb Creek and contemporaneously issue an Order granting a CPCN to Pluris.

On January 30, 2019, Pluris filed the bond commitment letter relating to the supplemental $190,000 bond filed by Pluris on December 28, 2018, as required by the Conditions Order.

On March 11, 2019, the Public Staff filed its Motion for Revocation of Franchise, Approval of Franchise, Continuing Interim Rates, and Requiring Customer Notice, requesting that the Commission revoke Webb Creek's CPCN and issue a CPCN to Pluris. In addition, the Public Staff and Pluris filed a Joint Proposed Order recommending that the Webb Creek CPCN be revoked, that a CPCN be granted to Pluris, and that the provisional rates be continued.

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

FINDINGS OF FACT

1. In addition to the various grounds adequate for revocation of the Webb Creek CPCN and franchise recognized in the June 28, 2018 Conditions Order, and in addition to the practical, operational, and financial problems and issues resulting from the deteriorated state of the Webb Creek wastewater system and the liens against system assets, and the fact that J. Hal Kinlaw is serving a lengthy sentence in federal prison, there is no reasonably foreseeable or feasible scenario in which Webb Creek would be able to resume operation of this system. The only clear path to bringing long-term stability to the provision of public utility wastewater service in the Webb Creek service area involves replacing Webb Creek with a competent and well-capitalized public utility that can make the investments necessary to bring the Webb Creek wastewater system into compliance and stabilize the provision of service to the public in this service area. It is in the public interest that the CPCN previously issued to Webb Creek be revoked.

2. On August 8, 2016, the Commission issued its Order Appointing Emergency Operator (EO), Approving Increased Rates and Requiring Customer Notice in Docket No. W-864, Sub 11 (the EO Order). Pursuant to the EO Order Pluris has served as emergency operator for Webb Creek since August 2016. As reflected in prior filings and Orders in these dockets, and the EO Order, Webb Creek was subject to over 500 environmental violations prior to Pluris being appointed as the emergency operator of the Webb Creek wastewater system by the Commission.

3. At the time it was appointed emergency operator, Pluris committed to investing $100,000 to address problems and needs in the Webb Creek WWTP and collection system. Pluris has now invested in excess of $800,000 in addressing problems and needs in the treatment plant and collection system. Because the Webb Creek WWTP cannot be brought back to the point where compliance with applicable environmental requirements and standards can be achieved, and because these costs will ultimately be borne by ratepayers, the Public Staff and Pluris maintain that further investment in the existing WWTP would be unreasonable and imprudent given all pertinent facts and circumstances.

4. Pluris and the Public Staff presented evidence at the hearing in these dockets on January 8, 2018, demonstrating that there are significant issues, problems, and concerns as to the deteriorated condition of the Webb Creek WWTP. Pluris has committed to design and build a new MBR WWTP to serve the Webb Creek service area, The Pines service area,[1] and the general vicinity. Pluris is well-capitalized and is prepared to make the necessary capital investment to construct the new MBR plant. The Public Staff fully supports Pluris's construction of the MBR WWTP. Pluris has advised the Public Staff that, barring any unforeseen circumstances, Pluris expects to complete construction of the MBR WWTP within approximately 12-15 months of the date a CPCN is issued to it.

5. As required by the Conditions Order and the Order Granting Pluris Webb Creek, LLC's Motion to Modify Order Requiring the Satisfaction of Certain Conditions Before the Issuance of a Certificate of Public Convenience and Necessity issued December 21, 2018 (collectively, the Conditions Orders), Pluris has acquired the Webb Creek WWTP and the collection system lift stations, together with any and all collection system assets associated with Webb Creek through tax foreclosure proceedings instituted by Onslow County to collect delinquent property taxes.

6. Pluris has complied with all conditions established in the Conditions Orders.

7. In the EO Order the Commission set rates "on a provisional basis for wastewater utility service provided by Pluris as emergency operator of the Webb Creek wastewater utility system, effective the date of this Order and subject to refund of any amounts found unjust and unreasonable, and subject to true up if the emergency operator has not recovered its costs and approved returns or has over-recovered." (EO Order ¶ 3, p. 7) In its March 11, 2019 Motion in Docket Nos. W-864, Sub 14 and W-1314, Sub 1, in recognition of the importance of facilitating Pluris's efforts to build the new MBR plant and demolish the existing Webb Creek WWTP as soon as possible, the Public Staff recommends that it is reasonable to continue the interim rates for Pluris.

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[1] On February 1, 2017, in Docket No. W-1314, Sub 0, the Commission issued an Order Approving Temporary Operating Authority, Approving Interim Rates, Requiring Undertaking, and Requiring Customer Notice which granted Pluris temporary authority to provide wastewater utility service in Eastport I, Timber Ridge, and Eastport III, Phase 1, which are part of The Pines Development in Onslow County. On February 12, 2018, in Docket Nos. W-1314, Sub 2 and W-822, Sub 3, Pluris Webb Creek, LLC, and Pines Utilities, Inc., filed an application to transfer the utility franchise serving The Pines Mobile Home Park and Immediate Environs in Onslow County, North Carolina and for approval of rates. These dockets are presently pending.

8. Due to deteriorating conditions, time is of the essence in replacing the existing WWTP. Because Pluris will be filing a general rate case at or near the time construction of the new MBR plant is completed, it is appropriate to accept the Public Staff's recommendation that the interim rates for Pluris shall be set at the same level as the provisional rates established in the EO Order. Therefore, in order to avoid the delay inherent in the true up and audit process at this juncture, it is appropriate to accept the Public Staff's recommendation that the interim rates shall continue until Pluris files the contemplated rate case, at which time Pluris shall prepare and file a final accounting to be audited by the Public Staff, and a true up of the provisional rates collected as emergency operator and interim rates shall be dealt with in the rate case.

9. It is appropriate, necessary, and in the public interest to issue a CPCN to Pluris at this time to allow Pluris to secure all permits necessary to expeditiously move forward with construction of a new MBR plant of sufficient size to serve the Webb Creek service area, The Pines service area, and anticipated growth in the immediate vicinity.

10. Given the level of Pluris's investment in the existing WWTP and collection system, and that Pluris now owns and will be responsible for demolishing the existing WWTP, the $100,000 proceeds the Commission received from forfeiture of Webb Creek's bond security shall be disbursed to Pluris as cost-free capital, which will be a reduction to rate base.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 1

This finding summarizes matters and findings established in prior orders in these dockets, including the Conditions Orders, as well as foundational undisputed matters of fact established in the pleadings or otherwise, none of which are contested by any party. In fact, Webb Creek has made no filings in connection with these dockets and no representative of Webb Creek appeared at any time at any hearing relating to these dockets. None of the findings and conclusions set forth herein are contested or disputed.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 2

This finding summarizes matters and findings established in the Order Appointing Emergency Operator, Approving Increased Rates, and Requiring Customer Notice in Docket No. W-864, Sub 11, which order was not opposed by Webb Creek. The various problems and issues with the operations, assets, equipment, and management of the Webb Creek wastewater system are established in the testimony of Public Staff witnesses Junis and Gregson. The testimony of Pluris witness Gallarda also addressed some aspects of the problems with the Webb Creek wastewater system, particularly including the problems and challenges Pluris has faced as the emergency operator of the Webb Creek wastewater system in terms of attempting to bring that system into compliance with the North Carolina Department of Environmental Quality (DEQ) requirements. As detailed in the Commission's EO Order issued pursuant to the Public Staff's Petition for Appointment of an Emergency Operator, DEQ's Division of Water Quality has issued over 500 Notices of Violation and administrative penalties to Webb Creek for construction, operations, effluent parameter discharge violations, and reporting violations.

In addition, in Docket No. W-864, Sub 11, the testimony of witness Junis and the Commission's EO Order addressed the relatively unique problems and issues with the assets, equipment, and properties comprising the Webb Creek wastewater system as a product of the fact that not all of the real property where Webb Creek wastewater system assets are located is owned by Webb Creek. Public Staff witness Junis filed testimony supporting the Public Staff's Complaint and Petition for Revocation on three separate occasions. As shown therein, five of the eight Webb Creek lift station sites are owned by entities other than Webb Creek, which entities are affiliated with Webb Creek by some common ownership and/or management. The problematic issues with ownership of the lift station sites are vividly illustrated by Junis Exhibit 2,[1] which is a copy of the Complaint filed by Onslow County against one of the Kinlaw-affiliated entities, Group Eight, Ltd., to collect delinquent property taxes and seeking the tax foreclosure sale of the three Webb Creek wastewater system lift station sites owned by Group Eight, Ltd.

The Commission concludes that it is in the public interest for the CPCN previously issued to Webb Creek be revoked.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 3-4

These findings relate to matters of record in these dockets and Docket No. W-864, Sub 11, as well as in the Public Staff's recent motion. Pluris's testimony, filings, and reports in these dockets have reflected its increasing expenditures and investment in efforts to address problems with the Webb Creek WWTP. These are undisputed matters of fact established in the pleadings and/or testimony, and are not contested by any party.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 5

This finding is based on the Conditions Orders, as well as the Verified Statement and attached legal and engineering certifications filed by Pluris pursuant to the Conditions Orders. This finding is an undisputed matter of fact established in the pleadings and is not contested by any party.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 6

This finding relates to a procedural matter and is a foundational and undisputed matter of fact established by the Verified Statement and certifications filed by Pluris, as well as the additional bond in the amount of $190,000 filed by Pluris. The fact that Pluris has acquired the Webb Creek wastewater system, including the WWTP, through the Onslow County tax foreclosure process, as required by the Conditions Orders, is an undisputed matter of fact established in the pleadings, and is not contested by any party.

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[1] Attached to the testimony of witness Junis filed on August 17, 2017.

WATER AND SEWER – EMERGENCY OPERATOR

The Commission appreciates Pluris work as emergency operator of the Webb Creek wastewater system and recognizes that, through no fault of Pluris, it now owns a WWTP with significant issues and problems, which needs to be replaced as soon as possible, which is what Pluris is prepared and planning to do.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 7

This finding relates to a matter established in the Order Appointing Emergency Operator, Approving Increased Rates and Requiring Customer Notice in Docket No. W-864, Sub 11, as well as the pleadings filed by the Public Staff in these dockets. This finding is an undisputed matter of fact established in the relevant Orders and the pleadings in these dockets, and is not contested by any party.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 8

This finding is based on matters established in the Order Appointing Emergency Operator, Approving Increased Rates and Requiring Customer Notice in Docket No. W-864, Sub 11, which Order was not opposed by Webb Creek. The various problems and issues with the operations and condition of the WWTP are established in the testimony of Public Staff witnesses Junis and Gregson, as well as in the testimony of Pluris witness Gallarda referenced previously in the Evidence and Conclusions for Finding of Fact No. 2.

The interim rates for Pluris shall be set at the same level as the provisional rates established in the EO Order. The interim rates shall continue until Pluris files the contemplated rate case, at which time Pluris shall prepare and file a final accounting to be audited by the Public Staff, and a true up of the provisional rates collected as emergency operator and interim rates shall be dealt with in the rate case. In the event that a rate case application has not been filed by Pluris by June 30, 2020, the Public Staff should file a recommendation with the Commission as to whether the provisional interim rates approved herein should be continued or adjusted. In addition, the Public Staff should inform the Commission whether the Public Staff considers that Pluris has not recovered its costs and approved returns or has over-recovered during Pluris's emergency operatorship of the Webb Creek wastewater system and customer refunds should be ordered by the Commission.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 9

This finding relates to matters of records in these dockets and findings previously set forth in the Conditions Orders, as well as the Public Staff's March 11, 2019 Motion. It is in the public interest to bring long-term stability to the provision of public utility wastewater service in the Webb Creek service area by revoking the CPCN previously issued to Webb Creek and issuing a CPCN to Pluris to serve the Webb Creek service area. Pluris is a competent and well-capitalized public utility that can make the investments necessary to bring the Webb Creek wastewater system into compliance and stabilize the provision of service to the public in that service area and general vicinity.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 10

This finding relates to a procedural matter and is supported by both the Public Staff's recommendation and by Pluris's request that the $100,000 proceeds the Commission received from forfeiture of Webb Creek's bond security be disbursed to Pluris. Pluris's investment in the Webb Creek wastewater system has far exceeded the $100,000 which it originally agreed to invest in an effort to address problems and issues in that system. Pluris has now invested in excess of $800,000 in addressing problems and needs in the treatment plant and collection system. Given the level of Pluris's investment in the existing WWTP and collection system, the fact that Pluris now owns the WWTP and will be responsible for demolishing it, the impact of the Webb Creek WWTP on other service areas in Onslow County (i.e., The Pines Development and general vicinity), and the Public Staff's recommendation in these dockets, the Commission concludes that it is appropriate to disburse the $100,000 proceeds from the forfeiture of Webb Creek's bond security to Pluris. This funding will constitute cost-free capital for Pluris and will allow Pluris to recover some portion of the expenditures it has made in addressing issues in the Webb Creek wastewater system.

IT IS THEREFORE, ORDERED as follows:

1. That the additional bond in the amount of $190,000 filed by Pluris Webb Creek, LLC, in these dockets is approved. Including the previously posted bond of $10,000 in Docket No. W-1314, Sub 0, Pluris now has a total of $200,000 in bonds posted with the Commission for its assigned service areas in Onslow County, North Carolina.

2. That all Certificates of Public Convenience and Necessity previously issued to Webb Creek Water and Sewage, Inc., are hereby revoked effective as of the date of this Order.

3. That effective as of the date of this Order, a certificate of public convenience and necessity is issued to Pluris Webb Creek, LLC, authorizing it to serve all of the Webb Creek franchises and service areas, including the following subdivisions:

Buckhead
Creekertown
Creekertown Villas
Cooper's Court Foxden
Foxlair
Fox Trace Sections I, II, and III
Fox Trace Section IV, Phases 1 through 6
Fox Trace Section V
Fox Trace Point I and
II Jack's Branch
Jack's Branch Townhomes
Quail Roost

4. That provisional interim rates for Pluris are approved at the same level as the provisional rates established in the EO Order, and those provisional interim rates shall continue as interim rates until Pluris files the contemplated rate case, at which time Pluris shall prepare and file

a final accounting to be audited by the Public Staff. The true up of the provisional rates (collected as emergency operator) and the provisional interim rates (approved herein with the granting of a franchise to Pluris) shall be dealt with in the rate case.

5. That the Schedule of Provisional Interim Rates, attached hereto as Appendix B, is hereby approved and deemed filed with the Commission pursuant to N.C.G.S. § 62-138.

6. That a copy of the Notice to Customers, attached hereto as Appendix C, shall be mailed with sufficient postage or hand delivered to all affected customers by Pluris in conjunction with the next regularly scheduled billing process.

7. That Pluris shall file the attached Certificate of Service, properly signed and notarized, not later than 45 days after the issuance date of this Order.

8. That, due to the unique circumstances set forth herein, the letter of credit proceeds of $100,000 obtained by the Commission through forfeiture of Webb Creek's bond security shall be disbursed to Pluris as cost-free capital, which will be a reduction to rate base.

9. That, in the event that a rate case application has not been filed by Pluris by June 30, 2020, the Public Staff shall file a recommendation with the Commission as to whether the provisional interim rates approved herein should be continued or adjusted. In addition, the Public Staff shall inform the Commission whether the Public Staff considers that Pluris has not recovered its costs and approved returns or has over-recovered during Pluris's emergency operatorship of the Webb Creek wastewater system and customer refunds should be ordered by the Commission.

10. That with the granting of a CPCN to Pluris herein, effective upon issuance of this Order, Pluris is hereby discharged as the emergency operator of the Webb Creek wastewater system.

11. That Docket No. W-864, Sub 11 shall remain open for future reports, motions, Commission orders, and other filings concerning the final accounting of the operations of Pluris as emergency operator of the Webb Creek wastewater system for the period August 8, 2016, through March 25, 2019.

ISSUED BY ORDER OF THE COMMISSION.

This the 26th day of March, 2019.

NORTH CAROLINA UTILITIES COMMISSION
A. Shonta Dunston, Deputy Clerk

APPENDIX A

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. W-1314, SUB 1

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

PLURIS WEBB CREEK, LLC

is granted this

CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

to provide wastewater utility service

in

WEBB CREEK WASTEWATER UTILITY SYSTEM SERVICE AREAS
INCLUDING THE FOLLOWING SUBDIVISIONS

Buckhead
Creekertown
Creekertown Villas
Cooper's Court
Foxden
Foxlair
Fox Trace Sections I, II, and III
Fox Trace Section IV, Phases 1 - 6
Fox Trace Section V
Fox Trace Point I and II
Jack's Branch
Jack's Branch Townhomes
Quail Roost

Onslow County, North Carolina
subject to any orders, rules, regulations,
and conditions now or hereafter lawfully made
by the North Carolina Utilities Commission.

ISSUED BY ORDER OF THE COMMISSION.
This the 26th day of March, 2019.

NORTH CAROLINA UTILITIES COMMISSION
A. Shonta Dunston, Deputy Clerk

APPENDIX B
PAGE 1 OF 2

SCHEDULE OF PROVISIONAL INTERIM RATES

for

PLURIS WEBB CREEK, LLC

for providing wastewater utility service in

ALL OF THE SERVICE AREAS SERVED BY THE
WEBB CREEK WASTEWATER UTILITY SYSTEM
Onslow County, North Carolina

Monthly Flat Rate (Residential):	$37.69
Monthly Metered Rates (Commercial Service):	
Monthly base charge, zero usage	$28.34
Usage charge, per 1,000 gallons (based on metered water usage)	
Sand Ridge Elementary School	$ 9.04
Nonresidential Sewer Service	$ 9.04

Connection Charge:

Residential	$1,800 payable when tap is made Sand
Ridge Elementary School	$125,000
Nonresidential (other)	$5.00 per gallon of designated daily flow based on DWR criteria

Reconnection Charge:

If sewer service cut off by utility for good cause	$141.00

APPENDIX B
PAGE 2 OF 2

Bills Due:	On billing date
Bills Past Due:	15 days after billing date
Billing Frequency:	Shall be monthly for service in arrears
Returned Check Fee:	$20.00
Finance Charge for Late Payment:	1% per month will be applied to the unpaid balance balance of all bills still past due 25 days after billing date.

Issued in Accordance with Authority Granted by the North Carolina Utilities Commission in Docket No. W-1314, Sub 1, on this the 26th day of March, 2019.

APPENDIX C
PAGE 1 OF 2

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. W-1314, SUB 1
DOCKET NO. W-864, SUB 11
DOCKET NO. W-864, SUB 14

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

NOTICE IS HEREBY GIVEN that the North Carolina Utilities Commission (Commission) has issued a certificate of public convenience and necessity to Pluris Webb Creek, LLC (Pluris), for wastewater utility service for all of the service areas in Onslow County, North Carolina previously franchised to Webb Creek Water and Sewage, Inc.

WATER AND SEWER – EMERGENCY OPERATOR

Pluris has served as the Commission-appointed emergency operator for these service areas since August 8, 2016, pursuant to the Commission's Order Appointing Emergency Operator, Approving Increased Rates, and Requiring Customer Notice issued in Docket No. W-864, Sub 11.

The Commission has also revoked the franchises previously granted to Webb Creek Water and Sewage, Inc.

The Commission has approved, for Pluris (as franchise owner) the continuation of the provisional interim rates previously approved by Order dated August 8, 2016, in Docket No. W-864, Sub 11, for Pluris when it was the Commission-appointed emergency operator.

The Commission-approved provisional interim rates are as follows:

<u>Monthly Flat Rate (Residential)</u>:	$37.69
<u>Monthly Metered Rates (Commercial Service)</u>:	
Monthly base charge, zero usage	$28.34
Usage charge, per 1,000 gallons (based on metered water usage)	
Sand Ridge Elementary School	$ 9.04
Nonresidential Sewer Service	$ 9.04

<u>Connection Charge</u>:

Residential	$1,800 payable when tap is made
Sand Ridge Elementary School	$125,000
Nonresidential (other)	$5.00 per gallon of designated daily flow based on DWR criteria

<u>Reconnection Charge</u>:

If sewer service cut off by utility for good cause	$141.00

In the next general rate case for Pluris, the provisional interim rates collected by Pluris as emergency operator and thereafter as franchise owner (effective upon the date of this notice), will be audited by the Public Staff – North Carolina Utilities Commission (Public Staff), and the

Public Staff will recommend to the Commission whether the Public Staff considers that there has been an overcollection and customer refunds should be ordered by the Commission.

ISSUED BY ORDER OF THE COMMISSION.
This the 26th day of March, 2019.

NORTH CAROLINA UTILITIES COMMISSION
A. Shonta Dunston, Deputy Clerk

CERTIFICATE OF SERVICE

I, ______________________________, mailed with sufficient postage or hand delivered to all affected customers a copy of the Notice to Customers issued by the North Carolina Utilities Commission in Docket Nos. W-864, Subs 11 and 14, and W-1314, Sub 1, and such Order was mailed or hand delivered by the date specified in the Order.

This the ____ day of ______________, 2019.

By: ______________________________
Signature

Pluris Webb Creek, LLC
Name of Utility Company

The above named Applicant, ______________________________, personally appeared before me this day and, being first duly sworn, says that the required copy of the Notice to Customers was mailed or hand delivered to all affected customers, as required by the Commission Order dated ______________________________ in Docket Nos. W-864, Subs 11 and 14 and W-1314, Sub 1.

Witness my hand and notarial seal, this the _______ day of ______________, 2019.

____
Notary Public

____
Printed Name

(SEAL) My Commission Expires: ______________________________
Date

DOCKET NO. W-218, SUB 497

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application by Aqua North Carolina, Inc., 202 MacKenan Court, Cary, North Carolina 27511, for Authority to Adjust and Increase Rates for Water and Sewer Utility Service in All Service Areas in	)))))	ORDER CLARIFYING RATE BASE REDUCTION CONCERNING CIAC AND REQUESTING RESPONSE

BY THE COMMISSION: On December 18, 2018, the Commission issued an Order Approving Partial Settlement Agreement and Stipulation, Granting Partial Rate Increase, and Requiring Customer Notice (Rate Order) in the above-captioned docket, a general rate case for Aqua North Carolina, Inc. (Aqua NC or Company).

In an email dated April 25, 2019, from the Public Staff – North Carolina Utilities Commission (Public Staff), written by William Grantmyre, Public Staff Attorney, and sent to Freda Hilburn, Commission Staff Financial Analyst, the Public Staff requested clarification regarding the $2,000,925 in contributions in aid of construction (CIAC) that Aqua NC collected from the Buffalo Creek developers prior to and through the date of the evidentiary hearing in the rate case. The Public Staff asked whether the entire amount of $2,000,925 related to the 333,671 gallons per day of capacity to be purchased from Johnston County was included by the Commission as CIAC (less amortization) in the Rate Order, and, thereby, reduced the rate base for Aqua NC Sewer Operations by that amount. The Public Staff commented that the Rate Order did not specifically set forth the precise amount that was deducted. The Public Staff stated that its interpretation of the Rate Order is that the entire $2,000,925 (less amortization) was included as CIAC, thereby reducing the rate base for Aqua NC Sewer Operations approved in the Rate Order.

On May 9, 2019, the Public Staff's email was accepted by the Clerk's Office and filed in Docket No. W-218, Sub 497. It is hereinafter referred to as the Public Staff's Motion for Clarification, or Motion. Also on May 9, 2019, Ms. Hilburn sent all parties an email with a copy of the Public Staff's Motion for Clarification attached. The email notified the parties that the Public Staff's Motion had been filed in the docket, and that the deadline to respond to the Motion was by close of business, Tuesday, May 14, 2019.

On May 14, 2019, Aqua NC filed its comments on the Public Staff's Motion. Aqua NC noted that the Company had no specific response to the Public Staff's Motion at that time, but stated that Aqua NC reserved the right to file a response to the Commission's order addressing the Public Staff's Motion, and/or any subsequent filing by the Public Staff containing comments on the Company's March 15, 2019 compliance filing required pursuant to Decretal Paragraph No. 25 of the Rate Order (Affidavit of Edward P. Thill, Controller II, Aqua North Carolina, Inc. Concerning Future Accounting Treatment of Johnston County Transmission and Capacity Fees).[1]

No other party filed comments on the Public Staff's Motion.

In response to the Public Staff's Motion, the Commission provides the following information:

- The $2,000,925 CIAC amount referred to in the Public Staff's Motion is found on Page 18 of 52, Table 2, in the rebuttal testimony of Aqua NC President Shannon Becker filed on September 4, 2018. The $2,000,925 amount is referred to as "YTD [Year-to-Date] 2018" CIAC collections for capacity sold to developers on the Buffalo Creek side of the Flowers Plantation development. A specific date in 2018 is not referenced in witness Becker's rebuttal testimony, only "YTD 2018".

- On Public Staff Cooper Supp. Exhibit I, Schedule 2-3 Revised, filed on September 13, 2018, Line 1, Column (b), is the Public Staff's "Adjustment to include post test year additions" to CIAC in the amount of $2,558,369.

- On Line 2, Column (b) of that same schedule, is the Public Staff's "Adjustment for Neuse Colony Wastewater Plant" which decreases the amount of CIAC deducted from rate base by $1,497,399. This adjustment is explained on Pages 51-52 of Public Staff Engineer Charles Junis' testimony filed on August 22, 2018.

- On Page 129 of the Rate Order, under the heading "Neuse Colony WWTP CIAC", the Commission stated:

  > As discussed elsewhere in this Order, the Commission has concluded that the adjustment recommended by the Public Staff to remove from rate base the CIAC collected by Aqua NC in the amount of $1.497 million related to the Neuse Colony WWTP is not appropriate in this proceeding. Further, the Commission concluded that the adjustment for the imputation of CIAC for the Buffalo Creek force main and pump station costs should be $218,999 rather than $315,687.

- As a result of the Commission's conclusions reached on Page 129 of the Rate Order, the amount of total CIAC the Commission deducted from the Aqua NC Sewer Operations Rate Base (see Page 169 of the Rate Order) was $80,683,472.

[1] On March 15, 2019, Aqua NC made a timely filing in response to the Commission's request that it provide the details of the future accounting treatment of the cost of capacity and transmission purchased from Johnston County, and the net rate base adjustment and total revenue requirement effect to the Company.

- The $80,683,472 amount was derived by the Commission as follows:

  Public Staff Cooper Supp. Exhibit I, Schedule 2(b) Revised, Line 3, Column (c) = $79,282,761.

  The Public Staff's $79,282,761 CIAC amount is increased by $1,497,399 and reduced by $315,687-$218,999 or $96,688 based on the Commission's conclusions stated on Page 129 of the Rate Order, as set forth above.

  $79,282,761 + $1,497,399 - $96,688 = $80,683,472 (Total gross CIAC amount for Aqua NC Sewer Operations deducted from rate base per Page 169 of the Rate Order).

- The test year for the Sub 497 rate proceeding was the 12 months ended September 30, 2017. Therefore, to the extent the update to include post test year additions on Line 1, Column (b) of Public Staff Cooper Supp. Exhibit I, Schedule 2-3 Revised, included the total "YTD 2018" CIAC amount of $2,000,925 referred to in witness Becker's rebuttal testimony, the Commission included it (less amortization) in the Rate Order as a reduction to rate base for Aqua NC Sewer Operations.

Based upon the foregoing and the record, to the extent the Public Staff included the entire amount of the "YTD 2018" CIAC in the amount of $2,000,925 (less amortization) in the supplemental exhibit of Public Staff witness Cooper filed on September 13, 2018, in this docket, the Commission confirms the Public Staff's interpretation of the Rate Order that the entire amount of such CIAC (less amortization) reduced the rate base for Aqua NC Sewer Operations in the general rate proceeding. Furthermore, the Commission finds good cause to request that the Public Staff provide a response indicating the precise amount of the $2,000,925 which is included in the supplemental exhibit of Public Staff witness Cooper filed on September 13, 2018. Consequently, the Commission requests that the Public Staff file, within five business days of this Order, its response, including any applicable supporting documentation, workpaper, or explanation, as appropriate.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 17th day of May, 2019.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

WATER AND SEWER – RATE INCREASE

DOCKET NO. W-218, SUB 497

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application by Aqua North Carolina, Inc.,	)	
202 MacKenan Court, Cary, North Carolina	)	ORDER APPROVING FLUSHING
27511 for Authority to Adjust and Increase	)	BILL CREDIT POLICY AND
Rates for Water and Sewer Utility Service	)	PROCEDURE AND REQUIRING
for all Areas in North Carolina	)	CUSTOMER NOTICE

BY THE COMMISSION: On December 18, 2018, in Docket No. W-218, Sub 497, the Commission issued an Order Approving Partial Settlement Agreement and Stipulation, Granting Partial Rate Increase, and Requiring Customer Notice. Ordering Paragraph No. 20, at page 185, provides as follows:

> 20. That Aqua NC shall work with the Public Staff to develop a policy and procedure for providing customers a bill credit when Aqua NC recommends that a customer flush his/her individual line to address a water quality issue. Within 90 days from the issuance of this Order, Aqua NC and the Public Staff shall submit to the Commission for approval their proposed policy and procedure for determining to whom, how and when bill credits will be given as well as how much the flushing bill credit will be.

On March 4, 2019, in the above-captioned dockets, Aqua North Carolina, Inc. (Aqua NC or Company) filed a motion for extension of time until June 14, 2019 to file its proposal for a flushing bill credit policy and procedure which was granted by Commission Order issued on March 8, 2019.

On June 14, 2019, Aqua NC filed the affidavit of Joseph R. Pearce, Jr., Director of Operations for Aqua NC, in compliance with Ordering Paragraph No. 20, which requested Commission approval of a policy and procedure jointly proposed by Aqua NC and the Public Staff – North Carolina Utilities Commission (Public Staff)(collectively, the Joint Respondents) to determine and apply a bill credit to customers when flushing is prescribed and requested by Aqua NC to address a water quality issue. Specifically, the Joint Respondents submitted the following proposed policy and procedure for Commission consideration and approval:

> **Policy:** Aqua [NC] shall provide bill credits for customers who are requested to flush their lines by Aqua [NC] due to a water quality issue.

Procedure:

- Aqua [NC]'s management, Technical Services Specialists, Customer Care Team Leads, and Field Service Representatives may occasionally request that a specific customer flush his/her service lateral in response to a water quality issue.

- Annual distribution flushing and system pressure advisories will not be considered blanket requests for customer flushing.

- If the specific customer agrees to flush the service lateral, Aqua [NC] will provide a flushing bill credit in an amount equal to the charge for 1,000 gallons of water under the applicable tariff. The credit will be applied within the customer's next two billing cycles.

- The cost of the bill credit will be considered an operating expense for accounting and ratemaking purposes.

Affiant Pearce stated that Aqua NC proposed to implement the flushing bill credit as soon as reasonably possible but no later than 60 days from the Commission's approval of the jointly recommended policy and procedure.

On June 21, 2019, the Commission issued an Order which allowed interested parties to file comments regarding Aqua NC's response to Ordering Paragraph No. 20 of the Commission's December 18, 2018 Order and Aqua NC to file reply comments. No comments were filed.

Based on the foregoing and the record, the Commission concludes that the policy and procedure proposed by the Joint Respondents and stated herein for providing Aqua NC's customers a bill credit when Aqua NC recommends that a customer flush his/her individual line to address a water quality issue should be approved. Further, the Commission concludes that Aqua NC should implement the approved policy and procedure as soon as practicable but no later than 60 days from the issuance date of this Order. Finally, Aqua NC shall provide an appropriate customer notice by bill message or insert informing customers regarding its approved flushing bill credit policy and procedure.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 15th day of July, 2019.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

DOCKET NO. W-218, SUB 497

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application by Aqua North Carolina, Inc., 202 MacKenan Court, Cary, North Carolina 27511 for Authority to Adjust and Increase Rates for Water and Sewer Utility Service in All Its Service Areas in North Carolina	)))))	ORDER REQUIRING VERIFIED INFORMATION AND ALLOWING COMMENTS

BY THE PRESIDING COMMISSIONER: On December 18, 2018, in Docket No. W-218, Sub 497, the Commission issued an Order Approving Partial Settlement Agreement and Stipulation, Granting Partial Rate Increase, and Requiring Customer Notice.

Ordering Paragraph No. 25 of the Commission's December 18, 2018 Order, at page 186, provides as follows:

> 25. That Aqua NC shall, within 30 days following issuance of this Order, make a compliance filing to show its present and future accounting treatment, in a manner consistent with the findings and conclusions of the Commission herein, of the capacity purchased from, and transmission expenses paid to, Johnston County. Such filing shall include the net rate base adjustment and total revenue requirement effect to the Company as a result of the Commission's determinations of these issues herein.

On January 18, 2019, Aqua North Carolina, Inc. (Aqua NC or Company), filed the affidavit of Tammy S. Bernard, Senior Accountant III for Aqua NC, which provided a partial response to the requirements of Ordering Paragraph No. 25. In particular, Affiant Bernard provided the Company's present accounting treatment of the capacity purchased from, and transmission expenses paid to, the Johnston County Department of Public Utilities (Johnston County). Aqua NC requested additional time to prepare and file its response to Ordering Paragraph No. 25 with respect to the Company's future accounting treatment of the capacity purchased from, and transmission expenses paid to, Johnston County and the net rate base adjustment and total revenue requirement effect to the Company as a result of the Commission's determinations in the December 18, 2018 Order. On January 24, 2019, the Commission issued an Order accepting the Affidavit of Tammy S. Bernard into the record and granting Aqua NC an extension of time until March 15, 2019, to file the remainder of its response to Ordering Paragraph No. 25.

On March 15, 2019, Aqua NC filed the affidavit of Edward P. Thill, Controller II for Aqua NC, which provided the Company's remaining response in compliance with Ordering Paragraph No. 25 of the December 18, 2018 Order, concerning the future accounting treatment of the Johnston County transmission and capacity fees.

On June 19, 2019, the Public Staff – North Carolina Utilities Commission (Public Staff) filed comments regarding the Affidavit of Edward P. Thill and requested that the Commission issue an order requiring Aqua NC to record all Johnston County reservation capacity and transmission fees received from the Flowers Plantation Buffalo Creek developers as contributions in aid of construction when received.

On June 27, 2019, the Commission issued an Order accepting the Affidavit of Edward P. Thill into the record and allowing interested parties to file reply comments regarding the Public Staff's June 19, 2019 comments and also initial comments regarding the Affidavits of Tammy S. Bernard and Edward P. Thill on or before July 26, 2019.

On July 26, 2019, Aqua NC filed the Second Affidavit of Edward P. Thill, Controller II for Aqua in which Affiant Thill informed the Commission that subsequent to the Public Staff filing its June 19, 2019 comments, the Company and the Public Staff discussed both the content of his initial Affidavit and the Public Staff's response thereto, and the parties have come to an agreement which satisfactorily resolved all their differences. In his Second Affidavit, Affiant Thill stated that Aqua is authorized to state that the Company and the Public Staff jointly support the following future accounting treatment of the Johnston County transmission and capacity fees:

(a) The full value of developer payments (including both T&D and capacity fees) will be recorded by Aqua as amortizing CIAC in accordance with past practice; and
(b) The full value of future capacity purchases from Johnston County (including both T&D and capacity fees) will be recorded by Aqua as depreciable Plant in Service.

Further, Aqua commented that the Company's June 2019 purchase of 51,440 gallons per day (gpd) of additional capacity from Johnston County at a total cost of $330,245 will be accounted for in accordance with the accounting treatment described above.

Based on the foregoing and the entire record in this proceeding, the Presiding Commissioner finds good cause to accept the Second Affidavit of Edward P. Thill filed on July 26, 2019, into the record. Further, the Presiding Commissioner finds that Aqua NC should be required to file verified responses to the following questions concerning its June 2019 purchase of additional capacity from Johnston County noted in the Second Affidavit of Edward P. Thill:

(1) The Commission observes that Aqua NC's June 2019 purchase of 51,440 gpd of additional sewer capacity from Johnston County at a total cost of $330,245 calculates to a fee of $6.42 per gpd. Please confirm the fee per gpd paid by Aqua NC to Johnston County in June 2019 for the additional sewer capacity. Did the fee per gpd include both a capacity fee component and a transmission fee component? Please delineate and explain the components of the fee per gpd paid by Aqua NC in June 2019.

(2) Please explain why the sewer plant capacity fee per gpd paid by Aqua NC to Johnston County in June 2019 is different from the tariff amount of $8.48 per gpd (consisting of sewer plant capacity fee per gpd of $5.34 and transmission fees per gpd of $3.14) included on Appendix A-1, Page 5 of 8, attached to the Commission's December 18, 2018 Order.

(3) Was the fee per gpd paid by Aqua NC in June 2019 a negotiated fee between Aqua NC and Johnston County? Please explain. In addition, please provide documentation supporting the sewer capacity fee charged by Johnston County for Aqua NC's June 2019 purchase of 51,440 gpd of additional sewer capacity.

Finally, the Presiding Commissioner finds good cause to allow interested parties to file comments regarding the Second Affidavit of Edward P. Thill filed by Aqua NC on July 26, 2019, as well as the verified responses to be filed by Aqua NC as required herein and for Aqua NC to file reply comments.

IT IS, THEREFORE, ORDERED as follows:

1. That the Second Affidavit of Edward P. Thill filed on July 26, 2019, in Docket No. W-218, Sub 497, is hereby accepted into the record.

2. That on or before Tuesday, October 1, 2019, Aqua NC shall file verified responses to the Commission's questions as stated herein concerning its June 2019 purchase of additional sewer capacity from Johnston County.

3. That on or before Tuesday, October 15, 2019, interested parties may file comments regarding the Second Affidavit of Edward P. Thill filed on July 26, 2019, as noted herein and the verified responses to be filed by Aqua NC as required herein by Ordering Paragraph No. 2.

4. That on or before Tuesday, October 29, 2019, Aqua NC may file reply comments.

ISSUED BY ORDER OF THE COMMISSION.
This the 17th day of September, 2019.

NORTH CAROLINA UTILITIES COMMISSION
A. Shonta Dunston, Deputy Clerk

WATER AND SEWER – RATE INCREASE

DOCKET NO. W-354, SUB 360

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application by Carolina Water Service, Inc., of North Carolina, 4944 Parkway Plaza Boulevard, Suite 375, Charlotte, North Carolina 28217, for Authority to Adjust and Increase Rates for Water and Sewer Utility Service in All of its Service Areas in North Carolina, Except Corolla Light and Monteray Shores Service Area	)))))))	ORDER APPROVING JOINT PARTIAL SETTLEMENT AGREEMENT AND STIPULATION, GRANTING PARTIAL RATE INCREASE, AND REQUIRING CUSTOMER NOTICE

HEARD: Tuesday, August 28, 2018, at 7:00 p.m., in the Craven County Courthouse, Courthouse Annex, Courtroom #4, 302 Broad Street, New Bern, North Carolina

Wednesday, August 29, 2018, at 7:00 p.m., in Courtroom 317, New Hanover County Courthouse, 316 Princess Street, Wilmington, North Carolina

Wednesday, September 19, 2018, at 7:00 p.m., in the Mecklenburg County Courthouse, Courtroom 5350, 832 East 4th Street, Charlotte, North Carolina

Tuesday, September 25, 2018, at 7:00 p.m., in the Watauga County Courthouse, Courtroom #1, 842 W. King Street, Boone, North Carolina

Wednesday, September 26, 2018, at 7:00 p.m., in the Buncombe County Courthouse, Courtroom 1A, 60 Court Plaza, Asheville, North Carolina

Monday, October 8, 2018, at 7:00 p.m., and Tuesday, October 16, 2018, at 10:00 a.m., in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Chairman Edward S. Finley, Jr., Presiding, and Commissioners ToNola D. Brown-Bland, Jerry C. Dockham, James G. Patterson, Lyons Gray, Daniel G. Clodfelter, and Charlotte A. Mitchell

APPEARANCES:

For Carolina Water Service, Inc. of North Carolina:

Jo Anne Sanford, Sanford Law Office, PLLC, Post Office Box 28085, Raleigh, North Carolina 27611

Robert H. Bennink, Jr., Bennink Law Office, 130 Murphy Drive, Cary, North Carolina 27513

For Corolla Light Community Association, Inc.:

Brady W. Allen, Allen Law Offices, PLLC, 1514 Glenwood Ave., Suite 200, Raleigh, North Carolina 27608

For the Using and Consuming Public:

Gina C. Holt, William E. Grantmyre, and John Little, Staff Attorneys, Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699

Margaret A. Force, Assistant Attorney General, North Carolina Department of Justice, Post Office Box 629, Raleigh, North Carolina 27602

BY THE COMMISSION: On March 23, 2018, in the above-captioned proceeding, pursuant to Commission Rule R1-17(a), Carolina Water Service, Inc., of North Carolina (CWSNC or Company) submitted notice of its intent to file a general rate case application.

On April 6, 2018, CWSNC filed a procedural request proposing that the impact of the Federal Tax Cuts and Jobs Act (the Tax Act) on the Company's rates be addressed and resolved in this docket, rather than in the Commission's generic tax docket (Docket No. M-100, Sub 148).

On April 27, 2018, CWSNC filed its verified application for a general rate increase (Application), seeking authority to: (1) increase and adjust its rates for water and sewer utility service in all of its service areas in North Carolina, except for the Company's Corolla Light/Monteray Shores service area (CLMS); and (2) pass through any increases in purchased bulk water rates, subject to CWSNC providing sufficient proof of the increases, as well as any increased costs of wastewater treatment performed by third parties and billed to CWSNC. Included with this filing were certain information and data required by NCUC Form W-1. The Company stated in its Application that it presently has approximately 34,871 water customers and 21,531 sewer customers in North Carolina (including water and sewer availability customers).[1] The present rates for water and sewer service have been in effect since November 8, 2017, pursuant to the Commission's Order Approving Stipulations, Granting Partial Rate Increase and Requiring Customer Notice in CWSNC's last general rate case in Docket No. W-354, Sub 356 (Sub 356 Order).[2]

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[1] The Company did not indicate the specific date related to its present number of customers stated in the Application. The number of customers presented in Finding of Fact No. 13 herein is based on the final revised detailed billing analysis prepared by Public Staff witness Casselberry for the 12-month period ended December 31, 2017, and is not disputed by the Company.

[2] The Elk River Development was excluded from the general rate increase application filed in Docket No. W-354, Sub 356, as the rates for those customers had increased effective September 20, 2016, pursuant to a rate increase application approved in Docket No. W-1058, Sub 7, for Elk River Utilities, Inc.

On May 16, 2018, the Company filed an Amendment to its Application, revising Page 4 of 7 to Appendix A-1.

On May 22, 2018, the Commission issued an Order Establishing General Rate Case, Suspending Rates, Scheduling Hearings, and Requiring Customer Notice. By that Order, the Commission declared this matter to be a general rate case pursuant to N.C.G.S. § 62-137, suspended the effect of the proposed new rates for up to 270 days pursuant to N.C.G.S. § 62-134, and required the parties to prefile testimony and exhibits. That Order also scheduled customer hearings in New Bern, Wilmington, Charlotte, Boone, Asheville, and Raleigh, North Carolina, set the evidentiary hearing in Raleigh, North Carolina, and required notice to all affected customers. On May 30, 2018, CWSNC filed its Ongoing Three-Year Water and Sewer Improvement Charges (WSIC/SSIC) Plan.

On July 27, 2018, CWSNC filed a certificate of service demonstrating that the Applicant sent the notices to customers as required by the Commission's Order issued in this proceeding on May 22, 2018.

Public hearings were held as scheduled. The following public witnesses testified at the public hearings in this proceeding:

August 28, 2018	New Bern	Ted Warnock, Simon Lock, Diana Viglianese, Jim Brown, Mike Shannon, Ralph Tridico, Irving Joffee, Michael Kaplan, John Gumbel, and Benny Thompson
August 29, 2018	Wilmington	David Holsinger
September 19, 2018	Charlotte	Patricia Marquardt, William Colyer, Nicoline Howell, Griffin Rice, Margaret Quan, Deborah Atkinson, Nicholas Stephen Kirkley, Tom Moody, Karen Cynowa, and Michael Tepedino
September 25, 2018	Boone	Harvey Bauman, Sid E. Von Ropeunt, George Hall, and Tim Presnell
September 26, 2018	Asheville	Jack Zinselmeir, Phil Reitano, Gerard Worster, Chuck Van Rens, and Connie Brown
October 8, 2018	Raleigh	William Stanley Glance, Vincent Roy, Judith Bassett, Vicki Smith, and Benjamin Farmer

CWSNC responded to public witness testimony by its filings of September 18, October 4, October 15, October 17, and October 25, 2018.

On September 4, 2018, CWSNC filed the direct testimony and exhibits of Company witnesses Richard Linneman, Financial Planning and Analysis Manager, CWSNC;[1] Dylan W. D'Ascendis, Director, ScottMadden, Inc.; and Deborah Clark, Communications Coordinator, CWSNC.

On September 24, 2018, the Corolla Light Community Association, Inc. (Corolla Light HOA) filed a Petition to Intervene, which the Commission granted by Order issued on October 11, 2018.

On September 25, 2018, the Public Staff filed a motion for an extension of time for the parties to file testimony and exhibits, which was granted by Commission Order issued September 26, 2018.

On September 26, 2018, the North Carolina Attorney General's Office (AGO) filed a Notice of Intervention in this proceeding. The Commission recognizes the AGO's intervention pursuant to N.C.G.S. § 62-20.

The Public Staff's participation in this proceeding is recognized pursuant to § 62-15(d) and Commission Rule R1-19.

On October 3, 2018, the Public Staff filed the direct testimony and exhibits of Public Staff witnesses Gina Y. Casselberry, Advanced Utilities Engineer, Public Staff Water, Sewer, and Telephone Division; John R. Hinton, Director, Public Staff Economic Research Division; Lynn Feasel, Staff Accountant, Public Staff Accounting Division[2]; and Sonja R. Johnson, Staff Accountant, Public Staff Accounting Division.

On October 4, 2018, the Public Staff filed the direct testimony of Michelle M. Boswell, Staff Accountant, Public Staff Accounting Division.

On October 5, 2018, the Public Staff filed the supplemental testimony of witness Johnson.

On October 11 and 12, 2018, the Public Staff filed the supplemental testimony and exhibits of witnesses Casselberry; Boswell; Windley E. Henry, Accounting Manager, Water/Communications Section, Public Staff Accounting Division; Hinton; and the second supplemental testimony of witness Johnson.

Also on October 12, 2018, CWSNC filed the rebuttal testimony and exhibits of witnesses J. Bryce Mendenhall, Vice President of Operations, CWSNC; D'Ascendis; and DeStefano.

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[1] CWSNC witness Dante DeStefano, Financial Planning and Analysis Manager, CWSNC, adopted the direct testimony initially submitted by CWSNC witness Richard Linneman. Hereafter, for convenience, the Commission will refer only to the testimony of witness DeStefano in this Order.

[2] Public Staff witness Henry adopted the direct testimony initially submitted by Public Staff witness Feasel. Hereafter, for convenience, the Commission will refer only to the testimony of witness Henry in this Order.

The evidentiary hearing began as scheduled at 10:00 a.m. on October 16, 2018, in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, and concluded that same day.

On October 19, 2018, CWSNC and the Public Staff filed a Partial Joint Settlement Agreement and Stipulation (Stipulation). On October 23, 2018, CWSNC filed a response to Commissioner Clodfelter's request for a late-filed exhibit addressing the Company's post-test year plant additions.

On October 30, 2018, the Public Staff filed the late-filed exhibits of witnesses Johnson and Casselberry.

On November 19, 2018, the Public Staff filed a motion for extension of time for all parties to file proposed orders or briefs, which was granted by Commission Order issued the same day.

On November 20 and 21, 2018, the Public Staff filed the late-filed exhibits of witness Casselberry and the Revised Supplemental Exhibits I and II of witness Henry.

On November 27, 2018, the Public Staff filed the Revised Late-Filed Exhibits 4, 7, and 9 of witness Casselberry.

Also on November 27, 2018, CWSNC, the Public Staff, and the AGO filed their respective proposed orders or briefs. In conjunction with its proposed order, CWSNC filed the affidavit of Anthony Gray regarding CWSNC's rate case expense and DeStefano Supplemental Exhibits I (Billing Analysis by Service Areas) and II (Calculation of Gross Revenue Impact of Company Adjustments).

Based upon the foregoing, including the verified Application and accompanying NCUC Form W-1, the testimony and exhibits of the public witnesses appearing at the hearings, the testimony and exhibits of the expert witnesses received into evidence, the Stipulation, and the entire record herein, the Commission makes the following:

FINDINGS OF FACT

General Matters

1. CWSNC is a corporation duly organized under the law and is authorized to do business in the State of North Carolina. CWSNC is a franchised public utility providing water and/or sewer utility service to customers in 38 counties in North Carolina. CWSNC is a wholly-owned subsidiary of Utilities, Inc. (UI).[1]

[1] Utilities, Inc. owns regulated utilities in 16 states, with primary service areas in Florida, North Carolina, South Carolina, Louisiana, and Nevada, which provide water and sewer utility service to approximately 197,732 customers.

2. CWSNC is properly before the Commission pursuant to Chapter 62 of the North Carolina General Statutes seeking a determination of the justness and reasonableness of its proposed rates and charges for the water and sewer utility service CWSNC provides to customers in North Carolina, with the exception of the Corolla Light and Monterey Shores Service Area.

3. The appropriate test period for use in this proceeding is the 12-month period ending December 31, 2017, updated for known and measurable changes through the close of the hearing

4. The present rates for water and sewer service have been in effect since November 8, 2017, pursuant to the Commission's Sub 356 Order, except for the Elk River Development, which rates have been in effect since September 20, 2016, pursuant to a rate general rate increase approved in Docket No. W-1058, Sub 7 for Elk River Utilities, Inc.

<u>The Stipulation</u>

5. On October 19, 2018, CWSNC and the Public Staff (Stipulating Parties) filed the Stipulation, resolving some of the issues between those two parties in this docket. Those issues that were not resolved by the Stipulation are referred to herein as the "Unsettled Issues."

6. The Stipulation is the product of the give-and-take in negotiations between the Stipulating Parties, is material evidence in this proceeding, and is entitled to be given appropriate weight in this case, along with the other evidence of record, including that submitted by the Company, the Public Staff, and the public witnesses that testified at the hearing.

7. The Stipulation is a nonunanimous settlement of matters in controversy in this proceeding and was not joined by the other parties.

8. The Stipulation resolves only some of the disputed issues between CWSNC and the Public Staff.

9. The Unsettled Issues, which were not resolved in the Stipulation, include the following:

1) Return on equity;
2) Public Staff adjustments to ADIT and EDIT;
3) Public Staff proposal that CWSNC refund to ratepayers the overcollection of federal taxes related to the decrease in the federal corporate tax rate since January 1, 2018;
4) Reduction of executive compensation and benefits, and related payroll taxes, by 50%;
5) Reallocation of insurance premium expenses, passed to CWSNC from its parent, UI;
6) Public Staff use of composite utility plant depreciation rates for calculating CIAC and PAA amortization expense;
7) Removal of purchased water and purchased sewer treatment expense from the cash working capital calculation;

8) Implementation of the proposed Consumption Adjustment Mechanism (CAM); and

9) Tariff rate design.

The Unsettled Issues are resolved by the Commission and are addressed later in this Order.

Acceptance of Stipulation

10. The Stipulation will provide CWSNC and its ratepayers just and reasonable rates when combined with the rate effects of the Commission's decisions regarding the Unsettled Issues in this proceeding.

11. The provisions of the Stipulation are just and reasonable to all parties to this proceeding and serve the public interest.

12. It is appropriate to approve the Stipulation in its entirety.

Customer Concerns and Service

13. As of the 12-month period ended December 31, 2017, CWSNC served approximately 30,437 water customers and 20,118 wastewater customers, including Elk River Development and CLMS.[1] There are also 3,774 water availability customers in Carolina Forest, Woodrun, Linville Ridge, Sapphire Valley, Connestee Falls, and Fairfield Harbour and 1,401 sewer availability customers in Sapphire Valley, Connestee Falls, and Fairfield Harbour. CWSNC operates 92 water utility systems and 39 sewer utility systems.

14. A total of 35 witnesses testified at the six public hearings held for the purpose of receiving customer testimony. In general, public testimony at those hearings primarily dealt with objections to the rate increase but some customers did express quality of service concerns, including but not limited to, hardness of the water, staining in sinks and toilet bowls, staining of clothing due to flushing, delay in patching asphalt, and frequently pumping out a lift station.

15. As of October 10, 2018, the Public Staff had received approximately 64 written customer statements of position from CWSNC customers, a petition with 27 signatures from Amber Acres North, a petition with approximately 263 signatures from Bradfield Farms, including a resolution expressing objection to the rate increase, and a petition from Yachtmans (Queens Harbour) with approximately 100 signatures. All of the customers objected to the magnitude of the rate increase. Their primary concerns included the high rate of return requested, the increase in rates compared to inflation, the impact of recent federal corporate income tax reductions, the increasing base facility charge, hardness of the water and discolored water. In addition, the Commission received approximately 12 written customer statements via electronic mail, primarily expressing opposition to CWSNC's proposed rate increase.

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[1] As of December 31, 2017, there were 321 water and 125 sewer customers in Elk River Development and 963 sewer-only customers in the CLMS service area.

16. CWSNC filed five verified reports with the Commission addressing the service-related concerns and other comments expressed by the witnesses who testified at the hearings held for the purpose of receiving public witness testimony. Such reports described each of the witnesses' specific service-related concerns and comments, the Company's response, and how each concern and comment was addressed, if applicable.

17. CWSNC has increased its attention to the communications component of service to customers since the last rate case, with an emphasis on more proactive communications and the launching of several social media platforms.

18. The Public Staff's description of the quality of service provided by CWSNC as "good" is supported by the record in this case.

19. The overall quality of service provided by CWSNC is adequate.

Rate Base

20. The appropriate level of rate base used and useful in providing service is $115,139,509 for CWSNC's combined operations, itemized as follows:

Item	Amount
Plant in service	$213,005,526
Accumulated depreciation	(52,955,117)
Net plant in service	160,050,409
Cash working capital	2,079,155
Contributions in aid of construction	(42,183,408)
Advances in aid of construction	(32,940)
Accumulated deferred income taxes	(3,972,592)
Customer deposits	(342,640)
Gain on sale and flow back taxes	(289,628)
Plant acquisition adjustment	(1,052,168)
Excess book value	(456)
Cost-free capital	(261,499)
Average tax accruals	(125,909)
Regulatory liability for excess deferred taxes	(251,770)
Deferred charges	1,522,955
Pro forma plant	0
Original cost rate base	$115,139,509

21. It is appropriate to exclude purchased water and sewer expense from the calculation of cash working capital.

22. It is appropriate to update ADIT to include the deferred tax related to the unamortized balance of rate case expense.

23. It is appropriate to adjust ADIT to reflect the deferred tax related to the unamortized balance of deferred maintenance charges.

Operating Revenues

24. It is appropriate to include in miscellaneous revenues allocated proceeds from the sale of utility property.

25. Miscellaneous revenues should be adjusted to correct the allocation of other water/sewer revenues between water and sewer operations for the Company's four rate divisions: (1) CWSNC Uniform Water; (2) CWSNC Uniform Sewer; (3) Bradfield Farms/Fairfield Harbour/Treasure Cove (BF/FH/TC) Water; and (4) Bradfield Farms/Fairfield Harbour (BF/FH) Sewer.

26. It is appropriate to adjust forfeited discounts and uncollectibles using the percentages calculated by the Public Staff based on test year service revenues and the respective test year forfeited discounts and uncollectibles balances.

27. The appropriate level of operating revenues under present rates for use in this proceeding is $32,575,467, consisting of service revenues of $32,429,699 and miscellaneous revenues of $360,163, reduced by uncollectibles of $214,395.

Maintenance and General Expenses

28. It is appropriate for CWSNC to recover total rate case expenses of $395,479 related to the current proceeding and $434,060 of unamortized rate case costs related to the prior proceeding in Docket No. W-354, Sub 356 (Sub 356 Proceeding). It is appropriate to amortize the total rate case costs for the current and prior proceedings over five years resulting in an annual level of rate case expense of $165,908.

29. It is inappropriate to reduce CWSNC's revenue requirement to reflect the Public Staff's recommendation to allocate to shareholders 50% of the compensation of three UI executive officers in the amount of $92,359.

30. It is appropriate to allocate automobile insurance based on the number of vehicles utilized for CWSNC's water and sewer operations as a percentage to the total number of UI automobiles.

31. It is appropriate to allocate workers compensation insurance based on the adjusted level of payroll.

32. It is appropriate to allocate property insurance based on the value of CWSNC's property covered by the current insurance policies.

Depreciation and Amortization Expense

33. It is appropriate to calculate CWSNC's ongoing annual level of depreciation expense based on the adjusted amount of plant in service and the depreciation lives for each plant account.

34. It is appropriate to reduce CWSNC's depreciation expense by the annual amortization of excess book value.

35. In calculating CWSNC's amortization expense–CIAC, it is appropriate to use a composite overall CIAC rate based on the actual amortization rates and balances at June 30, 2018, for each applicable account within the CIAC group of accounts.

36. In calculating CWSNC's amortization expense–PAA, it is appropriate to use the actual amortization rate of 2.47% for water operations and 3.53% for sewer operations.

37. The appropriate level of depreciation and amortization expense for combined operations for use in this proceeding is $4,073,516.

Franchise, Property, Payroll, and Other Taxes

38. The appropriate level of franchise and other taxes for use in this proceeding is ($49,702) for combined operations.

39. It is appropriate to calculate payroll taxes based on the adjusted level of salaries and wages and the current payroll tax rates.

40. It is inappropriate to reduce CWSNC's revenue requirement to reflect the Public Staff's recommendation to remove 50% of payroll taxes in the amount of $2,920 to match the adjustment to salaries and wages related to executive compensation.

41. The appropriate level of payroll taxes for use in this proceeding is $529,195 for combined operations.

42. The appropriate level of franchise, property, payroll, and other taxes for use in this proceeding is $713,068 for combined operations, consisting of ($49,702) for franchise and other taxes; $233,575 for property taxes, and $529,195 for payroll taxes.

Regulatory Fee and Income Taxes

43. It is appropriate to use the current statutory regulatory fee rate of 0.14% to calculate CWSNC's revenue requirement. The appropriate level of regulatory fee expense for use in this proceeding is $45,606.

44. It is appropriate to calculate income taxes for ratemaking purposes based on the adjusted level of revenues and expenses and the corporate tax rates for utility operations.

45. The appropriate level of state income taxes for use in this proceeding is $177,812.

46. The appropriate level of federal income taxes for use in this proceeding is $1,207,341.

The Federal Tax Cuts and Jobs Act

47. As proposed by the Company in its Application, agreed to by the Public Staff, and not opposed by any other party, CWSNC's revenue requirement shall reflect the reduction in the federal corporate income tax rate from 35% to 21% as enacted in the Tax Act, for the Company's ongoing income tax expense.

48. As outlined in the Stipulation between CWSNC and the Public Staff, the Company's federal protected EDIT should be amortized over a period of time equal to the expected lifespan of the plant, property, and equipment with which they are associated, in accordance with the normalization rules of the United States Internal Revenue Service (IRS).

49. The Company's federal unprotected EDIT should be returned to ratepayers through a levelized rider over a period of four years.

50. The Company's state EDIT recorded pursuant to the Commission's Order Addressing the Impacts of HB 998 on North Carolina Public Utilities issued on May 13, 2014, in Docket No. M-100, Sub 138 (Sub 138 Order) should continue to be amortized in accordance with the Sub 356 Order.

51. The Company's overcollection of federal income taxes in rates related to the decrease in the federal corporate income tax rate for the period beginning January 1, 2018, and corresponding interest, based on the overall weighted cost of capital, should be refunded to ratepayers as a credit for a one-year period beginning when the new base rates become effective in the present docket.

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

52. The cost of capital and revenue increase approved in this Order is intended to provide CWSNC, through sound management, the opportunity to earn an overall rate of return of 7.75%. This overall rate of return is derived from applying an embedded cost of debt of 5.68%, and a rate of return on equity of 9.75%, to a capital structure consisting of 49.09% long-term debt and 50.91% common equity.

53. A 9.75% rate of return on equity for CWSNC is just and reasonable in this general rate case.

54. A 50.91% common equity and 49.09% long-term debt ratio is a reasonable capital structure for CWSNC in this case.

55. A 5.68% embedded cost of debt for CWSNC is reasonable for the purpose of this case.

56. The rate increase approved in this case, which includes the approved rate of return on equity and capital structure, will be difficult for some of CWSNC's customers to pay, in particular CWSNC's low-income customers.

57. Continuous safe, adequate, and reliable water and wastewater utility service by CWSNC is essential to CWSNC's customers.

58. The rate of return on equity and capital structure approved by the Commission appropriately balances the benefits received by CWSNC's customers from CWSNC's provision of safe, adequate, and reliable water and wastewater utility service with the difficulties that some of CWSNC's customers will experience in paying the Company's increased rates.

59. The 9.75% rate of return on equity and the 50.91% equity capital structure approved by the Commission in this case result in a cost of capital that is as low as reasonably possible. They appropriately balance CWSNC's need to obtain equity and debt financing with its customers' need to pay the lowest possible rates.

60. The authorized levels of overall rate of return and rate of return on equity set forth above are supported by competent, material, and substantial record evidence, are consistent with the requirements of N.C.G.S. § 62-133, and are fair to CWSNC's customers generally and in light of the impact of changing economic conditions.

Revenue Requirement

61. CWSNC's rates and charges should be changed by amounts which, after pro forma adjustments, will produce the following increases in revenues:

Item	Amount
CWSNC Uniform Water	$489,336
CWSNC Uniform Sewer	290,260
BF/FH Water	270,044
BF/FH Sewer	374,448
Total CWSNC	$1,424,088

These increases will allow CWSNC the opportunity to earn a 7.75% overall rate of return, which the Commission has found to be just and reasonable in this case.

Consumption Adjustment Mechanism

62. In its Application, CWSNC requested Commission approval of a rate adjustment mechanism to account for variability in average monthly consumption per customer, which directly affects revenues.

63. CWSNC failed to demonstrate that its proposed consumption adjustment mechanism is reasonable or justified.

<u>Rate Design</u>

64. It is appropriate to charge customers in Sapphire Valley CWSNC's uniform metered sewer rates and to charge customers in Bradfield Farms and Fairfield Harbour CWSNC's flat sewer rate, as recommended by the Public Staff, agreed to by CWSNC, and not opposed by any party.

65. It is appropriate to charge customers in Linville Ridge and The Ridges at Mountain Harbour CWSNC's uniform metered water rates, as recommended by the Public Staff, agreed to by CWSNC, and not opposed by any party.

66. It is appropriate to charge customers in The Ridges at Mountain Harbour CWSNC's purchased sewer rates, as recommended by the Public Staff, agreed to by CWSNC, and not opposed by any party.

67. It is appropriate for CWSNC's rate design for water utility service for purposes of this proceeding to be a ratio of 52%/48% base charge to usage charge.

68. The rates and charges included in Appendices A-1, A-2, A-3, B-1, and B-2 are just and reasonable and should be approved.

<u>Water and Sewer System Improvement Charges</u>

69. Consistent with Commission Rules R7-39(k) and R10-36(k), CWSNC's WSIC and SSIC surcharges will reset to zero as of the effective date of the approved rates in this proceeding.

70. Pursuant to N.C.G.S. § 62-133.12, the cumulative maximum charges that the Company can recover between rate cases cannot exceed 5% of the total service revenues approved by the Commission in this rate case.

<u>Housekeeping on Bonds</u>

71. It is appropriate that the $20,000 bond and certificate of deposit from Branch Banking and Trust Company (BB&T) posted for Amherst Subdivision in Wake County, North Carolina and the $20,000 bond and certificate of deposit surety from BB&T posted for the Carolina Pines Service Area in Craven County, North Carolina be released to UI pursuant to the Commission's Order in Docket Nos. W-354, Sub 326; W-1152, Sub 8; and W-1151, Sub 7.

<u>EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1 – 4</u>

The evidence supporting these findings of fact is found in the Application and the accompanying NCUC Form W-1, the testimony and exhibits of the witnesses, and the entire record in this proceeding. These findings are informational, procedural, and jurisdictional in nature and are not contested by any party.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 5 – 12

The evidence supporting these findings of fact is found in the Stipulation and in the testimony of both CWSNC and the Public Staff's witnesses.

On October 19, 2018, CWSNC and the Public Staff jointly filed the Stipulation, which memorializes these parties' agreements on some of the issues in this proceeding. Attached to the Stipulation is Settlement Exhibit 1, which demonstrates the impact of the parties' agreements on the calculation of CWSNC's gross revenue for the test year ended December 31, 2017. Thus, the Stipulation is based on the same test period as CWSNC's Application, adjusted for certain changes in plant, revenues, and costs that were not known at the time the case was filed, but are based upon circumstances occurring or becoming known through the close of the evidentiary hearing. In addition to the parties' agreements on some of the issues in this proceeding, the Stipulation provides that CWSNC and the Public Staff agree that the Stipulation reflects a give-and-take partial settlement of contested issues, that the provisions of the Stipulation do not reflect any position asserted by either CWSNC or the Public Staff, but instead reflect compromise and settlement between them. The Stipulation is binding as between CWSNC and the Public Staff, conditioned upon the Commission's acceptance of the Stipulation in its entirety. No party filed a formal statement or presented testimony indicating opposition to the Stipulation. However, neither have the AGO or Corolla Light HOA indicated their assent to the Stipulation. There are no other parties to this proceeding.

The key provisions of the Stipulation are as follows:

Capital Structure

The Stipulating Parties agreed that the capital structure appropriate for use in this proceeding is a capital structure consisting of 50.91% common equity and 49.09% long-term debt at a cost of 5.68%.

ADIT

The Company agreed to the Public Staff's proposed adjustments to ADIT regarding unamortized rate case expense. The Stipulating Parties agreed to revise ADIT for any updates made to regulatory commission expense.

Deferred Maintenance

The Company has agreed to the amount of unamortized deferred maintenance and annual deferred maintenance and repair expense as calculated by the Public Staff. The Stipulating Parties disagree as to how these amounts should be recovered from ratepayers and this issue will be addressed in the Evidence and Conclusions for Findings of Fact Nos. 47 - 51.

Regulatory Commission Expense

The Stipulating Parties agreed to a methodology for calculating regulatory commission expense, also known as rate case expense, and agreed to update the number in Settlement Exhibit 1, Line 46, for actual and estimated costs once supporting documentation is provided by the Company. The Stipulating Parties further agreed to amortize regulatory commission expense for a five-year period.

Federal Protected EDIT

The Stipulating Parties agreed that the protected EDIT will be flowed back over a 45-year period using the Reverse South Georgia method, in accordance with tax normalization rules required by Internal Revenue Code (IRC) Section 203(e).

Deferral Accounting Treatment

The Company agreed to withdraw its request that deferral accounting treatment of costs related to Hurricane Florence be authorized by the Commission in this case and that amortization of such prudently-incurred costs be addressed in the Company's next general rate case.[1]

A stipulation entered into by less than all parties in a contested proceeding under Chapter 62 "should be accorded full consideration and weighted by the Commission with all other evidence presented by any of the parties in the proceeding." State ex rel. Utilities Commission v. Carolina Utility Customers Association, Inc., 348 N.C. 452, 466, 500 S.E. 2d 690, 700 (1998). Further, "[t]he Commission may even adopt the recommendations or provisions of the nonunanimous stipulation as long as the Commission sets forth its reasoning and makes 'its own independent conclusion' supported by substantial evidence on the record that the proposal is just and reasonable to all parties in light of all the evidence presented." Id.

Based upon the foregoing and the entire record herein, the Commission finds that the Stipulation was entered into by the Stipulating Parties after full discovery and extensive negotiations, that the Stipulation is the product of the "give-and-take" of the settlement negotiations between CWSNC and the Public Staff, and that the Stipulation represents a reasonable and appropriate resolution of certain specific matters in dispute in this proceeding. In making this finding, the Commission gives substantial weight to the testimony of CWSNC witness DeStefano and Public Staff witnesses Henry and Casselberry which support the Stipulation, and notes that no party expressed opposition to the provisions of the Stipulation. In addition, when the provisions of the Stipulation are compared to CWSNC's Application and the recommendations included in the testimony of the Public Staff's witnesses, the Stipulation results in a number of downward adjustments to the expenses sought to be recovered by CWSNC, and resolves issues that were

[1] On January 17, 2019, in Docket No. W-354, Sub 363, CWSNC filed a Petition for an Accounting Order to Defer Incremental Hurricane Florence Storm Damage Expenses, Capital Investments, and Revenue Loss. That matter is presently pending before the Commission.

more important to CWSNC, and, likewise, issues that were more important to the Public Staff. Therefore, the Commission further finds that the Stipulation is material evidence to be given appropriate weight in this proceeding, along with all other evidence of record, including that submitted by CWSNC, the Public Staff, and the public witnesses that testified at the hearings.

In addition, the Commission finds that the Stipulation is a nonunanmious settlement of matters in controversy in this proceeding and that the Stipulation resolves only some of the disputed issues between CWSNC and the Public Staff. The Stipulation leaves the following Unsettled Issues to be resolved by the Commission: (1) return on equity; (2) the Public Staff's proposed adjustments to ADIT and to EDIT, including how the amount of unamortized deferred maintenance expense should be recovered from ratepayers; (3) the Public Staff's proposal to require CWSNC to refund the overcollection of federal taxes related to the January 1, 2018, decrease in the federal corporate income tax rate; (4) the Public Staff's proposed 50% reduction in the Company's recovery of executive compensation, benefits, and payroll taxes; (5) the Public Staff's proposed re-allocation of insurance premiums passed-on to CWSNC by UI; (6) the Public Staff's proposed use of composite utility plant depreciation rates for calculating CIAC and PAA; (7) the Public Staff's proposed removal of purchased water and purchased sewer treatment expense from the calculation of cash working capital; (8) CWSNC's proposed implementation of a consumption adjustment mechanism (CAM); and (9) CWSNC's proposed tariff rate design.

After careful consideration, the Commission finds that when combined with the rate effects of the Commission's decisions regarding the foregoing Unsettled Issues, the Stipulation strikes a fair balance between the interests of CWSNC to maintain its financial strength at a level that enables it to attract sufficient capital, on the one hand, and its customers to receive safe, adequate, and reliable water and sewer service at the lowest reasonably possible rates, on the other. The Commission finds that the resulting rates are just and reasonable to both CWSNC and its ratepayers. In addition, the Commission finds that the provisions of the Stipulation are just and reasonable to all parties to this proceeding and serve the public interest, and that it is appropriate to approve the Stipulation in its entirety.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 13 – 19

The evidence supporting these findings of fact is found in the testimony of the public witnesses appearing at the hearings, in the testimony of Public Staff witness Casselberry, in the testimony and exhibits of CWSNC witnesses DeStefano, Mendenhall, and Clark, and in the verified reports filed by CWSNC in response to the concerns expressed by the public witnesses that testified at the hearings.

On April 27, 2018, CWSNC filed an application for a general rate increase, which was verified by CWSNC's Financial Planning and Analysis Manager. The Application stated that CWSNC presently serves approximately 34,871 water customers and 21,531 sewer customers in North Carolina. The Company's service territory spans 38 counties in North Carolina, from Corolla in Currituck County to Bear Paw in Cherokee County.

WATER AND SEWER – RATE INCREASE

The Commission held hearings throughout CWSNC's service territory for the purpose of receiving testimony from members of the public, and particularly from CWSNC's water and wastewater customers, as follows:

Hearing Date	Location	Public Witnesses
August 28, 2018	New Bern	Ted Warnock, Simon Lock, Diana Viglianese, Jim Brown, Mike Shannon, Ralph Tridico, Irving Joffee, Michael Kaplan, John Gumbel, and Benny Thompson
August 29, 2018	Wilmington	David Holsinger
September 19, 2018	Charlotte	Patricia Marquardt, William Colyer, Nicoline Howell, Griffin Rice, Margaret Quan, Deborah Atkinson, Nicholas Stephen Kirkley, Tom Moody, Karen Cynowa, and Michael Tepedino
September 25, 2018	Boone	Harvey Bauman, Sid E. Von Ropeunt, George Hall, and Tim Presnell
September 26, 2018	Asheville	Jack Zinselmeir, Phil Reitano, Gerrard Worster, Chuck Van Rens, and Connie Brown
October 8, 2018	Raleigh	William Stanley Glance, Vincent Roy, Judith Bassett, Vicki Smith, and Benjamin Farmer

Of the 10 witnesses who testified in New Bern, eight were CWSNC customers from the Fairfield Harbour service area, and one each were CWSNC customers from the Brandywine Bay and Carolina Pines service areas. Each witness expressed concern about the rate increase, and others addressed water quality issues such as hardness and discoloration.

At the Wilmington hearing, one witness, who is a CWSNC customer in the Belvedere-system service area testified. He objected to the rate increase, particularly so soon after the last one, and he complained of stains on his clothes caused by the water.

Ten CWSNC customers testified at the hearing in Charlotte, including seven from the Bradfield Farms service area, one from the Hemby Acres service area, and two from the Yachtsman, or Queens Harbor, service area. Generally, customers who testified expressed concerns about the proposed percentage increase in rates and about water quality with regard to the presence of particulates and hardness issues. Some witnesses objected to the rate design and others compared CWSNC's rates unfavorably to those in other jurisdictions, including publicly-owned water/wastewater systems, such as that owned by Union County.

Four witnesses testified at the hearing in Boone, including one witness from the Ski Mountain Acres community, two from the Elk River service area, and one from the Hound Ears service area. These witnesses focused their testimony on the proposed percentage increase in rates, water quality issues, and questions regarding the investments supporting CWSNC's requested rate increase.

WATER AND SEWER – RATE INCREASE

At the hearing in Asheville, five witnesses testified, including two witnesses from the Fairfield Mountain of Lake Lure community, two from the Mt. Carmel service area and one from the Woodhaven service area. These witnesses all expressed concern about the proposed percentage increase in rates. In addition, Ms. Connie Brown, a CWSNC customer in the Mt. Carmel service territory, testified regarding the Company's sewer service, stating that a sewer line near her house requires weekly pumping by a septic truck, and that CWSNC has failed to perform needed repairs or upgrades to that sewer line.

At the hearing in Raleigh, five witnesses testified, including two from the Carolina Trace service area, two from the Amber Acres service area, and one from the Jordan Woods service area. Each of these witnesses objected to CWSNC's proposed rate increase. One of the witnesses from the Amber Acres service territory testified she had seen no improvement in service that would warrant a rate increase, that the Company could be more efficient, and that she opposed the flat rate sewer service charge. The witness from the Jordan Woods service territory testified that his bill was 70% higher after the last rate increase. One of the witnesses appearing at the hearing in Raleigh who is a utilities representative of Carolina Trace testified regarding a good working relationship with CWSNC's local employees, concerns about communications with "headquarters" and about the incidence of boil water notices, criticisms of the Company's practice of adjusting charges for wastewater with respect to commercial pools, but not for residential pool owners, anticipation of completion of the Global Positioning System (GPS) mapping project so that all manholes are located, and criticism of the "uniform rate system." The witness recommended that the uniform rate communities be reorganized into smaller, more similar groups, and expressed difficulty understanding CWSNC's proposed CAM, and criticism of the higher base rates as a component of rate design, indicating that this "guarantees" the Company a net profit regardless of performance. This witness requested that the Commission reject CWSNC's request for a rate increase, noting that it is the second request within a year.

After conclusion of each of the public hearings, CWSNC filed verified reports responding to the testimony provided by the public witnesses. In summary, these reports addressed the public witnesses' concerns related to water hardness by stating that hardness is a function of the level of calcium ions in the source water and that it is not a matter subject to regulation. Further, CWSNC observed that many customers either have already made, or wish to make, their own arrangements for water softening, and that CWSNC leaves that matter to its customers' discretion. CWSNC stated its observation that some customers are not inclined to pay for water softening services for other customers, and CWSNC described its flushing protocol, which is designed to address discoloration and particulates in the water. CWSNC also indicated that it seeks to improve its flushing program to address water quality concerns.

Included in the Company's report on the Asheville hearing was a response to the testimony of Ms. Connie Brown in which CWSNC states that it is preparing a capital project to resolve the issue she identified.

With regard to the public witnesses' concerns regarding the magnitude of the rate increase requested, CWSNC expressed its view of the imperative for rate increases, when the need is demonstrated after a comprehensive audit by the consumer advocate, focusing on the capital-intensive nature of the regulated water and wastewater industry, and on the obligation to maintain safe and reliable service. CWSNC also quoted from published reports that indicate a need for billions of dollars of investment in water and wastewater infrastructure within North Carolina. Finally, CWSNC expressed its view that it is fallacy to compare rates among different kinds of providers, noting that the actual costs to serve customers vary by provider and system, and that companies regulated by the Commission are required to prove their actual cost of service, in the face of skilled examination and audits by the Public Staff and a rigorous review by the Commission.

In these reports, CWSNC also responded to the concerns expressed by the public witnesses who complained about specific issues or questions in the Ski Mountain Acres Property Owners' Association, the Elk River system, the Hound Ears Club and Fox Club communities, the Fairfield Mountain system, the Amber Acres community, the Jordan Woods community, and the Carolina Trace community. In some instances, CWSNC responded to concerns by stating that it would revisit the issues or questions raised by contacting the customers involved. The Commission encourages CWSNC to complete the customer outreach contemplated in these reports.

The Commission also recognizes the efforts of the public witnesses and appreciates their participation in this proceeding. The Commission has carefully considered the testimony provided at the hearings in reaching its conclusions in this Order.

Public Staff witness Casselberry testified that her investigation included review of the customer complaints filed in this proceeding, contacts with the North Carolina Department of Environmental Quality (DEQ), including the Water Quality and Public Water Supply Sections of the Division of Water Resources (DWR), review of CWSNC's records, and analysis of revenues at existing and proposed rates. Witness Casselberry testified that she had contacted representatives of all DEQ regional offices regarding the operation of the CWSNC water and sewer systems. Tr. Vol. 7, p. 301. She testified that none of the regional office personnel she contacted expressed any major concerns with the water and sewer systems serving CWSNC customers or identified any major water quality concerns. Id.

In addition, witness Casselberry testified that she had reviewed approximately 64 customer statements received from CWSNC's customers in connection with this proceeding. Witness Casselberry testified that the consumer statements received are from customers in the following service territories with the corresponding number of statements in parentheses:

> Abington (1), Amber Acres North (1) and petition with 27 signatures; Bradfield Farms (3) including a resolution objecting to the rate increase from the Bradfield Farms Homeowners Association, Board of Directors, and petition with approximately 263 signatures; Brandywine Bay (9); Carolina Pines (1); Carolina Trace (13); Connestee Falls (3); Elk River (1); Fairfield Harbour (12); Fairfield Mountain (2); Linville Ridge (1); Nags Head (1); Queens Harbor (1) including a petition with approximately 100 signatures; The Ridges at Mountain Harbor (4); The Villages at Sugar Mountain (1); Wood Haven/Pleasant Hill (2); and unspecified service areas (8). Tr. Vol. 7, p. 318.

Witness Casselberry summarized the customer statements by testifying that all customers objected to the magnitude of the rate increase, and expressed concern with CWSNC's proposed rate of return, the magnitude of the rates compared to inflation, the rates compared to rates of local municipalities, and the treatment of CWSNC's reduced federal corporate income tax rate. Tr. Vol. 7, pp. 318-334. Witness Casselberry provided a more detailed response to customer concerns in her supplemental testimony.

Witness Casselberry also testified with regard to the service and water quality complaints registered by customers at each of the six public hearings. Tr. Vol. 7, pp. 324-334. She testified that she had read each of the reports CWSNC filed after the hearings, and that there were a few isolated service issues, which the Company addressed or was in the process of resolving. She further testified that she had no additional comments or recommendations. Tr. Vol. 7, p. 333. Witness Casselberry concluded that CWSNC's quality of service had improved since its last general rate case, that, overall, CWSNC's service was good, and that the quality of water meets the standards set forth by the Safe Drinking Water Act and is satisfactory. Tr. Vol. 7, p. 333-334.

CWSNC witness Clark also testified in response to the public witness testimony and the consumer statements. She testified that CWSNC has increased its efforts to engage with and improve customers' overall interaction and experience with the Company. She further testified that the Company implemented multiple new social media and other types of communication, including the use of Facebook, Twitter, Instagram, "Carolina Water Drop" podcasts, bill inserts, phone calls, and face-to-face meetings. She also described a program of CWSNC personnel attending homeowners' association and property-owners' association meetings and the Company's design of a series of free Word Press sites with information about service, personnel, projects, and usage tips.

Based upon the foregoing and the entire record herein, the Commission finds that CWSNC's level of service has improved since its last rate case, and that, overall, the quality of service provided by CWSNC to its North Carolina customers is adequate. In reaching this conclusion, the Commission gives substantial weight to the testimony of Public Staff witness Casselberry, who testified that none of the North Carolina environmental agency regional office personnel she contacted expressed any major concerns with the water and sewer systems serving CWSNC customers or identified any major water quality concerns. In addition, after having carefully weighed the comments and concerns expressed by the public witnesses appearing at the hearing and the verified reports filed by the Company, the Commission determines that CWSNC has adequately addressed these comments and concerns, or has appropriately committed to do so outside of the formal proceeding. Finally, while the Commission has determined that CWSNC has met its quality of service obligations to its customers for the purpose of this case, the Commission further determines that these efforts should continue and should be considered again in CWSNC's next general rate case through similar investigative efforts by the Public Staff, testimony from the Company and the Public Staff, and reports in response to the public witnesses' concerns. In particular, the Commission is interested in obtaining information about the resolution of the concerns expressed by Ms. Brown at the hearing in Asheville. Therefore, the Commission will require CWSNC to report to the Commission on the progress of the capital project that is intended to resolve the issue identified by Ms. Brown.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 20 – 23

The evidence supporting these findings of fact is found in the Application and the accompanying NCUC Form W-1, the testimony of Company witness DeStefano, and of Public Staff witness Henry, and the Stipulation.

The following table summarizes the differences between the Company's level of rate base from its Application and the amounts recommended by the Public Staff:

Item	Company Application	Public Staff	Difference
Plant in service	$206,614,909	$ 213,005,526	$6,390,617
Accumulated depreciation	(51,498,888)	(52,955,117)	(1,456,229)
Net plant in service	155,116,021	160,050,409	4,934,388
Cash working capital	2,222,369	2,067,611	(154,758)
Contributions in aid of construct.	(42,813,916)	(41,895,670)	918,246
Advances in aid of construction	(32,940)	(32,940)	0
Accum. deferred income taxes	(5,167,701)	(3,972,592)	1,195,109
Customer deposits	(306,974)	(342,640)	(35,666)
Gain on sale and flow back taxes	(425,537)	(289,628)	135,909
Plant acquisition adjustment	(1,062,767)	(1,029,202)	33,565
Excess book value	(448)	(456)	(8)
Cost-free capital	(261,499)	(261,499)	0
Average tax accruals	112,327	(125,909)	(238,236)
Regulatory liability for EDIT	(251,770)	(251,770)	0
Deferred charges	2,538,827	1,522,955	(1,015,872)
Pro forma plant	5,149,664	0	(5,149,664)
Original cost rate base	$114,815,656	$115,438,669	$623,013

On the basis of the Stipulation and revisions made by the Public Staff in its supplemental testimony, Henry Supplemental Exhibit I, and Henry Revised Supplemental Exhibits I and II, the Company does not dispute adjustments recommended by the Public Staff to plant in service, accumulated depreciation, contributions in aid of construction, customer deposits, gain on sale and flow back taxes, plant acquisition adjustment, excess book value, average tax accruals, deferred charges, and pro forma plant. Therefore, the Commission finds that the adjustments recommended by the Public Staff to plant in service, accumulated depreciation, contributions in aid of construction, customer deposits, gain on sale and flow back taxes, plant acquisition adjustment, excess book value, average tax accruals, deferred charges, and pro forma plant, which are not contested, are appropriate adjustments to be made to rate base in this proceeding.

Based on the testimony of Company witness DeStefano, CWSNC disagrees with Public Staff adjustments to cash working capital and ADIT.

Cash Working Capital

Public Staff witness Henry testified that cash working capital provides the Company with the funds necessary to carry on the day-to-day operations of the Company. He testified that his calculation of cash working capital, included 1/8th of total adjusted operating and maintenance (O&M) and general and administrative (G&A) expenses, less purchased water and sewer expenses. Public Staff witness Henry testified that the calculation implemented by the Public Staff is defined as the "formula method" of calculating cash working capital. Tr. Vol. 8, p. 109. Witness Henry also explained the Public Staff's rationale for excluding purchased water and sewer expenses from cash working capital is that in general there is no lag time between the time the service is being provided and the time the Company pays for the cost of its purchased water and sewer expenses. Tr. Vol. 8, pp. 110-111.

On cross-examination, witness Henry testified that based on his research, the formula method had been used by the Commission for years to set rates in the water, electric, and natural gas industries before lead lag studies were used to calculate cash working capital. Witness Henry noted that in its filed rate case application, CWSNC also excluded purchased water and sewer expenses from its cash working capital calculation. Tr. Vol. 8, p. 110.

On re-direct, witness Henry testified that the Public Staff has been consistent on how it calculates cash working capital from rate case to rate case during the period of time he has been employed by the Public Staff.

Company witness DeStefano accepted the commonly used formula method of applying a 1/8th factor to O&M expenses as a measure of cash working capital; however, he argued that it is improper to remove purchased water and sewer expenses from the calculation, as they are cash expenses and are no different in nature from the remaining O&M expenses. As such, he requested that the purchased water and sewer expenses be included in cash working capital in this proceeding.

Witness DeStefano testified that it may be likely that purchased water and sewer expenses are excluded from the cash working capital calculation because there is currently a means (pursuant to N.C.G.S. § 62-133.11) to prospectively update recovery levels between base rate cases. He contended that this is only true for a portion of such expenses incurred by the Company; that is, only those systems that are supplied 100% by third-party suppliers. Further, he contended that this process only allows a change in rate recovery after the increase in expense has been experienced by the Company. Therefore, witness DeStefano requested that purchased water and sewer expenses be included in the cash working capital calculation in this proceeding.

During cross-examination, witness Henry was questioned concerning the pass-through application process allowed by N.C.G.S. § 62-133.11, in which water and sewer utilities may seek to adjust their rates, outside a general rate case proceeding, to reflect changes in costs based solely upon changes in rates imposed by third-party suppliers. In particular, witness Henry was asked whether there was still a lag in such pass-through application process. Witness Henry responded that there is a lag; however, the Company could prepare its schedules and calculations ahead of time in anticipation of an increase from a third-party supplier and also noted that the Public Staff processes these pass-through applications "pretty quickly." Tr. Vol. 8, p. 113.

When asked on cross-examination whether the Company can file for pass-through recovery of purchased water costs if the system is not 100% purchased water, witness Henry stated that he did not know, and that there was no evidence provided to explain how many CWSNC systems are not 100% purchased water versus how many would be able to file a pass-through and recover costs.

The Commission has carefully reviewed the evidence in this docket and concludes that it is appropriate to exclude purchased water and sewer expenses from the calculation of cash working capital. This treatment is consistent with Commission practice in other cases,[1] and recognizes the fact that there is no lag between the time a Company collects revenues from its customers for the provision of water and sewer utility service purchased from others and the time the Company pays for the purchased water and sewer expenses, since purchased water and sewer expenses are not due until after the service is provided, the meter has been read, and the Company has been billed by its supplier for the service. The Public Staff provided persuasive evidence supporting its use of the formula method for calculating cash working capital. The Public Staff testified and the Company confirmed that the Company's as-filed case used the formula method.

Further, the Commission finds that it is clear from the evidence that, notwithstanding the existence of a lag between the time the Company incurs a change in rates imposed by third-party suppliers of purchased water or sewer and receives authorization to pass through the increase in costs to its customers, the time lag is shorter than obtaining recovery through a general rate case proceeding. Additionally, the Commission determines that it is incumbent upon the Company to take measures to anticipate increases when possible and to take the time and effort to prepare pass through applications and file them as quickly as possible. The Commission determines that the testimony of company witnesses regarding purchased water systems that did not purchase 100% of their water was of no import, as there was no evidence of how many systems were prevented from filing pass-through applications due to this situation and the amount of purchased water expense that was not recoverable via the pass-through process. The Commission therefore finds, for the reasons stated above, that it is inappropriate to include purchased water and sewer expenses in the calculation of cash working capital.

ADIT

The difference in the level of ADIT is due to the differing levels of unamortized rate case expense, unamortized deferred maintenance, and EDIT recommended by the Company and the Public Staff. Based on the conclusions reached elsewhere in this Order regarding the levels of rate case expense, deferred maintenance, and EDIT, the Commission concludes that the appropriate level of ADIT for use in this proceeding is $3,972,592.

Summary Conclusion

Based on the foregoing, the Commission concludes that the appropriate level of rate base for combined operations for use in this proceeding is as follows:

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[1] See Recommended Order issued on February 10, 2006, in Docket No. W-176, Sub 32, et al. (and Order Overruling Exceptions and Affirming Recommended Order issued on April 17, 2006), a general rate case proceeding for Scientific Water and Sewerage Corporation.

Item	Amount
Plant in service	$ 213,005,526
Accumulated depreciation	(52,955,117)
Net plant in service	160,050,409
Cash working capital	2,079,155
Contributions in aid of construction	(42,183,408)
Advances in aid of construction	(32,940)
Accumulated deferred income taxes	(3,972,592)
Customer deposits	(342,640)
Gain on sale and flow back taxes	(289,628)
Plant acquisition adjustment	(1,052,168)
Excess book value	(456)
Cost-free capital	(261,499)
Average tax accruals	(125,909)
Regulatory liability for excess deferred taxes	(251,770)
Deferred charges	1,522,955
Pro forma plant	0
Original cost rate base	$115,139,509

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 24 – 27

The evidence supporting these findings of fact is found in the testimony of Public Staff witnesses Henry and Casselberry, and Company witness DeStefano. The following table summarizes the differences between the Company's level of operating revenues under present rates from its Application and the amounts recommended by the Public Staff:

Item	Company Application	Public Staff	Difference
Service revenues	$32,435,554	$32,429,699	($5,855)
Miscellaneous revenues	351,867	360,163	8,296
Uncollectible accounts	(193,143)	(214,395)	(21,252)
Total	$32,594,278	$32,575,467	($18,811)

On the basis of the Stipulation and the revisions made by the Public Staff in its supplemental testimony and Henry Supplemental Exhibit I, and Henry Revised Supplemental Exhibits I and II, the Company does not dispute the following Public Staff adjustments to operating revenues under present rates:

WATER AND SEWER – RATE INCREASE

Item	Amount
Reflect pro forma level of service revenues	($5,855)
Adjustment to forfeited discounts	7,387
Adjustment to other water/sewer revenues	(2)
Adjustment to sale of utility property	911
Adjustment to uncollectible accounts	(21,252)
Total	($18,811)

For reasons discussed elsewhere in this Order, the Commission has found that the adjustments listed above, which are not contested, are appropriate adjustments to be made to operating revenues under present rates in this proceeding.

Summary Conclusion

Based on the foregoing, the Commission concludes that the appropriate level of operating revenues under present rates for combined operations for use in this proceeding is as follows:

Item	Amount
Service revenues	$32,429,699
Miscellaneous revenues	360,163
Uncollectible accounts	(214,395)
Total operating revenues	$32,575,467

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 28 – 32

The evidence supporting these findings of fact is found in the Application and the accompanying NCUC Form W-1; the testimony of Public Staff witnesses Henry, Johnson, Boswell, and Casselberry; and Company witnesses DeStefano, Mendenhall, and Clark; the Public Staff's exhibit filed on October 30, 2018.

The following table summarizes the differences between the Company's requested level of maintenance and general expenses and the amounts recommended by the Public Staff:

Item	Company Application	Public Staff	Difference
Maintenance Expenses:			
Salaries and wages	$4,908,936	$4,765,636	($143,300)
Purchased power	1,934,268	1,932,358	(1,910)
Purchased water and sewer	2,059,238	1,972,527	(86,711)
Maintenance and repair	3,129,187	2,749,845	(379,342)
Maintenance testing	470,830	544,360	73,530
Meter reading	225,963	225,867	(96)
Chemicals	628,209	632,415	4,206
Transportation	449,313	447,271	(2,042)
Oper. expenses charged to plant	(707,831)	(673,065)	34,766
Outside services – other	482,562	455,369	(27,193)
Total	$13,580,675	$13,052,583	($528,092)
General Expenses:			
Salaries and wages	$2,112,000	$1,972,000	($140,000)
Off. supplies & other office exp.	563,875	560,363	(3,512)
Regulatory commission expense	436,013	165,908	(270,105)
Pension and other benefits	1,379,548	1,340,118	(39,430)
Rent	233,928	227,339	(6,589)
Insurance	572,345	429,335	(143,010)
Office utilities	744,196	742,300	(1,896)
Miscellaneous	215,612	23,469	(192,143)
Total	$6,257,517	$5,460,832	($796,685)

On the basis of the Stipulation and revisions made by the Public Staff in its supplemental testimony and Henry Supplemental Exhibit I, and Henry Revised Supplemental Exhibits I and II, the Company does not dispute adjustments recommended by the Public Staff to maintenance salaries and wages, purchased power, maintenance and repair, maintenance testing, meter reading, chemicals, transportation, operating expenses charged to plant, outside services – other, office supplies and other office expenses, rent, office utilities, and miscellaneous. For reasons detailed elsewhere in this Order, the Commission finds that the adjustments recommended by the Public Staff to maintenance salaries and wages, purchased power, maintenance and repair, maintenance testing, meter reading, chemicals, transportation, operating expenses charged to plant, outside services – other, office supplies and other office expenses, rent, office utilities, and miscellaneous expense, which are not contested, are appropriate adjustments to be made to maintenance and general expenses in this proceeding.

Based on the testimony of Company witnesses Clark, Mendenhall, and DeStefano, which was filed prior to the Stipulation and prior to the filing of Henry Revised Supplemental Exhibits I and II by the Public Staff, the Company disagreed with the Public Staff adjustments to (1) regulatory commission expense, (2) general salaries and wages/pensions and benefits, and (3) insurance.

Regulatory Commission Expense

With the Stipulation and revisions made by the Public Staff in its supplemental testimony and Henry Revised Supplemental Exhibit I, the Parties have agreed to total rate case costs of $395,479 for this current proceeding and $434,060 of unamortized rate case costs from the Sub 356 Proceeding. Amortization of the total rate case costs for the current and prior proceedings over five years results in an annual expense amount of $165,908.

The Commission now addresses the contested issues that have an impact on maintenance and general expenses.

Based on the foregoing the Commission finds that the regulatory commission expenses, agreed to by the Stipulating Parties and reflected in Henry Revised Supplemental Exhibit I, are just and reasonable and should be approved.

General Salaries and Wages/Pensions and Benefits

Public Staff witness Johnson testified that the Public Staff has proposed an adjustment to CWSNC's revenue requirement reflecting the removal of 50% of the compensation, including pension and benefits, of the top three executive officers of Utilities, Inc. Witness Johnson testified that the three UI executive officers whose compensation and benefits are the subject of the Public Staff's proposed adjustment are the Vice President & General Counsel, the President and Chief Executive Officer (CEO), and the President of Shared Services (Company Executives). She asserted that the Public Staff's recommendation is not based on the premise that the compensation of the Company Executives the Public Staff selected are excessive or should be reduced. Instead, witness Johnson testified that the Public Staff's recommendation is based on the Public Staff's belief that it is reasonable and appropriate for the shareholders of the large water and wastewater utilities to bear some of the cost of compensating those individuals who are most closely linked to furthering shareholder interests, which are not always the same as those of the ratepayers.

Witness Johnson testified that the Company Executives have fiduciary duties of care and loyalty to the shareholder, but not to customers. Consequently, witness Johnson maintained that the Company Executives are obligated to direct their efforts not only to minimizing the costs and maximizing the reliability of CWSNC's service to customers, but also to maximizing the Company's earnings and the value of its shares. Further, witness Johnson testified that it is reasonable to expect that management will serve the shareholder as well as the ratepayers; therefore, she argued that a portion of management compensation and pension and benefits should be borne by the shareholder.

On cross-examination, witness Johnson conceded that she: (1) had not specifically looked at the duties and responsibilities of the UI executive team, outside of an informal phone call; (2) could not say which of the named executives' specific duties were solely for the benefit of the shareholder and completely not for the benefit of the ratepayer; (3) was not sure whether any of the named executives provided communications or information for evaluation of investment by shareholders, though she noted that this sounded like a CEO function; (4) agreed that because the shareholders provide the capital necessary to operate the company, the management was required to be advertent to the interest of shareholders to provide service to customers; (5) agreed that such an adjustment had not been made by the Public Staff for CWSNC previously; and (6) agreed that a range of Corix[1] corporate costs, such as directors' fees, tax, and corporate legal costs, were not included for recovery in this case.

Witness Johnson testified that the compensation of the Company Executives allocated to CWSNC totaled $185,196, of which the Public Staff recommends 50%, totaling $92,598, be removed as shareholder expense. Tr. Vol. 8, p. 75. As shown In Johnson Late-Filed Exhibit I, Schedule 1, filed on October 30, 2018, witness Johnson updated her adjustment to remove 50% of the Company Executives' compensation to an amount totaling $92,359. She also recommended decreasing CWSNC's revenue requirement by $2,920 to remove 50% of payroll taxes to match the adjustment to salaries and wages related to executive compensation. Witness Johnson clarified in the cover letter to her late-filed exhibit that "[t]here was no adjustments made to pensions and incentive plans of the three executives, as these costs were not included by CWSNC for recovery."

On redirect examination, witness Johnson testified that in each of the respective recent general rate cases, both Duke Energy Progress LLC, (DEP) in Docket No. E-2, Sub 1142, and Duke Energy Carolinas LLC (DEC) in Docket No. E-7, Sub 1146, excluded in their E-1 filings 50% of the compensation of their top four executive officers. Tr. Vol. 8, p. 137. She testified that DEP and the Public Staff (in the DEP case) and DEC and the Public Staff (in the DEC case) stipulated to removing 50% of the compensation and benefits of five top officers in recognition of the work done on behalf of shareholders. Witness Johnson maintained that it is the Public Staff's principled position that work and loyalties are divided between shareholders and customers, which was the basis for her adjustment. Tr. Vol. 8, p. 130. Additionally, when questioned by the Commission, witness Johnson testified that the Company Executives received bonuses as a direct result of increasing the earnings per share, which directly benefitted shareholders. Tr. Vol. 8, p. 132.

CWSNC witness DeStefano testified that the function of the Company Executives is not the equivalent of publicly-traded parent company corporate executives whose job focus may be much more focused on benefits to the shareholders. Witness DeStefano stated UI is more of an operating company, as demonstrated by the roles of the three individuals at issue. Additionally, he stated that since UI is not a publicly-traded company, time spent on shareholder related activities is limited to that which is required to make sure risks are mitigated and capital is secured. Witness DeStefano testified that UI has only one shareholder and argued that dealing with that single investor requires comparable effort as working with the Company's debt holders.

With respect to the role of the Vice President & General Counsel, witness DeStefano testified that this position provides legal support to the regulated companies such as CWSNC, including, for example, on issues involving human resources matters, health, safety and environmental issues, contract review, litigation support, and review of various legal issues. He

[1] Corix Utilities (Illinois) LLC (Corix), acquired 100% of the membership interest of Hydro Star, LLC, which through its wholly owned subsidiary, Hydro Star Holdings Corporation, owned 100% of the issued and outstanding stock of UI, CWSNC's parent company. See Order Approving Acquisition of Stock and Requiring Customer Notice, N.C.U.C. Docket No. W-1000, Sub 14 (2012).

stated that such legal support includes regulatory and transactional matters, including rate filings, easement and right-of-way issues, and mandatory regulatory and legal policies such as record retention, privacy, and cybersecurity. He maintained that these are the basic legal functions of any regulated utility, which are discharged to the direct benefit of CWSNC's customers.

With regard to the role of the President of Shared Services, witness DeStefano stated that this position focuses on the delivery of services essential to local operations and customers, including: customer service; human resources; health, safety and environmental compliance; information technology; billing; insurance; accounting; and facilities management. Witness DeStefano rejected the Public Staff's assertion that any of the President of Shared Services' role supports the shareholder in any other manner than simply facilitating a well-run utility. On cross-examination, he reiterated his view that this officer oversees these local operations functions as his primary and key duty.

Witness DeStefano described the role of the CEO as having close interaction with local CWSNC leadership in evaluating capital investment plans and operating budgets, as well as providing expertise on and leadership with addressing customer concerns, industry "best practices," setting short- and long-term operating strategies, and generating company initiatives and policies such as safety, environmental, and business transformation programs. He maintained that the CEO assesses risks so that risks are addressed and mitigated to ensure that the Company provides safe, reliable, and cost-effective service. In addition, witness DeStefano testified that the CEO works closely with the single shareholder and lenders to secure capital and debt for improvements that directly address customer needs.

Witness DeStefano testified that a regulated utility exists solely to provide service to its customers and that it cannot exist without debt and equity funding. In summary, he argued that the functions of the Company Executives differ from those of publicly-traded parent company corporate executives whose job focus may very well be much more on benefits to the shareholders. He explained that UI is more of an operating company, as demonstrated by the roles of the three individuals at issue. Witness DeStefano asserted that since UI is not a publicly-traded company, time spent on shareholder-related activities is limited to that which is required to make sure risks are mitigated and capital is secured.

Witness DeStefano rejected as unfair Public Staff witness Johnson's representation that the Company Executives did not have fiduciary duties of care and loyalty to customers, but only to shareholders. Witness DeStefano observed that when the fundamental focus of the shareholder is ensuring customer satisfaction and welfare by providing the best service at the most reasonable possible price — which the management of these regulated utilities is required by statute to do — then the interests of the shareholder and the Company's ratepayers are understood to be exactly aligned. He maintained that this alignment becomes clearer when one considers the necessity, for the customers' benefit, for a utility to attract both high-quality human resources for management and leadership purposes, and to attract financial capital to support the capital-intensive industry.

Witness DeStefano explained that attracting capital from investors is vital to fund needed improvements in aging systems and, as other regulators have recognized, one of the great benefits to a local utility being part of a larger utility company is access to capital that the parent is able to provide. He contended that the ability to maintain and support proper service to customers at a reasonable cost is inextricably linked to the Company Executives' ability to meet shareholder expectations. Witness DeStefano opined that without the Company Executives' support and services, the Company would neither be positioned to meet the needs of its customers nor be eligible to achieve financial returns that attract debt and equity capital needed for the financial welfare of the utility. Therefore, in his view executive base compensation is an integral and necessary part of the Company's overall cost of service to meet the needs of its customers.

Witness DeStefano further contended that the Public Staff's recommendation to exclude from the cost of service 50% of CWSNC's share of the costs of compensation for the Company Executives is arbitrary and lacks support either in the facts or the reality of the functions of this executive team, whose contributions should be fully supported in rates as they focus on direct benefits to customers.

Moreover, witness DeStefano testified that Corix, a corporate level above UI, has provided beneficial services and support to UI and its affiliates, including CWSNC, since its acquisition of UI. Witness DeStefano pointed out that those Corix corporate costs (such as director fees, tax and corporate legal costs) have not been included for recovery in CWSNC's rates even though they are part of the overall costs to support the services provided to the Company.

After considering all of the evidence of record, and for the reasons discussed below, the Commission finds that the Public Staff's proposed adjustment to CWSNC's revenue requirement, representing the removal of 50% or $92,359, of the Company Executives' compensation is inappropriate. Consequently, the Commission concludes that the Public Staff's proposed adjustment should be rejected. In reaching this conclusion, the Commission gives great weight to the testimony of witness DeStefano that, because UI is not a publicly-traded company, time spent on shareholder-related activities is limited to that which is required to ensure risks are mitigated and capital is secured. The Commission is also persuaded by witness DeStefano's assertion that because UI has only one shareholder, dealing with that single investor requires comparable effort as working with debt holders. Moreover, the Commission gives significant weight to the testimony of witness DeStefano that Corix's corporate costs (such as director fees, tax and corporate legal costs) have not been included for recovery in CWSNC's rates. The Commission notes that Public Staff witness Johnson confirmed that Corix's corporate costs have not been included for recovery in this proceeding.

The Commission also gives substantial weight to the testimony of witness DeStefano in which he described the roles of the three Company Executives at issue. In particular, witness DeStefano pointed out that the Company Executives focus on local operations and have close interaction with local CWSNC leadership for the direct benefit of customers. Based upon the evidence in this proceeding, the Commission agrees with witness DeStefano that the functions of the Company Executives differ from those functions of similar corporate officers within a publicly-traded parent company in that the functions of corporate executives in a publicly-traded parent company may tend to focus more on benefitting the shareholders rather than focusing on interacting with local subsidiary operations for the benefit of customers.

The Commission is not persuaded by the Public Staff's observation that the Commission approved 50% adjustments for executive compensation for DEP in its Order Accepting Stipulation, Deciding Contested Issues and Granting Partial Rate Increase issued on February 23, 2018, in Docket No. E-2, Sub 1142, and for DEC in its Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction issued on June 22, 2018, in Docket No. E-7, Sub 1146. Both DEC and DEP originally filed their rate cases reflecting removal of 50% of the executive compensation of the top four executive officers and, later in the proceedings, the Company and the Public Staff reached a stipulation to remove 50% of the executive compensation for the top five executive officers. Thus, the Commission did not resolve the issue through litigation in either case.

The Commission acknowledges that in its recent Order Approving Partial Settlement Agreement and Stipulation, Granting Partial Rate Increase, and Requiring Customer Notice issued on December 18, 2018, in Docket No. W-218, Sub 497 (December 18, 2018 Order), for Aqua North Carolina, Inc. (Aqua NC), the Commission determined that it was appropriate to allocate 25% of the executive compensation, including pensions and incentive plans of the top five Aqua America executives to Aqua NC's shareholders (as proposed as an alternative recommendation of Aqua NC's witness) and not to ratepayers through inclusion of those expenses in the revenue requirement. That decision is consistent with the Commission's decision in Aqua NC's 2011 general rate case (Docket No. W-218, Sub 319). The Commission notes that, unlike Aqua NC, Public Staff witness Johnson testified that an adjustment to remove any portion of executive compensation has not been made for CWSNC in a past rate case proceeding.

The Commission determines that there are distinct differences between CWSNC and Aqua NC that justify allowing CWSNC to include in its revenue requirement the full amount of compensation allocated to CWSNC for the Company Executives. As noted in the December 18, 2018 Order, Aqua America, Inc., the parent company of Aqua NC, is the second largest investor-owned water and wastewater utility in the United States with its shares traded on the New York Stock Exchange and a $6.709 billion market capitalization at the August 17, 2018 market close as reported by Morningstar. In contrast, as witness DeStefano testified, the parent company of CWSNC, UI, is more of an operating company and its shares are not publicly-traded. Further, the Commission observes that Corix, a corporate level above UI, is also a privately held corporation. Finally, with respect to the size of CWSNC in comparison to that of Aqua NC, the Commission is cognizant that Aqua NC provides utility service to significantly more customers in North Carolina than CWSNC, with significantly greater total operating revenues, differences that the Commission determines are material to the resolution of this issue.[1]

The Commission disagrees with the Public Staff's view that shareholders of large water and wastewater utilities must bear some of the cost of compensating those individuals who are most closely linked to furthering shareholder interests should be applied mechanically in every case. Rather, the Commission finds that such an adjustment should be considered based upon all available information and the Commission will, in future general rate cases, continue to consider this issue on a case-by-case basis in light of all the evidence of record.

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[1] Aqua NC serves approximately 78,739 water customers and 17,940 wastewater customers with over $59 million in total annual operating revenues; whereas, CWSNC serves approximately 30,437 water customers and 20,233 wastewater customers with over $33 million in total annual operating revenues.

Based upon the foregoing and the entire record herein, the Commission finds that it is inappropriate to reduce CWSNC's revenue requirement to reflect the Public Staff's recommendation to allocate to shareholders 50% of the compensation, or $92,359, for the three Company Executives. Therefore, the Commission concludes that the Public Staff's proposed adjustment should be denied.

Insurance

Public Staff witness Henry testified that he adjusted insurance premiums to reflect the current amount for insurance for UI, the parent company of CWSNC, which was provided by the Company. Witness Henry allocated insurance premiums to CWSNC using the following factors: (1) allocated automobile insurance based on the number of automobiles for CWSNC's water and sewer operations as a percentage to the total number of UI automobiles; (2) allocated workers compensation insurance based on the adjusted level of payroll; (3) allocated property insurance to reflect the value of the property covered by the current insurance policies; and (4) allocated the remaining insurance items to the various entities based on the number of customers.

Witness Henry also testified that he removed two-thirds of the pollution liability insurance premium included in the Company's application since it is a three-year policy and only an annual level of premium expense should be included in operating expenses in this proceeding.[1]

Public Staff witness Henry testified that in cases where the Public Staff cannot directly tie a particular item to North Carolina, it uses an allocation factor based on the number of customers as a last resort. He testified that when there are tangible assets to which a value can be determined, it is reasonable and appropriate to directly assign costs based on that actual known information, as opposed to based on customer count.

On cross-examination, witness Henry testified that customer count was used by the Public Staff to allocate costs in seven out of 10 categories when there was no other means of determining the portion attributable to items in North Carolina. Tr. Vol. 8, p. 118. On cross-examination, in response to the question of whether the Company would ever fully recover through expense and rates its allocated insurance expense if the Public Staff's methodology is adopted, witness Henry stated that ratepayers should not have to bear more costs than necessary due to the Company's methodology of allocating costs based on customer count. Tr. Vol. 8, p. 121. Moreover, witness Henry stated that the Company should not be able to over-recover the insurance costs that are allocated from UI. He contended that the allocation methodology based upon customer count utilized by UI is incorrect and unfair. Tr. Vol. 8, p. 122.

CWSNC disagreed with the Public Staff's methodology of allocating automobile, worker's compensation, and property insurance to CWSNC's water and sewer operations. Company witness DeStefano testified that CWSNC's as-filed allocation method for insurance expenses is the most reasonable and appropriate allocation method. He stated that there are far too many factors in setting

[1] Of the Public Staff's total adjustment of ($143,010) to CWSNC's ongoing annual level of insurance expense, ($61,008) of this amount relates to its adjustment to correct the Company's overstatement of its annual pollution liability insurance premium.

policy premiums that were not considered by the Public Staff, to utilize only one factor for each policy when allocating insurance costs. Witness DeStefano also testified that the Company's allocation method avoids "going down the rabbit hole" of attempting to identify a perfect allocation method, and utilizes a single, consistent allocation method in each application. The Company's as-filed position for allocating all insurance cost is based on the percentage of customers in each state that it provides water and sewer utility service.

After careful consideration, the Commission finds that the Public Staff appropriately allocated insurance costs to CWSNC. The Commission is persuaded that the Public Staff method is a more direct allocation methodology than the methodology advocated by the Company, because using vehicle count, payroll, and property covered in CWSNC's service territory ensures that customers are not paying more for cost of service than they would if costs were allocated solely based on customer count. Moreover, the Commission recognizes that there is no perfect methodology for allocating costs, but directly assigning costs to the rate entities that created the cost, is a more reasonable and equitable policy to follow than an allocation based on the number of customers, which does not identify the entity that created the cost. The Commission acknowledges that the Public Staff used customer count when a more accurate allocation method was not available. The Commission agrees with the Public Staff that there is a risk that North Carolina customers could inappropriately incur extra expense resulting from possible over-recovery by the Company of insurance expense due to a single, consistent allocation method, when a more accurate method exists. Therefore, the Commission concludes that the methodology employed by the Public Staff in allocating automobile, worker's compensation, and property insurance to CWSNC's water and sewer operations is just and reasonable and should be approved for this proceeding.

<u>Summary Conclusion</u>

Based upon the foregoing, the Commission concludes that the appropriate level of maintenance and general expenses for combined operations for use in this proceeding are as follows:

Item	Amount
Maintenance Expenses:	
Salaries and wages	$4,765,636
Purchased power	1,932,358
Purchased water and sewer	1,972,527
Maintenance and repair	2,749,845
Maintenance testing	544,360
Meter reading	225,867
Chemicals	632,415
Transportation	447,271
Oper. expenses charged to plant	(673,065)
Outside services – other	455,369
Total	$13,052,583

Item	Amount
General Expenses:	
Salaries and wages	$2,064,359
Off. supplies & other office exp.	560,363
Regulatory commission expense	165,908
Pension and other benefits	1,340,118
Rent	227,339
Insurance	429,335
Office utilities	742,300
Miscellaneous	23,469
Total	$5,553,191

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 33 – 37

The evidence supporting these findings of fact is found in the Application and the accompanying NCUC Form W-1 of CWSNC, the testimony of Public Staff witness Henry, and the testimony of Company witness DeStefano. The following table summarizes the differences between the Company's level of depreciation and amortization expenses from its Application and the amounts recommended by the Public Staff:

Item	Company Application	Public Staff	Difference
Depreciation expense	$5,549,406	$5,617,382	$67,976
Amortization expense – CIAC	(1,480,909	(1,776,72	(295,811
Amortization expense – PAA	(39,197)	(77,331)	(38,134)
Amortization of ITC	(519)	(519)	0
Total	$4,028,781	$3,762,812	($265,969)

With respect to CWSNC's depreciation expense, in light of the agreements reached in the Stipulation and revisions recommended by the Public Staff in its supplemental testimony and reflected in Henry Supplemental Exhibit I, the Company does not dispute the adjustments recommended by the Public Staff to depreciation expense. As detailed elsewhere in this Order, the Commission finds that the adjustments recommended by the Public Staff to depreciation expense, which are not contested, are appropriate adjustments to be made to operating revenue deductions in this proceeding.

The Commission now addresses the Public Staff adjustments to amortization expense – CIAC and amortization expense – PAA.

Amortization Expense – CIAC and PAA

Public Staff witness Henry testified that the Public Staff adjusted CIAC amortization expense and PAA amortization expense to reflect the Public Staff's recommended level of CIAC and PAA, respectively, multiplied by an amortization percentage that is based on the composite depreciation rate for the Public Staff's adjusted level of direct plant in service.

On cross-examination, witness Henry testified that the Public Staff had previously made this adjustment in every rate case he had worked on involving CWSNC and the other UI utility subsidiaries in North Carolina, such as CWS Systems, Inc. and Transylvania Utilities, Inc. Witness Henry stated that the Public Staff initially adopted and utilized this adjustment to address problems with CWSNC's recording CIAC and PAA in prior years and also the portion of CIAC (tap-on fees) that is not directly allocated to a particular plant account. Witness Henry further testified that "in order for the customer to take advantage of those tap-on fees, the Public Staff calculated a composite depreciation rate to reduce the amount of PAA as well as CIAC." Tr. Vol. 8, p. 123.

During cross-examination, witness Henry acknowledged that the problems associated with errors affecting recordation of CIAC and PAA that existed in the past had been resolved by the Company, although the tap-on fee situation has not changed. According to witness Henry, the Company still has a problem with recording the right amount of tap-on fees in each plant account and, therefore, the Public Staff continues to think that it is necessary to use composite depreciation rates.

Witness Henry also acknowledged that, in theory, there is nothing wrong with the Company's position that CIAC and PAA amortization should use the actual amortization rates for each applicable account within the CIAC and PAA groups and not a proxy of composite depreciation rates. He continued by stating, however, that because of CWSNC's past problems, the Public Staff prefers to continue to use the composite depreciation rates. Witness Henry was not able to quantify the significance of the Public Staff's assertion of continuing tap-on fee problems. He also agreed that, in theory, it is true that what can be directly assigned should match the depreciation rates of the Company.

On cross-examination, witness Henry testified that the Public Staff's PAA adjustment in this case amounts to approximately $38,000, that the Public Staff's CIAC adjustment is approximately $296,000, and that the two adjustments total approximately $334,000. He further testified that the total adjustment is "significant," but added that it is also "appropriate." Witness Henry agreed that these two adjustments reduce the Company's revenue requirement in this case by approximately $334,000 per year; and that, under the Public Staff's position, CWSNC would not collect that amount of revenue each year that the new rates set in this proceeding remain in effect; and that the Company would never be allowed to recover such disallowed revenue.

CWSNC witness DeStefano disagreed with witness Henry's calculation of the annual amortization expenses for CIAC and PAA utilizing the composite depreciation rate for the Company's direct plant in service. Witness DeStefano testified that the Company believes CIAC and PAA amortization should use the actual amortization rates for each applicable account within the CIAC and PAA groups, and not the proxy of the composite depreciation rate for plant in service. He further testified that the Public Staff's calculation presumes the mix of asset account values in plant in service, CIAC, and PAA are exactly the same, which they are not. Applying the Company's rates, as witness DeStefano proposed, to the actual balances at June 30, 2018, produce composite CIAC rates of 2.49%, 2.04%, 2.50%, and 2.06% for CWSNC Water, CWSNC Sewer, Bradfield Farms/Fairfield Harbor/Treasure Cove Water, and Bradfield Farms/Fairfield Harbor Sewer, respectively. For PAA, witness DeStefano testified that CWSNC's actual water rate of 2.47% and actual sewer rate of 3.53% should be utilized. Witness DeStefano explained that the Company's actual CIAC and PAA composite rates differ from the composite depreciation rate for plant in service due to a varying asset mix, therefore, he recommended that the aforementioned rates were the more reasonable and supportable calculation for use in this proceeding.

In response to questions from Chairman Finley, witness DeStefano testified that the Company's rebuttal request is that, to the extent there is a one-to-one match between the utility plant account and the CIAC account, the Commission should use the same rate for a particular account's balance, and not just the composite rate for the entire CIAC balance, because the mix of assets is different between plant in service accounts and CIAC accounts. Witness DeStefano further stated that he did not believe that the Public Staff disputed the accuracy of the rates proposed by the Company. Witness DeStefano also acknowledged the existence of certain CIAC accounts that are called "tap fee, reconnect fee, things like that" which probably do not have an equivalent plant account. However, witness DeStefano stated that this lack of equivalency should not preclude the other CIAC balances' amortizations from being calculated based on their one-to-one matches. Witness DeStefano stated that the Company would be amenable to using the composite depreciation rate for tap-fees as a proxy if that is necessary, but not for the entire CIAC balance, just for the accounts that do not have one-to-one matches.

In response to further questions from Chairman Finley, witness DeStefano testified that he disagreed with the Public Staff's position that it is proper to use the composite depreciation rate applied to the Company's total CIAC balance, for the reason that the asset mixes are different, so the composite rates would be different. Witness DeStefano also agreed that the Company's recommendation is more refined than the Public Staff's general recommendation. He stated that the proper utility accounting is to match on the books the CIAC amortization, which is the credit on the income statement, and the depreciation expense, which is a debit on the income statement, so that there is no net benefit or detriment to the Company from contributed property.

In response to questions from Commissioner Brown-Bland, witness DeStefano again emphasized the Company's position that the proper accounting is to match CIAC amortization with the applicable utility plant assets. He stated that, with respect to depreciation and amortization expense, the Company should neither be punished nor benefit from for having received contributed property, which is proper accounting. Witness DeStefano stated that the Public Staff's methodology does not match what the Company is doing on its books; i.e., proper accounting. When asked if the methodology proposed by the Public Staff, which was stated to have been used consistently over many rate cases, would, over time, balance out both ways, witness DeStefano responded that he did not believe that it will balance out to the extent that the Company's recovery through rates and the entries on its books will not be in sync.

The Commission observes that in the Sub 356 Proceeding, as stated in Paragraph 13 of the Joint Stipulation, there was a difference of opinion between CWSNC and the Public Staff concerning the methodology used to calculate CIAC amortization expense and CIAC accumulated amortization. In that proceeding, CWSNC accepted the Public Staff's adjustment but "reserve[d] the right to request and advocate for a change in methodology in a future general rate case". The

Public Staff did not dispute or oppose the Company's right to seek a change in methodology in a subsequent rate case.

In the present proceeding, CWSNC's NCUC Form W-1, Item 10, Schedules B-22 and B-23, demonstrate that CWSNC has proposed utilizing per book amounts for CIAC amortization expense and PAA amortization expense with no pro forma adjustments. In his rebuttal testimony, CWSNC witness DeStefano proposed to utilize the composite CIAC rates of 2.49%, 2.04%, 2.50%, and 2.06% for Uniform Water, Uniform Sewer, Bradfield Farms/Fairfield Harbour/Treasure Cove Water, and Bradfield Farms/Fairfield Harbour Sewer, respectively. According to witness DeStefano, these composite CIAC rates are based upon the actual amortization rates for each applicable account within the CIAC group rather than utilizing the composite depreciation rates for plant in service as recommended by the Public Staff. For the calculation of PAA amortization expense, witness DeStefano recommended using the actual water rate of 2.47% and the actual sewer rate of 3.53% rather than the composite depreciation rates recommended by the Public Staff.

The Commission acknowledges that the Public Staff calculated an annual level of amortization expense for each amortization expense, CIAC and PAA, based on the recommended level of each balance multiplied by the composite depreciation rate for the Company's direct plant in service, consistent with the methodology used by the Public Staff in numerous past general rate case proceedings. However, the Commission determines that the basis of the Public Staff's historical use of the composite depreciation rate is undermined in this proceeding by witness Henry's testimony that the problems associated with errors affecting recordation of CIAC and PAA, which existed in the past with CWSNC, had been resolved. However, based upon the evidence presented in this proceeding, it is unclear whether the correction of these past problems occurred on a going-forward basis or if CWSNC recorded a restatement of historical data on the Company's books and records. Further, the Sub 356 Proceeding was the first general rate case proceeding filed by CWSNC since the merger of the UI entities operating in North Carolina into CWSNC was approved by the Commission on August 17, 2016. The Commission observes that the combined total amount of the Public Staff's adjustment to CIAC amortization expense in that proceeding was higher than in past proceedings, being an increase of $410,479 per Johnson Exhibit I, Schedules 3(a)–3(d)). The Public Staff's combined total adjustment to PAA amortization expense was a decrease of $9,459.

Based upon a review of previous general rate case proceedings for the individual pre-merger UI entities, the Commission notes that there have been significant adjustments recommended by the Public Staff and approved by the Commission for CIAC and PAA amortization expenses in past Commission Orders. For example, in Docket No. W-778, Sub 91, a stipulated general rate case proceeding for CWS Systems, Inc. (Order issued February 24, 2016), the Public Staff's adjustment to CIAC and PAA amortization expense was an increase of $138,481 and $7,093, respectively.[1] Similarly, in Docket No. W-354, Sub 344, a stipulated general rate case

[1] CWS Systems, Inc. had erroneously calculated both CIAC amortization expense and PAA amortization expense by applying the amortization percentage to the amount of CIAC and PAA, net of accumulated amortization, instead of applying the amortization percentage to the amount of CIAC and PAA before amortization. Part of the Public Staff's total adjustment in that proceeding was the correction of CWS Systems, Inc.'s error.

proceeding for CWSNC (Order issued December 7, 2015), the Public Staff's adjustment for CIAC and PAA amortization expense was an increase of $51,290 and $7,489, respectively. Although these general rate case proceedings were stipulated, the Commission finds it relevant that as a result of the Public Staff's audit of these general rate case application filings, significant adjustments to CIAC and PAA amortization expense were recommended by the Public Staff and approved by the Commission. For these reasons, the Commission determines that in CWSNC's next general rate case proceeding, the methodology used to calculate CIAC and PAA amortization expense should be examined and evaluated in greater detail by CWSNC and the Public Staff and the parties should seek to reach agreement on the proper methodology to use on a going-forward basis for the post-merger CWSNC entity in order to ensure that contributed property is depreciated at the same rate that the related CIAC is amortized. The Commission notes that Company witness DeStefano testified that CWSNC is amenable to using the composite depreciation rate as proposed by the Public Staff with respect to tap fees collected by CWSNC.

In the present rate case proceeding, the Public Staff has recommended a total increase to CIAC and PAA amortization expense of $295,811 and $38,144, respectively. In light of the significant increases to the Public Staff's adjustment to CIAC and PAA amortization expense in the Sub 356 Proceeding and in the present proceeding, the Commission determines that use of the Public Staff's past methodology may have overstated its recommended adjustments for the post-merger CWSNC entity, particularly since Public Staff witness Henry testified on cross-examination that the problems associated with errors affecting recordation of CIAC and PAA, which existed in the past with CWSNC, had been solved by the Company. Consequently, for purposes of this proceeding, the Commission finds that the methodology recommended by witness DeStefano for calculating the adjustment to CIAC and PAA amortization expenses should be adopted.

In reaching this conclusion, the Commission gives significant weight to Public Staff witness Henry's testimony on cross-examination that, in theory, there is nothing wrong with the Company's position that CIAC and PAA amortization should use the actual amortization rates for each applicable account within the CIAC and PAA groups and not a proxy of composite depreciation rates. On cross-examination, witness Henry also agreed that, in theory, it is true that what can be directly assigned should match the depreciation rates of the Company. The Commission determines that this testimony supports and provides justification for CWSNC's position regarding proper accounting for CIAC and PAA amortization and for the Commission's decision for purposes of this proceeding.

Accordingly, for the reasons set forth above, the Commission finds that an adjustment to increase CIAC and PAA amortization expenses by $8,073 and $15,168, respectively, based upon the methodology proposed by CWSNC is reasonable and appropriate for use in this proceeding.

Based on the foregoing, the Commission concludes that the appropriate level of depreciation and amortization expense for use in this proceeding is as follows:

Item	Amount
Depreciation expense	$5,617,382
Amortization expense – CIAC	(1,488,982)
Amortization expense – PAA	(54,365)
Amortization of ITC	(519)
Total	$4,073,516

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 38 – 42

The evidence supporting these findings of fact is found in the Application and the accompanying NCUC Form W-1 of CWSNC, and in the testimony of Public Staff witness Henry and of Company witness DeStefano. The following table summarizes the differences between the Company's level of franchise, property, payroll, and other taxes from its Application and the amounts recommended by the Public Staff:

Item	Company Application	Public Staff	Difference
Franchise and other taxes	($49,700)	($49,702)	($2)
Property tax	233,280	233,575	295
Payroll taxes	538,817	526,275	(12,542)
Total	$722,397	$710,148	($12,249)

With the Stipulation and revisions made by the Public Staff in its supplemental testimony and Henry Supplemental Exhibit I, the Company does not dispute adjustments recommended by the Public Staff to franchise and other taxes and property taxes. Therefore, the Commission finds that the adjustments recommended by the Public Staff to franchise and other taxes and payroll taxes, which are not contested, are appropriate adjustments to be made to operating revenue deductions in this proceeding.

Payroll Tax

The difference in the level of payroll taxes is due to the differing levels of salaries and wages recommended by the Company and the Public Staff. Based on the conclusions reached elsewhere in this Order regarding the appropriate levels of salaries and wages, the Commission concludes that the appropriate level of payroll taxes for use in this proceeding is $529,195.

Summary Conclusion

Based on the foregoing, the Commission concludes that the appropriate level of franchise, property, payroll, and property other taxes for use in this proceeding is as follows:

Item	Amount
Franchise and other taxes	($49,702)
Property tax	233,575
Payroll taxes	529,195
Total	$713,068

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 43 – 46

The evidence supporting these findings of fact is found in the testimony of Public Staff witnesses Boswell and Henry, and of Company witness DeStefano. The following summarizes the differences between the Company's level of regulatory fee and income taxes from its Application and the amounts recommended by the Public Staff:

Item	Company Application	Public Staff	Difference
Regulatory fee	$51,800	$45,606	($6,194)
Deferred income tax	0	(83,555)	(83,555)
State income tax	273,392	189,741	(83,651)
Federal income tax	1,856,324	1,288,340	(567,984)
Total	$2,181,516	$1,440,132	($741,384)

With the Stipulation and revisions made by the Public Staff in its supplemental testimony and Henry Supplemental Exhibit I, and in the testimony of witness Boswell and Boswell Exhibit 1, the Company agreed with the Public Staff adjustment to deferred income tax of $83,555 to reflect the annual amortization of protected federal EDIT.

Regulatory Fee

The difference in the level of regulatory fee is due to the differing levels of revenues recommended by the Company and the Public Staff. Based on conclusions reached elsewhere in this Order regarding the levels of revenues, the Commission concludes that the appropriate level of regulatory fee for use in this proceeding is $45,606.

State Income Taxes

The difference in the level of state income taxes is due to the differing levels of revenues and expenses recommended by the Company and the Public Staff. Based on the conclusions reached elsewhere in the Order regarding the levels of revenues and expenses, the Commission concludes that the appropriate level of state income taxes for use in this proceeding is $177,812.

Federal Income Taxes

The difference in the level of federal income taxes is due to the differing levels of revenues and expenses recommended by the Company and the Public Staff. Based on the conclusions reached elsewhere in the Order regarding the levels of revenues and expenses, the Commission concludes that the appropriate level of federal income taxes for use in this proceeding is $1,207,341.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 47 – 51

The evidence supporting these findings of fact is found in the Application and the accompanying NCUC Form W-1, in the testimony of CWSNC witness DeStefano and of Public Staff witnesses Henry and Boswell, and in the Stipulation.

CWSNC witness DeStefano noted in his direct testimony that on December 22, 2017, President Trump signed into law the Tax Act. Witness DeStefano stated that the most impactful component of the Tax Act to CWSNC was the reduction in the federal corporate income tax rate from 35% to 21%. Witness DeStefano maintained that this component not only impacts the current tax rate for corporations but also impacts the deferred income taxes recorded on the Company's books prior to the Tax Act. Witness DeStefano also noted that the second significant component of the Tax Act is the fact that contributed plant is now treated as a form of income and subject to the federal corporate income tax rate.

Witness DeStefano provided details on how the Company has proposed to implement and address the Tax Act in this proceeding. Witness DeStefano noted that CWSNC has reflected the new federal corporate income tax rate of 21% in its calculation of its proposed revenue requirement as reflected in its Application for a rate increase.

Witness DeStefano further testified that due to the fact that the Tax Act was a singular event occurring outside of the Company's historic test period, it should not be treated as a stand-alone event since many changes occur over the course of time. Witness DeStefano asserted that for that reason, CWSNC recommends that the Tax Act not automatically trigger a refund to customers of revenues collected from January 1, 2018, until a final order is received in this proceeding (a period of time CWSNC identified as the Review Period).

Witness DeStefano asserted that, instead, the Commission should consider all items within the Company's revenue requirement, as it is doing in this rate case, and, if the actual return earned by CWSNC during the Review Period exceeds the authorized return considering the new 21% federal corporate income tax rate, then, and only at that point, should the Commission order CWSNC to refund the revenues collected since January 1, 2018 based on the 35% federal corporate income tax rate. Witness DeStefano testified that should a refund be required, CWSNC suggests that such refund be instituted as a negative surcharge to the customers' bills over a 12-month period.

Witness DeStefano also described the impact of the Tax Act on the deferred income taxes on the Company's books. Witness DeStefano stated that prior to January 1, 2018, deferred taxes were recorded on the Company's books at the federal corporate income tax rate of 35% to normalize the impact of future tax liability or benefit. Witness DeStefano noted that due to the reduction in the corporate income tax rate to 21% on January 1, 2018, the tax liability is expected to be paid back at the new lower federal corporate income tax rate. Witness DeStefano maintained that because of the lower corporate income tax rate, the deferred taxes have been adjusted on the books as of December 31, 2017.

Witness DeStefano stated that CWSNC is proposing the following treatment for the EDIT. Witness DeStefano maintained that for EDIT protected under the IRS normalization rules, CWSNC proposes to apply the flow back in accordance with those rules. Witness DeStefano testified that for EDIT not protected by normalization rules, but related to property, plant, and equipment (PP&E), the Company proposes flow back over a 20-year period. During the evidentiary hearing, Company witness DeStefano clarified the Company's proposal, stating the Company did not have any EDIT related to PP&E. Finally, witness DeStefano stated that for EDIT not protected by normalization rules nor related to PP&E, CWSNC proposes flow back over a five year period.

The Public Staff noted in its proposed order that on December 22, 2017, the Tax Act was signed into law. The Public Staff stated that, among other provisions, the Tax Act reduced the federal corporate income tax rate from 35% to 21%, effective January 1, 2018[1], and it also repealed the manufacturing tax deduction and eliminated bonus depreciation.

The Public Staff stated that the reduction in the corporate income tax rate in the Tax Act also results in federal EDIT for utilities. The Public Staff explained that EDIT arise from the impact of tax changes on ADIT. The Public Staff explained that ADIT occur because of timing differences between when a utility collects income taxes from ratepayers and when those taxes are paid to the IRS. The Public Staff noted that one of the major types of ADIT arises from differing annual depreciation rates applied to the cost of assets purchased by a utility or other business. The Public Staff maintained that under generally accepted accounting principles and, in many cases, under the regulatory accounting principles followed by the Commission, a utility business is allowed to record on its books an annual depreciation expense representing the allocation of the cost of an item of property between its acquisition and the end of its useful life, and determine its annual income tax expense recovered from its ratepayers on that basis. The Public Staff stated that the depreciation expense is in most cases determined by the straight line method; that is, evenly over each year of the property item's life. The Public Staff maintained that, in contrast, the IRC allows accelerated depreciation for purposes of annual income tax determination: the business may deduct from its income, on its tax returns, a larger proportion of the property's value in the initial years of its life and a smaller percentage in the later years. The Public Staff commented that all other things being equal, for example, the tax basis and book basis of the asset, the total depreciation expense over the life of the asset will be the same for ratemaking and income tax purposes.

The Public Staff noted that for accounting and ratemaking purposes, the temporary tax savings that a utility obtains by using accelerated rather than straight-line depreciation for income

[1] The Public Staff noted that in response to the enactment of the Tax Act, on January 3, 2018, the Commission opened a generic rulemaking docket (Docket No. M-100, Sub 148, i.e., the Tax Docket) for the purpose of determining how the Commission should proceed. The Public Staff stated that in the order establishing the Tax Docket, the Commission placed all public utilities on notice that the federal corporate income tax expense component of all existing rates and charges, effective January 1, 2018, would be billed and collected on a provisional rate basis.

tax purposes is treated as a deferred tax liability. The Public Staff stated that the total amount of taxes a utility has been able to defer, at any given time, is classified as ADIT. The Public Staff maintained that ADIT is treated as cost-free capital and is deducted from rate base because the source of the funds that have not yet been paid to the IRS or another taxing authority is the ratepayer. The Public Staff asserted that if the income tax rate remains constant, the increased taxes a utility pays in the later years of a property item's life will be equal to the tax benefit of accelerated depreciation received by the utility in the earlier years but not flowed through to the ratepayers in the earlier years; and, if the time value of money is disregarded, the total taxes the utility pays with respect to that property item will not be increased or reduced by the use of accelerated depreciation.

The Public Staff commented that when the federal corporate income tax rate is reduced, as it was in the Tax Act, a portion of the federal ADIT that the utility has accumulated from the ratepayers will never be needed by the utility for the payment of taxes. The Public Staff stated that this portion is classified as federal EDIT. The Public Staff noted that the IRC requires that certain federal EDIT must be normalized, or flowed back, subject to certain limitations and that federal EDIT that is subject to this limitation is classified as federal protected EDIT. The Public Staff stated that all other types of federal EDIT are classified as unprotected, in that there are no limitations placed upon them by the IRS with regard to the length of time over which they can be returned to ratepayers.

In her supplemental testimony, Public Staff witness Boswell presented the Public Staff's proposal regarding the flowback of federal and state EDIT, as well as the flowback of the overcollection of taxes since January 1, 2018. She included three adjustments, based on the information provided by the Company. First, witness Boswell recommended the return of federal protected EDIT based upon the Company's calculation of the net remaining life of the timing differences, as required under the IRC. For federal unprotected EDIT, witness Boswell recommended removing the entire federal EDIT regulatory liability associated with the unprotected differences from rate base, and placing it in a rider to be refunded to ratepayers over three years on a levelized basis, with carrying costs calculated at the overall weighted average cost of capital. Public Staff witness Boswell stated that the immediate removal of federal unprotected EDIT from rate base increases the Company's rate base and mitigates regulatory lag that may occur from refunds of federal unprotected EDIT not contemporaneously reflected in rate base. Further, witness Boswell noted that the financing cost to the Company will be imposed ratably over the period that the EDIT is returned through the levelized rider.

Additionally, witness Boswell disagreed with the Company's proposal to offset the federal unprotected EDIT and state EDIT against deferred regulatory assets. Witness Boswell stated that the Public Staff deems that offsetting known and measurable reductions in taxes to be paid going forward against either unknown future regulatory assets, or regulatory assets previously approved by the Commission for recovery over a specified period, presents significant intergenerational issues and constitutes inappropriate ratemaking. Witness Boswell stated that existing deferred regulatory assets are the result of accounting adjustments approved or adopted by the Commission, the purpose of which typically is to spread the recovery of incurred costs over a specified period of time known as the amortization period. Witness Boswell maintained that the amortization period for each regulatory asset is approved by the Commission based upon its determination of what is fair and reasonable for the ratepayers with regard to the costs associated with that specific regulatory asset, or other specific factors taken into consideration by the Commission at the time of that approval. Witness Boswell stated that choosing to simply offset the new unprotected EDIT regulatory liability with the remaining unamortized portion of any regulatory asset would effectively override the Commission's prior decision as to the appropriate amortization period for the regulatory asset, by equalizing the remaining amortization period and the amortization period for the new EDIT regulatory liability. Witness Boswell stated that it is the Public Staff's opinion that the amortization periods for existing regulatory assets and the federal unprotected EDIT should be determined separately, based on the specific characteristics of each cost or benefit. Witness Boswell asserted that departing from this transparent process in the course of a general rate case simply to offset flowing through the benefit of reductions in an entirely separate category of costs (income taxes) is neither fair nor reasonable.

Witness Boswell also maintained that in the case of unknown future possible regulatory assets or other costs, currently offsetting them against the EDIT liability would likewise be inappropriate, not only because those costs are not currently known and actual, but also because doing so would be prejudging the appropriate amortization period for those future costs.

For state EDIT, witness Boswell did not recommend an adjustment in this case, as the Company has been amortizing the applicable regulatory liability over a three-year period as approved in the Sub 356 Proceeding.

Finally, witness Boswell recommended that the Commission require the Company to refund to ratepayers the overcollection of federal taxes related to the decrease in federal tax rates for the period beginning January 1, 2018, including the corresponding interest calculated at the overall weighted cost of capital, as a surcharge credit for a one-year period beginning when the new base rates become effective in the current docket. Witness Boswell noted that the Company did not file a proposal to return the overcollection[1].

Witness Boswell stated that it is the Public Staff's position that the Commission's October 5, 2018 Order in Docket No. M-100, Sub 148 was explicitly clear that the overcollection of taxes since January 1, 2018 should be flowed back to ratepayers. The Public Staff argued that these funds rightfully belong to the ratepayers and should be returned to them as soon as reasonably possible.

Witness Boswell also disagreed with the Company's proposal to retain the overcollection of taxes since January 1, 2018 if the Company has not earned its approved rate of return during the period. Witness Boswell maintained that the approved rate of return in any general rate case represents the amount the Company has the potential to earn, with proper management. She argued that it does not represent guaranteed dollars or return for the Company. Witness Boswell stated that the actual return earned by a utility fluctuates over time, and may fall below the approved rate of return for significant periods of time. Witness Boswell maintained that, nevertheless, it is ultimately the utility's choice as to when it should file for a general rate increase; otherwise, its rates as they exist at any moment in time are generally presumed to recover its costs. Witness Boswell stated that in this particular case even if the Company had not been recovering its currently

[1] CWSNC witness DeStefano did state in his direct testimony that should a refund of these amounts be required, CWSNC suggested a negative surcharge to the customers' bills over a 12-month period.

approved rate of return during 2018, applying the future Commission-mandated refund of overcollected income taxes against that past return deficiency would, in principle, constitute inappropriate retroactive ratemaking. Witness Boswell stated that the tax overcollection in question was to be used to pay taxes that the Company was expected to owe and that as of January 1, 2018, the overcollected taxes are no longer owed. Witness Boswell maintained that the overcollection is ratepayer money that should not be utilized to assist the Company in attaining its return, and thus benefit its shareholders.

Finally, witness Boswell asserted that the appropriate interest rate to apply to the overcollection should be calculated at the overall weighted cost of capital since the same methodology is utilized to calculate the revenue impacts of the collected taxes. Witness Boswell asserted that utilizing a lower rate would shortchange the ratepayers the full value of the refund.

The Public Staff maintained in its proposed order that the Commission's primary concern regarding the effects of the Tax Act should be to ensure that ratepayers receive the full benefit of the reduction in the federal corporate income tax rate. The Public Staff asserted that rates have been set to ensure that the Company has adequate funds with which to pay taxes; now that the federal income tax rate is reduced, rates should be adjusted accordingly. The Public Staff stated that the question before the Commission is how, and over what length of time, these effects should be implemented.

The Public Staff argued that the evidence shows that there is some agreement regarding how to implement the effects of the Tax Act. The Public Staff noted that the Company and the Public Staff agree upon the revenue requirement effect of the decrease in the corporate income tax rate; additionally, no party disputes the amounts presented by the Company regarding the impact of the Tax Act on these issues. The Public Staff recommended that the Commission find that the revenue requirement changes presented by the Company related to these issues are appropriate and should be approved.

The Public Staff noted that, additionally, the Company and the Public Staff agree, and no party disputes, that federal protected EDIT, which is subject to tax normalization rules, should not be returned to ratepayers any faster than allowed under the IRS rules. Therefore, the Public Staff recommended that the Commission find that it is appropriate for the Company to return federal protected EDIT in the amount, and over the time period, recommended by the Company and the Public Staff.

The Public Staff stated that the evidence shows there is not agreement as to how CWSNC should return to ratepayers the federal unprotected EDIT. The Public Staff noted that CWSNC proposed several solutions for handling the federal unprotected EDIT. The Public Staff maintained that in direct testimony, CWSNC proposed to amortize the balance over a five-year period. The Public Staff also noted that in rebuttal testimony, CWSNC proposed to utilize the federal unprotected EDIT as an offset against the Company's various unamortized deferred maintenance assets in the current proceeding. The Public Staff disagreed with the Company's rebuttal proposal, and proposed refunding the federal unprotected EDIT balance through a levelized rider over a three-year period. The Public Staff further recommended removing the entire federal EDIT balance from rate base in the current case, thus mitigating regulatory lag that may occur from refunds of federal unprotected EDIT not contemporaneously reflected in rate base.

CWSNC amended its Tax Act proposals as outlined in the rebuttal testimony of CWSNC witness DeStefano. Witness DeStefano reiterated that CWSNC has adjusted the federal corporate income tax rate to 21% in its Application. He also asserted that due to the fact that the Tax Act was a singular event occurring outside of the Company's historic test period, the Company contends that it should not be treated as a stand-alone event since many changes occur over the course of time. Witness DeStefano argued that for that reason, CWSNC contends that the Tax Act should not automatically trigger a refund to customers of revenues collected from January 1, 2018, until a final order is issued by the Commission in this proceeding.

Witoess DeStefano testified that the Commission should carefully and thoroughly consider all items within the Company's revenue requirement and that indeed is precisely what is occurring in the current proceeding. Witness DeStefano maintained that the Company has updated its original test year of December 31, 2017 with actual data as of June 30, 2018, which is approximately the midpoint between the Tax Act taking effect and the date the current rate case will likely become effective and reflects a fair representation of the Company's financial status in the Review Period. Witness DeStefano asserted that if the proper revenue requirement as determined by the Commission in this rate case meets or exceeds that of the Company's last rate case, excluding effects of the Tax Act beyond the change in the income tax rate to 21%, such as amortization of EDIT, it will therefore strengthen the claim that the Company did not exceed its authorized return. Consequently, witness DeStefano testified, the Company concludes that it is in a unique position relative to other North Carolina utilities, as the comprehensive financial review in this proceeding would directly support the retention of the Review Period funds by the Company to sustain its just-vetted operating needs. However, witness DeStefano maintained that should a refund be required by the Commission in this rate case, the Company recommends that the credit be offset by the Company's existing deferred asset balances.

Witness DeStefano also noted that the Company has provided supporting workpapers for the federal protected EDIT balance and requests a 45-year amortization of this balance using the Reverse South Georgia method, inclusive of gross up, in accordance with IRS normalization rules.

Witness DeStefano further noted that the Company was authorized in its last rate case to amortize state EDIT realized due to the recent North Carolina corporate income tax rate changes. Witness DeStefano testified that CWSNC proposes combining the remaining state EDIT with the federal unprotected EDIT and offsetting the balance against the Company's various unamortized deferred maintenance assets in this proceeding. Witness DeStefano maintained that the particular deferred assets to be utilized in this calculation are shown in the testimony of Public Staff witness Henry, Exhibit I, Schedule 2-10(a), and are comprised of tank painting, wastewater treatment plant painting, and wastewater pumping and hauling costs. Witness DeStefano argued that CWSNC contends, and the Public Staff's testimony confirms, that there are sufficient deferred assets to offset the combined EDIT credit balance, with a focus on those asset balances closest to conclusion of their amortization period in order to best align this proposal with the Public Staff proposal of a three-year amortization period.

Witness DeStefano testified that this proposal would smooth customer impacts by netting balances due-to and due-from customers immediately, as opposed to initiating offsetting customer rates (recovery in base rates of deferred asset rate base and amortization, versus an EDIT credit rider) with different effective periods, which would result in uneven customer impact over the next several years and mask price signals otherwise considered in rate design, or in other words, a yo-yoing of rates. Witness DeStefano argued that it will also mitigate cash flow concerns for the Company, as the lower tax rate going forward will lead to slower growth in the ADIT balance, which is a source of cash used for continued capital investment. Witness DeStefano argued that limiting interest payments required on refunds will also mitigate negative cash flow impacts. He stated that it will also avoid for both the Company and the Public Staff the additional effort of implementing a new rider, tracking the balances, and potentially manually calculating interest. Witness DeStefano maintained that a similar proposal was recently accepted by the Regulatory Commission of Alaska (RCA) in Docket U-18-042, Order No. 2.

Witness DeStefano stated that if the Commission does not adopt the Company's proposal as outlined in his rebuttal testimony of offsetting deferred assets against the unprotected EDIT, the Company alternatively reiterates its position articulated in the direct testimony presented by witness DeStefano, with a five-year amortization of unprotected non-PP&E EDIT.

Finally, witness DeStefano testified that, should a sur-credit be implemented for revenues recorded in the Review Period, the Company proposes to offset this credit balance with the unamortized deferred assets approved in this proceeding until the deferred assets are exhausted before implementing a sur-credit. Witness DeStefano maintained that any amount determined to be refunded should be credited to customers over one year, and accrue interest at an appropriate short-term interest rate, especially if refunds commence at or before January 1, 2019. Witness DeStefano argued that using an appropriate short-term interest rate is more reasonable than applying the cost of capital rate due to the funds being returned to customers approximately one year or less since they were billed. Witness DeStefano maintained that the Company proposes that any calculation of Review Period revenues to be refunded should identify the percent revenue reduction due to the decrease in income tax expense for each tariff group. He stated that this percentage would then be multiplied by the actual applicable revenues booked for the Review Period to determine the level of refund.

Witness DeStefano also noted that the Commission issued an Order on October 5, 2018 in Docket No. W-100, Sub 57, which initiated a generic proceeding to review the impacts of the Tax Act on water and wastewater utilities, specifically CIAC, in North Carolina. He noted that comments were due on October 25, 2018. Witness DeStefano stated that CWSNC plans on providing comments in the generic proceeding and will, in the interim, comply with the Commission's requirement that the full gross-up method be utilized, excepting circumstances where the present value method is authorized by the Commission.

The AGO stated in its post-hearing brief that ratepayers should promptly enjoy the benefits of CWSNC's cost savings resulting from recent changes in the federal tax law. The AGO asserted that recent reductions in federal and state corporate income tax rates result in lower operating expenses for utilities, with a favorable impact on the cost of public utility service, and produce an excess accumulation of funds for deferred income taxes that may be returned to ratepayers. The AGO noted that the Commission determined in a recent order in a generic proceeding that the issue of how to reflect the changes in federal tax rates in new utility rates would be determined for CWSNC in this general rate case proceeding. See Order Addressing the Impacts of the Federal Tax Cuts and Jobs Act on Public Utilities in Docket No. M-100, Sub 148 issued on October 5, 2018 at p. 58. The AGO stated that it supports rate adjustments to flow through the benefits of tax changes to ratepayers as soon as possible.

The AGO noted that the change in the federal corporate income tax rate results in five impacts: (1) the federal corporate income tax rate reduction from 35% to 21% is reflected in the Company's proposed operating expenses; (2) the Company proposes not to return the amount of tax expense that was overcollected in rates from January 1, 2018 until new rates take effect; (3) the Company proposes that the return of EDIT associated with the recent reductions in the state corporate income tax rate decided in the Company's last general rate case proceeding be modified in this case and treated similarly to the Company's proposal for federal unprotected EDIT; (4) the Company proposes to use the federal unprotected EDIT as an offset to existing deferred asset balances, instead of returning it to ratepayers; and (5) CWSNC proposes to return the federal protected EDIT through rates over the period required by federal tax provisions, which it shows to be a 45-year period.

The AGO stated that it does not object to the first and fifth impacts noted above, but objects to the second, third, and fourth.

The AGO noted that, first, the federal corporate income tax rate reduction from 35% to 21% is reflected in the Company's proposed operating expenses and that this proposed impact is not disputed.

Second, the AGO maintained that the Company proposes not to return the amount of tax expense that was overcollected in rates from January 1, 2018 until new rates take effect. The AGO stated that that amount has been booked as a regulatory liability as required by the Commission's January 3, 2018 Order in Docket No. M-100, Sub 148 and will amount to approximately $1.26 million for the calendar year. The AGO noted that if not allowed to keep the amount, CWSNC asks the Commission to allow the amount to be used as an offset by the Company to existing deferred asset balances.

The AGO asserted that CWSNC's argument that it should be allowed to keep the provisional amount that was collected since January 1, 2018 lacks merit. The AGO noted that the Commission considered arguments in its October 5, 2018 Order in Docket No. M-100, Sub 148, and concluded on page 55 that it is "appropriate to require an immediate reduction in the base rates (for the expense piece) of affected utilities to reflect the 21% federal corporate income tax rate mandated by the Tax Act, effective January 1, 2018." The AGO further noted that the Commission explained on pages 55 and 56 of the Order that "the federal corporate income tax rate reduction mandated by the Tax Act is material and substantial," and concluded that "ratepayers should not be forced to continue paying base rates that were set to recover a 35% federal corporate income tax rate that has been reduced to 21% until the utility's next general rate case proceeding."

The AGO argued that there is no justification for allowing CWSNC to retain the provisional amount collected after the federal corporate income tax rate was reduced on January 1, 2018. The AGO stated that the Public Staff has proposed that the amounts overcollected for taxes since January 1, 2018 be returned to customers in a rider over a one-year period with carrying costs calculated using the weighted cost of capital approved in this case. The AGO stated that it agrees with the Public Staff's proposal in this regard.

The AGO stated that, third, the appropriate treatment of the state EDIT was addressed in the Company's last general rate case proceeding. The AGO noted that CWSNC proposed in rebuttal testimony in this proceeding that the return of the state EDIT be modified and treated similarly to the Company's proposal for federal unprotected EDIT.

The AGO stated that it does not support such a change and agrees with the recommendation of Public Staff witness Boswell that no adjustment be made to the provision for return of state EDIT from what was proposed and approved in the Company's prior rate case proceeding. The AGO asserted that the Company's vague proposal would offset the state EDIT against either unknown future regulatory assets or known regulatory assets that have been reviewed and approved with particular treatment in previous cases and that it is not appropriate to override such prior determinations or to set aside ratepayer funds for possible future uses.

The AGO noted that, fourth, the Company's initial proposal was to return federal unprotected EDIT to ratepayers over a five-year period. The AGO stated that, however, in rebuttal testimony the Company proposed instead that the money be used as an offset to existing deferred asset balances.

The AGO noted that it recommended a return of the federal unprotected EDIT over a period of two years or less in the recent Duke Energy Carolinas rate case in Docket No. E-7, Sub 1146, so that ratepayers benefit as soon as possible from the amounts they are owed. The AGO asserted that, likewise, in this proceeding, the AGO recommends a two-year period. The AGO stated that the Public Staff's proposal in this case would return the federal unprotected EDIT over a three-year period, as was done under the settlement reached between the Public Staff and Aqua North Carolina in the recent Aqua North Carolina rate case proceeding (Docket No. W-218, Sub 497). The AGO noted that Public Staff witness Boswell testified that although the Public Staff has proposed a three-year period in this proceeding, a two-year time frame is feasible and is within the range that the Public Staff has proposed in other cases. The AGO also noted that the time frame has not been specified in the Stipulation in this case and that the AGO supports a return of the federal unprotected EDIT as soon as possible, but in no event longer than two years. The AGO asserted that with the adoption of a two-year timeframe to return the federal unprotected EDIT, ratepayers will benefit immediately from the use of the amounts they are owed.

The AGO maintained that CWSNC's proposal not to return federal unprotected EDIT to ratepayers and instead to apply the EDIT to unspecified asset balances should be denied because it is unjust and unreasonable. The AGO asserted that it is inappropriate to override prior determinations about the amortization of regulatory assets. The AGO noted that, further, CWSNC has not shown that any harm will fall to the Company by the prompt return of the funds. The AGO maintained that it is time for CWSNC to stop relying on excess revenues from its customers to maintain the overly flush cash flow that was provided under former tax deferral policies. The AGO asserted that the alternative of not returning dollars to consumers who struggle to pay their bills, or to consumers who would use their money for different purposes if given the opportunity, results in an undue burden on ratepayers and communities in North Carolina.

The AGO stated that, fifth, CWSNC proposes to return the federal protected EDIT associated with the reduction in the federal corporate income tax rate through rates over the period of time required by federal tax provisions, which the Company shows to be a 45-year period. The AGO noted that the Public Staff does not dispute the 45-year time frame based on its investigation and that the Public Staff explained that federal tax provisions do not permit regulators to flow back the EDIT immediately and instead require a flow back that is ratable over the life of the timing differences that gave rise to the excess. The AGO stated that based on the federal requirements and the Public Staff's investigation, the AGO does not object to this proposal.

After reviewing the entire record, the Commission notes that there are five separate issues that need to be addressed for CWSNC in this proceeding concerning the Tax Act. Further, as concluded by the Commission on page 58 of its October 5, 2018 Order in Docket No. M-100, Sub 148, the Commission will address these impacts of the Tax Act on CWSNC in this rate case proceeding.

Based upon the foregoing, and after careful consideration of all of the evidence in this proceeding, the Commission reaches the following findings regarding the issues related to the Tax Act for CWSNC in this proceeding:

1. It is appropriate in this proceeding to reflect the reduction in the federal corporate income tax rate from 35% to 21% on the Company's ongoing federal income tax expense.

2. It is appropriate in this proceeding to amortize CWSNC's federal protected EDIT over 45 years in accordance with the IRC.

3. It is appropriate in this proceeding to implement a four-year levelized rider for the return of federal unprotected EDIT to ratepayers.

4. It is appropriate in this proceeding to maintain the decision reached by the Commission in CWSNC's last general rate case proceeding to amortize over three years the Company's state EDIT recorded pursuant to the Commission's Sub 138 Order.

5. It is appropriate in this proceeding to adopt the Public Staff's recommendation that CWSNC should refund to ratepayers the overcollection of federal income taxes related to the decrease in the federal corporate income tax rate for the period beginning January 1, 2018, including interest at the overall weighted cost of capital, as a credit for a one-year period.

Federal Income Tax Expense - First, the Commission notes that the Company reflected the use of the 21% federal corporate income tax rate in calculating its proposed revenue requirement as filed in its Application. No party has disputed reflecting the 21% rate in this proceeding, and the Commission finds that it is appropriate to calculate CWSNC's revenue requirement in this proceeding using the current 21% federal corporate income tax rate.

Federal Protected EDIT - Second, the Commission notes that the Public Staff and CWSNC agreed in the Stipulation on the appropriate treatment for the Company's federal protected EDIT. Specifically, Section III, Paragraph G of the Stipulation states as follows:

> The Stipulating Parties agree that the protected EDIT will be flowed back over a 45-year period using the Reverse South Georgia method, in accordance with tax normalization rules required by IRC Section 203(e).

As shown on Public Staff witness Boswell Exhibit 1, CWSNC has a regulatory liability of $4,907,523 for federal protected EDIT.

No party disputed this treatment for CWSNC's federal protected EDIT. Therefore, the Commission finds it appropriate to approve this treatment for CWSNC's federal protected EDIT.

Federal Unprotected EDIT – CWSNC's proposed treatment for its federal unprotected EDIT changed during the course of this proceeding. In direct testimony, the Company recommended that EDIT not protected by normalization rules, but related to PP&E be flowed back over a 20-year period and that EDIT not related to PP&E be flowed back over a five-year period. CWSNC witness DeStefano confirmed during cross-examination by the AGO that the Company does not have any PP&E-related federal unprotected EDIT and has approximately $1 million in non-PP&E federal unprotected EDIT.[1] However, in rebuttal testimony, CWSNC recommended that the federal unprotected EDIT be offset against deferred assets, but that if that proposal is not adopted by the Commission that the federal unprotected EDIT be returned with a five-year amortization period.

On cross-examination by the Public Staff, witness DeStefano agreed that the deferred maintenance assets he referenced in his rebuttal testimony to be used as offsets were already decided and approved in a prior CWSNC rate case. He stated that the balances and the amortization periods were set in a prior case and that CWSNC is proposing to change that in order to smooth out the impacts of the Tax Act. Witness DeStefano maintained that it appears to the Company to be a unique offset situation that could be utilized to smooth out the impact to customers for cost spread to future years. He also stated that he is not aware of a situation wherein the North Carolina Utilities Commission has approved such offsetting treatment.

Both the Public Staff and the AGO recommended that the Commission not approve CWSNC's offsetting proposal.

Based upon the record of evidence, the Commission finds that CWSNC's federal unprotected EDIT should be returned to ratepayers through a levelized rider.[2] The Commission finds that this treatment appropriately balances the interests of ratepayers and the Company.

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[1] Public Staff witness Boswell Exhibit 2 shows $966,595 in federal unprotected EDIT.

[2] The Commission notes that the calculation of the rider should reflect the return on equity approved by the Commission herein.

In arriving at its conclusion, the Commission gives substantial weight to the testimony of Public Staff witness Boswell. The Commission agrees with witness Boswell that offsetting known and measurable reductions in taxes to be paid going forward against either unknown future regulatory assets, or regulatory assets previously approved by the Commission for recovery over a specified period, presents significant intergenerational issues and constitutes inappropriate ratemaking. The Commission further agrees with witness Boswell that the amortization period for each regulatory asset is approved by the Commission based upon its determination of what is fair and reasonable for the ratepayers with regard to the costs associated with that specific regulatory asset, or other specific factors taken into consideration by the Commission at the time of that approval. The Commission finds that choosing to simply offset the new unprotected EDIT regulatory liability with the remaining unamortized portion of any regulatory asset would effectively override the Commission's prior decision as to the appropriate amortization period for the regulatory asset, by equalizing the remaining amortization period and the amortization period for the new EDIT regulatory liability. And as CWSNC witness DeStefano testified, he is not aware of a situation wherein the Commission has approved such offsetting treatment.

The Commission further agrees with witness Boswell that the amortization periods for existing regulatory assets and the federal unprotected EDIT should be determined separately, based on the specific characteristics of each cost or benefit. The Commission agrees with witness Boswell that departing from this transparent process in the course of a general rate case simply to offset flowing through the benefit of reductions in an entirely separate category of costs (income taxes) is neither fair nor reasonable. Further, the Commission notes that for customers, a rider will be separately identified on their bills so they can see in dollars and cents the impact of the federal unprotected EDIT flow through. This transparency would not occur with the offsetting proposed by the Company.

Through the years the Commission has set rates at a level to ensure that the Company would be able to pay its taxes, including deferred taxes, when they became due.[1] These funds were paid by ratepayers to the Company to enable the Company to pay its taxes; now that the funds are no longer needed to pay the Company's taxes, they should be flowed back to ratepayers as quickly as practicable. The fact that the Company has made use of these funds as cost-free capital does not change the fact that these funds are ultimately customer money that is no longer needed for tax payments. The only remaining question for the Commission to decide is what is a reasonable period of time to refund these federal unprotected EDIT to ratepayers.

The Commission has carefully considered the evidence as to the appropriate time period over which to return federal unprotected EDIT. The evidence shows that all of the parties agree that the timeframe should be within a two-year to five-year range. Specifically, the Public Staff recommends three years, the AGO recommends two years, and the Company, if its offsetting proposal is not adopted, recommends five years. The Company no longer needs these funds to pay its taxes, which is why they were collected from ratepayers in the first place. Therefore, based on the evidence in this case, the Commission finds that it is appropriate in this case to return federal

[1] The Commission notes that the last reduction in the corporate income tax rate occurred in 1986. The evidence in the record shows that the Company in that instance did not propose to create two separate classifications of federal unprotected EDIT, but simply refunded all of its federal unprotected EDIT through amortization over a five-year period.

unprotected EDIT over a four-year period through a levelized rider. The Commission finds that this decision appropriately balances the interests of ratepayers and the Company. By removing the total amount of the federal unprotected EDIT credit from rate base in the current case, the Company will be provided with an increase in rates to moderate any cash flow issues, to the extent they would exist. Further, the Commission finds that requiring the flowback over four years provides the Company with additional time to return the money and is the appropriate timeframe to balance both the Company's and the ratepayer's interests.

State EDIT - Additionally, the Commission does not find it appropriate to adopt witness DeStefano's proposal to utilize the state EDIT to offset various unamortized deferred maintenance assets in the current proceeding. The Commission has previously approved the amortization of state EDIT in the Sub 356 proceeding, and does not find any of the evidence presented in this proceeding persuasive to change the decision reached by the Commission in that docket.

In arriving at its conclusion, the Commission gives substantial weight to the testimony of witness Boswell. The Commission agrees with witness Boswell that CWSNC's proposal to offset the state EDIT against deferred regulatory assets presents significant intergenerational issues and constitutes inappropriate ratemaking. The Commission also agrees with the Public Staff and the AGO that there is no compelling reason to change the amortization of the state EDIT in this proceeding.

Therefore, the Commission finds that the state EDIT regulatory liability should continue to be amortized over a three-year period as approved in the Sub 356 Order.

Provisional Amount – Finally, the Commission finds that it is appropriate to require CWSNC to return the overcollection of federal taxes related to the decrease in the federal corporate income tax rate, including interest calculated at the overall weighted cost of capital, as a credit over a one-year period beginning when new base rates become effective. The rates with respect to the federal income tax expense have been provisional based on the Commission's generic order, so retroactive ratemaking is not at issue.

The Commission notes that CWSNC witness DeStefano specified during cross-examination by the AGO that the Company will have approximately $1.26 million in provisional revenues for the 2018 calendar year. In reaching its conclusion on this issue, the Commission notes that in its generic order issued in Docket No. M-100, Sub 148 on January 3, 2018, the Commission ordered all utility rates based on the federal corporate income tax rate of 35% rather than the Congressionally approved 21%, effective January 1, 2018, to be provisional and required accompanying deferred accounting for the amount of reduced rates. This meant that the Commission in subsequent orders could require refunds of revenues collected after January 1, 2018 to return to customers the portion of rates providing revenues to cover federal income tax expense greater than 21%. The North Carolina Supreme Court in State ex rel. Utilities Com. v. Nantahala Power & Light Co., 326 N.C. 190, 388 S.E.2d 118, 1990 N.C. LEXIS 12, 110 P.U.R.4th 250, ruled that this procedure in a generic rulemaking case is appropriate with respect to a similar federal income tax reduction with respect to the Tax Reform Act of 1986. The

Court rejected challenges to the Commission's order requiring generic rate reductions as constituting single-issue rate adjustments. The Court held, however, that should utilities wish to demonstrate that their overall rate level not be reduced to reflect lower federal income tax expense, the remedy was to file a general rate case.

In this case, CWSNC has filed a general rate case, and the cost of service evidence justifies a rate increase, thus offsetting the reduction in cost of service from the tax rate decrease with increases elsewhere.

CWSNC nevertheless wishes to retain the overcollected, provisional revenues from January 1, 2018 to October 16, 2018. CWSNC's theory is that it failed to recover its overall cost of service during that period. The Commission determines that the Company's proposed justification to permit CWSNC to retain the revenues at issue is inapposite. The Commission uses the historic test year as adjusted through the end of the hearing to set rates prospectively, effective as of the date of this rate case Order. The reduction in federal income tax expense to 21% is an ongoing reduction in cost of service. To authorize the Company to effectively add a surcharge in rates beginning on January 1, 2018 with respect to this expense item would be no different than authorizing a surcharge for recovery of rates covering a decrease in labor costs during the test year as adjusted.

In addition, on cross-examination by the Public Staff, witness DeStefano noted that an affiliate of CWSNC pointed him to a recent Order by the RCA wherein that Commission declined to make a portion of the revenues received by two water utilities refundable pursuant to the Tax Act. The Commission gives little weight to witness DeStefano's testimony concerning the August 28, 2018 Order by the RCA. Witness DeStefano agreed during cross-examination that the utilities that were granted the favorable treatment by the RCA are distinguishable from CWSNC's case in this instance. First, the Alaska decision addresses two specific water utilities wherein the RCA opened the dockets and held show cause proceedings to investigate if the rates charged by the two utilities remained just and reasonable given the reduction to the annual revenue requirement caused by the Tax Act. In contrast, in North Carolina, in response to the Tax Act, the Commission established a generic rulemaking docket (Docket No. M-100, Sub 148) on January 3, 2018, and in the Order establishing the docket, the Commission put the utilities on notice that any revenues collected on and after January 1, 2018, were to be considered provisional pending a final ruling by the Commission. In addition, the two Alaskan utilities had not been in for rate cases since 2014, and both companies are required to file their next rate case by July 1, 2020, if not sooner. Witness DeStefano also stated on cross- examination that he was not aware of any other state besides Alaska to make this decision, although he did not think he had "uncovered every stone" on this issue and that a lot of states are still working through this process. Witness DeStefano also agreed that he is aware of several other states that are ordering their utilities to refund these provisional amounts.

In fact, in North Carolina, the Commission has required other utilities in its October 5, 2018 Order issued in Docket No. M-100, Sub 148 to return the provisional amount collected since January 1, 2018, with interest reflected at each company's overall weighted cost of capital as approved in the company's last general rate case proceeding, in each utility's next general rate case proceeding or in three years, whichever is sooner.

Addressing CWSNC witness DeStefano's proposal to use a short-term interest rate instead of the overall weighted cost of capital for the provisional amount, the Commission notes that on cross-examination by the Public Staff, witness DeStefano stated that he does not have a proposed short-term interest rate offhand to apply to the provisional amount in question in this proceeding. He specified that the rate could be anything that would reflect the retention of funds for one calendar year or less. Witness DeStefano stated that in this case applying the cost of capital rate seems too high for something that is refunded within a 12-month period from when it was generated. Witness DeStefano specified that the short-term borrowing rate would be less than the overall weighted cost of capital and could be very low, in the 2% range. Both the Public Staff and the AGO disagreed with witness DeStefano on using a short-term interest rate for the provisional amount.

After reviewing the record of evidence on this issue, the Commission finds that the Company's recommendation that the interest on any refund be calculated using a short-term debt rate is not appropriate or reasonable to ratepayers when the Company earns a return on its rate base, based on the overall weighted cost of capital. In reaching this conclusion, the Commission gives substantial weight to the testimony of the Public Staff's witness and the arguments of the AGO.

The Commission also notes that it recently required Cardinal Pipeline Company, LLC, to return to ratepayers the provisional amount that it voluntarily decided to return now instead of under the parameters of the October 5, 2018 Order with interest reflected at the company's overall weighted cost of capital as approved in its last general rate case proceeding (See Docket Nos. G-39, Sub 42 and M-100, Sub 148).

In summary, the Commission finds and concludes that these decisions concerning the Tax Act are appropriate and provide for the full flowback to ratepayers of the effects of the Tax Act. As noted in Public Staff witness Casselberry's supplemental testimony, many of the public witnesses that testified at the public hearings in New Bern and Charlotte noted the tax reductions due to the Tax Act. The decisions herein address those concerns expressed by the various public witnesses in this proceeding and do provide a full flowback to ratepayers of the decrease in the federal corporate income tax rate resulting from the Tax Act.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 52 – 60

The evidence supporting these findings of fact and conclusions is found in the Application and the accompanying NCUC Form W-1 of the Company, the testimony and exhibits of the public witnesses, the testimony and exhibits of Company witness D'Ascendis, the testimony and exhibits of Public Staff witness Hinton, and the entire record of this proceeding.

Rate of Return on Equity

In its Application and in the direct testimony of CWSNC witness D'Ascendis, the Company requested approval for its rates to be set using a rate of return on equity in a range of 11.50% to 11.90%. In his rebuttal testimony, witness D'Ascendis reduced his recommended rate of return on equity to a range of 10.80% to 11.20% after updating his analysis and making several changes to the application of his models. For the reasons set forth herein, the Commission finds that a rate of return on equity of 9.75% is just and reasonable.

Rate of return on equity, also referred to as the cost of equity capital, is often one of the most contentious issues to be addressed in a rate case. In the absence of a settlement agreed to by all parties, the Commission must exercise its independent judgment and arrive at its own independent conclusion as to all matters at issue, including the rate of return on equity. See, State ex rel. Utils. Comm'n v. Carolina Utils. Customers Ass'n, 348 N.C. 452, 466, 500 S.E.2d 693, 707 (1998). In order to reach an appropriate independent conclusion regarding the rate of return on equity, the Commission should evaluate the available evidence, particularly that presented by conflicting expert witnesses. State ex rel. Utils. Comm'n v. Cooper, 366 N.C. 484, 491-93, 739 S.E.2d 541, 546-47 (2013) (Cooper I). In this case, the evidence relating to the Company's cost of equity capital was presented by CWSNC witness D'Ascendis and Public Staff witness Hinton. No other rate of return on equity expert evidence was presented by any party.

In addition to its evaluation of the expert evidence, the Commission must also make findings of fact regarding the impact of changing economic conditions on customers when determining the proper rate of return on equity for a public utility. Cooper I, 366 N.C. at 494, 739 S.E.2d at 548. This was a factor newly announced by the Supreme Court in its Cooper I decision and not previously required by the Commission or any appellate courts as an element that must be considered in connection with the Commission's determination of an appropriate rate of return on equity. The Commission's discussion of the evidence with respect to the findings required by Cooper I is set out in detail in this Order.

Cooper I was the result of the Supreme Court's reversal and remand of the Commission's approval of the agreement regarding the rate of return on equity in a stipulation between the Public Staff and Duke Energy Carolinas, LLC (DEC) in Docket No. E-7, Sub 989. The Commission has had occasion to apply both prongs of Cooper I in subsequent orders, specifically the following:

- Order Granting General Rate Increase, Docket No. E-2, Sub 1023 (May 30, 2013) (2013 DEP Rate Order), which was affirmed by the North Carolina Supreme Court in State ex rel. Utils. Comm'n v. Cooper, 367 N.C. 444, 761 S.E.2d 640 (2014) (Cooper III)[1];

- Order on Remand, Docket No. E-7, Sub 989 (Oct. 23, 2013) (DEC Remand Order), which was affirmed by the North Carolina Supreme Court in State ex rel. Utils. Comm'n v. Cooper, 367 N.C. 644, 766 S.E.2d 827 (2014) (Cooper IV);

- Order Granting General Rate Increase, Docket No. E-7, Sub 1026 (Sep. 24, 2013) (2013 DEC Rate Order), which was affirmed by the Supreme Court in State ex rel. Utils. Comm'n v. Cooper, 367 N.C. 741, 767 S.E.2d 305 (2015) (Cooper V);

[1] An intervening case, State ex rel. Utils. Comm'n v. Cooper, 367 N.C. 430, 758 S.E.2d 635 (2014) (Cooper II), arose from Dominion North Carolina Power's 2012 rate case and resulted in a remand to the Commission, inasmuch as the Commission's Order in that case predated Cooper I.

- Order on Remand, Docket No. E-22, Sub 479 (July 23, 2015), which was not appealed to the Supreme Court;

- Order Approving Rate Increase and Cost Deferrals and Revising PJM Regulatory Conditions, Docket No. E-22, Sub 532 (Dec. 22, 2016);

- Order Accepting Stipulation, Deciding Contested Issues and Granting Partial Rate Increase, Docket No. E-2, Sub 1142 (Feb. 23, 2018); and

- Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction, Docket No. E-7, Sub 1146 (June 22, 2018).

In order to give full context to the Commission's decision herein and to elucidate its view of the requirements of the General Statutes as they relate to rate of return on equity, as interpreted by the Supreme Court in Cooper I, the Commission deems it important to provide in this Order an overview of the general principles governing this subject.

A. Governing Principles in Setting the Rate of Return on Equity

First, there are, as the Commission noted in the 2013 DEP Rate Order, constitutional constraints upon the Commission's rate of return on equity decisions established by the United States Supreme Court Decisions in Bluefield Waterworks & Improvement Co., v. Pub. Serv. Comm'n of W. Va., 262 U.S. 679 (1923) (Bluefield), and Fed. Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591 (1944) (Hope):

> To fix rates that do not allow a utility to recover its costs, including the cost of equity capital, would be an unconstitutional taking. In assessing the impact of changing economic conditions on customers in setting a return on equity, the Commission must still provide the public utility with the opportunity, by sound management, to produce a fair profit for its shareholders, in view of current economic conditions, (2) maintain its facilities and service, and (3) compete in the marketplace for capital. State ex rel. Utilities Commission v. General Telephone Co. of the Southeast, 281 N.C. 318, 370, 189 S.E.2d 705, 757 (1972). As the Supreme Court held in that case, these factors constitute "the test of a fair rate of return" in Bluefield and Hope. Id.

2013 DEP Rate Order, p. 29.

Second, the rate of return on equity is, in fact, a cost. The return that equity investors require represents the cost to the utility of equity capital. In his dissenting opinion in Missouri ex rel. Southwestern Bell Tel. Co. v. Missouri Pub. Serv. Comm'n, 262 U.S. 276 (1923), Justice Brandeis remarked upon the lack of any functional distinction between the rate of return on equity (which he referred to as a "capital charge") and other items ordinarily viewed as business costs, including operating expenses, depreciation, and taxes:

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

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

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

> While utilities enjoy varying degrees of monopoly in the sale of public utility services, they must compete with everyone else in the free open market for the input factors of production, whether it be labor, materials, machines, or capital. The prices of these inputs are set in the competitive marketplace by supply and demand, and it is these input prices which are incorporated in the cost of service computation. This is just as true for capital as for any other factor of production. Since utilities must go to the open capital market and sell their securities in competition with every other issuer, there is obviously a market price to pay for the capital they require, for example, the interest on capital debt, or the expected return on equity.
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> * * *
>
> [T]he cost of capital to the utility is synonymous with the investor's return, and the cost of capital is the earnings which must be generated by the investment of that capital in order to pay its price, that is, in order to meet the investor's required rate of return.

Morin, Roger A., Utilities' Cost of Capital (Public Utilities Reports, Inc. 1984), at pp. 19-21. Professor Morin adds: "The important point is that the prices of debt capital and equity capital are set by supply and demand, and both are influenced by the relationship between the risk and return expected for those securities and the risks expected from the overall menu of available securities." Id. at 20 (emphasis added).

Changing economic circumstances as they impact CWSNC's customers may affect those customers' ability to afford rate increases. For this reason, customer impact weighs heavily in the overall ratemaking process, including, as set out in detail elsewhere in this Order, the Commission's own decision of an appropriate authorized rate of return on equity. In addition, in the event of a settlement, customer impact no doubt influences the process by which the parties to a rate case decide to settle contested matters and the level of rates achieved by any such settlement.

However, a customer's ability to afford a rate increase has absolutely no impact upon the supply of or the demand for capital. The economic forces at work in the competitive capital market determine the cost of capital – and, therefore, the utility's required rate of return on equity. The cost of capital does not go down because some customers may find it more difficult to pay for an increase in water and wastewater prices as a result of prevailing adverse economic conditions, any more than the cost of capital goes up because some customers may be prospering in better times.

Third, the Commission is and must always be mindful of the North Carolina Supreme Court's command that the Commission's task is to set rates as low as possible consistent with the dictates of the United States and North Carolina Constitutions. State ex rel. Utils. Comm'n v. Pub. Staff-N. Carolina Utils. Comm'n, 323 N.C. 481, 490, 374 S.E.2d 361, 370 (1988). Further, and echoing the discussion above concerning the fact that rate of return on equity represents the cost of equity capital, the Commission must execute the Supreme Court's command "irrespective of economic conditions in which ratepayers find themselves." (2013 DEP Rate Order, p. 37.) The Commission noted in that Order:

> The Commission always places primary emphasis on consumers' ability to pay where economic conditions are difficult. By the same token, it places the same emphasis on consumers' ability to pay when economic conditions are favorable as when the unemployment rate is low. Always there are customers facing difficulty in paying utility bills. The Commission does not grant higher rates of return on equity when the general body of ratepayers is in a better position to pay than at other times, which would seem to be a logical but misguided corollary to the position the Attorney General advocates on this issue.

Id. Indeed, in Cooper I the Supreme Court emphasized "changing economic conditions" and their impact upon customers. Cooper I, at 548.

Fourth, while there is no specific and discrete numerical basis for quantifying the impact of economic conditions on customers, the impact on customers of changing economic conditions is embedded in the rate of return on equity expert witnesses' analyses. The Commission noted this in the 2013 DEP Rate Order: "This impact is essentially inherent in the ranges presented by the return on equity expert witnesses, whose testimony plainly recognized economic conditions – through the use of econometric models – as a factor to be considered in setting rates of return." 2013 DEP Rate Order, p. 38.

Fifth, under long-standing decisions of the North Carolina Supreme Court, the Commission's subjective judgment is a necessary part of determining the authorized rate of return on equity. State ex rel. Utils. Comm'n v. Pub. Staff, 323 N.C. 481, 490, 374 S.E.2d 361, 369 (1988). As the Commission also noted in the 2013 DEP Rate Order:

Indeed, of all the components of a utility's cost of service that must be determined in the ratemaking process, the appropriate [rate of return on equity] is the one requiring the greatest degree of subjective judgment by the Commission. Setting [a return on equity] for regulatory purposes is not simply a mathematical exercise, despite the quantitative models used by the expert witnesses. As explained in one prominent treatise:

> Throughout all of its decisions, the [United States] Supreme Court has formulated no specific rules for determining a fair rate of return, but it has enumerated a number of guidelines. The Court has made it clear that confiscation of property must be avoided, that no one rate can be considered fair at all times and that regulation does not guarantee a fair return. The Court also has consistently stated that a necessary prerequisite for profitable operations is efficient and economical management. Beyond this is a list of several factors the commissions are supposed to consider in making their decisions, but no weights have been assigned.
>
> The relevant economic criteria enunciated by the Court are three: financial integrity, capital attraction and comparable earnings. Stated another way, the rate of return allowed a public utility should be high enough: (1) to maintain the financial integrity of the enterprise, (2) to enable the utility to attract the new capital it needs to serve the public, and (3) to provide a return on common equity that is commensurate with returns on investments in other enterprises of corresponding risk. These three economic criteria are interrelated and have been used widely for many years by regulatory commissions throughout the country in determining the rate of return allowed public utilities.
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> In reality, the concept of a fair rate of return represents a "zone of reasonableness." As explained by the Pennsylvania commission:
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>> There is a range of reasonableness within which earnings may properly fluctuate and still be deemed just and reasonable and not excessive or extortionate. It is bounded at one level by investor interest against confiscation and the need for averting any threat to the security for the capital embarked upon the enterprise. At the other level it is bounded by consumer interest against excessive and unreasonable charges for service.
>
> As long as the allowed return falls within this zone, therefore, it is just and reasonable. . . . It is the task of the commissions to translate these generalizations into quantitative terms.

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

2013 DEP Rate Order, pp. 35-36.

Thus, the Commission must exercise its subjective judgment so as to balance two competing rate of return on equity-related factors – the economic conditions facing the Company's customers and the Company's need to attract equity financing in order to continue providing safe and reliable service.

The Supreme Court in Cooper V affirmed the 2013 DEC Rate Order, in which this framework was fully articulated. But to the framework we can add additional factors based upon the Supreme Court's decisions in Cooper III, Cooper IV, and Cooper V. Specifically, the Supreme Court held that nothing in Cooper I requires the Commission to "quantify" the influence of changing economic conditions upon customers (see, e.g., Cooper V, 367 N.C. at 745-46; Cooper IV, 367 N.C. at 650; Cooper III, 367 N.C. at 450), and, indeed, the Supreme Court reiterated that setting the rate of return on equity is a function of the Commission's subjective judgment: "Given th[e] subjectivity ordinarily inherent in the determination of a proper rate of return on common equity, there are inevitably pertinent factors which are properly taken into account but which cannot be quantified with the kind of specificity here demanded by [the appellant]." Cooper III, 367 N.C. at 450, quoting State ex rel. Utils. Comm'n v. Pub. Staff-North Carolina Utils. Comm'n, 323 NC 481, 490 (1988).

Finally, the Supreme Court discussed with approval the Commission's reference to and reliance upon expert witness testimony that used econometric models that the Commission had noted "inherently" contained the effects of changing economic circumstances upon customers and also discussed with approval the Commission's reference to and reliance upon expert witness testimony correlating the North Carolina economy with the national economy. See, e.g., Cooper V, 367 N.C. at 747; Cooper III, 367 N.C. at 451.

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

B. Application of the Governing Principles to the Rate of Return Decision

1. Evidence from Expert Witnesses on Cost of Equity Capital

Company witness D'Ascendis recommended in his direct testimony a rate of return on equity range of 11.50% to 11.90%. This range was based upon his indicated cost of common equity of 11.50% plus a recommended size adjustment of 0.40%. In his rebuttal testimony, witness D'Ascendis provided an updated analysis including changes in the application of his models and reduced his recommended rate of return on equity to a range of 10.80% to 11.20%.

D'Ascendis Direct Testimony

Witness D'Ascendis' recommendation was based upon his Discounted Cash Flow (DCF) model, his Risk Premium Model (RPM), and his Capital Asset Pricing Model (CAPM), applied to market data of a proxy group of six publicly-traded water companies (Utility Proxy Group). He also applied the DCF, RPM, and CAPM to a proxy group of domestic, non-price regulated companies (Non-Price Regulated Proxy Group) which he described as comparable in total risk to his Utility Proxy Group.

The results derived from witness D'Ascendis' analyses in his direct testimony are as follows:

Summary of D'Ascendis' Common Equity Cost Rate Analyses in Direct Testimony

Utility Proxy Group	
Discounted Cash Flow Model	9.10%
Risk Premium Model	12.12
Capital Asset Pricing Model	11.31
Cost of Equity Models Applied to Non-Price Regulated Proxy Group	12.63
Indicated Common Equity Cost Rate Before Adjustments	11.50%
Size Adjustment	0.40
Range of Common Equity Cost Rates After Adjustments	11.50% - 11.90%

He concluded that a common equity cost rate of 11.50% for CWSNC is indicated before any Company-specific adjustments. He then adjusted upward by 0.40% to reflect CWSNC's smaller relative size as compared with the members of his Utility Proxy Group, resulting in a size-adjusted indicated common equity cost rate of 11.90%.

Witness D'Ascendis testified he used the single-stage constant growth DCF model. He testified his unadjusted dividend yields are based on the proxy companies' dividends as of March 29, 2018, divided by the average of closing market prices for the 60 trading days ending March 29, 2018.[1] He made an adjustment to the dividend yield because dividends are paid periodically, usually quarterly.

For witness D'Ascendis' DCF growth rate, he testified he used only analysts' five-year forecasts of earning per share (EPS) growth. He testified that the mean result of his application of the single-stage DCF model is 9.12%, the median result is 9.07%, and the average of the two is 9.10% for his Utility Proxy Group.

CWSNC witness D'Ascendis used two risk premium methods. He testified his first method is the Predictive Risk Premium Model (PRPM), while the second method is a RPM using a total market approach. He testified that the inputs to his PRPM are the historical returns on the common shares of each company in the Utility Proxy Group minus the historical monthly yield on long-term U.S. Treasury securities through March 2018. He testified he added the forecasted 30-year U.S. Treasury Bond yield, 3.69% to each company's PRPM-derived equity risk premium to arrive at an indicated cost of common equity. He testified that the mean PRPM indicated common

[1] See Schedule DWD-3, page 1, column 1.

equity cost rate for the Utility Proxy Group is 13.52%, the median is 13.33%, and the average of the two is 13.43%.

Witness D'Ascendis testified that his total market approach RPM adds a prospective public utility bond yield to an average of (1) an equity risk premium that is derived from a beta-adjusted total market equity risk premium, and (2) an equity risk premium based on the S&P Utilities Index. He calculated his adjusted prospective bond yield for the Utility Proxy Group to be 5.00%, and the average equity risk premium to be 5.80% resulting in a risk premium derived common equity of 10.80% for his RPM using his total market approach.

To determine the results of his risk premium method, he testified that he averaged the PRPM result of 13.43% and the RPM results of 10.80% and the indicated cost of equity from his risk premium method was 12.12%.

For his CAPM, witness D'Ascendis testified that he applied both the traditional CAPM and the empirical CAPM (ECAPM) to the companies in his Utility Proxy Group and averaged the results. For his CAPM beta coefficient, he considered two methods of calculation: the average of the beta coefficients of the Utility Proxy Group companies reported by Bloomberg Professional Services, and the average of the beta coefficients of the Utility Proxy Group companies as reported by Value Line resulting in a mean beta of 0.78 and a median beta of 0.74.

Witness D'Ascendis testified that the risk-free rate adopted for both applications of the CAPM is 3.69%. This risk-free rate of 3.69% is based on the average of the *Blue Chip* consensus forecast of the expected yields on 30-year U.S. Treasury bonds for the six quarters ending with the second calendar quarter of 2019, and long-term projections for the years 2019 to 2023 and 2024 to 2028.

Witness D'Ascendis stated that he used three sources of data to determine the risk premium in his CAPM: historical, Value Line, and Bloomberg, that when averaged, result in an average total market equity risk premium of 9.12%. He testified that the mean result of his CAPM/ECAPM analyses is 11.25%, the median is 11.37%, and the average of the two is 11.31%.

Witness D'Ascendis also selected 17 domestic non-price regulated companies for his Non-Price Regulated Proxy Group that he believes are comparable in total risk to his Utility Proxy Group. He calculated common equity cost rates using the DCF, RPM, and CAPM for the Non-Price Regulated Proxy Group. His DCF result was 14.15%, his RPM cost rate was 12.46%, and his CAPM/ECAPM cost rate was 11.78%.

Witness D'Ascendis also made a 0.40% equity cost rate adjustment due to CWSNC's small size relative to the Utility Proxy Group. He testified that the Company has greater relative risk than the average company in the Utility Proxy Group because of its smaller size compared with the group, as measured by an estimated market capitalization of common equity for CWSNC (whose common stock is not publicly-traded).

Hinton Direct Testimony

Public Staff witness Hinton recommended a common equity cost rate of 9.20%. He testified that, according to Moody's Bond Survey, yields on long-term "A" rated public utility bonds as of August 2018 were 4.26% and 4.27% for July 2018. Witness Hinton noted that such bonds yielded 4.63% on January 10, 2014 which is the time of filing of the Public Staff and Company Stipulation in Docket No. W-354, Sub 336 that included a 9.75% cost of equity. He further testified that the relative decrease in long-term bond yields since the last rate case is not indicative of an increase in financing costs for utilities; rather, it portends a lowering of financing costs for long-term capital. However, he also testified that there has been an increase in the cost of short-term financing.

Witness Hinton stated that the current lower interest rates and stable inflationary environment of today indicate that borrowers are paying less for the time value of money. He testified that this is significant since utility stocks and utility capital costs are highly interest-rate sensitive relative to most industries. Furthermore, given that investors often view purchases of the common stocks of utilities as substitutes for fixed income investments, the reductions in interest rates observed over the past 10 years or more have paralleled the decreases in investor required rates of return on common equity.

Witness Hinton testified that he generally does not rely on interest rate forecasts. Rather, he considers that relying on current interest rates, especially in relation to yields on long-term bonds, is more appropriate for ratemaking in that, it is reasonable to expect that as investors are pricing bonds, they are based on expectations on future interest rates, inflation rates, etc. He testified that while he has a healthy respect for forecasting, he is aware of the risk of relying on predictions of rising interest rate cases. He presented a case that can be observed in the testimony of Company witness Ahern in the 2013 Aqua NC rate case. In that case, witness Ahern identified several point forecasts of year Treasury Bond yields that were predicted to rise to 4.3% in 2015, 4.7% in 2016, and 5.2% in 2017. He presented a graph of 30-Year US Treasury Bonds yields which showed in 2016 and 2017 the range was approximately 2.25% to 3.10%. Tr. Vol. 7, pp. 136-137.

Witness Hinton testified that he used the DCF model and the RPM to determine the cost of equity for CWSNC. He testified that the DCF model is a method of evaluating the expected cash flows from an investment by giving appropriate consideration to the time value of money. The DCF model is based on the theory that the price of the investment will equal the discounted cash flows of return. The return to an equity investor comes in the form of expected future dividends and price appreciation. He testified that as the new price will again be the sum of the discounted cash flows, price appreciation is ignored and attention is focused on the expected stream of dividends.

Witness Hinton testified that he applied the DCF method to a comparable group of water utilities followed by the Value Line Investment Survey (Value Line). He testified that the standard edition of Value Line covers nine water companies. He excluded Connecticut Water Service, Inc. and the SJW Group because of a merger of the two companies and also excluded Consolidated Water Co. because of its significant overseas operations.

Witness Hinton calculated the dividend yield component of the DCF by using the Value Line estimate of dividends to be declared over the next 12 months divided by the price of the stock as reported in the Value Line Summary and Index sections for each week of the 13-week period June 29, 2018 through September 21, 2018. He testified that a 13-week averaging period tends to smooth out short-term variations in the stock prices. This process resulted in an average dividend yield of 2.1% for his proxy group of water utilities.

To calculate the expected growth rate component of the DCF, Public Staff witness Hinton employed the growth rates of his proxy group in EPS, dividends per share (DPS), and book value per share (BVPS) as reported in Value Line over the past 10 and five years. He also employed the forecasts of the growth rates of his proxy group in EPS, DPS, and BVPS as reported in Value Line. He testified that the historical and forecast growth rates are prepared by analysts of an independent advisory service that is widely available to investors, and should also provide an estimate of investor expectations. He testified that he included both historical known growth rates and forecast growth rates, because it is reasonable to expect that investors consider both sets of data in deriving their expectations.

Witness Hinton incorporated the consensus of various analysts' forecasts of five-year EPS growth-rate projections as reported in Yahoo Finance. He testified that the dividend yields and growth rates for each of the companies and for the average for his comparable proxy group are shown in Exhibit JRH-3.

Witness Hinton concluded based upon his DCF analysis that a reasonable expected dividend yield is 2.1% with an expected growth rate of 6.1% to 7.1%. Thus, he testified that his DCF analysis produces a cost of common equity for his comparable proxy group of water utilities of 8.20% to 9.20%.

Witness Hinton testified that the equity risk premium method can be defined as the difference between the expected return on a common stock and the expected return on a debt security. The differential between the two rates of return are indicative of the return investors require in order to compensate them for the additional risk involved with an investment in the Company's common stock over an investment in the Company's bonds that involves less risk.

Witness Hinton testified that his method relies on approved returns on common equity for water utility companies from various public utility commissions as reported in a RRA Water Advisory, published by the Regulatory Research Associates, Inc. (RRA), a group within S&P Global Market Intelligence (RRA Water Advisory). In order to estimate the relationship with a representative cost of debt capital, he regressed the average annual allowed equity returns with the average Moody's A-rated yields for Public Utility bonds from 2006 through 2018. His regression analysis, which incorporates years of historical data, is combined with recent monthly yields to provide an estimate of the current cost of common equity.

Witness Hinton testified that the use of allowed returns as the basis for the expected equity return has two strengths over other approaches that involve various models that estimate the expected equity return on common stocks and subtracting a representative cost of debt. He stated that one strength of his approach is that authorized returns on equity are generally arrived at through lengthy investigations by various parties with opposing views on the rate of return required by investors. He testified that it is reasonable to conclude that the approved allowed returns are good estimates of the cost of equity.

Witness Hinton testified that the summary data of risk premiums shown on his Exhibit JRH-4, page 1 of 2, indicates that the average risk premium is 4.95% with a maximum premium of 5.78% and minimum premium of 3.73%, which when combined with the last six months of Moody's A-rated utility bond yields produces yields with an average cost of equity of 9.11%, a maximum cost of equity of 9.94%, and a minimum cost of equity of 7.89%. He performed a statistical regression analysis as shown on Exhibit JRH-4, page 2 of 2 in order to quantify the relationship of allowed equity returns and bond costs. He testified that by applying this relationship to the current utility bond cost of 4.22%, resulted in a current estimate of the cost of equity of 9.70% which reflects a risk premium of 5.48%.

Witness Hinton concluded that based on all of the results of his DCF model that indicate a cost of equity from 8.20% to 9.20% with a central point estimate of 8.70%, and the risk premium model that indicates a cost of equity of 9.70%, he determined that the investor required rate of return on equity for CWSNC is between 8.70% and 9.70%. He concluded that 9.20% is his single best estimate of the Company's cost of common equity.

Witness Hinton testified as to the reasonableness of his recommended return, that he considered the pre-tax interest coverage ratio produced by his cost estimates for the cost of equity. He testified that based on his recommended capital structure, cost of debt, and equity return of 9.20%, the pre-tax interest coverage ratio is approximately 3.2 times. He testified that this pre-tax interest coverage and a funds flow to debt ratio of 26% should allow CWSNC to qualify for a single "A" bond rating.

Witness Hinton testified that his recommended return on common equity takes into consideration the impact of the water and sewer system improvement charges pursuant to N.C.G.S. § 62-113.12 on CWSNC's financial risk. He testified that these improvement charges are seen by debt and equity investors as supportive regulation that mitigates business risk. Witness Hinton stated that he considers this mechanism to be noteworthy and is supportive of his 9.20% return on equity recommendation.

Witness Hinton testified that it is not appropriate to add a risk premium to the cost of equity due to the size of the company. He testified that from a regulatory policy perspective, ratepayers should not be required to pay higher rates because they are located in the franchise area of a utility of a size which is arbitrarily considered to be small. He further testified that if such adjustments were routinely allowed, an incentive would exist for large existing utilities to form subsidiaries when merging or even to split-up into subsidiaries to obtain higher allowed returns. He further testified that CWSNC operates in a franchise environment that insulates the Company from competition and it operates with procedures in place that allow for rate adjustments for eligible capital improvements, cost increases, and other unusual circumstances that impact its earnings.

D'Ascendis Rebuttal Testimony

In his rebuttal testimony, CWSNC witness D'Ascendis disagreed with witness Hinton that a 9.20% common equity rate is appropriate for CWSNC and stated that the Public Staff's recommendation would not be sufficient to maintain the integrity of presently invested capital and permit the attraction of needed new capital at a reasonable cost in competition with other firms of comparable risk.

Witness D'Ascendis also disagreed with witness Hinton's exclusion of the CAPM and comparable earnings model (CEM), both of which witness Hinton used as a check on his DCF and RPM in a previous proceeding involving Aqua NC (Docket No. W-218, Sub 319). According to witness D'Ascendis, both the academic literature and the Commission support the use of multiple models in determining a return on common equity. Witness D'Ascendis then attempted to supplement what would have been witness Hinton's analysis with a CAPM and CEM, which indicated results of 10.93% and 12.49%, respectively.

Witness D'Ascendis objected to witness Hinton's DCF analysis and he also took issue with witness Hinton's use of historical growth rates in EPS, DPS, and BVPS as well as his use of projected growth rates in DPS and BVPS. He asserted that it is appropriate to rely exclusively upon security analysts' forecasts of EPS growth rates in a DCF analysis for multiple reasons.

First, he believed that individual investors who could potentially invest in utility stocks generally have more limited informational resources than institutional investors and are therefore likely to place greater significance on the opinions and projections expressed by financial information services such as Value Line, Reuters, Zacks, and Yahoo! Finance, which are all easily accessible and/or available on the Internet and through public libraries. Witness D'Ascendis testified that security analysts have significant insight into the dynamics of the industries and individual companies they analyze, as well as company's abilities to effectively manage the effects of a changing industry, economic, or market environment. Second, over the long run, there can be no growth in DPS without growth in EPS. Security analysts' earnings expectations have a more significant, but not exclusive, influence upon market prices than dividend expectations, providing a better matching between investors' market price appreciation expectation and the growth component of the DCF model. Third, there is academic support for the superiority of analysts' forecasts of growth in EPS as the growth component in the DCF model. Witness D'Ascendis asserted that witness Hinton should have relied exclusively upon the Value Line and Yahoo! Finance EPS forecasts.

Witness D'Ascendis also disagreed with witness Hinton's application of his RPM because of his use of annual average authorized returns on equity for water companies instead of using individual cases and his use of current interest rates instead of projected interest rates. According to witness D'Ascendis, using current or historical measures, such as interest rates, are inappropriate for cost of capital and ratemaking purposes because they are both prospective in nature.

In addition, witness D'Ascendis disagreed with witness Hinton on risk due to size. Witness D'Ascendis emphasized that because it is the rate base of a specific regulated jurisdictional utility to which a regulatory allowed rate of return will be applied, it is the unique risk of that rate base which needs to be reflected in the allowed rate of return, including any additional risk due to small size. In addition, the corporate structure of the owners of that rate base is irrelevant as it is the use of the funds which gives rise to the investment risk, not the source of those funds. It matters not whether the rate base is held privately, by a municipality, by a large holding company, by a small holding company, by an equity investment fund, multiple shareholders, or a single shareholder. Only the riskiness of the particular rate base is relevant. The size of any given jurisdictional rate base is not arbitrary, it is what it is, and it is imminently relevant relative to the size of any publicly-traded utilities from whose market data a common equity cost rate recommendation is derived. Therefore, there is no incentive for "large existing utilities to form subsidiaries when merging or even to split-up into subsidiaries" because it is the risk of the regulated rate base which is relevant.

Witness D'Ascendis testified that witness Hinton's corrected cost of common equity analysis results in a common equity cost rate of 10.62% for witness Hinton's comparable group of water utilities before adjustment for CWSNC's increased risk due to size relative to the proxy group.

In his rebuttal testimony, Company witness D'Ascendis also updated his analysis and made certain changes in the application of the models he used to determine the cost of equity in his direct testimony. As a result, he revised his recommended rate of return on equity range to be 10.80% to 11.20%. This range was based upon his indicated cost of common equity of 10.80% plus a recommended size adjustment of 0.40%.

Witness D'Ascendis' rebuttal testimony also updated his original DCF, RPM, and CAPM models with relation to his Utility Proxy Group, as well as his Non-Price Regulated Proxy Group.

The results derived from witness D'Ascendis' analyses in his rebuttal testimony are as follows:

Summary of D'Ascendis' Common Equity Cost Rate Analyses
in Rebuttal Testimony

Utility Proxy Group	
Discounted Cash Flow Model	9.15%
Risk Premium Model	10.73
Capital Asset Pricing Model	10.93
Cost of Equity Models Applied to Non-Price Regulated Proxy Group	12.43
Indicated Common Equity Cost Rate Before Adjustments	10.80%
Size Adjustment	0.40
Range of Common Equity Cost Rates After Adjustments	10.80% - 11.20%

He concluded that a common equity cost rate of 10.80% for CWSNC is indicated before any Company-specific adjustments. He then adjusted upward by 0.40% to reflect CWSNC's smaller relative size as compared with the members of his Utility Proxy Group, resulting in a size-adjusted indicated common equity cost rate of 11.20%.

Witness D'Ascendis testified that his rebuttal testimony provided an updated analysis as of September 28, 2018. In addition, he testified that his rebuttal testimony differed from his direct testimony in the application of his models, which he had changed in May 2018. Witness D'Ascendis listed such changes as follows:

> 1. In the Predictive Risk Premium Model (PRPM) applicable to the proxy group companies, instead of averaging the spot and long-term average predicted variances, I selected the minimum value for each company;
>
> 2. For the beta adjusted equity risk premium (ERP), instead of averaging the ERPs by source (i.e. Ibbotson, Value Line, and Bloomberg), I gave all six ERP measures equal weight;
>
> 3. For the Standard & Poor's (S&P) utility-specific ERP, instead of averaging the ERPs by source, I gave all five ERP measures equal weight; and
>
> 4. For the market risk premium (MRP) used in the Capital Asset Pricing Model (CAPM), instead of averaging the MRPs by source. I gave all six MRP measures equal weight.

Tr. Vol. 7, p. 184.

D'Ascendis Cross-Examination

On cross-examination, witness D'Ascendis testified he was aware that CWSNC has approximately 50,000 customers in North Carolina and that CWSNC is the second largest regulated water and wastewater company in North Carolina. Witness D'Ascendis further testified on cross-examination that CWSNC obtains all of its debt and all of its equity from Utilities, Inc., and in this general rate case both CWSNC and the Public Staff are using Utilities, Inc.'s capital structure and cost of debt.

Witness D'Ascendis testified that Public Staff D'Ascendis Direct Cross-Examination Exhibit 1 lists the market capitalizations for four of the companies in his Utility Proxy Group as shown on D'Ascendis Direct Exhibit No. 1, Schedule DWD-8, page 2, column 6. He testified that this cross-examination exhibit correctly listed the Utilities, Inc. book equity on June 30, 2018, at $252.2 million and when the Utility Proxy Group market to book ratio of 300.5 was applied to Utilities Inc.'s $252.2 million book equity, the resulting Utilities, Inc. market capitalization is $758 million. He testified Utilities, Inc.'s $758 million market capitalization was larger than two of his Utility Proxy Group companies, Middlesex Water Company at $600 million and York Water Company at $399 million.

Witness D'Ascendis also testified that he was aware that as testified to by Public Staff witness Hinton, in the 1990s the Commission specifically rejected a size adjustment for CWS Systems, an affiliate of CWSNC.

CWSNC witness D'Ascendis testified on cross-examination that Public Staff D'Ascendis Cross-Examination Exhibit 2 was his response to a Public Staff data request showing water and wastewater utility general rate cases in which he testified recommending a return on equity range or a specific return on equity. He testified that in the Emporium Water case in Pennsylvania, which was a fully litigated case, he recommended an 11.05% return on equity and the Commission approved a 10.0% return on equity in January 2015, being 105 basis points below his recommendation.

He testified that in the Carolina Water Service, Inc. general rate case in South Carolina with decision on December 22, 2015, he recommended a return on equity range of 10.0% to 10.50% which had a mid-point of 10.25%, and the Commission approved a return on equity of 9.34% which was 91 basis points below his mid-point. He further testified in the Aqua Illinois, Inc. general rate case with decision on March 2, 2018, he recommended a specific return on equity of 10.85%, and the Commission approved a return on equity of 9.60%, which was 125 basis points below his recommendation.

Witness D'Ascendis testified that in the Middlesex Water Company general rate case in New Jersey with decision on March 6, 2018, he recommended a specific return on equity of 10.70% and the Commission approved a return on equity of 9.60%, which was 110 basis points below his recommendation. Witness D'Ascendis testified that in the current Aqua Virginia general rate case, in which he recommended a specific return on equity of 10.60%, Aqua Virginia recently agreed in a settlement to a 9.25% return on equity, which the Hearing Examiner accepted.

Witness D'Ascendis testified that most of the authorized returns on equity on Public Staff D'Ascendis Direct Cross-Examination Exhibit 2 were the result of settlements which the Commissions approved. He testified for the nine cases with approved returns on equity, the average approved return on equity was 142 basis points below his recommendation.

He testified that his most recent litigated and most relevant case was for Carolina Water Service, Inc. in South Carolina where on May 26, 2018, the Commission approved a return on equity of 10.50%, which was within his range of 10.45% to 10.95%.

CWSNC witness D'Ascendis testified that Public Staff Direct Cross-Examination Exhibit 3 is a RRA Water Advisory, S&P Global, dated July 27, 2018, which lists water utility rate case decisions in the years 2014 through 2017, and through June 30, 2018. He testified that in 2018 through June 30, 2018, the average approved return on equity was 9.41%. He testified that if for any reason the South Carolina 10.5% return on equity decision for Carolina Water Service was dropped, the 2018 average would be 9.23% return on equity. He testified that the four 2018 California return on equity decisions have fully forecasted test years, full decoupling, and three year rate plans. He testified that these California decisions dated March 22, 2018, were all fully litigated, and the approved returns on equity were: California America Water – 9.20%, California Water Service – 9.20%, Golden State Water Co. – 8.90%, and San Jose Water Co. – 8.90%. He testified that more relevant than these cases was the recent Duke Energy Carolinas case Docket No. E-7, Sub 1146 with a settlement approved 9.90% return on equity.

CWSNC witness D'Ascendis further testified that in 2014 where the RRA Water Advisory reported 13 water utility rate case decisions with approved returns on equity, none were 10% or above. He testified that in 2015 where the RRA Water Advisory reported 11 water utility decisions with approved returns on equity, only two were 10.0% or above, being Maryland American Water at 10.0% and Kona Water in Hawaii with 10.10% return on equity. He testified that in 2016 where the RRA Water Advisory reported nine water utility rate case decisions with approved returns on equity, only Hawaii Water Service at 10.10% return on equity, had an approved return on equity at 10.0% or above. He testified that in 2017 where the RRA Water Advisory reported nine water utility rate case decisions with approved returns on equity averaging 9.56%, only Utilities, Inc. of Florida with a formula-based return on equity of 10.40% and a 41.92% approved common equity capital structure, had an approved return on equity at 10.0% or above.

CWSNC witness D'Ascendis further testified on cross-examination as shown on Public Staff D'Ascendis Direct Cross-Examination Exhibit 5, that three of the four California water utilities with the litigated decisions dated March 22, 2018, being California American Water with a 9.20% approved return on equity, California Water Service with a 9.20% approved return on equity, and Golden State Water with an approved 8.90% return on equity, being a subsidiary of American States Water, are companies included in his Utility Proxy Group. CWSNC witness D'Ascendis testified that Public Staff D'Ascendis Cross-Examination Exhibit 5 contained the 2018 return on equity decisions for five of the companies in his Utility Proxy Group and the average approved return on equity was 9.30%.

On cross-examination witness D'Ascendis further testified that there was a backlash in the investment community relating to the four California March 22, 2018, return on equity decisions. He testified that MSN Money is a reliable source for the market prices on Public Staff D'Ascendis Cross-Examination Exhibit 4. This cross-examination exhibit listed the market close prices on March 22, 2018, and October 15, 2018, for American Waterworks, American States Water, California Water Service, and San Jose Water. The respective market price percentage increases between March 22, 2018, and October 15, 2018 were: American Waterworks — 9.80%, American States Water — 8.40%, California Water Service — 7.30%, and San Jose Water — 9.50%. He testified that in comparison the S&P 500 from March 22, 2018 to October 15, 2018 had increased 4.10%, being less than one half the market price gains of the four water companies.

2. Evidence of Impact of Changing Economic Conditions on Customers

As noted above, utility rates must be set within the constitutional constraints made clear by the United States Supreme Court in Bluefield and Hope. To fix rates that do not allow a utility to recover its costs, including the cost of equity capital, would be an unconstitutional taking. In assessing the impact of changing economic conditions on customers in setting a return on equity, the Commission must nonetheless provide the public utility with the opportunity, by sound management, to (1) produce a fair profit for its shareholders, in view of current economic conditions, (2) maintain its facilities and service, and (3) compete in the marketplace for capital. State ex rel. Utils. Comm'n v. General Telephone Co. of the Southeast, 281 N.C. 318, 370, 189 S.E.2d 705 (1972). As the Supreme Court held in that case, these factors constitute "the test of a fair rate of return" in Bluefield and Hope. Id.

a. Discussion and Conclusions Regarding Evidence Introduced During the Evidentiary Hearing

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

As to the impact of changing economic conditions on CWSNC's customers, Public Staff witness Hinton testified that he reviewed information on the economic conditions in the areas served by CWSNC, specifically, the 2014, 2015, and 2016 data on total personal income from the Bureau of Economic Analysis (BEA) and the Development Tier Designations published by the North Carolina Department of Commerce for the counties in which CWSNC's systems are located. The BEA data indicates that from 2014 to 2016, total personal income weighted by the number of water customers by county grew at a compound annual growth rate (CAGR) of 3.0%.

Witness Hinton testified that the North Carolina Department of Commerce annually ranks the State's 100 counties based on economic well-being and assigns each a Tier designation. The most distressed counties are rated a "1" and the most prosperous counties are rated a "3". The rankings examine several economic measures such as, household income, poverty rates, unemployment rates, population growth, and per capita property tax base. For 2017, the average Tier ranking that has been weighted by the number of water customers by county is 2.6. He testified that both these economic measures indicate that there has been improvement in the economic conditions for CWSNC's service area relative to the three previous CWSNC rate increases in Docket Nos. W-354, Subs 356, 344, and 336 that were approved in 2017, 2015, and 2014, respectively.

CWSNC witness D'Ascendis testified on economic conditions in North Carolina that he reviewed. He testified that he reviewed: unemployment rates from the United States, North Carolina, and the counties comprising CWSNC's service territory; the growth in Gross Domestic [sic] Product (GDP) in both the United States and North Carolina; median household income in the United States and in North Carolina; and national income and consumption trends.

He testified that the rate of unemployment has fallen substantially in North Carolina and the United States since late 2009 and early 2010, when the rates peaked at 10.00% and 12.00%, respectively. He testified that by February 2018, the unemployment rate had fallen to less than one-half of those peak levels: 4.10% nationally; and 4.60% in North Carolina.

He testified that he was also able to review (seasonally unadjusted) unemployment rates in the counties served by CWSNC. At its peak, which occurred in late 2009 into early 2010, the unemployment rate in those counties reached 12.58% (58 basis points higher than the statewide average); by February 2018 it had fallen to 4.87% (27 basis points higher than the statewide average).

Witness D'Ascendis testified that for real GDP growth, there also has been a relatively strong correlation between North Carolina and the national economy (approximately 69%). Since the financial crisis, the national rate of growth at times (during portions of 2010 and 2012) outpaced North Carolina. He testified that since the third quarter of 2015, however, North Carolina has consistently exceeded the national growth rate.

Witness D'Ascendis testified that as to median household income, the correlation between North Carolina and the United States is relatively strong (approximately 88% from 2005 through 2015). Since 2009 (that is, the years subsequent to the financial crisis), median household income in North Carolina has grown at a faster annual rate than the national median income (3.62% vs. 2.47%).

Witness D'Ascendis noted that in the Commission's Order on Remand in Docket No. E-22, Sub 479, the Commission observed that economic conditions in North Carolina were highly correlated with national conditions, such that they were reflected in the analyses used to determine the cost of common equity. He testified that those relationships still hold: Economic conditions in North Carolina continue to improve from the recession following the 2008/2009 financial crisis, and they continue to be strongly correlated to conditions in the United States generally. He testified unemployment, at both the State and county level, continues to fall and remains highly correlated with national rates of unemployment; real GDP recently has grown faster in North Carolina than the national rate of growth, although the two remain fairly well correlated; and median household income also has grown faster in North Carolina than the rest of the country, and remains strongly correlated with national levels.

b. Evidence Introduced During Public Hearings and Further Conclusions

The Commission's review also includes consideration of the evidence presented during the public hearings by public witnesses, almost all of whom presently are customers of CWSNC. The hearings provided 35 witnesses the opportunity to be heard regarding their respective positions on CWSNC's application to increase rates. The Commission held six evening hearings throughout CWSNC's North Carolina service territory to receive public testimony. The testimony presented at the hearings illustrates the difficult economic conditions facing many North Carolina citizens. The Commission accepts as credible, probative, and entitled to substantial weight the testimony of the public witnesses.

c. Commission's Decision Setting Rate of Return and Approving Rate Increase/ Takes Into Account and Ameliorates the Impact of Current Economic Conditions on Customers

As noted above, the Commission's duty under N.C.G.S. § 62-133 is to set rates as low as reasonably possible without impairing the Company's ability to raise the capital needed to provide reliable water and wastewater service and recover its cost of providing service. The Commission is especially mindful of this duty in light of the evidence in this case concerning the impact of current economic conditions on customers.

Chapter 62 of the North Carolina General Statues in general, and N.C.G.S. § 62-133 in particular, set forth the formula that the Commission must employ in establishing rates. The rate of return on cost of property element of the formula in N.C.G.S. § 62-133(b)(4) is a significant, but not independent one. Each element of the formula must be analyzed to determine the utility's cost of service and revenue requirement. The Commission must make many subjective decisions with respect to each element in the formula in establishing the rates it approves in a general rate case. The Commission must approve accounting and pro forma adjustments to comply with N.C.G.S. § 62-133(b)(3). The Commission must approve depreciation rates pursuant to N.C.G.S. § 62-133(b)(1). The decisions the Commission makes in each of these subjective areas have multiple and varied impacts on the Decisions it makes elsewhere in establishing rates, such as its decision on rate of return on equity.

Economic conditions existing during the test year, at the time of the public hearings, and at the date of this Commission Order affect not only the ability of CWSNC's consumers to pay water and wastewater utility rates, but also the ability of CWSNC to earn the authorized rate of return during the period rates will be in effect. Pursuant to N.C.G.S. § 62-133, rates in North Carolina are set based on a modified historic test period.[1] A component of cost of service as important as return on investment is test year revenues.[2] The higher the level of test year revenues the lower the need for a rate increase, all else remaining equal. Historically, and in this case, test year revenues are established through resort to regression analysis, using historic rates of revenue growth or decline to determine end of test year revenues.

When costs and expenses grow at a faster pace than revenues during the period when rates will be in effect, the utility will experience a decline in its realized rate of return on investment to a level below its authorized rate of return. Differences exist between the authorized return and the earned or realized return. Components of the cost of service must be paid from the rates the utility charges before the equity investors are paid their return on equity. Operating and administrative expenses must be paid, depreciation must be funded, taxes must be paid, and the utility must pay interest on the debt it incurs. To the extent revenues are insufficient to cover the entire cost of service, the shortfall reduces the return to the equity investor, last in line to be paid. When this occurs, the utility's realized or earned return is less than the authorized return.

This phenomenon, caused by incurrence of higher costs prior to the implementation of new rates to recover those higher costs, is commonly referred to as regulatory lag. Just as the Commission confronts constitutional and statutory restrictions in making discrete decrements to rate of return on equity to mitigate the impact of rates on consumers, it also confronts statutory constraints on its ability to adjust test year revenues to mitigate for regulatory lag. However, the WSIC and SSIC legislation § 62-133.12 and Commission Rules R7-39 and R10-26, have mitigated the regulatory lag for CWSNC. The Commission, in its expert experience and judgment and based on evidence in the record, is aware of the effects of regulatory lag in the existing economic environment. However, just as the Commission is constrained to address difficult economic times on customers' ability to pay for service by establishing a lower rate of return on equity in isolation from the many subjective determinations that must be made in a general rate case, it likewise does not address the effect of regulatory lag on the Company by establishing a higher rate of return on equity. Instead, in setting the rate of return, the Commission considers both of these negative impacts in its ultimate decision fixing CWSNC's rates. The Commission keeps all factors affected by current economic conditions in mind in the many subjective decisions it makes in establishing rates. In doing so in the case at hand, the Commission is approving a 9.75% rate of return on equity in the context of weighing and balancing numerous factors and making many subjective decisions. When these decisions are viewed as a whole, including the decision to establish the rate of return on equity at 9.75%, the Commission's overall decision fixing rates in this general rate case results in lower rates to consumers in the existing economic environment.

Consumers pay rates, a charge in dollars per 1,000 gallons for the water they consume and for the metered wastewater that is treated (or a monthly flat rate for certain residential wastewater customers). Investors are compensated by earning a return on the capital they invest in the business. Consumers do not pay a rate of return on equity.

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[1] N.C.G.S. § 62-133(c).

[2] N.C.G.S. § 62-133(b)(3).

All of the scores of adjustments the Commission approves reduce the revenues to be recovered from ratepayers and the return to be paid to equity investors. Some adjustments reduce the authorized rate of return on investment financed by equity investors. The adjustments are made solely to reduce rates and provide rate stability to consumers (and return to equity investors) to recognize the difficulty for consumers to pay in the current economic environment. While the equity investor's cost was calculated by resort to a rate of return on equity of 9.75% instead of within a range of 10.80% to 11.20% as proposed by the Company, this is only one approved adjustment that reduced ratepayer responsibility and equity investor reward. Many other adjustments reduced the dollars the investors actually have the opportunity to receive. Therefore, nearly all of these other adjustments reduce ratepayer responsibility and equity investor returns in compliance with the Commission's responsibility to establish rates as low as reasonably permissible without transgressing constitutional constraints.

For example, to the extent the Commission makes downward adjustments to rate base, or disallows test year expenses, or increases test year revenues, or reduces the equity capital structure component, the Commission reduces the rates consumers pay during the future period when rates will be in effect. Because the utility's investors' compensation for the provision of service to consumers takes the form of return on investment, downward adjustments to rate base or disallowances of test year expenses or increases to test year revenues, or reduction in the equity capital structure component, reduce investors' return on investment irrespective of its determination of rate of return on equity.

The rate base, expenses, and revenue adjustments are instances where the Commission makes decisions in each general rate case, including the present case, that influence the Commission's determination on rate of return on equity and cost of service and the revenue requirement. The Commission always endeavors to comply with the North Carolina Supreme Court's requirements that it "fix rates as low as may be reasonably consistent" with U.S. Constitutional requirements irrespective of economic conditions in which ratepayers find themselves. While compliance with these requirements may have been implicit and, the Commission reasonably assumed, self-evident as shown above, the Commission makes them explicit in this case to comply with the Supreme Court requirements of <u>Cooper I</u>.

Based on the changing economic conditions and their effects on CWSNC's customers, the Commission recognizes the financial difficulty that the increase in CWSNC's rates will create for some of CWSNC's customers, especially low-income customers. As shown by the evidence, relatively small changes in the rate of return on equity have a substantial impact on a utility's base rates. Therefore, the Commission has carefully considered the changing economic conditions and their effects on CWSNC's customers in reaching its decision regarding CWSNC's approved rate of return on equity. The Commission also recognizes that the Company is investing significant sums in system improvements to serve its customers, thus requiring the Company to maintain its creditworthiness in order to compete for large sums of capital on reasonable terms. The Commission must weigh the impact of changing economic conditions on CWSNC's customers against the benefits that those customers derive from the Company's ability to provide safe, adequate, and reliable water and wastewater service. Safe, adequate, and reliable water and wastewater service is essential to the well-being of CWSNC's customers.

The Commission finds that these investments by the Company provide significant benefits to CWSNC's customers. The Commission concludes that the return on equity approved by the Commission in this proceeding appropriately balances the benefits received by CWSNC's customers from CWSNC's provision of safe, adequate, and reliable water and wastewater service with the difficulties that some of CWSNC's customers will experience in paying CWSNC's increased rates.

The Commission in every case seeks to comply with the North Carolina Supreme Court mandate that the Commission establish rates as low as possible within constitutional limits. The adjustments the Commission approves in this case comply with that mandate. Nearly all of them reduced the requested return on equity and benefit consumers' ability to pay their bills in this economic environment.

Summary and Conclusions on the Rate of Return on Equity

The Commission has carefully evaluated the return on equity testimony of CWSNC witness D'Ascendis and Public Staff witness Hinton. The results of each of the models or methods used by these two witnesses to derive the return on equity that each witness recommends is shown below:

	D'Ascendis		Hinton
Utility Proxy Group			
DCF	9.15%		8.70%
Risk Premium	10.73%		9.70%
PRPM		10.90%	
Total Market RPM		10.56%	
CAPM	10.93%		------
Traditional CAPM		10.67%	
ECAPM		11.18%	
Non-Price Regulated Proxy Group	12.43%		------
DCF		13.79%	
Risk Premium		12.32%	
CAPM		11.52%	
Indicated Return on Equity Before Adjustment	10.80%		9.20%
Size Adjustment	0.40%		------
Recommended Return on Equity	10.8-11.2%		9.20%

The range of these results is 8.70% to 12.43%. Underlying the low result of 8.70%, is a range of 8.20% to 9.20%, according to witness Hinton's testimony concerning his application of the DCF. Similarly, underlying the high result of 12.43% is a range of 11.52% (CAPM) to 13.79% (DCF), according to witness D'Ascendis' testimony concerning the cost of equity models applied to his Non-Price Regulated Proxy Group. Such a wide range of estimates by expert witnesses is not atypical in proceedings before the Commission with respect to the return on equity issue. Neither is the seemingly endless debate and habitual differences in judgment among expert witnesses on the virtues of one model or method versus another and how to best determine and measure the required inputs of each model in representing the interest of their intervening party. Nonetheless, the Commission is uniquely situated, qualified, and required to use its impartial judgment to determine the return on equity based on the testimony and evidence in this proceeding in accordance with the legal guidelines discussed above.

In so doing, the Commission finds that the testimony of Company witness D'Ascendis regarding the DCF (9.15%), traditional CAPM (10.67%), and total market RPM (10.56%) analyses of his Utility Proxy Group and the DCF (8.70%) and risk premium (9.70%) analysis testimony of Public Staff witness Hinton are credible, probative, and are entitled to substantial weight as set forth below.

Company witness D'Ascendis, noting that CWSNC is not publicly-traded, first established a group of six relatively comparable risk water companies that are publicly-traded (Utility Proxy Group). He testified that use of relatively comparable risk companies as proxies is consistent with principles of fair rate of return established in the Hope and Bluefield cases, which are recognized as the primary standards for the establishment of a fair return for a regulated public utility. He then applied the DCF, the CAPM, and the risk premium models to the market data of the Utility Proxy Group. Witness D'Ascendis' DCF model indicated a cost of equity of 9.15%, his traditional CAPM model indicated a cost of equity of 10.67%, and his total market RPM model indicated a cost of equity of 10.56%.

Witness Hinton applied a risk premium analysis by performing a regression analysis using the allowed returns on common equity for water utilities from various public utility commissions, as reported in an RRA Water Advisory, with the average Moody's A-rated bond yields for public utility bonds from 2006 through 2018. The results of the regression analysis were combined with recent monthly yields to provide the current cost of equity. According to witness Hinton, the use of allowed returns as the basis for the expected equity return has strengths over other (risk premium) approaches that estimate the expected return on equity and subtract a representative cos of debt. He testified that one strength of his approach is that authorized returns on equity are generally arrived at through lengthy investigations by various parties with opposing views on the rate of return required by investors. Thus, it is reasonable to conclude that the approved returns are good estimates for the cost of equity. Witness Hinton testified that applying the significant statistical relationship of the allowed equity returns and bond yields from the regression analysis and adding current bond cost of 4.22% resulted in a current estimate of the cost of equity of 9.70%.

Witness Hinton also applied the DCF model to a proxy risk group of publicly-traded water utilities. To determine the expected growth rate component in his application of the DCF, witness Hinton testified that he employed both historical and forecasted growth rates of earnings per share (EPS), book value per share (BVPS), and dividends per share (DPS). He concluded that an expected growth rate of 6.10% to 7.10% should be combined with a dividend yield of 2.10% which produced his cost of equity estimate of 8.20% to 9.20% for his comparable risk group based on his DCF analysis, with a specific cost of equity estimate of 8.70%.

The average of witness D'Ascendis' Utility Proxy Group DCF result of 9.15%, traditional CAPM result of 10.67%, total market RPM result of 10.56%, witness Hinton's DCF result of 8.70%, and RPM of 9.70% is 9.75%. The Commission approved return on equity of 9.75% is thus supported by the average of the results of the above-listed cost of equity models which the Commission finds are entitled to substantial weight based on the record in this proceeding.

Witness D'Ascendis used two risk premium methods to estimate the cost of equity to CWSNC. He testified that his first method is the PRPM and the second method is a RPM using a total market approach. In his PRPM, he employed the Eviews© statistical software applied to the historical returns on the common shares of each company in his Utility Proxy Group minus the historical monthly yields on long-term U.S. Treasury securities through March 2018 to arrive at a predicted annual equity risk premium. He then added the forecasted 30-year U.S. Treasury yield to each company's PRPM derived equity risk premium. Using this approach, he calculated a cost of equity estimate of 10.90%. In his total market approach RPM, he added a prospective public utility bond yield to an average of (1) an equity risk premium that is derived from a beta-adjusted total market equity risk premium, and (2) an equity risk premium based on the S&P Utilities Index. His RPM result produced a rate of return estimate of 10.56%. Averaging his PRPM result of 10.90% and his total market approach RPM, he determined that the cost of equity is 10.73% using his risk premium methods.

The Commission gives little weight to witness D'Ascendis' PRPM result of 10.90%. This result is considerably lower than his original PRPM result of 13.43%, highlighting the sensitivity of his model to changes in the way it is applied. Further, the Commission is skeptical that investor expectations are influenced by a method analyzing economic time series with time-varying volatility using the statistical software employed by witness D'Ascendis.

Witness D'Ascendis also used two CAPM methods to estimate the cost of equity to CWSNC. He testified that his first method is the traditional CAPM, and the second method is the empirical CAPM approach. The traditional CAPM method adds a risk-free rate to the product of a company specific beta and a market risk premium for each company in the Utility Proxy Group. This approach yields a cost of equity estimate of 10.67%. Witness D'Ascendis' empirical CAPM approach, which assumes a Security Market Line that is less steep than that described by the CAPM formula, produced a cost of equity estimate of 11.18%.

The Commission gives little weight to witness D'Ascendis' ECAPM result of 11.18%. The Commission concludes that, in this instance, witness D'Ascendis's testimony fails to demonstrate how the ECAPM approach is superior to the CAPM approach which is widely accepted by the investment community.

In addition to estimating the cost of equity for his Utility Proxy Group of publicly-traded water utilities, witness D'Ascendis attempted to estimate the cost of equity for another proxy group consisting of 17 domestic, non-price regulated companies. In order to select a proxy group of domestic, non-price regulated companies similar in risk to the Utility Proxy Group, he testified that he relied on the beta coefficients and related statistics derived from Value Line regression analyses of weekly market prices over the last five years. After selecting the 17 unregulated companies, he applied the DCF, RPM, and CAPM in the identical manner used for his Utility

Proxy Group, with certain limited expectations. The results of the DCF, RPM, and CAPM applie to the non-price regulated proxy group are 13.79%, 12.32%, and 11.52%, respectively. Th Commission concludes that these results are unreasonably high. Each of these results are highe than witness D'Ascendis' estimates of the cost of equity for his own Utility Proxy Group an deserve no weight, particularly with respect to the DCF. The Commission further concludes th given the difference in these results, the risk of the two groups is not equal and the Utility Prox Group is more reliable as a proxy for the investment risk of common equity in CWSNC.

After determining that the indicated cost of equity from the DCF, CAPM, and risk premiun methods applied to both of his proxy groups equals 10.80%, witness D'Ascendis then adjusted th indicated cost of equity upward by 0.40% to reflect CWSNC's smaller size compared to companie in his Utility Proxy Group. He testified that the size of the company is a significant element o business risk for which investors expect to be compensated through higher returns. Witnes D'Ascendis calculated his size adjustment as described in his prefiled direct testimony and state that even though a 4.61% upward size adjustment is indicated, he applies a 0.40% size premium t CWSNC's indicated common equity cost rate. Witness Hinton testified that he does not believe it appropriate to add a risk premium to the cost of equity of CWSNC due to size for several reasons First, from a regulatory policy perspective, witness Hinton stated that ratepayers should not b required to pay higher rates because they are located in the franchise area of a utility which i arbitrarily considered to be small. Further, if such adjustments were routinely allowed, an incentiv would exist for large utilities to form subsidiaries or split-up subsidiaries to obtain higher return In addition, he noted that CWSNC operates in a franchise environment that insulates the Compan from competition with procedures in place for rate adjustments for circumstances that impact it earnings. Finally, while witness Hinton stated that while there are studies that address how th small size of a company relates to higher returns, he is aware of only one study that focuses on th size of regulated utilities and risk and that study concluded that utility stocks do not exhibit significant size premium. In rebuttal, witness D'Ascendis maintained that a small size adjustmen was necessary based on the results of studies he cited and discussed and contended that the stud concerning size premiums for utilities discussed by witness Hinton was flawed.

Based upon the foregoing and the entire record in this proceeding, the Commission conclude that a size adjustment of 0.40% is not warranted and should not be approved. The Commissio determines there is insufficient evidence to authorize an adjustment to the approved rate of retu on equity in this case. The record simply does not indicate the extent to which CWSNC's size alon justifies added risk. While a small water/wastewater utility might face greater risk than a publicl traded peer group, because for example the service area was confined to a hurricane prone coast geographic area, evidence of such factual predicates is absent from the record. The Commissio notes that the witnesses also disagreed with respect to whether the studies discussed in the testimon concerning size and risk are reliable or even applicable to regulated utilities. The Commissio concludes that the testimony regarding these studies is not convincing and does not support a siz adjustment. In addition, while witness D'Ascendis calculates and testifies that a 4.61% upwar size adjustment is indicated, he applies a size premium of 0.40% to CWSNC's indicated cost o equity. The Commission thus concludes that the 0.40% adjustment is not supported by hi testimony and is rather arbitrary.

Having determined that the appropriate rate of return on equity based upon the evidence i this proceeding is 9.75%, the Commission notes that there is considerable testimony concernin the authorized returns on equity for water utilities in other jurisdictions. While the Commission has relied upon the record in this proceeding and is certainly aware that returns in other jurisdictions can be influenced by many factors, such as different capital market conditions during different periods of time, settlements versus full litigation, the Commission concludes that the rate of return on equity trends and decisions by other regulatory authorities deserve some weight as (1) they provide a check or additional perspective on the case-specific circumstances, and (2) the Company must compete with other regulated utilities in the capital markets, meaning that a rate of return significantly lower than that approved for other utilities of comparable risk would undermine the Company's ability to raise necessary capital, while a rate of return significantly higher than other utilities of comparable risk would result in customers paying more than necessary. Public Staff D'Ascendis Cross-Examination Exhibit 3, the RRA Water Advisory publication showing approved return on equity decisions for water utilities across the country from January 2014 through June 30, 2018, is helpful in illustrating that the average rate of return on equity for water utilities is 9.59% in 2014, 9.76% in 2015, 9.71% in 2016, 9.56% in 2017, and in the only seven cases reported on for the first six months of 2018 the average is 9.41% with a range of 8.9% to 10.5%. This authorized return data is generally supportive of the Commission approved return on equity of 9.75% based upon the evidence in this proceeding. To the extent it is not, the record evidence justifies any such difference.

In its post-hearing brief, the AGO notes that the 10.80% to 11.20% range for rate of return on equity requested by CWSNC is substantially higher than the 9.6% return on equity stipulated to in the Sub 356 Proceeding. In this case, the AGO, in its role as consumer advocate, argues that the DCF model is relied upon by investors using widely available current market data and the DCF results produced by expert witnesses for CWSNC and the Public Staff show that a 9.2% return on equity is more than sufficient to attract the investment dollars needed for adequate service. However, unlike the AGO, the Commission cannot ignore the other evidence in this proceeding. When other such evidence is considered and weighed by the Commission as discussed hereinabove, the Commission finds that the reasonable and appropriate return on equity is 9.75%.

The Commission notes further that its approval of a rate of return on equity at the level of 9.75% or for that matter at any level, is not a guarantee to the Company that it will earn a rate of return on equity at that level. Rather, as North Carolina law requires, setting the rate of return on equity at this level merely affords CWSNC the opportunity to achieve such a return. The Commission finds, based upon all the evidence presented, that the rate of return on equity provided for herein will indeed afford the Company the opportunity to earn a reasonable and sufficient return for its shareholders while at the same time producing rates that are just and reasonable to its customers.

Capital Structure

CWSNC witness D'Ascendis recommended the use of the actual capital structure of Utilities Inc., on June 30, 2018 consisting of 49.09% long-term debt and 50.91% common equity.

In his supplemental testimony, Public Staff witness Hinton also recommended a 49.09% long-term debt and 50.91% common equity capital structure based upon updated information provided by CWSNC concerning the capital structure at June 30, 2018. The Partial Stipulation also supports a 49.09% long-term debt, 50.91% common equity capital structure. No other part presented evidence as to a different capital structure.

Accordingly, the Commission finds that the recommended capital structure of 50.91% common equity and 49.09% long-term debt is just and reasonable to all parties in light of all th evidence presented.

Cost of Debt

In its Application, the Company proposed a cost rate for long-term debt of 6.00%. I supplemental testimony, witness Hinton revised his recommended cost of debt to 5.68%. In addition, the Stipulation includes a cost of debt rate of 5.68%. No intervenor offered any evidenc supporting a debt cost rate below 5.68%.

Therefore, the Commission finds that the use of a debt cost rate of 5.68% is just an reasonable to all parties based upon all the evidence presented in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 61

The following schedules summarize the gross revenue and rate of return that the Compan should have a reasonable opportunity to achieve based on the increases in revenues approved i this Order for each rate entity. These schedules, illustrating the Company's gross revenu requirements, incorporate the adjustments found appropriate by the Commission in this Order.

SCHEDULE I

Carolina Water Service, Inc. of North Carolina
Docket No. W-354, Sub 360
Net Operating Income for a Return
For the Twelve Months Ended December 31, 2017
Combined Operations

	Present Rates	Increase Approved	After Approved Increase
Operating Revenues:			
Service revenues	$32,429,699	$1,434,93	$33,864,637
Miscellaneous revenues	360,163	3,314	363,477
Uncollectibles	(214,395)	(14,164	(228,559)
Total operating revenues	32,575,467	1,424,088	33,999,555
Operating Revenue Deductions:			
Salaries and wages – Maintenance	4,765,636	0	4,765,636
Purchased power	1,932,358	0	1,932,358
Purchased water and sewer	1,972,527	0	1,972,527
Maintenance and repair	2,749,845	0	2,749,845
Maintenance testing	544,360	0	544,360
Meter reading	225,867	0	225,867
Chemicals	632,415	0	632,415
Transportation	447,271	0	447,271
Operating expense charged to plant	(673,065)	0	(673,065)
Outside services – other	455,369	0	455,369
Salaries and wages – General	2,064,359	0	2,064,35
Office supplies & other office expense	560,363	0	560,363
Regulatory commission expense	165,908	0	165,908
Pension and other benefits	1,340,118	0	1,340,118
Rent	227,339	0	227,339
Insurance	429,335	0	429,335
Office utilities	742,300	0	742,300
Miscellaneous	23,469	0	23,469
Depreciation expense	5,617,382	0	5,617,382
Amortization of CIAC	(1,488,982)	0	(1,488,98
Amortization of PAA	(54,365)	0	(54,365)
Amortization of ITC	(519)	0	(519)
Franchise and other taxes	(49,702)	0	(49,702)
Property taxes	233,575	0	233,575
Payroll taxes	529,195	0	529,195
Regulatory fee	45,606	1,994	47,600
Deferred income tax	(83,555)	0	(83,555)
State income tax	177,812	42,663	220,475
Federal income tax	1,207,341	289,680	1,497,021
Total operating revenue deductions	24,739,562	334,337	25,073,899
Net operating income for a return	$7,835,905	$1,089,751	$8,925,656

SCHEDULE II

Carolina Water Service, Inc. of North Carolina
Docket No. W-354, Sub 360
Original Cost Rate Base
For the Twelve Months Ended December 31, 2017
Combined Operations

Item	Amount
Plant in service	$213,005,526
Accumulated depreciation	(52,955,117)
Net plant in service	160,050,409
Cash working capital	2,079,155
Contributions in aid of construction	(42,183,408)
Advance in aid of construction	(32,940)
Accumulated deferred income taxes	(3,972,592)
Customer deposits	(342,640)
Gain on sale and flow back taxes	(289,628)
Plant acquisition adjustment	(1,052,168)
Excess book value	(456)
Cost-free capital	(261,499)
Average tax accruals	(125,909)
Regulatory liability for excess deferred taxes	(251,770)
Deferred charges	1,522,955
Pro forma plant	0
Original cost rate base	$115,139,509
Rates of return:	
Present	6.81%
Approved	7.75%

SCHEDULE III

Carolina Water Service, Inc. of North Carolina
Docket No. W-354, Sub 360
Statement of Capitalization and Related Costs
For the Twelve Months Ended December 31, 2017
Combined Operations

	Ratio %	Original Cost Rate Base	Embedded Cost %	Net Operating Income
		PRESENT RATES		
Long-Term Debt	49.09	$56,521,985	5.68	$3,210,449
Common Equity	50.91	58,617,524	7.89	4,625,456
Total	100.00	$115,139,509		$7,835,905
		APPROVED RATES		
Long-Term Debt		$56,521,985	5.68	$3,210,449
Common Equity	50.91	58,617,524	9.75	5,715,207
Total	100.00	$115,139,509		$8,925,656

WATER AND SEWER – RATE INCREASE

SCHEDULE I-A

Carolina Water Service, Inc. of North Carolina
Docket No. W-354, Sub 360
Net Operating Income for a Return
For the Twelve Months Ended December 31, 2017
CWSNC Water Operations

	Present Rates	Increase Approved	After Approved Increase
Operating Revenues:			
Service revenues	$16,931,032	$490,858	$17,421,890
Miscellaneous revenues	189,225	1,325	190,550
Uncollectibles	(98,200)	(2,847)	(101,047)
Total operating revenues	17,022,057	489,336	17,511,393
Operating Revenue Deductions:			
Salaries and wages – Maintenance	2,587,126	0	2,587,126
Purchased power	957,880	0	957,880
Purchased water and sewer	1,285,290	0	1,285,290
Maintenance and repair	828,186	0	828,186
Maintenance testing	208,965	0	208,965
Meter reading	197,562	0	197,562
Chemicals	224,644	0	224,644
Transportation	238,827	0	238,827
Operating expense charged to plant	(370,288)	0	(370,288)
Outside services – other	254,847	0	254,847
Salaries and wages – General	1,120,684	0	1,120,684
Office supplies & other office expense	306,345	0	306,345
Regulatory commission expense	90,071	0	90,071
Pension and other benefits	713,025	0	713,025
Rent	123,289	0	123,289
Insurance	233,072	0	233,072
Office utilities	413,686	0	413,686
Miscellaneous	15,929	0	15,929
Depreciation expense	2,877,977	0	2,877,977
Amortization of CIAC	(712,658)	0	(712,658)
Amortization of PAA	(105,674)	0	(105,674)
Amortization of ITC	(287)	0	(287)
Franchise and other taxes	(21,943)	0	(21,943)
Property taxes	134,370	0	134,370
Payroll taxes	287,285	0	287,285
Regulatory fee	23,831	685	24,516
Deferred income tax	(35,576)	0	(35,576)
State income tax	102,338	14,660	116,998
Federal income tax	694,876	99,538	794,414
Total operating revenue deductions	12,673,680	114,883	12,788,563
Net operating income for a return	$4,348,377	$374,453	$4,722,830

SCHEDULE II-A

Carolina Water Service, Inc. of North Carolina
Docket No. W-354, Sub 360
Original Cost Rate Base
For the Twelve Months Ended December 31, 2017
CWSNC Water Operations

Item	Amount
Plant in service	$109,412,912
Accumulated depreciation	(27,471,271)
Net plant in service	81,941,641
Cash working capital	1,017,981
Contributions in aid of construction	(18,419,357)
Advance in aid of construction	(23,760)
Accumulated deferred income taxes	(1,699,612)
Customer deposits	(191,669)
Gain on sale and flow back taxes	(196,947)
Plant acquisition adjustment	(2,282,334)
Excess book value	(456)
Cost-free capital	(121,791)
Average tax accruals	(71,951)
Regulatory liability for excess deferred taxes	(144,323)
Deferred charges	1,116,295
Pro forma plant	0
Original cost rate base	$60,923,717
Rates of return:	
Present	7.14%
Approved	7.75%

SCHEDULE III-A

Carolina Water Service, Inc. of North Carolina
Docket No. W-354, Sub 360
Statement of Capitalization and Related Costs
For the Twelve Months Ended December 31, 2017
CWSNC Water Operations

	Ratio %	Original Cost Rate Base	Embedded Cost %	Net Operating Income
		PRESENT RATES		
Long-Term Debt	49.09	$29,907,453	5.68	$1,698,743
Common Equity	50.91	31,016,264	8.54	2,649,634
Total	100.00	$60,923,717		$4,348,377
		APPROVED RATES		
Long-Term Debt	49.09	$29,907,453	5.68	$1,698,743
Common Equity	50.91	31,016,264	9.75	3,024,087
Total	100.00	$60,923,717		$4,722,830

WATER AND SEWER – RATE INCREASE

SCHEDULE I-B

Carolina Water Service, Inc. of North Carolina
Docket No. W-354, Sub 360
Net Operating Income for a Return
For the Twelve Months Ended December 31, 2017
CWSNC Sewer Operations

	Present Rates	Increase Approved	After Approved Increase
Operating Revenues:			
Service revenues	$12,685,778	291,163	$12,976,941
Miscellaneous revenues	110,138	815	110,953
Uncollectibles	(74,846)	(1,718)	(76,564)
Total operating revenues	12,721,070	290,260	13,011,330
Operating Revenue Deductions:			
Salaries and wages – Maintenance	1,540,179	0	1,540,179
Purchased power	748,066	0	748,066
Purchased water and sewer	687,237	0	687,237
Maintenance and repair	1,606,630	0	1,606,630
Maintenance testing	302,561	0	302,561
Meter reading	0	0	0
Chemicals	347,986	0	347,986
Transportation	142,640	0	142,640
Operating expense charged to plant	(219,769)	0	(219,769)
Outside services – other	154,330	0	154,330
Salaries and wages – General	667,170	0	667,170
Office supplies & other office expense	183,350	0	183,350
Regulatory commission expense	53,622	0	53,622
Pension and other benefits	424,543	0	424,543
Rent	73,562	0	73,562
Insurance	138,751	0	138,751
Office utilities	246,763	0	246,763
Miscellaneous	9,931	0	9,931
Depreciation expense	2,271,822	0	2,271,822
Amortization of CIAC	(574,609)	0	(574,609)
Amortization of PAA	(22,136)	0	(22,136)
Amortization of ITC	(232)	0	(232)
Franchise and other taxes	(17,738)	0	(17,738)
Property taxes	79,520	0	79,520
Payroll taxes	171,028	0	171,028
Regulatory fee	17,809	407	18,216
Deferred income tax	(39,438)	0	(39,438)
State income tax	74,266	8,695	82,961
Federal income tax	504,263	59,043	563,306
Total operating revenue deductions	9,572,107	68,145	9,640,252
Net operating income for a return	$3,148,963	$222,11	$3,371,078

SCHEDULE II-B

Carolina Water Service, Inc. of North Carolina
Docket No. W-354, Sub 360
Original Cost Rate Base
For the Twelve Months Ended December 31, 2017
CWSNC Sewer Operations

Item	Amount
Plant in service	$84,335,000
Accumulated depreciation	(21,353,928)
Net plant in service	62,981,072
Cash working capital	802,539
Contributions in aid of construction	(18,442,146)
Advance in aid of construction	(9,180)
Accumulated deferred income taxes	(1,862,686)
Customer deposits	(114,105)
Gain on sale and flow back taxes	(92,681)
Plant acquisition adjustment	271,225
Excess book value	0
Cost-free capital	(139,708)
Average tax accruals	(43,322)
Regulatory liability for excess deferred taxes	(85,491)
Deferred charges	220,825
Pro forma plant	0
Original cost rate base	$43,486,342
Rates of return:	
Present	7.24%
Approved	7.75%

SCHEDULE III-B

Carolina Water Service, Inc. of North Carolina
Docket No. W-354, Sub 360
Statement of Capitalization and Related Costs
For the Twelve Months Ended December 31, 2017
CWSNC Sewer Operations

	Ratio %	Original Cost Rate Base	Embedded Cost %	Net Operating Income
		PRESENT RATES		
Long-Term Debt	49.09	$21,347,445	5.68	$1,212,535
Common Equity	50.91	22,138,897	8.75	1,936,428
Total	100.00	$43,486,342		$3,148,963
		APPROVED RATES		
Long-Term Debt	49.09	$21,347,445	5.68	$1,212,535
Common Equity	50.91	22,138,897	9.75	2,158,543
Total	100.00	$43,486,342		$3,371,078

SCHEDULE I-C

Carolina Water Service, Inc. of North Carolina
Docket No. W-354, Sub 360
Net Operating Income for a Return
For the Twelve Months Ended December 31, 2017
BF/FH/TC Water Operations

	Present Rates	Decrease Approved	After Approved Decrease
Operating Revenues:			
Service revenues	$1,043,134	$273,574	$1,316,708
Miscellaneous revenues	46,306	492	46,798
Uncollectibles	(15,334)	(4,022)	(19,356)
Total operating revenues	1,074,106	270,044	1,344,150
Operating Revenue Deductions:			
Salaries and wages – Maintenance	312,749	0	312,749
Purchased power	70,816	0	70,816
Purchased water and sewer	0	0	0
Maintenance and repair	62,128	0	62,128
Maintenance testing	9,286	0	9,286
Meter reading	28,305	0	28,305
Chemicals	32,714	0	32,714
Transportation	32,241	0	32,241
Operating expense charged to plant	(40,679)	0	(40,679)
Outside services – other	22,632	0	22,632
Salaries and wages – General	135,473	0	135,473
Office supplies & other office expense	34,624	0	34,624
Regulatory commission expense	10,884	0	10,884
Pension and other benefits	99,239	0	99,239
Rent	14,938	0	14,938
Insurance	28,178	0	28,178
Office utilities	40,103	0	40,103
Miscellaneous	(1,172)	0	(1,172)
Depreciation expense	127,603	0	127,603
Amortization of CIAC	(55,682)	0	(55,682)
Amortization of PAA	14,897	0	14,897
Amortization of ITC	0	0	0
Franchise and other taxes	(3,653)	0	(3,653)
Property taxes	9,645	0	9,645
Payroll taxes	34,729	0	34,729
Regulatory fee	1,504	378	1,882
Deferred income tax	1,178	0	1,178
State income tax	(1,317)	8,090	6,773
Federal income tax	(8,945)	54,931	45,986
Total operating revenue deductions	1,012,417	63,399	1,075,816
Net operating income for a return	$61,689	$206,645	$268,334

SCHEDULE II-C

Carolina Water Service, Inc. of North Carolina
Docket No. W-354, Sub 360
Original Cost Rate Base
For the Twelve Months Ended December 31, 2017
BF/FH/TC Water Operations

Item	Amount
Plant in service	$5,924,076
Accumulated depreciation	(1,625,325)
Net plant in service	4,298,751
Cash working capital	111,557
Contributions in aid of construction	(1,095,675)
Advance in aid of construction	0
Accumulated deferred income taxes	48,827
Customer deposits	(18,063)
Gain on sale and flow back taxes	0
Plant acquisition adjustment	22,332
Excess book value	0
Cost-free capital	0
Average tax accruals	(5,124)
Regulatory liability for excess deferred taxes	(10,756)
Deferred charges	109,634
Pro forma plant	0
Original cost rate base	$3,461,483
Rates of return:	
Present	1.78%
Approved	7.75%

SCHEDULE III-C

Carolina Water Service, Inc. of North Carolina
Docket No. W-354, Sub 360
Statement of Capitalization and Related Costs
For the Twelve Months Ended December 31, 2017
BF/FH/TC Water Operations

	Ratio %	Original Cost Rate Base	Embedded Cost %	Net Operating Income
		PRESENT RATES		
Long-Term Debt	49.09	$1,699,242	5.68	$96,517
Common Equity	50.91	1,762,241	(1.98)	(34,828)
Total	100.00	$3,461,483		$61,689
		APPROVED RATES		
Long-Term Debt	49.09	$1,699,242	5.68	$96,517
Common Equity	50.91	1,762,241	9.75	171,817
Total	100.00	$3,461,483		$268,334

WATER AND SEWER – RATE INCREASE

SCHEDULE I-D

<u>Carolina Water Service, Inc. of North Carolina</u>
Docket No. W-354, Sub 360 Net
Operating Income for a Return
For the Twelve Months Ended December 31, 2017
BF/FH Sewer Operations

	Present Rates	Increase Approved	After Approved Increase
Operating Revenues:			
Service revenues	$1,769,755	$379,343	$2,149,098
Miscellaneous revenues	14,494	682	15,176
Uncollectibles	(26,015)	(5,577)	(31,592)
Total operating revenues	1,758,234	374,448	2,132,682
Operating Revenue Deductions:			
Salaries and wages – Maintenance	325,582	0	325,582
Purchased power	155,596	0	155,596
Purchased water and sewer	0	0	0
Maintenance and repair	252,901	0	252,901
Maintenance testing	23,548	0	23,548
Meter reading	0	0	0
Chemicals	27,071	0	27,071
Transportation	33,563	0	33,563
Operating expense charged to plant	(42,329)	0	(42,329)
Outside services – other	23,560	0	23,560
Salaries and wages – General	141,032	0	141,032
Office supplies & other office expense	36,044	0	36,044
Regulatory commission expense	11,331	0	11,331
Pension and other benefits	103,311	0	103,311
Rent	15,550	0	15,550
Insurance	29,334	0	29,334
Office utilities	41,748	0	41,748
Miscellaneous	(1,220)	0	(1,220)
Depreciation expense	339,980	0	339,980
Amortization of CIAC	(146,033)	0	(146,033)
Amortization of PAA	58,548	0	58,548
Amortization of ITC	0	0	0
Franchise and other taxes	(6,368)	0	(6,368)
Property taxes	10,040	0	10,040
Payroll taxes	36,153	0	36,153
Regulatory fee	2,462	524	2,986
Deferred income tax	(9,719)	0	(9,719)
State income tax	2,525	11,218	13,743
Federal income tax	17,147	76,168	93,315
Total operating revenue deductions	1,481,357	87,910	1,569,267
Net operating income for a return	$276,877	$286,538	$563,415

SCHEDULE II-D

Carolina Water Service, Inc. of North Carolina
Docket No. W-354, Sub 360
Original Cost Rate Base
For the Twelve Months Ended December 31, 2017
BF/FH Sewer Operations

Item	Amount
Plant in service	$13,333,538
Accumulated depreciation	(2,504,593)
Net plant in service	10,828,945
Cash working capital	147,078
Contributions in aid of construction	(4,226,230)
Advance in aid of construction	0
Accumulated deferred income taxes	(459,121)
Customer deposits	(18,803)
Gain on sale and flow back taxes	0
Plant acquisition adjustment	936,609
Excess book value	0
Cost-free capital	0
Average tax accruals	(5,512)
Regulatory liability for excess deferred taxes	(11,200)
Deferred charges	76,202
Pro forma plant	0
Original cost rate base	$7,267,968
Rates of return:	
Present	3.81%
Approved	7.75%

SCHEDULE III-D

Carolina Water Service, Inc. of North Carolina
Docket No. W-354, Sub 360
Statement of Capitalization and Related Costs
For the Twelve Months Ended December 31, 2017
BF/FH Sewer Operations

	Ratio %	Original Cost Rate Base	Embedded Cost %	Net Operating Income
		PRESENT RATES		
Long-Term Debt	49.09	$3,567,845	5.68	$202,654
Common Equity	50.91	3,700,123	2.01	74,223
Total	100.00	$7,267,968		$276,877
		APPROVED RATES		
Long-Term Debt	49.09	$3,567,845	5.68	$202,654
Common Equity	50.91	3,700,123	9.75	360,761
Total	100.00	$7,267,968		$563,415

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 62 AND 63

The evidence supporting these findings of fact is found in the Application and the accompanying NCUC Form W-1, and in the testimony and exhibits of CWSNC witness DeStefano and of Public Staff witness Casselberry.

CWSNC witness DeStefano testified that the Company's experience is consistent with that of the water utility industry in general, as CWSNC continues to experience a decline in consumption. He testified that this decline in consumption, combined with regulatory lag resulting from use of traditional historical test year ratemaking principles, impairs CWSNC's opportunity to achieve its Commission-authorized rate of return on equity. Witness DeStefano further testified that, in its Application, CWSNC requested authority to implement a "consumption band" water and wastewater rate adjustment mechanism within each of the Company's four rate divisions for non-purchased water and wastewater commodity customers. He explained that the proposed CAM is a mechanism that balances the risk and impact on ratepayers and shareholders of levels of water and wastewater consumption that are either significantly higher or significantly lower than those levels of consumption that were used to set rates. He further explained that should actual consumption be greater than 1% less than what was used in designing rates within the rate case, then a surcharge would be placed on the customers' bills for a period not to exceed 12 months to make the Company whole. Conversely, he stated that if actual consumption is greater than 1% higher than the consumption used to design rates within the rate case, then a negative surcharge would be applied to the customers' bills for a period not to exceed 12 months. Witness DeStefano requested that the Commission approve the water and wastewater CAM based on the Commission's inherent regulatory authority to do so in a general rate case, recognizing that a rulemaking proceeding would be required to develop and adopt the terms of such a mechanism, and based on a finding that the proposed CAM serves the public interest. Absent approval of a water and wastewater CAM, witness DeStefano contended the Company and its customers would continue to needlessly experience the vicissitudes of significant variances in consumption over a significant period.

Witness DeStefano further testified that the CAM is a mechanism that balances the risk and impact on ratepayers and shareholders of levels of water and wastewater consumption that are either significantly higher or significantly lower than those levels of consumption that were used to set the Company's base rates. In addition, he testified that, generally, an increased conservation ethic among customers and the proliferation of efficient water fixtures that conform to increasingly strict manufacturing standards, contribute to a persistent and gradual decline in consumption per customer. He testified that these factors are out of the control of the Company and will continue to drive consumption decline for the foreseeable future as older, less-efficient fixtures are replaced with more efficient fixtures and new homes are built at current efficiency standards. Witness DeStefano also testified that the water and sewer industry operates with a cost structure that is mostly fixed; however, the utility's revenues are generated in large portion by the variable consumption component of rates. Additionally, he testified that the Company's revenue requirement is set based on an expected "normal" consumption level, which does not account for the considerable seasonal weather variations which can occur. He contended that it is highly unlikely that any particular year will result in exactly the level of consumption utilized in the setting of rates.

Witness DeStefano then testified that the proposed CAM helps to alleviate the negative impact to the Company of declining consumption and significant seasonal weather variation and to protect customers from overcollection in an increasing consumption scenario. In addition, he testified that such a mechanism would eliminate the throughput incentive, which currently presents the Company with conflicting motivations inasmuch as the Company is currently incentivized to sell more water to improve its financial performance, yet this would increase costs to customers and fail to promote conservation of a valuable resource. The CAM mechanism, he concluded, would remove this conflict and allow the Company to promote wise water use without concern for the impacts on its financial results, in short, better aligning the interests of customers and the Company.

Public Staff witness Casselberry testified that the Public Staff's position is that any new rate mechanism, such as a CAM, should be authorized by the North Carolina General Assembly (General Assembly) before being considered by the Commission for rulemaking. Witness Casselberry further testified that, assuming the Commission does have the authority or is granted the authority to approve a CAM, the Public Staff still opposes a CAM, based on the Public Staff's concerns with the 1% threshold proposed by CWSNC. More specifically, witness Casselberry testified that the 1% threshold could be triggered by 50 seconds longer in the shower or one additional flush of the commode per day. She argued that an alternate rate design should not be triggered by such an insignificant deviation in normal customer usage. When asked how customer growth may influence consumption, witness Casselberry testified that consumption and customer growth would have to be evaluated annually, that it is possible that customer growth may decrease and consumption increase or some other combination, and that any mechanism that benefits the Company by ensuring it collects its full revenue requirement should also benefit customers by crediting customers with revenue resulting from increased usage due to customer growth.

Witness Casselberry also testified in response to witness DeStefano's testimony that the overall trend of per-capita usage continues to decline, referring to Table 1 in his testimony, which highlighted the Company's average usage for a non-seasonal window. Witness Casselberry testified that the Company's average did not take into account the newly consolidated seasonal customers, such as those who live in Sapphire Valley, Connestee Falls, and Fairfield Mountain who do not use water in the winter months and use 50% less than the average residential customer. She further testified that the reduction in consumption could also be due to higher rates after consolidation of CWSNC's service areas in the last rate case. Witness Casselberry also testified that water efficient appliances have been on the market for close to 10 years and that many customers have already installed these appliances. She testified that CWSNC's experienced reduction in consumption is more likely due to the age of the Company's meters. Witness Casselberry testified that CWSNC has no meter replacement program, that many of CWSNC's meters are more than 30 years old, and that it is common knowledge that as meters age, they slow down. Witness Casselberry suggested that more historical data was necessary to determine what the consumption trend will be now that CWSNC's service areas have been consolidated.

In its post-hearing brief, the AGO argued that CWSNC's proposed CAM is not authorized by statute and that CWSNC has not justified the approval of a non-statutory rider. The AGO further argued that the new rider harms consumers by increasing the frequency of changes to rates outside of a general rate proceeding, by shifting business risks from investors to ratepayers, and by discouraging water conservation efforts. Like the Public Staff, the AGO noted that legislation was introduced in the regular session of the General Assembly in 2017 that, if adopted, would have authorized the creation of a rate adjustment mechanism for water and wastewater utilities based on changes in consumption, if the Commission should find such a mechanism to be in the public interest. However, the legislation was not enacted. The AGO concluded that, in light of the General Assembly's decision not to authorize this rate adjustment mechanism, the Commission should reject CWSNC's request that it approve such a mechanism as an exercise of discretion.

The AGO also argued that CWSNC had not justified the approval of a non-statutory rider, citing cases where the State appellate courts have approved non-statutory riders in limited circumstances involving highly variable and unpredictable expense or volume levels, of significant magnitude, that are beyond the control of the utility. The AGO concluded that the evidence adduced in this case does not compel approval of the new mechanism, based upon the following. First, the AGO cites the testimony of witness D'Ascendis, who testified that there is not any statistically significant change in investor-required return before or after the implementation of such a "decoupling" mechanism (i.e. a rate adjustment mechanism for changes in consumption); and that there are many things affecting publicly-traded companies, and this one factor is not measureable. Second, the AGO argued that the CAM is not justified by extreme variability or trends and the witnesses for CWSNC and the Public Staff did not agree about the significance of evidence regarding changes in consumption and whether the evidence indicates a problem of a magnitude requiring a new rate adjustment mechanism. Third, the AGO argued that the proposed mechanism is designed to make rate adjustments for changes in per customer consumption without consideration of other factors that tend to offset the impact, such as growth in the number of customers that CWSNC serves. Thus, the AGO argues that any mechanism that boosts rates relating to changes in per-customer consumption should also credit customers for increased growth in customer count. Fourth, the AGO argued that the CAM proposal would trigger a rate adjustment based on a relatively small departure from normal habits, such as by shortening a daily shower by less than a minute. Fifth, the AGO argued that, contrary to CWSNC's contention that the mechanism would balance the interests of the utility and its consumers, the new rider is harmful to consumers because it increases the frequency of changes to rates outside of general rate proceedings. The AGO contrasted the adjustments required in a general rate case, where CWSNC would be required to "net" all costs and benefits of operation at the time rates are set to take into consideration offsetting cost decreases as well as other offsetting factors, with the proposed CAM. The AGO argued that the CAM would allow CWSNC to shift normal business risk associated with a single factor from its investors to ratepayers. Finally, the AGO argued that consumers will tend to be discouraged from investing in water conservation measures if their efforts are met with an offsetting rate increase. In sum, the AGO argued that the proposed CAM should be rejected because it is not authorized by statute, is not justified, and is harmful to consumers.

The Commission has carefully evaluated the foregoing evidence presented in this proceeding concerning CWSNC's request to implement a CAM and the entire record in this proceeding. The Commission finds persuasive the evidence presented by the Public Staff, and agrees with the arguments of the Public Staff and the AGO that the proposed CAM is not appropriately structured. More specifically, the Commission agrees with Public Staff witness Casselberry that the 1% threshold is too narrow, and would inappropriately trigger a rate change based on relatively small departures from normal consumption habits, such as shortening a daily shower by less than one minute or one additional flush of the commode. The Commission, therefore, finds that CWSNC has not demonstrated that a consumption adjustment mechanism is reasonable or justified. In making this finding, the Commission gives substantial weight to the arguments of the Public Staff and the AGO that the mechanism was designed to make rate adjustments for changes in per-customer consumption without consideration of other factors that tend to offset the impact, such as growth in the number of customers that the Company serves and periods of warm weather. The Commission concludes that these factors are relevant in determining whether circumstances establish that a decline in consumption denies the Company a reasonable opportunity to earn its authorized rate of return and whether the CAM is reasonable or justified based on the evidence in this case. The Commission finds the testimony of CWSNC witness DeStefano generally unpersuasive. Specifically, witness DeStefano's testimony is unpersuasive because, as witness Casselberry testified, the proposed CAM does not account for customer growth, potentially allowing CWSNC to earn its reasonable revenue requirement in a year when declining consumption is offset by customer growth.

Based upon the foregoing and the entire record herein, the Commission finds that CWSNC has failed to demonstrate that its proposed CAM is reasonable or justified for the purposes of this case. The Commission, therefore, concludes that CWSNC's request for approval to implement its proposed CAM should be denied.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 64 – 68

The evidence supporting these findings of fact is found in the Application and the accompanying NCUC Form W-1, and in the testimony and exhibits of Public Staff witness Casselberry and CWSNC witness DeStefano.

The water rates proposed by CWSNC in its Application were based on a fixed-to-variable ratio of 47% fixed for the base facility charge and 53% variable for the usage charge. Further, as part of its Application and as a matter of rate design in this case, CWSNC proposed no rate changes for customers in the CLMS service area. CWSNC stated that its proposal to not increase (but hold constant) the water and sewer rates for those affected customers is consistent with the ratemaking and rate design approved by the Commission in the Company's last three general rate cases (Docket Nos. W-354, Subs 336, 344, and 356) and will continue the orderly process of moving the CLMS service area toward full inclusion in the Company's uniform water and sewer rates in future general rate cases.

With respect to sewer rates, Paragraph 25 of the Company's Application stated that, pursuant to Paragraph No. 15 (entitled, "Metered Sewer Rates") of the Joint Stipulation between CWSNC and the Public Staff filed in the Sub 356 Proceeding on September 9, 2017, the Company agreed to:

> ...consider implementing metered sewer rates for customers in its Fairfield Harbour, Bradfield Farms, and Sapphire Valley service areas in the Company's next general rate case filing and reserves the right to independently propose metered sewer rates for these systems. (Footnote omitted)

WATER AND SEWER – RATE INCREASE

In its Application, CWSNC stated that, after careful consideration, the Company decided to file its Application premised upon continuation of flat rate sewer service for customers in its Fairfield Harbour, Bradfield Farms, and Sapphire Valley service areas, but that the Company was willing to discuss this matter with the Public Staff and reserved the right, after such consultation, to either affirm the current decision to continue flat rates or, instead, propose metered rates for the three service areas in question.

In regard to rate design, CWSNC witness DeStefano testified that, as an alternative proposal to CWSNC's requested CAM, the Company requested that the Commission find it reasonable, necessary, and appropriate to direct the parties to develop a rate design that is based on a 60% to 40% ratio of base facility to volumetric charges for water. He testified that this would be a change from the Company's current ratio of approximately 50%/50%, base to volumetric. According to witness DeStefano, the proposed ratio is needed to more closely align cost recovery with actual costs incurred. He argued that with the current ratio of approximately 50%/50%, base to volumetric, the recovery to actual costs incurred is not properly aligned. Witness DeStefano testified that the Company is currently experiencing an actual cost ratio of approximately 80%/20% fixed to variable, yet rates are designed with an approximately 50%/50% ratio for fixed and variable. He maintained that this misalignment hinders the Company's ability to earn its fair and reasonable return should consumption continue its decline. Witness DeStefano contended that the consumption trend across the industry is currently one of decline due to conservation efforts and the installation of more efficient water fixtures. Witness DeStefano testified that the current rate design reduces the Company's ability to promote conservation efforts without negatively impacting its ability to earn a fair and reasonable return.

Public Staff witness Casselberry testified that in the Sub 356 Proceeding, the Public Staff recommended that CWSNC consider implementing metered sewer rates for customers in its Sapphire Valley, Fairfield Harbour, and Bradfield Farms Subdivision service areas, and reserved the right to independently propose metered sewer rates for these systems. Witness Casselberry stated that as part of the settlement agreement in the Sub 356 Proceeding, CWSNC supported the recommendation and agreed to undertake such consideration in conjunction with its next general rate case. Witness Casselberry noted that, in this proceeding, CWSNC decided not to implement metered sewer rates for customers in those service areas.

Witness Casselberry testified that, since sewer customers in Sapphire Valley were incorporated into CWSNC's uniform sewer rate division, they should be charged the same rate as other metered sewer customers within that rate division. In addition, customers with multiple units behind a master meter should be billed the same way as the other master metered customers, which specifies that commercial customers, including condominiums or other property owner associations who bill their members directly, shall have a separate account set up for each meter and each meter shall be billed separately based on the size of the meter and usage associated with the meter as stated in the schedule of rates for water and sewer service.

Further, witness Casselberry testified that it was also the Public Staff's position that since Bradfield Farms and Fairfield Harbour are in their own separate rate division and all of the customers in that rate division have flat sewer rates and the Public Staff received only one complaint concerning the flat rate, the Public Staff agreed with the Company that the flat rate should remain for the BF/FH rate division. However, she recommended that, in the future, should the BF/FH rate division be eliminated and customers are incorporated into the CWSNC uniform sewer rate division, they too should be charged the metered sewer rate for customers who also have metered water. Witness Casselberry testified that it was also her understanding that the Company agreed with the Public Staff's recommendation that customers in Sapphire Valley should be billed the uniform metered sewer rate and that customers in Bradfield Farms and Fairfield Harbour should be billed a flat sewer rate in this general rate case.

Regarding the customers in the Linville Ridge Subdivision and The Ridges at Mountain Harbour (The Ridges), witness Casselberry testified that the Public Staff recommends uniform metered water rates. The Public Staff also recommended purchased sewer rates for The Ridges. Witness Casselberry testified that since CWSNC's last general rate case, water meters have been installed for all the residential customers in Linville Ridge and The Ridges. Both systems are located in the mountains and are considered seasonal mountain systems, because many of the customers' premises are occupied only during the summer months and during holidays. Witness Casselberry testified that she had evaluated the consumption for the other seasonal mountain systems and determined that the average residential monthly consumption is 1,920 gallons. She stated that it was her understanding that CWSNC has agreed that using 1,920 gallons as the estimated consumption for calculated revenue is reasonable and acceptable for Linville Ridge and The Ridges.

According to witness Casselberry, The Ridges is a purchased sewer system. CWSNC purchases sewage treatment from Clay County Water and Sewer District. Clay County charges a flat bi-monthly rate of $1,621.24. Based on the billing data provided, there are 44 single-family equivalents (SFEs). The base facility charge per SFE is $18.42 ($1621.24/2 months/44 SFE). Witness Casselberry recommended the following base facility charges:

Residential customers	
< 1" meter	$ 18.42
Commercial customers:	
< 1" meter	$ 18.42
2" meter	$147.36

Witness Casselberry testified that it was her understanding that CWSNC agreed with the Public Staff's recommended base facility charges for The Ridges.

Witness Casselberry testified that Carolina Trace is a purchased water system and the supplier is the City of Sanford (City). She noted that the usage rate is established based on the supplier's rate and that the existing usage charge is $2.21 per 1,000 gallons. She explained that under the general statutes, utility companies may petition the Commission for a pass-through outside of a general rate case which allows a company to directly pass on to customers the increased cost of purchased water. She observed that in this proceeding, there is no change in the City's usage charge and, therefore, CWSNC is proposing the same usage charge as the existing usage rate. However, witness Casselberry testified that since Carolina Trace is in the uniform water rate division, should the base charge for uniform rates increase, the new rate would apply to Carolina Trace as well.

Witness Casselberry further testified that CWSNC proposed, as an alternative to a CAM, that the Commission should direct the parties to develop a rate design that is based on a 60%/40% ratio of base charge to usage charge for water versus the current ratio of approximately 50%/50%. Witness Casselberry opposed CWSNC's alternative proposal. Witness Casselberry calculated the current ratio as 47%/53% base charge to usage charge based upon the end of period (EOP) residential customers for uniform rates, with meters less than one inch, and actual consumption for the test year period ending December 31, 2017 (not including Elk River or purchased water customers). In regard to rate design and seasonal customers, witness Casselberry testified that in order for seasonal customers to have water and sewer service year round, the water and sewer facilities must remain operational year round. Witness Casselberry explained that the base charge covers those costs to keep the systems operating such as testing, purchased power, maintenance and repairs, chemicals, sludge removal, salaries, and other general fixed costs. Witness Casselberry testified that the Public Staff would like to take the present ratio closer to a range of 40%/60% base charge to usage charge; thus; she recommended a ratio in the range of 45%/55% base charge to usage charge for this proceeding, which she noted is consistent with what has been recommended by the Public Staff in the past.

Witness Casselberry testified that it is the Public Staff's position that higher usage charges promote conservation and that when the base charge is increased and the consumption charge is reduced, customers have a tendency to use more water and they also have less control over their water bill. She opined that with a higher base charge, customers have less ability to reduce their bills. In addition, witness Casselberry testified that, according to the customer testimony received at the public hearings, base charges are getting extremely high and that it is becoming difficult for some CWSNC customers to pay their base charges.

On cross-examination, witness Casselberry testified that some of the declining consumption that CWSNC has experienced may be attributed to aged meters and that the Company should implement a meter changeout plan to recoup such lost consumption. She commented that many of CWSNC's systems are over 30 years old and some of these systems still have the same meters installed that were in use when CWSNC originally acquired the systems. Witness Casselberry recommended that CWSNC evaluate the status of its current meters and implement an appropriate meter changeout program.

In his rebuttal testimony, witness DeStefano responded to witness Casselberry's view that higher base charges do not encourage conservation. He asserted that witness Casselberry's statement exemplifies the throughput incentive conflict in that the Public Staff believes a lower base charge encourages conservation, which may be reasonable. However, he contended that absent a CAM to stabilize revenues, this adds revenue volatility to the Company due to a higher proportion of revenues being subject to the unpredictability and the unexpected changes of seasonal weather patterns and any conservation measures adopted by customers. Witness DeStefano maintained that the Company is therefore not properly incented to promote conservation, and the Public Staff's position on rate design highlights the need to implement the CAM. Witness DeStefano testified that, if the Commission does not approve implementation of CWSNC's proposed CAM, the Company alternatively requests that the Commission find it reasonable, necessary, and appropriate to direct the parties to develop a rate design that is based on a 60%/40% ratio of base charges to volumetric charges for water.

WATER AND SEWER – RATE INCREASE

Based upon the foregoing and the entire record herein, the Commission finds that the following specific rate design proposals recommended by Public Staff witness Casselberry and agreed to by the Company which were not opposed by any party, are reasonable and appropriate:

- That sewer customers in Sapphire Valley, who were incorporated into CWSNC's uniform sewer rate division, should be charged the same rate as other metered sewer customers within that rate division.

- That sewer customers in Bradfield Farms and Fairfield Harbour should continue to be charged a flat rate.

- That CWSNC's uniform metered water rates should be charged to customers in Linville Ridge and at The Ridges at Mountain Harbor based on the Public Staff's estimated usage of 1,920 gallons per EOP customer per month, consistent with the average for CWSNC's other seasonal mountain systems.

- That customers at The Ridges at Mountain Harbor should be charged purchased sewer rates at the Public Staff's recommended base facility charge, which is $18.42 per SFE. The resulting base facility charges, exclusive of the collection charge that is the same as for customers in all of CWSNC's purchased sewer systems are shown below.

Residential customers	
< 1" meter	$ 18.42
Commercial customers:	
< 1" meter	$ 18.42
2" meter	$147.36

Further, the Commission concludes, consistent with the recommendation of witness Casselberry, that CWSNC's customers in Carolina Trace, which is a purchased water system in the CWSNC uniform water rate division, should be charged the same base charge as approved in this case for that rate division.

In this case, CWSNC proposed no rate changes for customers in the Company's CLMS service area. CWSNC maintained that its proposal to not increase (but hold constant) the water and sewer rates for its customers in the CLMS service area is consistent with the ratemaking and rate design approved by the Commission in the Company's last three general rate cases (Docket Nos. W-354, Subs 336, 344, and 356) and will continue the orderly process of moving the CLMS service area toward full inclusion in the Company's uniform water and sewer rates in future general rate cases. No party to this case opposed the Company's recommendation to maintain the status quo of rates for the CLMS service area. Accordingly, the Commission finds good cause to not increase (but hold constant) the sewer rates for the CLMS service area.

As discussed in the preceding section, the Commission concluded that CWSNC's request for approval to implement its proposed CAM should be denied. In conjunction with the Company's

CAM request, CWSNC also proposed a metered water rate structure for purposes of designing rates in this proceeding consisting of 47%/53% ratio of base charge to usage charge. Alternatively, if the proposed CAM was not approved, the Company proposed a ratio of 60%/40% base charge to usage charge for rate design purposes.

The Public Staff opposed using CWSNC's alternative to a CAM in this proceeding. Witness Casselberry testified that since the Public Staff would like to take the ratio closer to a 40%/60% base charge to usage charge ratio to promote conservation and give customers more control over their bills, she recommended the slightly lower ratio range of 45%/55% base charge to usage charge for this proceeding rather than the present ratio of 47%/53%.

Based upon the foregoing and the entire record herein, the Commission determines that the appropriate ratio of base charge to usage charge for use in this proceeding is 52%/48%. In reaching this conclusion, the Commission gives equal weight to the testimony of CWSNC witness DeStefano and of Public Staff witness Casselberry. Witness DeStefano testified that CWSNC continues to experience a consistent decline in consumption due to conservation efforts by customers and the installation of more water efficient household fixtures, and witness Casselberry's Late-Filed Exhibit 1 lends support to witness DeStefano's assertion concerning declining consumption. Further, the Commission notes that the testimony of witness Casselberry indicated that both CWSNC uniform water rate division and the BF/FH/TC water rate division had a customer growth factor of less than 1% in this proceeding. Tr. Vol. 8, p. 302. Consequently, the Commission recognizes that CWSNC would not have the opportunity to recover any significant portion of its declining consumption through customer growth.

The Commission also agrees with witness DeStefano that the rate design proposed by the Public Staff is weighted too heavily toward variable costs, in light of witness Casselberry's testimony that approximately 75% [1] of the Company's water service costs are fixed. Tr. Vol. 7, p. 343. Both these witnesses generally agreed that CWSNC has a substantial number of seasonal customers who have water and/or sewer service available on-demand year round, but do not contribute to cost recovery through CWSNC's volumetric charges to the same extent as year-round customers. Furthermore, the Commission recognizes the importance of the Public Staff's stated goal to encourage conservation through a decline in consumption, and relying on higher usage charges to provide incentive to customers to do so. However, the Public Staff's proposed rate design could also have the unintended effect of making it even more difficult for the Company to achieve and earn its allowed return and diminishing the Company's incentive to promote conservation of a natural resource by its customers and, ultimately, cause more frequent general rate case filings. The Commission concludes that approving a rate design in this proceeding which should work to reduce the need for CWSNC to file frequent rate case applications would benefit customers in the long term, as customers ultimately pay through monthly rates the reasonable and prudent costs incurred for rate case filings.

Having carefully weighed these competing goals or interests, and having considered the foregoing and the entire record herein, the Commission finds that it is appropriate to utilize a ratio of 52%/48% base charge to usage charge in this proceeding. The Commission concludes that such

[1] CWSNC witness DeStefano testified that 80% of the Company's water service costs are fixed.

rate design is fair and reasonable to both CWSNC and its customers as it appropriately balances the competing interests involved, as testified to by the witnesses in this proceeding. Therefore, taking into account the foregoing findings and conclusions, the Commission concludes that the rates and charges included in Appendices A-1, A-2, A-3, B-1, and B-2 are just and reasonable and should be approved.

Finally, the Commission notes that CWSNC's requested changes in its rate design, and the Public Staff's opposition thereto, is not unique to this case.[1] The Commission's experience in deciding the issues in this case and other general rate cases has informed the Commission's view that the problems that CWSNC asserts concerning declining consumption and revenue volatility due to the unpredictability and unexpected changes in weather patterns that make it difficult for the Company to generate revenue that is both stable and sufficient to cover its fixed costs of providing service to its customers is one that merits further consideration outside the context of a discrete general rate case. Although the tension between a utility's desire for stable and sufficient revenue generation, on the one hand, and policies that support conservation, on the other, is not a new phenomenon, the Commission acknowledges that there are new tools available to utilities and regulators and new research publications that may support addressing these issues in a more nuanced manner than the Company's proposal in this case. Therefore, the Commission will open a generic docket, by issuance of a forthcoming order, to investigate issues related to rate design, and require CWSNC, the Public Staff, and other specifically selected water utilities to participate in such a proceeding. The Commission's goal in doing so will be to explore and consider rate design proposals that may better achieve the utility's desire for revenue sufficiency and stability, while also sending appropriate price signals to consumers that support and encourage water efficiency and conservation.

<u>EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 69 AND 70</u>

The evidence supporting these findings of fact is found in the Commission's prior Orders approving rulemaking in Docket No. W-100, Sub 54 establishing the procedures for implementing and applying the WSIC and SSIC approved in CWSNC's rate case in Docket No. W-354, Sub 336 and in the Commission's prior Orders approving WSIC and SSIC mechanisms for CWSNC and the other Utilities, Inc. companies that have been merged into CWSNC.

The Commission's previously approved WSIC/SSIC improvement charge rate adjustment mechanism continues in effect, although it has been reset to zero in this rate case. The WSIC/SSIC mechanism is designed to recover, between rate case proceedings, the costs associated with investment in certain completed, eligible projects for water and sewer system or water quality improvements pursuant to N.C.G.S. § 62-133.12. The WSIC/SSIC surcharge is subject to commission approval and to audit and refund provisions. Any cumulative system improvement charge recovered pursuant to the WSIC/SSIC mechanism may not exceed 5% of the total annual service revenues approved by the Commission in this rate case proceeding.

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[1] <u>See, e.g.</u>, Docket No. W-218, Sub 497, a general rate case proceeding for Aqua North Carolina, Inc.

Based on the service revenues set forth and approved in this Order, the maximum WSIC/SSIC charges as of the effective date of this Order are:

Item	Service Revenues	Cap %	WSIC & SSIC Cap
CWSNC Uniform Water Operations	$17,421,890	X 5% =	$871,095
CWSNC Uniform Sewer Operations	$12,976,941	X 5% =	$648,847
BF/FH/TC Water Operations	$1,316,708	X 5% =	$65,835
BF/FH Sewer Operations	$2,149,098	X 5% =	$107,455

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 71

With respect to CWSNC's bonding requirements, CWSNC presently has posted with the Commission a $3,730,000 bond, secured by a letter of credit from The Toronto - Dominion Bank, New York Branch. Such bond was approved by Commission Order issued on September 27, 2016, in Docket No. W-354, Sub 350, et al. (In the Matter of a Joint Application by Carolina Water Service, Inc. of North Carolina; Bradfield Farms Water Company, Carolina Trace Utilities, Inc., CWS Systems, Inc., Elk River Utilities, Inc., and Transylvania Utilities, Inc. for Approval of Merger). As of the date of this Order, an amount of $3,690,000 of the approved bond has been assigned to the existing service areas of CWSNC, leaving an amount of $40,000 of bond and surety unassigned.

Upon review of the Commission's bond files, it was determined that in its Order Approving Merger, issued on August 2, 2010, in Docket Nos. W-354, Sub 326; W-1152, Sub 8; and W-1151, Sub 7, the Commission assigned $20,000 of CWSNC's unassigned bond to Amherst Subdivision in Wake County, North Carolina and $20,000 of the unassigned bond to the Carolina Pines Service Area in Craven County, North Carolina and stated that the bonds previously posted by Nero Utility Services, Inc. and Carolina Pines Utility, Inc. would be released to those entities (which were owned by Utilities, Inc.) upon the Commission's receipt of written notification that the merger has been completed.

On September 1, 2010, Utilities, Inc. filed a letter with the Commission providing notification that the merger had been completed. The Commission has determined that neither the $20,000 bond and certificate of deposit surety from BB&T for Amherst Subdivision nor the $20,000 bond and certificate of deposit surety from BB&T posted for the Carolina Pines Service Area have been released to UI. The Commission concludes that since UI has satisfied the requirement for the release of these two bonds and sureties as established by a previous Commission Order and that the Commission's bonding requirements for these two service areas are now included in CWSNC's present bond posted with the Commission in Docket No. W-354, Sub 350, et al., the two $20,000 bonds and sureties relating to Amherst Subdivision and the Carolina Pines Service Area should be released to UI. With the release of these two bonds and sureties, CWSNC has a total bond and surety of $3,730,000 posted with the Commission, of which $3,690,000 has been assigned to existing service areas of CWSNC and $40,000 is unassigned.

IT IS, THEREFORE, ORDERED as follows:

1. That the Partial Joint Settlement Agreement and Stipulation is incorporated by reference herein and is hereby approved in its entirety;

2. That the Partial Joint Settlement Agreement and Stipulation, filed on September 17, 2018, and the parts of this Order pertaining to the contents of that agreement shall not be cited or treated as precedent in future proceedings;

3. That the Schedules of Rates, attached hereto as Appendices A-1, A-2, A-3, and A-4, and the Schedules of Connection Fees for Uniform Water and Uniform Sewer, attached hereto as Appendices B-1 and B-2, are hereby approved and deemed to be filed with the Commission pursuant to N.C.G.S. § 62-138, and are hereby authorized to become effective for service rendered on and after the issuance date of this Order;

4. That the Notices to Customers, attached hereto as Appendices C-1 and C-2 shall be mailed with sufficient postage or hand delivered to all affected customers in each relevant service area, respectively, in conjunction with the next regularly scheduled billing process;

5. That CWSNC shall file the attached Certificate of Service, properly signed and notarized, not later than 10 days after the Notices to Customers are mailed or hand delivered to customers;

6. That CWSNC shall refund to ratepayers the overcollection of federal income taxes related to the decrease in the federal corporate income tax rate for the period beginning January 1, 2018, including interest at the overall weighted cost of capital, as a credit to customers' bills for a one-year period beginning when the new rates become effective in the present docket;

7. That the decision reached by the Commission in CWSNC's Sub 356 Order to amortize over three years the Company's state EDIT recorded pursuant to the Commission's Sub 138 Order shall remain in full force and effect;

8. That the unprotected EDIT associated with the reduction in the federal corporate income tax rate shall be returned by CWSNC to ratepayers through a levelized rider to rates over a four-year period;

9. That the protected federal EDIT shall be amortized by CWSNC over 45 years in accordance with the IRC;

10. That in CWSNC's next general rate case proceeding, CWSNC and the Public Staff shall evaluate in detail and determine the appropriate methodology to calculate CIAC and PAA amortization expense for the post-merger entity on a going-forward basis for ratemaking purposes in order to ensure that contributed property is depreciated at the same rate that the related CIAC is amortized;

11. That, within 180 days of the date of this Order, CWSNC shall file a report with the Commission on the progress of the capital project intended to resolve the quality of service concern

identified by Ms. Brown, one of the public witnesses appearing at the public hearing in Asheville, as is discussed in more detail in this Order. Such report shall state whether Ms. Brown has indicated to CWSNC that the final resolution of the issue is satisfactory;

12. That the two certificate of deposit bond sureties previously filed by Utilities, Inc. (as noted above) from BB&T for Amherst Subdivision in Wake County and for the Carolina Pines Service Area in Craven County, North Carolina shall be released to Utilities, Inc. The Chief Clerk shall file a copy of the letter to Utilities, Inc. from the Deputy Clerk releasing the bond sureties in Docket Nos. W-354, Sub 326, W-1152, Sub 8, W-1151, Sub 7, and this docket;

13. That the Chief Clerk shall establish Docket No. W-354, Sub 360A as the single docket to be used for all future WSIC/SSIC filings, orders, and reporting requirements. To that end, the Chief Clerk shall copy CWSNC's WSIC/SSIC pending application filed on January 31, 2019, in Docket No. W-354, Sub 356A and Sub 360 into Docket No. W-354, Sub 360A; and

14. That the Chief Clerk shall close Docket No. W-354, Subs 356A, 344A, and 336A.

ISSUED BY ORDER OF THE COMMISSION.
This the 21st day of February, 2019.

NORTH CAROLINA UTILITIES COMMISSION
A. Shonta Dunston, Deputy Clerk

Commissioner Daniel G. Clodfelter concurring in part and dissenting in part.

DOCKET NO. W-354, SUB 360

Commissioner Daniel G. Clodfelter, concurring in part and dissenting in part:

On all save one point I join in the Commission's opinion and in the result. My difference is in the matter of rate design and more specifically in the Commission's approval of a rate structure whereby the Company will earn 52% of its revenue requirement from fixed charges and the remaining 48% from volumetric charges. There is no special magic to the 52%/48% ratio of revenues from fixed charges to revenue from volumetric charges settled on by the Commission. The Public Staff advocated for a ratio of 45% revenue from fixed charges to 55% revenue from variable charges for setting rates, while testifying that it would prefer to move as close to a 40% fixed to 60% variable ratio as possible. The Company proposed a revenue ratio of 47% fixed to 53% variable if the requested CAM adjustment mechanism was approved and a ratio of 60% fixed to 40% variable without the CAM.[1] The actual figures for the Company's test year, as calculated by witness Casselberry, were 47% of revenue derived from fixed charges and 53% derived from volumetric rates. Nothing in the evidence presented by any of the witnesses supports a conclusion

[1] I agree with and concur in the Commission's refusal to approve the CAM adjustment mechanism for the reasons stated in the Commission's opinion.

that any particular one of these ratios or, for that matter, any other ratio within the range of values advocated by the parties will ensure just the right balance between the need for revenue stability to cover fixed costs and a rate design that will encourage water efficiency and conservation.

The tension between the policy goal of providing adequate and stable revenue to cover a high level of fixed costs, a feature inherent in most water and sewer systems, and the second policy goal of encouraging water use reduction is very real and has worsened in recent years as appliances have become more efficient and as drought events have changed public consciousness of the relative abundance or scarcity of water. This tension is not, however, unmanageable, and the academic and research literature together with extensive real world experience by public and private water utilities demonstrate that there are a number of different techniques that have now been adopted; either in general use or as experiments, that can mitigate the conflicts between the competing objectives of revenue stability and water conservation. [1] Some of these mechanisms are more complex than others, and many of them take advantage of increasingly sophisticated data resources concerning customer usage patterns. All of them are more nuanced than the Company's proposals or the Commission's result in this case, and they attempt to accommodate both major goals for rate design without sacrificing or ignoring either one. A "single factor" approach to managing the conflicting objectives by simply adjusting the ratio of fixed to variable charges ignores this available research and field experience and misses opportunities for the Company to implement rate designs that are tailored to the unique characteristics of its systems, its customers, and their usage patterns.

I fully agree with the Commission majority that it is time to open a generic docket to explore alternative ratemaking options for water and sewer companies regulated by the Commission for the sound reasons articulated in the Commission's order. Where I differ is that I would maintain the existing ratio of fixed to volumetric charges unchanged pending the conclusion of proceedings in that separate docket. This is especially so since I can find nothing in this record that supports picking any one fixed-to-variable ratio rather than any other. I find no persuasive evidence in this record that maintaining the present rate design will unreasonably hinder the Company's operations or its chance to earn its permitted rate of return while the Commission conducts a more thorough examination of the question.

/s/ Daniel G. Clodfelter
Commissioner Daniel G. Clodfelter

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[1] See, e.g., "Designing Water Rate Structures for Conservation and Revenue Stability," a 2014 joint study report by the Environmental Finance Center at the University of North Carolina at Chapel Hill and the Sierra Club Lone Star Chapter concerning rate design options in Texas; and "Achieving Revenue Stability through Your Water Rate Structure," a 2017 webinar presentation by, among others, the Environmental Finance Center at the University of North Carolina at Chapel Hill and the American Water Works Association. This is a topic on which the Environmental Finance Center has recognized expertise which could be invaluable to this Commission.

WATER AND SEWER – RATE INCREASE

SCHEDULE OF RATES

for

CAROLINA WATER SERVICE, INC. OF NORTH CAROLINA

for providing water and sewer utility service
in
ALL OF ITS SERVICE AREAS IN NORTH CAROLINA

(excluding Corolla Light, Monteray Shores, Fairfield Harbour Service Area, Treasure Cove, Register Place Estates, North Hills and Glen Arbor/North Bend Subdivisions, Bradfield Farms, Larkhaven, Silverton, and Woodland Farms Subdivisions, and Hawthorne at the Green Apartments)

WATER RATES AND CHARGES

Monthly Metered Water Service (Residential and Commercial): Base

Facility Charge (based on meter size with zero usage):

< 1" meter	$ 27.53
1" meter	$ 68.83
1½" meter	$ 137.65
2" meter	$ 220.24
3" meter	$ 412.95
4" meter	$ 688.25
6" meter	$1,376.50

Usage Charge:

A. Treated Water, per 1,000 gallons	$ 7.08
B. Untreated Water, per 1,000 gallons (Brandywine Bay Irrigation Water)	$ 4.11

Commercial customers, including condominiums or other property owner associations who bill their members directly, shall have a separate account set up for each meter and each meter shall be billed separately based on the size of the meter and usage associated with the meter.

WATER AND SEWER – RATE INCREASE

C. Purchased Water for Resale, per 1,000 gallons:

Service Area	Bulk Provider	
Carolina Forest	Montgomery County	$ 3.19
High Vista Estates	City of Hendersonville	$ 3.25
Riverpointe	Charlotte Water	$ 6.30
Whispering Pines	Town of Southern Pines	$ 2.23
White Oak Plantation/ Lee Forest	Johnston County	$ 2.40
Winston Plantation	Johnston County	$ 2.40
Winston Point	Johnston County	$ 2.40
Woodrun	Montgomery County	$ 3.19
Yorktown	City of Winston-Salem	$ 5.01
Zemosa Acres	City of Concord	$ 5.27
Carolina Trace	City of Sanford	$ 2.21

When because of the method of water line installation utilized by the developer or owner, it is impractical to meter each unit or other structure separately, the following will apply:

Sugar Mountain Service Area:
Where service to multiple units or other structures is provided through a single meter, the average usage for each unit or structure served by that meter will be calculated. Each unit or structure will be billed based upon that average usage plus the base monthly charge for a <1" meter.

Mount Mitchell Service Area:
Service will be billed based upon the Commission-approved monthly flat rate.

<u>Monthly Flat Rate Water Service</u>: (Billed in Arrears) $ 53.58

<u>Availability Rate</u>: (Semiannually)

Applicable only to property owners in Carolina Forest and Woodrun Subdivisions in Montgomery County $ 24.65

WATER AND SEWER – RATE INCREASE

APPENDIX A-1
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Availability Rate: (Monthly)	
Applicable only to property owners in Linville Ridge Subdivision	$ 12.35
Availability Rate: (Monthly rate, billed semiannually)	
Applicable only to property owners in Fairfield Sapphire Valley Service Area	$ 9.10
Availability Rate: (Monthly rate, billed quarterly)	
Applicable only to property owners in Connestee Falls	$ 4.80
Meter Testing Fee: [1/]	$ 20.00
New Water Customer Charge:	$ 27.00
Reconnection Charge: [2/]	
If water service is cut off by utility for good cause	$ 27.00
If water service is discontinued at customer's request	$ 27.00
Reconnection Charge: [3/] (Flat-rate water customers)	
If water service is cut off by utility for good cause	Actual Cost
Management Fee: (in the following subdivisions only) (Per connection)	
Wolf Laurel	$150.00
Covington Cross Subdivision (Phases 1 & 2)	$100.00
Oversizing Fee: (in the following subdivision only) (One-time charge per single-family equivalent) Winghurst	$400.00
Meter Fee:	
For <1" meters	$ 50.00
For meters 1" or larger	Actual Cost
Irrigation Meter Installation:	Actual Cost

SEWER RATES AND CHARGES

Monthly Metered Sewer Service:

A. Base Facility Charge:

Residential (zero usage)	$ 46.31
Commercial (based on meter size with zero usage)	
< 1" meter	$ 46.31
1" meter	$ 115.78
1½" meter	$ 231.55
2" meter	$ 370.48
3" meter	$ 694.65
4" meter	$1,157.75
6" meter	$2,315.50

B. Usage charge, per 1,000 gallons (based on metered water usage) $ 3.62

Commercial customers, including condominiums or other property owner associations who bill their members directly, shall have a separate account set up for each meter and each meter shall be billed separately based on the size of the meter and usage associated with the meter.

Monthly Metered Purchased Sewer Service:

Collection Charge (Residential and Commercial) $ 31.63

Usage charge, per 1,000 gallons
(based on metered water usage from the water supplier)

Service Area	Bulk Provider	
White Oak Plantation/ Lee Forest/Winston Pt.	Johnston County	$ 5.06
Kings Grant	Two Rivers Utilities	$ 3.80
College Park	Town of Dallas	$ 5.70

Monthly Flat Rate Sewer Service: $ 57.82

Multi-residential customers who are served by a master meter shall be charged the flat rate per unit. $ 57.82

WATER AND SEWER – RATE INCREASE

Mt. Carmel Subdivision Service Area:

Monthly Base Facility Charge	$ 6.77
Monthly Collection Charge (Residential and Commercial)	$ 31.63
Usage Charge, per 1,000 gallons (based on metered water usage from the water supplier)	$ 5.88

Regalwood and White Oak Estates Subdivision Service Area:

Monthly Flat Rate Sewer Service	
Residential Service	$ 57.82
White Oak High School	$1,799.66
Child Castle Daycare	$ 223.58
Pantry	$ 119.49

Fairfield Mountain/Apple Valley (a.k.a. Rumbling Bald) Service Area and Highland Shores Subdivision:

Monthly Sewer Rates:

Residential	
Collection charge/dwelling unit	$ 31.63
Treatment charge/dwelling unit	$ 69.50
Total monthly flat rate/dwelling unit	$ 101.13
Commercial and Other:	
Minimum monthly collection and treatment charge	$ 101.13
Monthly collection and treatment charge for customers who do not take water service	$ 101.13
Treatment charge per dwelling unit	
Small (less than 2,500 gallons per month)	$ 78.50
Medium (2,500 to 10,000 gallons per month)	$ 139.50
Large (over 10,000 gallons per month)	$ 219.50
Collection Charge (per 1,000 gallons)	$ 13.93

APPENDIX A-1
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The Ridges at Mountain Harbour:

Monthly Sewer Rates:

Collection charge (Residential and Commercial)	$ 31.63
Treatment Charge (Residential and Commercial)	
< 1" meter	$ 18.42
2" meter	$ 147.36

Availability Rate: (Monthly rate, billed semiannually)

Applicable only to property owners in Fairfield Sapphire Valley Service Area	$ 8.30

Availability Rate: (Monthly rate, billed quarterly)

Applicable only to property owners in Connestee Falls	$ 4.70

New Sewer Customer Charge: 4/ $ 27.00

Reconnection Charge: 5/
If sewer service is cut off by utility for good cause — Actual Cost

MISCELLANEOUS UTILITY MATTERS

Charge for Processing NSF Checks:	$ 25.00
Bills Due:	On billing date
Bills Past Due:	21 days after billing date
Billing Frequency:	Bills shall be rendered monthly in all service areas, except for Mt. Carmel, which will be billed bimonthly. Availability rates will be billed quarterly in advance for Connestee Falls, semiannually in advance for Carolina Forest, Woodrun, and Fairfield Sapphire Valley, and monthly for Linville Ridge.

WATER AND SEWER – RATE INCREASE

Finance Charge for Late Payment: 1% per month will be applied to the unpaid balance of all bills still past due 25 days after billing date.

Notes:

[1/] If a customer requests a test of a water meter more frequently than once in a 24-month period, the Company will collect a $20.00 service charge to defray the cost of the test. If the meter is found to register in excess of the prescribed accuracy limits, the meter testing charge will be waived. If the meter is found to register accurately or below prescribed accuracy limits, the charge shall be retained by the Company. Regardless of the test results, customers may request a meter test once in a 24-month period without charge.

[2/] Customers who request to be reconnected within nine months of disconnection at the same address shall be charged the base facility charge for the service period they were disconnected.

[3/] The utility shall itemize the estimated cost of disconnecting and reconnecting service and shall furnish this estimate to customer with cut-off notice.

[4/] This charge shall be waived if customer is also a water customer within the same service area.

[5/] The utility shall itemize the estimated cost of disconnecting and reconnecting service and shall furnish this estimate to customer with cut-off notice. This charge will be waived if customer also receives water service from Carolina Water Service within the same service area. Customers who request to be reconnected within nine months of disconnection at the same address shall be charged the base facility charge for the service period they were disconnected.

Issued in Accordance with Authority Granted by the North Carolina Utilities Commission in Docket No. W-354, Sub 360, on this the 21st day of February, 2019.

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SCHEDULE OF RATES

for

CAROLINA WATER SERVICE, INC. OF NORTH CAROLINA
for providing sewer utility service
in
COROLLA LIGHT AND MONTERAY SHORES SERVICE AREA

SEWER RATES AND CHARGES

Monthly Metered Sewer Service (Residential and Commercial):

Base Facility Charge (based on meter size with zero usage)

< 1" meter	$ 52.06
1" meter	$ 130.15
1½" meter	$ 260.31
2" meter	$ 416.49
3" meter	$ 780.92
4" meter	$ 1,301.54
6" meter	$ 2,603.07

Usage Charge, per 1,000 gallons (based on metered water usage per the water supplier)	$ 6.62

Commercial customers, including condominiums or other property owner associations who bill their members directly, shall have a separate account set up for each meter and each meter shall be billed separately based on the size of the meter and usage associated with the meter.

New Sewer Customer Charge: $ 21.92

Reconnection Charge: [1/]

If sewer service cut off by utility for good cause — Actual Cost

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Uniform Connection Fees: [2/]

The following uniform connection fees apply unless specified differently by contract approved by and on file with the North Carolina Utilities Commission.

Connection Charge (CC), per SFE (Single-Family Equivalent)	$ 100.00
Plant Modification Fee (PMF), per SFE	$1,000.00

The systems where connection fees other than the uniform fees have been approved and/or allowed to become effective by the North Carolina Utilities Commission are as follows. These fees are per SFE:

Subdivision	CC	PMF
Corolla Light	$ 700.00	$ 0.00
Monteray Shores	$ 700.00	$ 0.00
Monteray Shores (Degabrielle Bldrs.)	$ 0.00	$ 0.00
Corolla Bay[3/]	$ 100.00	$ 1,000.00
Corolla Bay[4/]	$ 700.00	$ 0.00
Corolla Shores	$ 700.00	$ 0.00

One SFE shall equal 360 gallons per day of capacity.

MISCELLANEOUS UTILITY MATTERS

Charge for Processing NSF Checks:	$ 24.91
Bills Due:	On billing date
Bills Past Due:	21 days after billingdate
Billing Frequency:	Bills shall be rendered monthly
Finance Charge for Late Payment:	1% per month will be applied to the unpaid balance of all bills still past due 25 days after billing date.

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PAGE 3 OF 3

Notes:

[1/] The Utility shall itemize the estimated cost of disconnecting and reconnecting service and shall furnish the estimate to customer with cut-off notice.

Customers who request to be reconnected within nine months of disconnection at the same address shall be charged the base facility charge for the service period they were disconnected.

[2/] These fees are only applicable one time, when the unit is initially connected to the system.

[3/] The connection charge of $100 per SFE and the plant modification fee of $1,000 per SFE specified herein apply to new wastewater connections requested at Corolla Bay prior to June 4, 2015.

[4/] The connection charge of $700 per SFE applies to new wastewater connections requested at Corolla Bay on and after June 4, 2015.

Issued in Accordance with Authority Granted by the North Carolina Utilities Commission in Docket No. W-354, Sub 360, on this the 21st day of February, 2019.

APPENDIX A-3
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SCHEDULE OF RATES
for
CAROLINA WATER SERVICE, INC. OF NORTH CAROLINA
for providing water and sewer utility service

in

TREASURE COVE, REGISTER PLACE ESTATES, NORTH HILLS, GLEN ARBOR/NORTH BEND SUBDIVISIONS, FAIRFIELD HARBOUR SERVICE AREA, BRADFIELD FARMS SUBDIVISION, LARKHAVEN SUBDIVISION, SILVERTON AND WOODLAND FARMS SUBDIVISIONS, AND HAWTHORNE AT THE GREEN APARTMENTS

WATER RATES AND CHARGES

Monthly Metered Water Service (Residential and Commercial):

Base Facility Charge (based on meter size with zero usage)

< 1" meter	$ 16.74
1" meter	$ 41.85
1½" meter	$ 83.70
2" meter	$ 133.92

Usage Charge, per 1,000 gallons	$ 3.75

Availability Rate: (Monthly rate, billed semiannually)

Applicable only to property owners in Fairfield Harbour Service Area	$ 3.28

Connection Charge:

Treasure Cove Subdivision	$ 0.00
North Hills Subdivision	$ 100.00
Glen Arbor/North Bend Subdivision	$ 0.00
Register Place Estates	$ 500.00

WATER AND SEWER – RATE INCREASE

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PAGE 2 OF 5

Fairfield Harbor: 1/

All Areas Except Harbor Pointe II Subdivision

Recoupment of capital fees per tap	$ 335.00
Connection charge per tap	$ 140.00

Harbor Pointe Subdivision and any area where mains have been installed after July 24, 1989

Recoupment of capital fee per tap	$ 650.00
Connection charge per tap	$ 320.00

Bradfield Farms:

Connection charge per tap	None

Meter Testing Fee: 2/	$ 20.00
New Water Customer Charge:	$ 27.00

Reconnection Charge: 3/

If water service is cut off by utility for good cause	$ 27.00
If water service is discontinued at customer's request	$ 27.00

New Meter Charge:	Actual Cost
Irrigation Meter Installation:	Actual Cost

SEWER RATES AND CHARGES

Monthly Sewer Service:

Residential:

Flat Rate, per dwelling unit	$ 50.46
Bulk Flat Rate, per REU	$ 50.46

Commercial and Other:

Monthly Flat Rate (Customers who do not take water service)	$ 50.46

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PAGE 3 OF 5

Monthly Metered Rates
(based on meter size with zero usage)

<1" meter	$ 44.58
1" meter	$111.45
1½" meter	$222.90
2" meter	$356.64

Usage Charge, per 1,000 gallons $ 1.43

Bulk Sewer Service for Hawthorne at the Green Apartments: 4/

Bulk Flat Rate, per REU $ 50.46

(To be collected from Hawthorne and delivered to Carolina Water Service, Inc. of North Carolina for treatment of the Hawthorne wastewater pursuant to Docket No. W-218, Sub 291)

Availability Rate: (Monthly rate, billed semiannually)

Applicable only to property owners in Fairfield Harbour Service Area $ 2.65

Connection Charge:

Fairfield Harbour: 1/

All Areas Except Harbor Pointe II Subdivision

Recoupment of capital fees per tap	$ 735.00
Connection charge per tap	$ 140.00

Harbor Pointe Subdivision and any area where mains have been installed after July 24, 1989

Recoupment of capital fee per tap	$2,215.00
Connection charge per tap	$ 310.00

Bradfield Farms:
Connection charge per tap None

New Sewer Customer Charge: 5/ $ 27.00

Reconnection Charge: [6/]
If sewer service is cut off by utility for good cause — Actual Cost

MISCELLANEOUS UTILITY MATTERS

Charge for Processing NSF Checks:	$ 25.00
Bills Due:	On billing date
Bills Past Due:	21 days after billing date
Billing Frequency:	Bills shall be monthly for service in arrears. Availability billings semiannually in advance.
Finance Charge for Late Payment:	1% per month will be applied to the unpaid balance of all bills still past due 25 days after billing date.

Notes:

[1/] The recoupment of capital portion of the connection charges shall be due and payable at such time as the main water and sewer lines are installed in front of each lot, and the tap-on fee for water and sewer shall be payable upon request by the owner of each lot to be connected to the water and sewer lines. With written consent of the company, payment of the recoupment capital portion of the connection charge may be made payable over five-year period following the installation of the water and sewer mains in front of each lot, payment to be made in such a manner and in such installments as agreed upon between lot owner and the company, together with interest on the balance of the unpaid recoupment of capital fee from said time until payment in full at the rate of 6% per annum.

[2/] If a customer requests a test of a water meter more frequently than once in a 24-month period, the Company will collect a $20.00 service charge to defray the cost of the test. If the meter is found to register in excess of the prescribed accuracy limits, the meter testing charge will be waived. If the meter is found to register accurately or below prescribed accuracy limits, the charge shall be retained by the Company. Regardless of the test results, customers may request a meter test once in a 24-month period without charge.

[3/] Customers who request to be reconnected within nine months of disconnection at the same address shall be charged the base facility charge for the service period they were disconnected.

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[4/] Each apartment building will be considered 92.42% occupied on an ongoing basis for billing purposes as soon as the certificate of occupancy is issued for that apartment building.

[5/] This charge shall be waived if customer is also a water customer within the same service area.

[6/] The utility shall itemize the estimated cost of disconnecting and reconnecting service and shall furnish this estimate to customer with cut-off notice. This charge will be waived if customer also receives water service from Carolina Water Service within the same service area. Customers who request to be reconnected within nine months of disconnection at the same address shall be charged the base facility charge for the service period they were disconnected.

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by the North Carolina Utilities Commission in Docket No. W-354, Sub 360, on this the 21st day of February, 2019.

APPENDIX B-1
PAGE 1 OF 3

CAROLINA WATER SERVICE, INC. OF NORTH CAROLINA
SCHEDULE OF CONNECTION FEES
FOR WATER UTILITY SERVICE UNDER UNIFORM RATES

Uniform Connection Fees: [1/]

The following uniform connection fees apply unless specified differently by contract approved by and on file with the North Carolina Utilities Commission.

Connection Charge (CC), per SFE (Single-Family Equivalent)	$ 100.00
Plant Modification Fee (PMF), per SFE	$ 400.00

The systems where connection fees other than the uniform fees have been approved and/or allowed to become effective by the North Carolina Utilities Commission are as follows. These fees are per SFE:

Subdivision	CC	PMF
Abington	$ 0.00	$ 0.00
Abington, Phase 14	$ 0.00	$ 0.00
Amherst	$ 250.00	$ 0.00
Bent Creek	$ 0.00	$ 0.00
Blue Mountain at Wolf Laurel	$ 925.00	$ 0.00
Buffalo Creek, Phase I, II, III, IV	$ 825.00	$ 0.00
Carolina Forest	$ 0.00	$ 0.00
Chapel Hills	$ 150.00	$ 400.00
Eagle Crossing	$ 0.00	$ 0.00
Elk River Development	$1,000.00	$ 0.00
Forest Brook/Old Lamp Place	$ 0.00	$ 0.00
Harbour	$ 75.00	$ 0.00
Hestron Park	$ 0.00	$ 0.00
Hound Ears	$ 300.00	$ 0.00
Kings Grant/Willow Run	$ 0.00	$ 0.00
Lemmond Acres	$ 0.00	$ 0.00
Linville Ridge	$ 400.00	$ 0.00
Monterrey (Monterrey LLC)	$ 0.00	$ 0.00
Quail Ridge	$ 750.00	$ 0.00
Queens Harbour/Yachtsman	$ 0.00	$ 0.00
Riverpointe	$ 300.00	$ 0.00
Riverpointe (Simonini Bldrs.)	$ 0.00	$ 0.00
Riverwood, Phase 6E (Johnston County)	$ 825.00	$ 0.00

WATER AND SEWER – RATE INCREASE

Subdivision	CC	PMF
Saddlewood/Oak Hollow (Summey Bldrs.)	$ 0.00	$ 0.00
Sherwood Forest	$ 950.00	$ 0.00
Ski Country	$ 100.00	$ 0.00
The Ridges at Mountain Harbour	$2,500.00	$ 0.00
White Oak Plantation	$ 0.00	$ 0.00
Wildlife Bay	$ 870.00	$ 0.00
Willowbrook	$ 0.00	$ 0.00
Winston Plantation	$1,100.00	$ 0.00
Winston Pointe, Phase 1A	$ 500.00	$ 0.00
Wolf Laurel	$ 925.00	$ 0.00
Woodrun	$ 0.00	$ 0.00
Woodside Falls	$ 500.00	$ 0.00

Other Connection Fees:

The following connection fees apply unless specified differently by contract approved and/or filed with the North Carolina Utilities Commission.

Amber Acres, Amber Acres North, Amber Ridge, Ashley Hills North, Bishop Pointe, Carriage Manor, Country Crossing, Covington Cross, Heather Glen, Hidden Hollow, Jordan Woods, Lindsey Point, Neuse Woods, Oakes Plantation, Randsdell Forest, Rutledge Landing, Sandy Trails, Stewart's Ridge, Tuckahoe, Wilder's Village, and Forest Hill Subdivisions

Connection Charge:

A. 5/8" meter	$ 500.00
B. All other meter sizes	Actual cost of meter and installation

The systems where other connection fees have been approved and/or allowed to become effective by the North Carolina Utilities Commission are as follows:

Subdivision	CC
Lindsey Point Subdivision	$ 0.00
Amber Acres North, Sections II & IV	$ 570.00
Fairfield Mountain/Apple Valley (a.k.a. Rumbing Bald) Service Area	$ 500.00
Highland Shores Subdivision	$ 500.00
Laurel Mountain Estates	$ 0.00
Carolina Trace	$ 605.00
Connestee Falls	$ 600.00

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The following connection fees apply unless specified differently by contract approved and/or filed with the North Carolina Utilities Commission.

All Areas Except Holly Forest XI, Holly Forest XIV, Holly Forest XV, Whisper Lake I, WhisperLake II, Whisper Lake III, Deer Run, Lonesome Valley Phases I and II, and Chattooga Ridge

Recoupment of Capital Fee (RCF) [2/]	$ 0.00
Connection charge	$ 400.00

The systems where other connection fees have been approved and/or allowed to become effective by the North Carolina Utilities Commission are as follows:

Subdivision	CC	RCF
Holly Forest XI	$ 400.00	$2,400.00
Holly Forest XIV	$ 400.00	$ 250.00
Holly Forest XV	$ 400.00	$ 500.00
Whispering Lake Phase I	$ 400.00	$1,250.00
Whispering Lake Phases II and III	$ 400.00	$2,450.00
Deer Run	$ 400.00	$1,900.00
Lonesome Valley Phases I and II	$ 0.00	$ 0.00
Chattooga Ridge	$ 0.00	$ 0.00

Notes:

[1/] These fees are only applicable one time, when the unit is initially connected to the system.

[2/] The recoupment of capital portion of the connection charges shall be due and payable at such time as the main water and sewer lines are installed in front of each lot, and the tap-on fee for water and sewer shall be payable upon request by the owner of each lot to be connected to the water and sewer lines. With written consent of the company, payment of the recoupment capital portion of the connection charge may be made payable over five-year period following the installation of the water and sewer mains in front of each lot, payment to be made in such a manner and in such installments as agreed upon between lot owner and the company, together with interest on the balance of the unpaid recoupment of capital fee from said time until payment in full at the rate of 6% per annum.

Issued in Accordance with Authority Granted by the North Carolina Utilities Commission in Docket No. W-354, Sub 360, on this the 21st day of February, 2019.

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PAGE 1 OF 3

CAROLINA WATER SERVICE, INC. OF NORTH CAROLINA

SCHEDULE OF CONNECTION FEES FOR

SEWER UTILITY SERVICE UNDER UNIFROM RATES

Uniform Connection Fees: 1/

The following uniform connection fees apply unless specified differently by contract approved by and on file with the North Carolina Utilities Commission.

Connection Charge (CC), per SFE (Single-Family Equivalent)	$ 100.00
Plant Modification Fee (PMF), per SFE	$1,000.00

The systems where connection fees other than the uniform fees have been approved and/or allowed to become effective by the North Carolina Utilities Commission are as follows. These fees are per SFE:

Subdivision	CC	PMF
Abington	$ 0.00	$ 0.00
Abington, Phase 14	$ 0.00	$ 0.00
Amber Acres North (Phases II & IV)	$ 815.00	$ 0.00
Ashley Hills	$ 0.00	$ 0.00
Amherst	$ 500.00	$ 0.00
Bent Creek	$ 0.00	$ 0.00
Brandywine Bay	$ 100.00	$ 1,456.00
Camp Morehead by the Sea	$ 100.00	$ 1,456.00
Elk River Development	$1,200.00	$ 0.00
Hammock Place	$ 100.00	$1,456.00
Hestron Park	$ 0.00	$ 0.00
Hound Ears	$ 30.00	$ 0.00
Independent/Hemby Acres/Beacon Hills (Griffin Bldrs.)	$ 0.00	$ 0.00
Kings Grant/Willow Run	$ 0.00	$ 0.00
Kynwood	$ 0.00	$ 0.00
Mt. Carmel/Section 5A	$ 500.00	$ 0.00
Queens Harbor/Yachtsman	$ 0.00	$ 0.00
Riverpointe	$ 300.00	$ 0.00
Riverpointe (Simonini Bldrs.)	$ 0.00	$ 0.00
Steeplechase (Spartabrook)	$ 0.00	$ 0.00
The Ridges at Mountain Harbour	$2,500.00	$ 0.00

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Subdivision	CC	PMF
White Oak Plantation	$ 0.00	$ 0.00
Willowbrook	$ 0.00	$ 0.00
Willowbrook (Phase 3)	$ 0.00	$ 0.00
Winston Pointe (Phase 1A)	$2,000.00	$ 0.00
Woodside Falls	$ 0.00	$ 0.00

Other Connection Fees:

The systems where other connection fees have been approved and/or allowed to become effective by the North Carolina Utilities Commission are as follows:

Subdivision

Carolina Pines

Residential	$1,350.00 per unit (including single-family homes, condominiums, apartments, and mobile homes)
Hotels	$750.00 per unit
Nonresidential	$3.57 per gallon of daily design of discharge or $900.00 per unit, whichever is greater

Subdivision	CC
Fairfield Mountain/Apply Valley (a.k.a. Rumbling Bald)	
Service Area	$ 550.00
Highland Shores	$ 550.00
Carolina Trace	$ 533.00
Connestee Falls	$ 400.00

The following connection fees apply unless specified differently by contract approved and/or filed with the North Carolina Utilities Commission.

All Areas Except Holly Forest XIV, Holly Forest XV, Deer Run, and Lonesome Valley Phases I and II

Recoupment of Capital Fee (RCF) [2/]	$ 0.00
Connection Charge	$ 550.00

WATER AND SEWER – RATE INCREASE

The systems where other connection fees have been approved and/or allowed to become effective by the North Carolina Utilities Commission are as follows:

Subdivision	CC	RCF
Holly Forest XIV	$ 550.00	$1,650.00
Holly Forest XV	$ 550.00	$ 475.00
Deer Run	$ 550.00	$1,650.00
Lonesome Valley Phases I and II	$ 0.00	$ 0.00

Notes:

[1/] These fees are only applicable one time, when the unit is initially connected to the system.

[2/] The recoupment of capital portion of the connection charges shall be due and payable at such time as the main water and sewer lines are installed in front of each lot, and the tap-on fee for water and sewer shall be payable upon request by the owner of each lot to be connected to the water and sewer lines. With written consent of the company, payment of the recoupment capital portion of the connection charge may be made payable over five-year period following the installation of the water and sewer mains in front of each lot, payment to be made in such a manner and in such installments as agreed upon between lot owner and the company, together with interest on the balance of the unpaid recoupment of capital fee from said time until payment in full at the rate of 6% per annum.

Issued in Accordance with Authority Granted by the North Carolina Utilities Commission in Docket No. W-354, Sub 360, on this the 21st day of February, 2019.

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STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. W-354, SUB 360

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application by Carolina Water Service, Inc. of North Carolina, 4944 Parkway Plaza Boulevard, Suite 375, Charlotte, North Carolina 28217, for Authority to Adjust and Increase Rates for Water and Sewer Utility Service in All of its Service Areas in North Carolina, Except Corolla Light and Monteray Shores Service Area	)	**NOTICE TO CUSTOMERS**

NOTICE IS HEREBY GIVEN that the North Carolina Utilities Commission has issued an Order authorizing Carolina Water Service, Inc. of North Carolina (CWSNC) to increase rates for water and sewer utility service in all of its service areas in North Carolina (excluding Corolla Light and Monteray Shores Service Area). The new approved rates are as follows:

WATER RATES AND CHARGES

(Excluding Corolla Light and Monteray Shores Service Area, Fairfield Harbour Service Area, Treasure Cove, Register Place Estates, North Hills and Glen Arbor/North Bend Subdivisions, Bradfield Farms, Larkhaven Subdivision, Silverton and Woodland Farms Subdivisions, and Hawthorne at the Green Apartments)

Uniform Water Customers:

Monthly Metered Water Service (Residential and Commercial):

Base Facility Charge (based on meter size with zero usage)

< 1" meter	$ 27.53
1" meter	$ 68.83
1½" meter	$ 137.65
2" meter	$ 220.24
3" meter	$ 412.95
4" meter	$ 688.25
6" meter	$1,376.50

WATER AND SEWER – RATE INCREASE

Usage Charge:

A. Treated Water, per 1,000 gallons	$	7.08
B. Untreated Water, per 1,000 gallons (Brandywine Bay Irrigation Water)	$	4.11

C. Purchased Water for Resale, per 1,000 gallons:

Service Area	Bulk Provider		
Carolina Forest	Montgomery County	$	3.19
High Vista Estates	City of Hendersonville	$	3.25
Riverpointe	Charlotte Water	$	6.30
Whispering Pines	Town of Southern Pines	$	2.23
White Oak Plantation/ Lee Forest	Johnston County	$	2.40
Winston Plantation	Johnston County	$	2.40
Winston Point	Johnston County	$	2.40
Woodrun	Montgomery County	$	3.19
Yorktown	City of Winston-Salem	$	5.01
Zemosa Acres	City of Concord	$	5.27
Carolina Trace	City of Sanford	$	2.21

Commercial customers, including condominiums or other property owner associations who bill their members directly, shall have a separate account set up for each meter and each meter shall be billed separately based on the size of the meter and usage associated with the meter.

When because of the method of water line installation utilized by the developer or owner, it is impractical to meter each unit or other structure separately, the following will apply:

Sugar Mountain Service Area:
Where service to multiple units or other structures is provided through a single meter, the average usage for each unit or structure served by that meter will be calculated. Each unit or structure will be billed based upon that average usage plus the base monthly charge for a <1" meter.

Mount Mitchell Service Area:
Service will be billed based upon the Commission-approved monthly flat rate.

Monthly Flat Rate Water Service: (Billed in Arrears) $ 53.58

<u>Availability Rate</u>: (Semiannually)

Applicable only to property owners in Carolina Forest and Woodrun Subdivisions in Montgomery County	$24.65

<u>Availability Rate</u>: (Monthly)

Applicable only to property owners in Linville Ridge Subdivision	$ 12.35

<u>Availability Rate</u>: (Monthly rate, billed semiannually)

Applicable only to property owners in Fairfield Sapphire Valley Service Area	$ 9.10

<u>Availability Rate</u>: (Monthly rate, billed quarterly)

Applicable only to property owners in Connestee Falls	$ 4.80

SEWER RATES AND CHARGES

<u>(Excluding Corolla Light and Monteray Shores Service Area, Fairfield Harbour Service Area, Treasure Cove, Register Place Estates, North Hills and Glen Arbor/North Bend Subdivisions, Bradfield Farms, Larkhaven Subdivision, Silverton and Woodland Farms Subdivisions, and Hawthorne at the Green Apartments)</u>

<u>Uniform Sewer Customers:</u>

<u>Monthly Metered Sewer Service</u>:

Base Facility Charge:

Residential (zero usage)	$ 46.31
Commercial (based on meter size with zero usage)	
< 1" meter	$ 46.31
1" meter	$ 115.78
1½" meter	$ 231.55
2" meter	$ 370.48
3" meter	$ 694.65
4" meter	$1,157.75
6" meter	$2,315.50

Usage charge, per 1,000 gallons	$ 3.62

Commercial customers, including condominiums or other property owner associations who bill their members directly, shall have a separate account set up for each meter and each meter shall be billed separately based on the size of the meter and usage associated with the meter.

Monthly Metered Purchased Sewer Service:

Collection Charge (Residential and Commercial)	$ 31.63

Usage charge, per 1,000 gallons
(based on metered water usage from the water supplier)

Service Area	Bulk Provider	
White Oak Plantation/ Lee Forest/Winston Pt.	Johnston County	$ 5.06
Kings Grant	Two Rivers Utilities	$ 3.80
College Park	Town of Dallas	$ 5.70

Monthly Flat Rate Sewer Service:	$ 57.82
Multi-residential customers wh o are served by a master meter shall be charged the flat rate per unit.	$ 57.82

Mt. Carmel Subdivision Service Area:

Monthly Base Facility Charge	$ 6.77
Monthly Collection Charge (Residential and Commercial)	$ 31.63
Usage Charge, per 1,000 gallons (based on metered water usage from the water supplier)	$ 5.88

Regalwood and White Oak Estates Subdivision Service Area:

Monthly Flat Rate Sewer Service

Residential Service	$ 57.82
White Oak High School	$1,799.66
Child Castle Daycare	$ 223.58
Pantry	$ 119.49

WATER AND SEWER – RATE INCREASE

Fairfield Mountain/Apple Valley (a.k.a. Rumbling Bald) Service Area and Highland Shores Subdivision.

Monthly Sewer Rates:

Residential	
Collection charge/dwelling unit	$ 31.63
Treatment charge/dwelling unit	$ 69.50
Total monthly flat rate/dwelling unit	$ 101.13
Commercial and Other	$ 101.13
Minimum monthly collection and treatment charge	$ 101.13
Monthly collection and treatment charge for customers who do not take water service (per single-family unit)	$ 101.13
Treatment charge per dwelling unit	
Small (less than 2,500 gallons per month)	$ 78.50
Medium (2,500 to 10,000 gallons per month)	$ 139.50
Large (over 10,000 gallons per month)	$ 219.50
Collection Charge (per 1,000 gallons)	$ 13.93

The Ridges at Mountain Harbour:

Monthly Sewer Rates (Residential and Commercial):

Collection charge	$ 31.63
Treatment Charge	
< 1" meter	$ 18.42
2" meter	$ 147.36

Availability Rate: (Monthly rate, billed semiannually)

Applicable only to property owners in Fairfield Sapphire Valley Service Area	$ 8.30

Availability Rate: (Monthly rate, billed quarterly)

Applicable only to property owners in Connestee Falls	$ 4.70

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RATE ADJUSTMENT MECHANISM:

The Commission-authorized water and sewer system improvement charge (WSIC/SSIC) rate adjustment mechanism continues in effect and will now be applicable to all customers in CWSNC's North Carolina service areas. It has been reset at zero in the Docket No. W-354, Sub 360 rate case. On January 31, 2019, in Docket No. W-354, Sub 360A, CWSNC applied, under the Rules and Regulations of the Commission, for a rate surcharge to become effective April 1, 2019. The WSIC/SSIC mechanism is designed to recover, between rate case proceedings, the costs associated with investment in certain completed, eligible projects for system or water quality improvement. The WSIC/SSIC mechanism is subject to Commission approval and to audit and refund provisions. Any cumulative system improvement charge recovered pursuant to the WSIC/SSIC mechanism may not exceed 5% of the total annual service revenues approved by the Commission in this general rate case proceeding. Additional information regarding the WSIC/SSIC mechanism is contained in the Commission's Order and can be accessed from the Commission's website at www.ncuc.net, under Docket Information, using the Docket Search feature for docket number "W-354 Sub 356A" and "W-354 Sub 360A".

CREDIT/REFUNDS DUE TO REDUCTION IN FEDERAL CORPORATE INCOME TAX RATE:

On December 22, 2017, President Donald J. Trump signed into law the Tax Cuts and Jobs Act (The Tax Act), which among other things, reduced the federal corporate income tax rate from 35% to 21%, effective for taxable years beginning after December 31, 2017. In the present rate case proceeding, CWSNC's revenue requirement reflects the reduction in the federal corporate income tax rate from 35% to 21%, on the Company's ongoing federal income tax expense. Further, the Commission is requiring that CWSNC refund to its customers the overcollection of federal income taxes related to the decrease in the federal corporate income tax rate for the period beginning January 1, 2018, and corresponding interest, through a surcharge credit for a one-year period beginning with the effective date of the new rates.

With respect to excess deferred income taxes (EDIT) resulting from the reduction in the federal corporate income tax rate, the Commission is requiring that: (1) CWSNC's Protected Federal EDIT shall be flowed back to customers over a 45-year period using the Reverse South Georgia method, in accordance with tax normalization rules required by Internal Revenue Code Section 203(e) and (2) CWSNC's Unprotected Federal EDIT shall be returned to ratepayers through a levelized rider over a period of four years.

CWSNC will provide the applicable dollar amounts concerning (1) the one-year surcharge credit and (2) the federal EDIT rider (refund) shown as separate line items on individual customers' monthly bills, along with explanatory information.

ISSUED BY ORDER OF THE COMMISSION.
This the 21st day of February, 2019.

NORTH CAROLINA UTILITIES COMMISSION
A. Shonta Dunston, Deputy Clerk

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PAGE 1 OF 4

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. W-354, SUB 360

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application by Carolina Water Service, Inc. of North Carolina, 4944 Parkway Plaza Boulevard, Suite 375, Charlotte, North Carolina 28217, for Authority to Adjust and Increase Rates for Water and Sewer Utility Service in All of its Service Areas in North Carolina, Except Corolla Light and Monteray Shores Service Area	)	**NOTICE TO CUSTOMERS IN TREASURE COVE, REGISTER PLACE ESATES, NORTH HILLS, AND GLEN ARBOR/NORTH BEND SUBDIVISIONS, FAIRFIELD HARBOUR SERVICE AREA, BRADFIELD FARMS SUBDIVISION, LARKHAVEN SUBDIVISION, SILVERTON AND WOODLAND FARMS SUBDIVISIONS, AND HAWTHORNE AT THE GREEN APARTMENTS**

WATER AND SEWER – RATE INCREASE

NOTICE IS HEREBY GIVEN that the North Carolina Utilities Commission has issued an Order authorizing Carolina Water Service, Inc. of North Carolina (CWSNC) to charge the following new rates for water and sewer utility service in Treasure Cove, Register Place Estates, North Hills, and Glen Arbor/North Bend Subdivisions, Fairfield Harbour Service Area, Bradfield Farms Subdivision, Larkhaven Subdivision, Silverton and Woodland Farms Subdivisions, and Hawthorne at the Green Apartments:

WATER RATES AND CHARGES

Monthly Metered Water Service (Residential and Commercial):

Base Facility Charge (based on meter size with zero usage)

< 1" meter	$ 16.74
1" meter	$ 41.85
1½" meter	$ 83.70
2" meter	$ 133.92

Usage Charge, per 1,000 gallons	$ 3.75

Availability Rate: (Monthly rate, billed semiannually)

Applicable only to property owners in Fairfield Harbour Service Area	$ 3.28

SEWER RATES AND CHARGES

Monthly Sewer Service:

Residential:

Flat Rate, per dwelling unit	$ 50.46
Bulk Flat rate, per REU	$ 50.46

Commercial and Other:

Monthly Flat Rate (Customers who do not take water service)	$ 50.46

WATER AND SEWER – RATE INCREASE

Monthly Metered Rates
(based on meter size with zero usage)

<1" meter	$ 44.58
1" meter	$111.45
1½" meter	$222.90
2" meter	$356.64

Usage Charge, per 1,000 gallons	$ 1.43

Bulk Sewer Service for Hawthorne at the Green Apartments:

Bulk Flat Rate, per REU	$ 50.46

(To be collected from Hawthorne and delivered to Carolina Water Service, Inc. of North Carolina for treatment of the Hawthorne wastewater pursuant to Docket No. W-218, Sub 291)

Availability Rate: (Monthly rate, billed semiannually)

Applicable only to property owners in Fairfield Harbour Service Area	$ 2.65

RATE ADJUSTMENT MECHANISM:

The Commission-authorized water and sewer system improvement charge (WSIC/SSIC) rate adjustment mechanism continues in effect and will now be applicable to all customers in CWSNC's North Carolina service areas. It has been reset at zero in the Docket No. W-354, Sub 360 rate case. On January 31, 2019, in Docket No. W-354, Sub 360A, CWSNC applied, under the Rules and Regulations of the Commission, for a rate surcharge to become effective April 1, 2019. The WSIC/SSIC mechanism is designed to recover, between rate case proceedings, the costs associated with investment in certain completed, eligible projects for system or water quality improvement. The WSIC/SSIC mechanism is subject to Commission approval and to audit and refund provisions. Any cumulative system improvement charge recovered pursuant to the WSIC/SSIC mechanism may not exceed 5% of the total annual service revenues approved by the Commission in this general rate case proceeding. Additional information regarding the WSIC/SSIC mechanism is contained in the Commission's Order and can be accessed from the Commission's website at www.ncuc.net, under Docket Information, using the Docket Search feature for docket number "W-354 Sub 356A" and "W-354 Sub 360A".

CREDIT/REFUNDS DUE TO REDUCTION IN FEDERAL CORPORATE INCOME TAX RATE:

On December 22, 2017, President Donald J. Trump signed into law the Tax Cuts and Jobs Act (The Tax Act), which among other things, reduced the federal corporate income tax rate from 35% to 21%, effective for taxable years beginning after December 31, 2017. In the present rate case proceeding, CWSNC's revenue requirement reflects the reduction in the federal corporate income tax rate from 35% to 21%, on the Company's ongoing federal income tax expense. Further, the Commission is requiring that CWSNC refund to its customers the overcollection of federal income taxes related to the decrease in the federal corporate income tax rate for the period beginning January 1, 2018, and corresponding interest, through a surcharge credit for a one-year period beginning with the effective date of the new rates.

With respect to excess deferred income taxes (EDIT) resulting from the reduction in the federal corporate income tax rate, the Commission is requiring that: (1) CWSNC's Protected-Federal EDIT shall be flowed back to customers over a 45-year period using the Reverse South Georgia method, in accordance with tax normalization rules required by Internal Revenue Code Section 203(e) and (2) CWSNC's Unprotected Federal EDIT shall be returned to ratepayers through a levelized rider over a period of four years.

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CWSNC will provide the applicable dollar amounts concerning (1) the one-year surcharge credit and (2) the federal EDIT rider (refund) shown as separate line items on individual customers' monthly bills, along with explanatory information.

ISSUED BY ORDER OF THE COMMISSION.
This the 21st day of February, 2019.

NORTH CAROLINA UTILITIES COMMISSION
A. Shonta Dunston, Deputy Clerk

WATER AND SEWER – RATE INCREASE

CERTIFICATE OF SERVICE

I,_____________________________________, mailed with sufficient postage or hand delivered to all affected customers the attached Notices to Customers issued by the North Carolina Utilities Commission in Docket No. W-354, Sub 360, and the Notices were mailed or hand delivered by the date specified in the Order.

This the _____ day of ___________________, 2019.

By: ___________________________________
Signature

____
Name of Utility Company

The above named Applicant, ____, personally appeared before me this day and, being first duly sworn, says that the required Notices to Customers were mailed or hand delivered to all affected customers, as required by the Commission Order dated ____ in Docket No. W-354, Sub 360.

Witness my hand and notarial seal, this the _________ day of _________________, 2019.

____
Notary Public

____
Printed or Typed Name

(SEAL) My Commission Expires: ___________________________________
Date

DOCKET NO. W-218, SUB 486

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Notification by Aqua North Carolina, Inc., 202 MacKenan Court, Cary, North Carolina 27511, of Intention to Begin Operations in an Area Contiguous to a Present Service Area to Provide Sewer Utility Service in The Legacy at Jordan Lake, Phase 5A3, Subdivision in Chatham County, North Carolina	)))))))	ORDER RECOGNIZING CONTIGUOUS EXTENSION AND APPROVING RATES

BY THE COMMISSION: On November 13, 2017, in accordance with N.C. Gen. Stat. § 62-110.3(b) and Commission Rule R10-25(a), Aqua North Carolina, Inc. (Aqua or Company), filed a Notification of Intention to Begin Operations in Area Contiguous to Present Service Area (Notification) for wastewater utility service for The Legacy at Jordan Lake, Phase 5A3, Subdivision, which is contiguous to Aqua's The Legacy at Jordan Lake, Phase 5A, service area in Chatham County, North Carolina. Aqua filed an amendment to the Notification on November 8, 2018. Aqua proposes to charge the same rates for sewer utility service currently approved for The Legacy at Jordan Lake service area.

The Public Staff presented this matter at the Commission's Staff Conference on March 25, 2019. The Public Staff recommended that the Commission issue an order recognizing the contiguous extension and approving rates, but not approving the December 22, 2008 Amended and Restated Agreement by and between The Legacy at Jordan Lake, LLC (Developer) and Aqua (Developer Agreement).

Public Staff Attorney William Grantmyre provided comments and responded to questions from the Commission. Aqua's legal counsel, Jo Anne Sanford, Sanford Law Office, PLLC, Shannon Becker, State President of Aqua, and Ruffin Poole, Aqua's Director of Business Development responded to the Public Staff's comments and also to questions from the Commission.

The Public Staff expressed concern regarding the "prior consent of the developer" clause in the Developer Agreement, taking the position that this clause gives the Developer control of the entire service area. The Public Staff contended that the Commission, not the Developer, has the authority to control the expansion of the service territory. The Public Staff pointed out that because there are other contracts forthcoming from Aqua for approval that contain the same "prior consent of the developer" clause, approval of the Developer Agreement in this docket could set precedent for these future contracts as well. The Public Staff represented that it will also recommend that those contracts not be approved, or at a minimum, that the prior consent clause contained in the contract should not be approved. The Public Staff suggested "[t]hat clause can be taken out of the contracts" without voiding the contracts.

The Public Staff also pointed out that, pursuant to the Developer Agreement, Aqua paid up front $265,442 in costs for the construction of the wastewater treatment plant (WWTP) which resulted in Aqua's taking on the risk of the development. In response to questions from the Commission, Aqua conceded that it is not the normal course of business for Aqua to pay a portion of the water and/or wastewater system; hence, there are only three instances in which Aqua agreed with a developer to pay for approximately 20% of the cost of the construction of a WWTP. Aqua noted that the costs associated with these three WWTPs have been subject to excess capacity adjustments in general rates case proceedings;[1] therefore, customers are not charged for these costs. The Public Staff acknowledged that all three of these developer agreements that have resulted in excess capacity adjustments were entered into quite some years ago by former Aqua leadership and that the person who was Aqua's president at the time departed the Company in 2006.

Aqua recommended that when, if ever, the prior consent option agreed to in the contract were exercised, that would be the appropriate time for the Commission to express its position, approval, or disapproval of the clause. Aqua requested that the Commission approve the Developer Agreement or, in the alternative, that the Commission find (1) that Aqua has not acted imprudently by entering into the Developer Agreement and (2) that Aqua can operate under the Developer Agreement in the contiguous territory for which notification was provided.

Based upon the verified notification, and the entire record in this matter, the Commission makes the following

FINDINGS OF FACT

1. Aqua presently holds water franchises serving approximately 80,000 customers and wastewater franchises serving approximately 19,000 customers throughout North Carolina. Aqua's record of service is satisfactory.

2. Aqua expects eventually to serve 17 sewer customers in The Legacy at Jordan Lake, Phase 5A3, Subdivision. The service area is shown on plans filed with the Notification. The Legacy at Jordan Lake, Phase 5A3, Subdivision is contiguous to Aqua's existing service territory and is not currently being served by any other public utility.

3. The North Carolina Department of Environmental Quality (NCDEQ), Division of Water Resources (DWR), has issued permit number WQ0039593, dated February 9, 2018, for the construction and operation of The Legacy at Jordan Lake, Phase 5A3, Subdivision, wastewater collection system extension.

4. Aqua has entered into an Amended and Restated Agreement dated December 22, 2008, with The Legacy at Jordan Lake, LLC, under which the Developer is contributing the effluent storage pond, upset storage pond, complete wastewater collection system, and spray

[1] In Aqua's most recent general rate case proceeding, Docket No. W-218, Sub 497, the following excess capacity adjustments for Aqua's WWTPs were approved by the Commission: (1) The Legacy at Jordan Lake – 38.67%; Carolina Meadows – 30.63%; and Westfall (aka Booth Mountain) – 35.56%.

irrigation facilities for The Legacy at Jordan Lake, at no cost to Aqua. Developer is also paying $1,121,089 towards the total cost of the construction of the WWTP as a contribution in aid of construction, while Aqua paid the approximately $265,442 balance of the WWTP construction cost.

5. Pursuant to the Developer Agreement, Aqua agreed not to connect any customers located outside of The Legacy at Jordan Lake without the prior consent of the Developer, unless otherwise required by the Commission.

6. The Public Staff has reviewed the Developer Agreement and flagged the following issues for the Commission's attention: (a) Aqua assumed the Developer's risk of development by paying up front construction costs of $265,442 for the WWTP; and the Developer Agreement contains a "prior consent of the Developer" provision with respect to service connections to customers located outside The Legacy at Jordan Lake or the extended service area located outside, but in the general vicinity, of The Legacy at Jordan Lake to be served by the WWTP.

7. The Public Staff recommended that the Commission recognize this contiguous extension and approve the requested rates but not approve the Developer Agreement due to Aqua's up-front payment of constructions costs for the WWTP and due to the "prior consent of the Developer" provision contained therein. Additionally, the Public Staff recommended that the Commission require Aqua to file and request approval of all future amendments to the Developer Agreement within 30 days after signing said amendments.

8. The Commission will not disapprove the Developer Agreement in this docket for Aqua's $265,442 payment up front of construction costs for the WWTP; rather, the Commission will continue to address the proper ratemaking treatment as a result of such payment in future general rate case proceedings for Aqua.

9. The Commission will not disapprove the Developer Agreement in this docket for the "prior consent of the developer" clause contained therein. Such prior consent clause will not prevent the Commission from exercising its authority to control the growth of the franchise.

10. It is appropriate for Aqua to bring any exercise of the "prior consent clause" to the Commission for approval or disapproval prior to rejecting a service connection to any customer located outside The Legacy at Jordan Lake service area.

11. Aqua may operate under the Developer Agreement for the contiguous territory for which notification has been provided in this docket.

12. Aqua has filed all exhibits required with the notification.

13. Aqua has the technical, managerial, and financial capacity to provide sewer utility service in this franchise location.

14. The Public Staff has recommended that Aqua be required to post a $10,000 bond for The Legacy at Jordan Lake, Phase 5A3, Subdivision. Aqua currently has $13,000,000 of bonds

posted with the Commission. Of this amount, $12,200,000 of bond surety is assigned to specific subdivisions, and $800,000 of bond surety is unassigned.

CONCLUSIONS

The Commission acknowledges that N.C. Gen. Stat. § 62-110 - Certificate of Convenience and Necessity, Subsection (a) permits Aqua to extend service to The Legacy at Jordan Lake, Phase 5A3, Subdivision, which is contiguous to Aqua's The Legacy at Jordan Lake, Phase 5A, service area in Chatham County, North Carolina, without first obtaining a certificate of public convenience and necessity from the Commission. However, N.C. Gen. Stat. § 62-110.3 – Bond Required for Water and Sewer Companies, Subsection (b) further provides:

> (b) Notwithstanding the provisions of G.S. 62-110(a) and subsection (a) of this section, no water or sewer utility shall extend service into territory contiguous to that already occupied without first having advised the Commission of such proposed extension. Upon notification, the Commission shall require the utility to furnish an appropriate bond, taking into consideration both the original service area and the proposed extension.

Further, Commission Rule R10-25 – Notification of Contiguous Extension, Subsection (a) states that:

> At least 30 days prior to constructing, acquiring, or beginning the operation of any public utility plant or equipment capable of providing water utility service to customers in territory contiguous to that already occupied, for which, by virtue of its contiguity, no certificate of public convenience and necessity is required, a public utility shall provide written notice to the Commission of its intention to construct, acquire, or begin operation of such plant. The notice shall be in the form approved by the Commission and shall identify the area to be served by the extension.

Consequently, under North Carolina General Statute and Commission Rule, neither a water nor a sewer public utility is required to obtain the approval of the Commission recognizing a contiguous extension. The utility is obligated to notify the Commission of its intent to extend service and to furnish a bond in the amount deemed appropriate by the Commission. The Public Staff agreed with this conclusion at the March 25, 2019 Staff Conference. In this particular docket, Aqua has notified the Commission of its intent to extend service into the contiguous territory on the form approved by the Commission and has posted the appropriate bond. Therefore, the Commission recognizes the contiguous extension as filed.

The Commission notes that on Page 76, in Footnote No. 25, of the Commission's Order Approving Partial Settlement Agreement and Stipulation, Granting Partial Rate Increase, and Requiring Customer Notice issued on December 18, 2018, in Docket No. W-218, Sub 497, (the Sub 497 Rate Case Order), the Commission stated as follows:

> With respect to future proceedings to review applications for Certificates of Public Convenience and Necessity and/or notifications of contiguous extensions filed with the Commission pursuant to Commission Rule R7-38, the Commission expects that, going forward, the Public Staff will audit and more closely scrutinize water and sewer contracts governing capacity and/or connection fees between the developer, the utility, and/or any third party from whom wastewater capacity is purchased. In the future, the Public Staff shall, for all such water utility contracts (not only those to which Aqua is a party), more closely investigate developer contracts before recommending the approval of such contracts to the Commission.

As a result of that Commission directive, in the present docket, the Public Staff has raised two issues for the Commission's attention regarding the Developer Agreement. First, the Public Staff asserted that Aqua assumed the development risk of The Legacy at Jordan Lake when Aqua paid the approximately $265,442 balance of the WWTP construction cost. The Public Staff noted that, to this end, the Commission has approved an excess capacity adjustment for The Legacy at Jordan Lake in Aqua's last three general rate cases. Second, the Public Staff objected to Aqua's agreeing not to connect any customers located outside of The Legacy at Jordan Lake to the WWTP without prior consent of the Developer, unless otherwise required by the Commission, taking the position that the Commission, not the Developer, controls the customer growth in the utility's franchised service area.

At the March 25, 2019 Staff Conference, Aqua requested that the Developer Agreement be approved, or in the alternative, that the Commission find: (1) that Aqua has not acted imprudently by entering into the Developer Agreement and (2) that Aqua can operate under the Developer Agreement in the contiguous territory for which notification was provided. Aqua also recommended that when, if ever, the prior consent option agreed to in the contract were exercised, that would be the appropriate time for the Commission to rule on such matter.

The Public Staff has appropriately brought this matter to the attention of the Commission in a timely manner. The Commission finds the additional information provided by the Public Staff and Aqua at the March 25, 2019 Staff Conference to be informative and pertinent in making its decision in this matter. For the reasons set forth below, the Commission concludes that in its discretion that the Commission will not disapprove the Agreement for Aqua's upfront payment of $265,442 in constructions costs related to the WWTP or for the "prior consent of the developer" clause contained in the Agreement and that Aqua may operate under the Developer Agreement in the contiguous territory for which notification was provided.

As in past general rate case proceedings, the Commission notes that an excess capacity adjustment for The Legacy at Jordan Lake, provided that it is appropriate and supported by the evidence of record, will continue in Aqua's next general rate case proceeding. The Commission recognizes that the Developer Agreement is unusual in that it is one of three instances in which Aqua has paid a portion of the construction costs up front resulting in excess capacity and Aqua's being subject to excess capacity adjustments when establishing customer rates in general rate case proceedings. The Commission acknowledges that the original Developer Agreement related to this docket was entered into 12 or 13 years ago, either in 2005 or 2006 and that the officers who executed the Developer Agreement on behalf of Aqua have since left the Company. The

Commission agrees with Aqua that customers are not harmed by this Developer Agreement due to the ratemaking treatment approved by the Commission in Aqua's general rate case proceedings, specifically, the reduction to rate base resulting from the excess capacity adjustment which reduces customer rates. For these reasons, the Commission concludes that it will not disapprove the Developer Agreement in this docket for Aqua's $265,442 payment up front of construction costs for the WWTP; rather, the Commission will continue to address the proper ratemaking treatment as a result of such payment in future general rate case proceedings for Aqua.

The Commission observes that Paragraph 7.2 Operation of Wastewater Utility System Assets, subsection (a) of the Developer Agreement provides in pertinent part:

> [Aqua] shall not connect any customers located outside The Legacy or the ESA[1] to the Wastewater Utility System without the prior consent of Jordan Lake, <u>unless otherwise required by the Commission.</u> [Emphasis added.]

The Commission considers that the phrase "unless otherwise required by the Commission" recognizes the Commission's ultimate jurisdiction over this matter. Thus, the Commission does not consider that the prior consent clause will prevent the Commission from exercising its authority to control the growth of the franchise, which is the concern expressed by the Public Staff. As a general principle, the Commission considers that, to the extent a developer has contributed all or a large percentage of major subdivision wastewater infrastructure, such as the WWTP, and can reasonably be expected to utilize the capacity from the plant for lots within the subdivision the developer is developing, it is reasonable that the utility reserve such capacity for the developer. On the other hand, the Commission is of the opinion that should subsequent events indicate that capacity in excess of the developer's needs become available (i.e., a NCDEQ-DWR reduction in the capacity needed to serve lots), the developer should not be allowed to prohibit the utility from using capacity beyond the subdivision boundaries to serve additional customers. Accordingly, the Commission concludes that, if and when Aqua would be called upon to deny extension of service based on the prior consent clause, Aqua shall request a ruling from the Commission based on the facts and circumstances presented at that time prior to rejecting a service connection to any customer located beyond the subdivision boundaries.

Based on the foregoing and the recommendations of the Public Staff, the Commission is of the opinion that $10,000 of Aqua's unassigned bond surety should be assigned to the contiguous extension; that the contiguous extension by Aqua in The Legacy at Jordan Lake, Phase 5A3, Subdivision should be recognized; and that the requested rates should be approved.

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[1] On Page 3 of the Developer Agreement under Paragraph 1 Definitions, Subsection 1.14 defines ESA as follows: "'ESA' shall mean an extended service area located outside, but in the general vicinity, of The Legacy to be served by the Wastewater Utility System".

Further, for the reasons set forth herein, the Commission will not disapprove the Agreement for Aqua's upfront payment of $265,442 for construction costs related to the WWTP or for the "prior consent of the developer" clause contained therein. Aqua may operate under the Developer Agreement in the contiguous territory for which notification was provided. The Commission concludes that Aqua should bring the exercise of such clause in the future to the Commission for a ruling prior to rejecting a service connection to any customer located outside The Legacy or an extended service area located outside, but in the general vicinity of The Legacy at Jordan Lake to be served by the WWTP. Furthermore, the Commission concludes that Aqua shall file and request Commission approval of all future amendments to the Developer Agreement within 30 days after signing said amendments.

Finally, the Commission maintains that the conclusions reached herein are based on the limited facts and circumstances presented and shall not be cited or treated as precedent in future proceedings.

IT IS, THEREFORE, ORDERED as follows:

1. That, for the reasons set forth herein, the Commission will not disapprove the Amended and Restated Agreement dated December 22, 2008, between The Legacy at Jordan Lake, LLC, and Aqua for Aqua's payment up front of $265,442 in construction costs or for the "prior consent of the developer" clause contained therein. Aqua may operate under the Developer Agreement in the contiguous territory for which notification was provided.

2. That Aqua shall bring any exercise of the "prior consent clause" to the Commission for approval or disapproval prior to rejecting a service connection to any customer located outside The Legacy at Jordan Lake service area.

3. That Aqua shall file all future amendments to the Developer Agreement within 30 days after the execution of any such amendment and that the Public Staff shall review such amendments and make a recommendation to the Commission regarding the amendment.

4. That $10,000 of Aqua's unassigned surety bond is assigned to The Legacy at Jordan Lake, Phase 5A3, Subdivision. The remaining unassigned bond surety shall be $750,000 (a total of $50,000 is being assigned concurrently by Commission Orders issued in Docket Nos. W-218, Subs 480, 486, 494, 500, and 513).

5. That the contiguous extension of wastewater utility service from The Legacy at Jordan Lake, Phase 5A, service area into The Legacy at Jordan Lake, Phase 5A3, Subdivision in Chatham County, North Carolina, is recognized as meeting the Commission's criteria for the extension.

6. That Appendix A-14, attached hereto, acknowledges the contiguous extension of The Legacy at Jordan Lake, Phase 5A3, pursuant to N.C. Gen. Stat. § 62-110(a) to Aqua's Certificate of Public Convenience and Necessity covering the contiguous extension.

7. That Aqua's existing Schedule of Rates approved by Commission Order issued on December 18, 2018, in Docket No. W-218, Sub 497, is approved for utility service in The Legacy at Jordan Lake, Phase 5A3, Subdivision.

8. That the conclusions reached herein are based on the limited facts and circumstances presented and shall not be cited or treated as precedent in future proceedings.

ISSUED BY ORDER OF THE COMMISSION.
This the 26th day of April, 2019.

NORTH CAROLINA UTILITIES COMMISSION
A. Shonta Dunston, Deputy Clerk

WATER AND SEWER – WATER CONTIGUOUS EXTENSION

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

APPENDIX A-14

DOCKET NO. W-218, SUB 486

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

AQUA NORTH CAROLINA, INC.

is given this acknowledgement of
contiguous extension pursuant to N.C. Gen. Stat. § 62-110(a) to the

CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

to provide water utility service in

BEECHWOOD COVE, CEDAR TERRACE, CHATHAM, HIDDEN VALLEY, POLK'S LANDING, POLK'S TRAIL AND WOODBRIDGE SUBDIVISIONS
AND

to provide sewer utility service in

CAROLINA MEADOWS, COUNTY LINE PLAZA, GOVERNORS CLUB, GOVERNORS FOREST, GOVERNORS VILLAGE, **THE LEGACY AT JORDAN LAKE (PHASES 1, 2, 3, 4A, 5A, AND 5A3)**, THE PRESERVE AT JORDAN LAKE AND WESTFALL SUBDIVISIONS

Chatham County, North Carolina

subject to any orders, rules, regulations, and
conditions now or hereafter lawfully made
by the North Carolina Utilities Commission.

ISSUED BY ORDER OF THE COMMISSION.

This the 26th day of April, 2019.

NORTH CAROLINA UTILITIES COMMISSION
A. Shonta Dunston, Deputy Clerk

DOCKET NO. WR-2773, SUB 0

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application by 2905 Cottage Place, LLC, 3926 Marcom Street, Raleigh, North Carolina 27606, for Certificate of Authority to Charge for Water and/or Sewer Service Utilizing the Hot Water Capture, Cold Water Allocation Method in North Lake Apartments in Guilford County, North Carolina	)	ORDER GRANTING HWCCWA CERTIFICATE OF AUTHORITY AND APPROVING RATES

BY THE COMMISSION: On April 11, 2019, 2905 Cottage Place, LLC (Applicant), filed an application with the Commission seeking a certificate of authority to charge for water and/or sewer utility service utilizing the **hot water capture, cold water allocation (HWCCWA)** method provided in North Lake Apartments (formerly Mallard Lake Apartments) in Guilford County, North Carolina, and for approval of rates. The Applicant purchases water and sewer service from the City of Greensboro.

Based upon the filings of the Applicant, the Public Staff has recommended approval of a monthly administrative fee of $13.97 (consisting of $3.75 for the Applicant's meter reading, billing, and collecting costs plus a pass through of Greensboro's $10.22 base charges for water and sewer service). Based upon 4,000 gallons per month usage and rates of $4.01 per 1,000 gallons for water and $4.97 per 1,000 gallons for sewer, the total monthly bill will be $49.89 ($35.92 usage charge and $13.97 administrative fee).

Based upon the foregoing, the Commission is of the opinion that the Applicant should be granted a HWCCWA certificate of authority to charge for water and/or sewer service and that the Public Staff's recommended rates should be approved. The Commission is also of the opinion that, if Greensboro's base charges and/or usage rates should be reduced for any reason, the Applicant should be required to notify the Commission immediately for a tariff revision.

IT IS, THEREFORE, ORDERED as follows:

1. That 2905 Cottage Place, LLC, is granted a certificate of authority to charge for water and/or sewer service utilizing the hot water capture, cold water allocation method in North Lake Apartments in Guilford County, North Carolina, pursuant to N.C. Gen. Stat. § 62-110(g)(1a) and Commission Rules R18-1 through R18-8 of Chapter 18 Provision of Water and Sewer Service by Lessors. This Order shall constitute the Certificate of Authority to Charge for Water and/or Sewer Service Utilizing the Hot Water Capture, Cold Water Allocation Method.

2. That the Schedule of Rates, attached as Appendix A, is approved and deemed to be filed with the Commission pursuant to N.C. Gen. Stat. § 62-138. **Said Schedule of Rates is authorized to become effective for service rendered on and after the date of this Order.**

3. That, if Greensboro's base charges and/or usage rates should be reduced for any reason, the Applicant shall notify the Commission immediately for a tariff revision.

4. That a copy of the Notice to Customers, attached as Appendix B, shall be mailed with sufficient postage or hand delivered by the Applicant to all its customers in North Lake Apartments contemporaneously with the next billing to customers.

5. That, if the service area is sold or the ownership changes, the Applicant and the new owner shall file an Application for Transfer of Authority (Form WR2 may be found on the Commission's website – www.ncuc.net). Failure to do so may result in revocation of the certificate of authority and suspension of rates.

ISSUED BY ORDER OF THE COMMISSION.

This the 7th day of May, 2019.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

APPENDIX A

SCHEDULE OF RATES

for

2905 COTTAGE PLACE, LLC

for water and sewer utility (HWCCWA) service in

NORTH LAKE APARTMENTS

Guilford County, North Carolina

Monthly Metered Rates:

Water usage charge, per 100 cubic feet (ccf)	$3.00
Sewer usage charge, per 100 cubic feet (ccf)	$3.72
or	
Water usage charge, per 1,000 gallons	$4.01
Sewer usage charge, per 1,000 gallons	$4.97

Monthly Administrative Fee:	$13.97 per unit
Bills Due:	On billing date
Bills Past Due:	25 days after billing date
Billing Frequency:	Shall be monthly for service in arrears

Issued in Accordance with Authority Granted by the North Carolina Utilities Commission in Docket No. WR-2773, Sub 0, on this the 7th day of May, 2019.

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

APPENDIX B

NOTICE TO CUSTOMERS
DOCKET NO. WR-2773, SUB 0
BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

Notice is hereby given that the North Carolina Utilities Commission has granted 2905 Cottage Place, LLC (3926 Marcom Street, Raleigh, North Carolina 27606), a certificate of authority to charge for water and/or sewer service **utilizing the hot water capture, cold water allocation method** provided in North Lake Apartments in Guilford County, North Carolina, for the purpose of passing along the cost of purchasing water and sewer utility service from the City of Greensboro. The rates approved by the Commission are as follows and are effective for service provided on and after the date of this Notice:

Monthly Metered Rates:

Water usage charge, per 100 cubic feet (ccf)	\$3.00
Sewer usage charge, per 100 cubic feet (ccf)	\$3.72

or

Water usage charge, per 1,000 gallons	\$4.01
Sewer usage charge, per 1,000 gallons	\$4.97

Monthly Administrative Fee: \$13.97 per unit

The average monthly residential water and sewer bill will be \$49.89, based on an estimated average usage of 4,000 gallons.

ISSUED BY ORDER OF THE COMMISSION.
This the 7th day of May, 2019.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

WATER RESELLERS – TARIFF REVISION FOR PASS-THROUGH

DOCKET NO. WR-1883, SUB 2

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Notification by SBMF Phase 3, LLC,	)	ORDER APPROVING TARIFF
806 Green Valley Road, Suite 311,	)	REVISION, GRANTING
Greensboro, North Carolina 27408, of	)	INTERIM AUTHORITY TO
Revised Rates and Fees for Charging for	)	PASS THROUGH FLAT RATE
Water and/or Sewer Utility Service in	)	FOR SEWER SERVICE, AND
Stillwater at Southbridge Apartments,	)	REQUIRING CUSTOMER NOTICE
Phase III, in Onslow County, North Carolina	)	

BY THE COMMISSION: On June 26, 2019, the Governor signed into law House Bill 432 (S.L. 2019-56) [1] This legislation, entitled "An Act Providing That if the Utilities Commission Approves a Flat Rate to be Charged by a Water or Sewer Utility for Water or Sewer Services to Contiguous Dwelling Units, the Lessor of the Units May Pass Through and Charge the Tenants That Same Flat Rate", added a new subsection (1b) to N.C. Gen. Stat. § 62-110(g), providing as follows:

> (1b) Notwithstanding the provisions of subdivisions (1) and (1a) of this subsection, if the Commission approves a flat rate to be charged by a water or sewer utility for the provision of water or sewer services to contiguous dwelling units, the lessor may pass through and charge the tenants of the contiguous dwelling units the same flat rate for water or sewer services, rather than a rate based on metered consumption, and an administrative fee as authorized in subdivision (2) of this subsection. Bills for water and sewer service sent by the lessor to the lessee shall contain all the information required by sub-sub-subdivisions e.2. through e.5. of subdivision (1a) of this subsection.

On August 21, 2019, SBMF Phase 3, LLC (Applicant), filed with the Commission a notification of revised rates and fees for charging for water and sewer service to its lessees in Stillwater at Southbridge Apartments, Phase III, in Onslow County, North Carolina, to reflect the increased cost of purchasing water service from Onslow Water and Sewer Authority (ONWASA). The Applicant also requested that the Commission grant the Applicant authority to pass through and charge each of the lessees of its contiguous dwelling units the monthly flat rate of $58.08 from Pluris, LLC for sewer service as allowed by N.C.G.S. § 62-110(g)(1b). This is one of three such applications received by the Commission since the enactment of N.C.G.S. § 62-110(g)(1b).[2]

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[1] Such legislation became effective June 26, 2019.

[2] The three applications pertain to the following dockets: Docket No. WR-1883, Sub 2; WR-1390, Sub 3; and WR-2488, Sub 5.

WATER RESELLERS – TARIFF REVISION FOR PASS-THROUGH

On August 29, 2019, the Public Staff – North Carolina Utilities Commission (Public Staff) filed with the Commission its recommendation concerning the Applicant's August 21, 2019 notification of revised rates and fees. On September 4, 2019, the Commission issued an Order Suspending Tariff Revision pending review of the additional information requested by the Commission Staff from by the Applicant.

Based upon the filings of the Applicant, the Public Staff has recommended approval of a monthly flat rate of $58.08 per residential unit for sewer service and a monthly administrative fee of $10.59 (consisting of $3.75 for the Applicant's meter reading, billing, and collecting costs plus a pass through of ONWASA's $6.84 base charges for water service). Based upon 4,000 gallons per month usage and a rate of $4.24 per 1,000 gallons for water, the total monthly bill will be $85.63 ($16.96 usage charge for water, $58.08 flat rate for sewer, and a $10.59 administrative fee).

Based upon the foregoing and the entire record herein, the Commission concludes that the Public Staff's recommended rates for water utility service and the monthly administrative fee should be approved. Further, the Commission concludes that the Applicant's requested authority to pass through and charge each of the lessees of its contiguous dwelling units the monthly flat rate of $58.08 from Pluris, LLC, for sewer service should be granted on an interim basis with the following condition: that the Applicant shall apply the flat rate for sewer service on a going-forward basis when current leases expire to ensure that no lessee with an existing lease is charged for flat rate sewer service in addition to the Applicant's current rental fee.

Finally, the Commission finds good cause to require the Applicant to provide customer notice of the matters approved herein by providing a copy of this Order to its lessees; to promptly notify the Commission of any changes in ONWASA's or Pluris's rates; and to promptly file an Application for Transfer of Authority (Form WR2) jointly with the new owner, if the service area is sold or the ownership changes,.

In the near future, in a generic rulemaking docket to be established, the Commission will revise its Rules and Regulations in Chapter 18, Provision of Water and Sewer Service by Lessors to implement N.C.G.S. § 62-110(g)(1h) and update its form applications to reflect this statutory change. Upon the adoption of those rules the Commission will consider whether the Applicant's filings meet the requirements of those rules and whether the authority granted in this Order should be allowed on a permanent basis.

IT IS, THEREFORE, ORDERED as follows:

1. That SBMF Phase 3, LLC, shall be, and is hereby granted a tariff revision for water utility service for Stillwater at Southbridge Apartments, Phase III, in Onslow County, North Carolina, as set forth herein;

2. That SBMF Phase 3, LLC, shall be, and is hereby granted interim authority to pass through and charge its lessees in the Stillwater at Southbridge Apartments, Phase III, in Onslow County, North Carolina, the flat rate charge for sewer service reflected in the Public Staff's memorandum filed in this docket on August 29, 2019, and as set forth in the attached Schedule of Rates (Appendix A);

3. That SBMF Phase 3, LLC, shall apply the new flat sewer charge authorized herein only after the expiration of current leases to ensure that lessees with current leases are not charged for flat rate sewer service in addition to the Applicant's current rental fee;

4. That, if ONWASA's base charges and/or usage rates for water service or Pluris' flat rate charge for sewer service should be reduced for any reason, the Applicant shall notify the Commission immediately for a tariff revision;

5. That a copy of this Order and the Schedule of Rates, attached hereto as Appendix A, shall be mailed with sufficient postage or hand delivered by the Applicant to each of its lessees in Stillwater at Southbridge Apartments, Phase III, contemporaneously with the next billing of customers;

6. That upon adoption of rules implementing N.C.G.S. § 62-110(g)(1b) and updating of the Commission's form applications, the Commission will proceed as appropriate to consider the Applicant's requested authority on a permanent basis; and

7. That, if the Applicant's service area is sold or the ownership changes, the Applicant and the new owner shall promptly file an Application for Transfer of Authority (Form WR2 may be found on the Commission's website – www.ncuc.net). Failure to do so may result in revocation of the certificate of authority and suspension of rates.

ISSUED BY ORDER OF THE COMMISSION.

This the 21st day of October, 2019.

NORTH CAROLINA UTILITIES COMMISSION
Kimberley A. Campbell, Chief Clerk

APPENDIX A

SCHEDULE OF RATES

for

SBMF PHASE 3, LLC

for water and sewer utility service in

STILLWATER AT SOUTHBRIDGE APARTMENTS, PHASE III

Onslow County, North Carolina

Monthly Metered Rates:

Water usage charge, per 100 cubic feet (ccf)	$ 3.17
or	
Water usage charge, per 1,000 gallons	$ 4.24

Monthly Flat Rate Sewer Charge: [1/] $58.08 per unit

[1/] This flat rate charge was approved by the Commission on an interim basis pursuant to N.C. Gen. Stat. § 62-110(g)(1b) and the Commission's Order issued October 21, 2019, in Docket No. WR-1883, Sub 2.

Monthly Administrative Fee:	$10.59 per unit
Bills Due:	On billing date
Bills Past Due:	25 days after billing date
Billing Frequency:	Shall be monthly for service in arrears

Issued in Accordance with Authority Granted by the North Carolina Utilities Commission in Docket No. WR-1883, Sub 2, on this the 21st day of October, 2019.

WATER RESELLER NON-CONTIGUOUS – CERTIFICATE

DOCKET NO. WRN-86, SUB 0

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application by HPA JV Borrower 2019-1 ATH, LLC, 180 North Stetson Avenue, Suite 3650, Chicago, Illinois 60601, for Certificate of Authority to Charge for Water and Sewer Service and for Approval of Administrative Fee for Its Single-Family Dwellings in North Carolina	)))))))	ORDER GRANTING CERTIFICATE OF AUTHORITY AND APPROVING ADMINISTRATIVE FEE

BY THE COMMISSION: On September 4, 2019, HPA JV Borrower 2019-1 ATH, LLC, (Applicant) filed an application with the Commission seeking a certificate of authority to charge for water and sewer service and for approval of a monthly administrative fee for single-family dwellings in North Carolina owned by the Applicant and available for rental as a residence.

Based upon the filings of the Applicant, the Public Staff – North Carolina Utilities Commission (Public Staff) recommends (1) approval of a certificate of authority for the Applicant to charge for water and sewer service in the single-family dwellings in North Carolina owned by the Applicant and available for rental as a residence and (2) approval of a monthly administrative fee of $3.75 per residence.

Based upon the foregoing, the Commission grants the Applicant a certificate of authority to charge for water and sewer service and approves the monthly administrative fee of $3.75 requested by the Applicant and recommended by the Public Staff.

With respect to charges by the supplier to the Applicant for water and sewer service, the Commission concludes that, pursuant to N.C. Gen. Stat. § 62-110(g) and Commission Rules and Regulations in Chapter 18 Provision of Water and Sewer Service by Lessors, the Applicant shall be allowed to pass through the actual costs of providing water and sewer service to lessees who occupy the leased single-family dwellings owned by the Applicant. Such actual costs shall include both the consumption charges and the base charges, if applicable, billed by the suppliers.

The Commission finds and concludes that the List of Single-Family Dwellings in North Carolina Owned by the Applicant, filed on September 4, 2019, with the application and attached hereto as Appendix C, should be approved. With respect to single-family dwellings purchased by the Applicant subsequent to September 4, 2019, and available for rental for residential purposes, the Applicant shall similarly abide by the rules and regulations of the Commission as well as the specific directives established herein. Moreover, the Applicant shall update the Commission regarding such properties on the Annual Update of Utility Service Areas for Single-Family Dwellings Charging for Water and/or Sewer Service (Form WRN-2) on or before April 30th, each year following the certificate approval year.

Furthermore, the Commission finds and concludes that if the Applicant desires to change its monthly administrative fee in the future, the Applicant shall be required to request and obtain Commission approval by further order of the Commission for an administrative fee revision.

IT IS, THEREFORE, ORDERED as follows:

1. That HPA JV Borrower 2019-1 ATH, LLC, is granted a certificate of authority to charge for water and sewer utility service for single-family dwellings in North Carolina owned by the Applicant and available for rental as a residence, pursuant to N.C. Gen. Stat. § 62-110(g) and Commission Rules and Regulations in Chapter 18 Provision of Water and Sewer Service by Lessors. This Order shall constitute the Certificate of Authority to Charge for Water and Sewer Service;

2. That the Applicant shall pass through to each lessee the actual consumption charges and the base charges, if applicable, charged by the supplier to the Applicant for the applicable single-family dwelling owned by the Applicant which has been leased for residential purposes;

3. That the Schedule of Rates, attached as Appendix A, is approved and deemed filed with the Commission pursuant to N.C. Gen. Stat. § 62-138. Said Schedule of Rates is authorized to become effective for bills rendered on and after the date of this Order;

4. That the List of Single-Family Dwellings in North Carolina Owned by the Applicant, filed on September 4, 2019, attached as Appendix C, is approved. With respect to single-family dwellings purchased by the Applicant subsequent to September 4, 2019, and available for lease for residential purposes, the Applicant shall similarly abide by the directives established for the Certificate of Authority approved herein and shall update the Commission regarding such properties as required hereinbelow in Decretal Paragraph No. 7;

5. That if the Applicant desires to change its monthly administrative fee, the Applicant shall request and obtain approval from the Commission for an administrative fee revision by filing a Notification of Revised Administrative Fee for Single-Family Dwellings (Form WRN-3 may be found on the Commission's website – www.ncuc.net);

6. That a copy of the Schedule of Rates and the Notice to Lessees, attached as Appendices A and B, respectively, shall be mailed with sufficient postage or hand delivered by the Applicant to all its lessees in North Carolina contemporaneously with the next billing to such lessees; and

7. That the Applicant is required to file an Annual Update of Utility Service Areas for Single-Family Dwellings Charging for Water and/or Sewer Service on or before April 30th, each year following the certificate approval year (Form WRN-2 may be found on the Commission's website – www.ncuc.net). Failure to do so may result in revocation of the certificate of authority and suspension of the monthly administrative fee.

ISSUED BY ORDER OF THE COMMISSION.

This the 5th day of December, 2019.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

APPENDIX A

SCHEDULE OF RATES

for

HPA JV BORROWER 2019-1 ATH, LLC

for water and sewer utility service in

ALL ITS LEASED SINGLE-FAMILY DWELLINGS
IN NORTH CAROLINA OWNED BY
HPA JV BORROWER 2019-1 ATH, LLC

Monthly Metered Water and Sewer Charges:

Base charge
Shall be the same as charged by the supplier of the service.

Usage charge
Shall be the same as charged by the supplier of the service.

Monthly Administrative Fee:	$3.75 per residence
Bills Due:	On billing date
Bills Past Due:	25 days after billing date
Billing Frequency:	Shall be monthly for service in arrears
Returned Check Charge:	Pursuant to Commission Rule R18-6(d)

Issued in Accordance with Authority Granted by the North Carolina Utilities Commission in Docket No. WRN-86, Sub 0, on this the 5th day of December, 2019.

APPENDIX B

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

NOTICE TO LESSEES
DOCKET NO. WRN-86, SUB 0
BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

Notice is hereby given that the North Carolina Utilities Commission has granted HPA JV Borrower 2019-1 ATH, LLC (180 North Stetson Avenue, Suite 3650, Chicago, Illinois 60601), a certificate of authority to charge for water and sewer utility service provided in single-family dwellings in North Carolina owned by HPA JV Borrower 2019-1 ATH, LLC, and available for rental as a residence, for the purpose of passing along the actual cost of purchasing water and sewer utility service from its suppliers.

In addition, the Commission has approved a monthly administrative fee of $3.75 to compensate HPA JV Borrower 2019-1 ATH, LLC, for billing and collection expenses, which is effective for bills rendered on and after the date of this Notice. Information regarding this proceeding can also be accessed from the Commission's website at www.ncuc.net under the docket number of this proceeding (i.e., WRN-86 Sub 0).

ISSUED BY ORDER OF THE COMMISSION.
This the 5th day of December, 2019.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

LIST OF SINGLE-FAMILY DWELLINGS OWNED BY
HPA JV BORROWER 2019-1 ATH, LLC (WRN-86, SUB 0)
AND LEASED OR AVAILABLE FOR LEASE AS A RESIDENCE

Assigned Number	Address	City	State	Zip Code	County	Water Supplier	Sewer Supplier
1	15030 Northgreen Dr	Huntersville	NC	28078	Cabarrus	City of Charlotte	City of Charlotte
2	10325 Merlin Meadows Ct	Charlotte	NC	28277	Mecklenburg	City of Charlotte	City of Charlotte
3	10401 Ebbets Rd	Charlotte	NC	28273	Mecklenburg	City of Charlotte	City of Charlotte
4	1332 Bershire Ln	Charlotte	NC	28262	Mecklenburg	City of Charlotte	City of Charlotte
5	2421 Arden Gate Ln	Charlotte	NC	28262	Mecklenburg	City of Charlotte	City of Charlotte
6	4406 Lenox Hill Pl	Charlotte	NC	28269	Mecklenburg	City of Charlotte	City of Charlotte
7	5614 Falls Ridge Ln	Charlotte	NC	28269	Mecklenburg	City of Charlotte	City of Charlotte
8	9142 Swallow Tail Ln	Charlotte	NC	28269	Mecklenburg	City of Charlotte	City of Charlotte
9	20106 N Cove Rd	Cornelius	NC	28031	Mecklenburg	City of Charlotte	City of Charlotte
10	13611 Toka Ct	Huntersville	NC	28078	Mecklenburg	City of Charlotte	City of Charlotte
11	9321 Brown Gelly Dr	Huntersville	NC	28078	Mecklenburg	City of Charlotte	City of Charlotte
12	15000 Boudins Ln	Charlotte	NC	28278	Mecklenburg	City of Charlotte	City of Charlotte
13	11009 Charmont Place	Huntersville	NC	28078	Mecklenburg	City of Charlotte	City of Charlotte
14	10610 Spring Rain Ct	Charlotte	NC	28278	Mecklenburg	City of Charlotte	City of Charlotte
15	1236 Danielle Downs Ct SE	Concord	NC	28025	Cabarrus	City of Concord	City of Concord
16	209 Patrick Ave	Concord	NC	28025	Cabarrus	City of Concord	City of Concord
17	4137 Appleton Hollow Ave NW	Concord	NC	28027	Cabarrus	City of Concord	City of Concord
18	1810 Trentwood Dr	Greensboro	NC	27408	Guilford	City of Greensboro	City of Greensboro
19	5215 Bodie Ln	Greensboro	NC	27455	Guilford	City of Greensboro	City of Greensboro
20	3143 Helmsley Ct	Kannapolis	NC	28027	Cabarrus	City of Kannapolis	City of Kannapolis
21	5829 Brambleton Ave	Raleigh	NC	27610	Wake	City of Raleigh	City of Raleigh
22	3108 Selkirk Pl	Raleigh	NC	27604	Wake	City of Raleigh	City of Raleigh
23	11198 Bridgewater Drive	Huntersville	NC	28078	Cabarrus	HOA	HOA
24	332 Falls Dr	Clayton	NC	27527	Johnston	Johnston County Public Utilities	Johnston County Public Utilities

. LIST OF SINGLE-FAMILY DWELLINGS OWNED BY HPA JV BORROWER 2019-1 ATH, LLC (WRN-86, SUB 0) AND LEASED OR AVAILABLE FOR LEASE AS A RESIDENCE

Assigned Number	Address	City	State	Zip Code	County	Water Supplier	Sewer Supplier
25	121 Saratoga Ln	Clayton	NC	27520	Johnston	Johnston County Public Utilities	Johnston County Public Utilities
26	4828 Pepper Dr	Harrisburg	NC	28075	Cabarrus	Town of Harrisburg	Town of Harrisburg
27	8403 Mossy Cup Trl	Harrisburg	NC	28075	Cabarrus	Town of Harrisburg	Town of Harrisburg
28	104 Renville Pl	Mooresville	NC	28115	Iredell	Town of Mooresville	Town of Mooresville
29	145 Eden Avenue	Mooresville	NC	28115	Iredell	Town of Mooresville	Town of Mooresville
30	162 Blueview Rd	Mooresville	NC	28117	Iredell	Town of Mooresville	Town of Mooresville
31	289 Flanders Dr	Mooresville	NC	28115	Iredell	Town of Mooresville	Town of Mooresville
32	3013 Thistlewood Cir	Indian Trail	NC	28079	Union	Union County Public Works	Union County Public Works
33	5008 Singletree Ln	Indian Trail	NC	28079	Union	Union County Public Works	Union County Public Works
34	1212 Screech Owl Rd	Waxhaw	NC	28173	Union	Union County Public Works	Union County Public Works
35	4001 Garfield Ct	Waxhaw	NC	28173	Union	Union County Public Works	Union County Public Works
36	6402 Providence Rd S	Waxhaw	NC	28173	Union	Union County Public Works	Union County Public Works

Note: Appendix C includes only those properties which were included in the application filed by HPA JV Borrower 2019-1 ATH ATH, LLC on September 4, 2019, in Docket No. WRN-86, Sub 0.

Issued in Accordance with Authority Granted by the North Carolina Utilities Commission in Docket No. WRN-86, Sub 0, on the 5th day of December, 2019.

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SMALL POWER PRODUCERS – Filings Due Per Order

ORDER ACCEPTING REGISTRATION OF NEW RENEWABLE ENERGY FACILITY

Orders Issued

Company	Docket No.	Date
Adams Solar, LLC	SP-6059, SUB 0	(03/04/2019)
Asheville Alternative Energy, LLC	SP-5573, SUB 1	(03/13/2019)
ATOOD Solar II, LLC	SP-14154, SUB 0	(05/09/2019)
Aulander Hwy 42 Solar, LLC	SP-4258, SUB 0	(03/13/2019)
Boxer Solar, LLC	SP-11345, SUB 0	(02/26/2019)
Dorothy Solar, LLC	SP-10394, SUB 0	(10/23/2019)
Gastonia Solar Center, LLC	SP-8845, SUB 0	(02/25/2019)
Madison Solar, LLC	SP-6061, SUB 0	(03/04/2019)
Oak Hill Farms, Inc.	SP-16248, SUB 0	(05/09/2019)
Orbit Energy Charlotte, LLC	SP-4854, SUB 0	(03/11/2019)
Panda Solar NC 9, LLC	SP-9830, SUB 1	(03/28/2019)
Panda Solar NC 10, LLC	SP-9831, SUB 1	
Panda Solar NC 11, LLC	SP-9832, SUB 1	
PG Solar, LLC	SP-11264, SUB 0	(05/09/2019)
Red Toad 315 Vinson Road, LLC	SP-5193, SUB 0	(05/09/2019)
Remley Farms Energy, LLC	SP-16152, SUB 0	(03/22/2019)
Thunderhead Solar, LLC	SP-8671, SUB 0	(03/04/2019)

Carolina Poultry Power RGI, LLC – SP-7904, SUB 0; Order Accepting Amended Registration of New Renewable Energy Facility (10/24/2019)

Clean Energy, III – SP-2422, SUB 1; Order Amending Registration of New Renewable Energy Facility (04/24/2019)

Clear Solar I, LLC – SP-5099, SUB 0; Order Amending Certificate of Public Convenience and Necessity and Registration Statement (11/06/2019)

Kapstone Kraft Paper Corporation – SP-3419, SUB 0; Errata Order (05/30/2019)

Staley Solar, LLC – SP-4463, SUB 0; Order Allowing Withdrawal of Application, Cancelling CPCN, and Closing Docket (02/07/2019)

Suncaster, LLC – SP-8198, SUB 0; Order Issuing Amended Certificate and Amending Registration of New Renewable Energy Facility (10/08/2019)

University of North Carolina at Chapel Hill; The – SP-790, SUB 3; Order Accepting Registration of New Renewable Energy Facility (12/16/2019)

Yadkin Solar Farm, LLC – SP-7950, SUB 0; Order Allowing Limited Construction With Conditions (12/31/2019)

SMALL POWER PRODUCERS – Filings Due Per Order *(Continued)*

ORDER ALLOWING WITHDRAWAL OF APPLICATION, CANCELLING CPCN AND REGISTRATION, AND CLOSING DOCKET

Orders Issued

Company	Docket No.	Date
Alexis Solar, LLC	SP-5040, SUB 0	(09/16/2019)
Carnation Solar, LLC	SP-6051, SUB 0	(07/10/2019)
Catawba County	SP-112, SUB 2	(04/02/2019)
	SP-112, SUB 3	(04/02/2019)
Crimson Solar, LLC	SP-6935, SUB 0	(07/10/2019)
Fresh Air Energy II, LLC	SP-2665, SUB 29	(04/12/2019)
	SP-2665, SUB 32	(04/12/2019)
Halifax Solar, LLC	SP-8224, SUB 0	(04/11/2019)
June Solar, LLC	SP-5047, SUB 0	(09/16/2019)
Loblolly Pine Solar, LLC	SP-8266, SUB 0	(08/06/2019)
Longleaf Solor, LLC	SP-5038, SUB 0	(09/16/2019)
McCraw Solar, LLC	SP-8544, SUB 0	(11/01/2019)
Poplar Solar, LLC	SP-3757, SUB 0	(07/10/2019)
Raccoon Solar, LLC	SP-13907, SUB 0	(07/10/2019)
Range Solar, LLC	SP-8332, SUB 0	(09/16/2019)
Roman Solar, LLC	SP-5074, SUB 0	(09/16/2019)
South Hertford Solar, LLC	SP-8265, SUB 0	(07/29/2019)

ORDER CANCELLING REGISTRATION AND CLOSING DOCKET

Orders Issued

Company	Docket No.	Date
Ajax Solar, LLC	SP-5721, SUB 0	(10/04/2019)
Bear Creek Solar, LLC	SP-6309, SUB 0	(10/08/2019)
Beaucatcher Solar, LLC	SP-9096, SUB 0	(09/17/2019)
Carolina Solar Energy, LLC	SP-159, SUB 5	(05/29/2019)
Cohen Farm Solar, LLC	SP-4472, SUB 0	(10/04/2019)
Exum Farm Solar, LLC	SP-4473, SUB 0	(10/04/2019)
Firetower Solar, LLC	SP-10564, SUB 0	(09/20/2019)
Five Forks Solar, LLC	SP-5440, SUB 0	(10/04/2019)
Floyd Solar, LLC	SP-3852, SUB 0	(10/01/2019)
Franklinton Solar, LLC	SP-3798, SUB 0	(10/01/2019)
Graybeard Solar, LLC	SP-9098, SUB 0	(09/20/2019)
Greensboro Solar LLC	SP-8879, SUB 0	(08/20/2019)
Greenville Farm 2, LLC	SP-2894, SUB 1	(09/24/2019)
Hardin Solar, LLC	SP-8755, SUB 0	(09/17/2019)

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TRANSPORTATION

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Transportation – Common Carrier Certificate *(Continued)*

ORDER GRANTING APPLICATION FOR CERTIFICATE OF EXEMPTION
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Company	Docket No.	Date
Movers Near Me, LLC	T-4760, SUB 0	(04/26/2019)
Moving Ahead Services, LLC	T-4779, SUB 0	(11/13/2019)
Open Box Moving Solutions; The, d/b/a	T-4758, SUB 0	(05/02/2019)
QC Tech Installers, d/b/a Building Blocks Moving	T-4767, SUB 0	(06/17/2019)
Quality Transports and Relocation, LLC	T-4738, SUB 0	(10/15/2019)
Raleigh Moving Company LLC	T-4783, SUB 0	(11/18/2019)
Rocket Movers L.L.C.	T-4784, SUB 0	(12/16/2019)
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(West Haven Apartments)	WR-1929, SUB 1	(10/10/2019)
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Arcadian Village Owner, LLC		
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ARIM Williamsburg, LLC		
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Arium Lake Norman Owner, LLC		
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ARWC – 5650 Netherfield Place, LLC		
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Arwen Vista Property Owner, LLC		
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ASC Property, LLC		
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Ascot Point Village Apartments, LLC		
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Ashborough Investors, LLC		
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Ashbrook Investors, LLC		
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Auston Woods – Charlotte – Phase II Apartments, LP		
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Ginkgo Brookford, LLC		
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Ginkgo Croasdaile, LLC		
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Ginkgo Willowdaile, LLC		
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Glenhaven G, LLC		
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Golden Triangle #1, LLC		
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Golden Triangle #4-5th Street, LLC		
(Crest Gateway Apartments)	WR-1809, SUB 5	(09/12/2019)
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Grand Reserve at Pavilions, LP		
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Guardian Tryon Village, LLC		
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GUGV Poplar Charlotte Property Owning, LP		
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Hudson Capital Park Forest, LLC		
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Marsh Realty Company		
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Mason Andrew NC Partners, LLC		
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(Colonial Village at Chancellor Park Apartments)	WR-22, SUB 151	(07/09/2019)
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Mill Pond Charlotte, LLC		
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Millbrook Estate, LLC		
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Morgan Bond Charlotte, LLC		
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(Mosswood/Twin Oaks Mobile HP)	WR-924, SUB 22	(11/13/2019)
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MP Artisan Brightleaf Apartments, LLC		
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MP Bridges at Southpoint, LLC		
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MRP North Pointe, LLC		
(Discovery on Broad Apartments)	WR-2533, SUB 2	(11/04/2019)
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(Main Street Square Apartments)	WR-936, SUB 4	(09/23/2019)

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NC2, LLC		
(Beechwood Apartments)	WR-1730, SUB 5	(08/30/2019)
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(Marq at Weston Apartments; The)	WR-2159, SUB 4	(08/14/2019)
New Brookstone, LLC		
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New Centre Wilmington, LLC		
(Hawthorne at New Centre Apartments)	WR-2500, SUB 1	(10/16/2019)
New Haw Creek Associates, LLC		
(Haw Creek Mews Apartments)	WR-624, SUB 7	(03/04/2019)
(Haw Creek Mews Apartments)	WR-624, SUB 8	(10/28/2019)
New Park Ridge Associates, LLC		
(Park Ridge Estates Apartments)	WR-1225, SUB 5	(05/13/2019)
New Willow Ridge Associates, LLC		
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Northland River Birch I, LLC		
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Northland Windemere, LLC		
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Northpoint at 68, LLC		
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Northwestern Mutual Life Insurance Co., d/b/a Chapel Hill North Apts.		
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(Chapel Hill North Apartments)	WR-1516, SUB 2	(09/04/2019)

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(Cosgrove Hill Apartments)	WR-1515, SUB 2	(09/04/2019)
Northwestern Mutual Life Insurance Co., d/b/a Trinity Commons		
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NP Six Forks, LLC		
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NR Edge Apartments Property Owner, LLC		
(Carraway Village Apartments)	WR-2686, SUB 1	(10/23/2019)
NR Holly Crest Property Owner, LLC		
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(Providence Row/Pinehurst on Providence Apartments)	WR-1745, SUB 2	(02/26/2019)
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NR Van Alen, LLC		
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OREI Plantation at Fayetteville Property Owner, LLC		
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Paces Village, LLC		
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Palladium Park Apartments, LLC		
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Park HAT LAP, LLC		
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(District Lofts Apartments)	WR-2226, SUB 3	(09/12/2019)
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Passco Columns DST		
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(Town Station Lofts Apartments)	WR-2423, SUB 2	(07/31/2019)
VR Chatham Pointe Limited Partnership		
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Wafra Invest Loft 135, LP		
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Waterford Valley NC Partners, LLC		
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Waverly Apartments, LLC		
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Waypoint Barrington Owner, LLC, et al.		
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Waypoint CapCreek MF Owner, LLC		
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WB Tatton, LLC, et al.		
(Weirbridge Village Apartments)	WR-2429, SUB 2	(08/05/2019)
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West Market Partners, LLC		
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West Shore Aurea, LLC		
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Westdale Arrowhead Crossing NC, LLC		
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Westdale Brentmoor, LLC		
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Westdale Chase on Monroe NC, LLC		
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Westdale NC Summit Creek, Ltd.		
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Westdale Willow Glen NC, LLC		
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Westridge Village, LLC		
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Willows at the University, LLC		
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WMCi Raleigh II, LLC		
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WMCi Raleigh III, LLC		
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